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Application of Mechanistic Modeling for Gas Lift Optimization: A General Correction Factor for Variations of Tubing Size

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Abstract

Gas Lift is currently held as one of the most prominent method in artificial lift, proudly operated flawlessly in hundreds of oil wells in Indonesia. However, gas lift optimization is still governed by the exhaustive Gas Lift Performance Curves (GLPC). This practice, albeit as established as it should be, does require repetitive calculations to be able to perform in life of well operations. Therefore, a new approach is introduced based on the mechanistic modeling. This research highlights the application of fundamental mechanistic modeling and its derivative, the Flow Pattern Map (FPM) for quick estimation of optimum injection gas rate, accompanied by a novel correction factor to account changing tubing sizes. It is hoped that this approach can be beneficial in developing a multitude of gas lift wells with changing tubing sizes.

INTRODUCTION

Indonesia's oil production has been on the decline lately, where the production is not complemented with new hydrocarbon findings, making Banyu Urip discovery the latest and further efforts have been directed to EOR implementation (Hakiki et al., 2017; Hartono et al., 2017). Therefore, a new approach is required to optimize mainly marginal oil fields. Gas lift currently holds as one of the most prominent artificial lift methods not only in Indonesia, but also worldwide. The unique properties of gas lift, such as containing almost no moving part and being able to handle a wide range of well specifications and reservoir properties, making it a suitable, versatile candidate for high percentages of oil wells in Indonesia (Arachman, Utami, Wasonoaji, & Tobing, 2017).

Nowadays, there are basically two different approaches in optimizing gas lift design. The first one can be termed as engineering optimization where new types of valves, gas lift injection method, and gas lift valve placement are optimized based on new findings and technologies (Asheim, 1988; Betancourt, Dahlberg, Hovde, & Jalali, 2002; Cendra, Fitrianti, & Putra, 2018; Decker, 2007; Glass, 1975; Mukherjee & Brown, 1986; Musnal & Fitrianti, 2017). These approaches have been developing as an answer to increase practicality and long-term use of gas lifted systems namely in marginal oil fields. The second approach is mainly developed in conjunction to the need for field wide gas lift optimization or allocation scheduling, with prominent algorithms taken from the field of non-linear optimization, machine learning and genetic algorithm (Lu & Fleming, 2011; Posenato & Rosa, 2012; Ranjan, Verma, & Singh, 2015; Samier, 2010; Wang & Litvak, 2008).

Current gas lift optimization practices have been revolving around the concept of Gas Lift Performance Curve (GLPC), an augmentation of nodal analysis, in which a single curvature mapping liquid recovery as a function of incremental gas injected is presented. Several extensions have been disseminated to enrich the concept of GLPC, namely quantification of the curves and observation of curvature behavior (Alarcón, Torres, & Gómez, 2002; Fang & Lo, 1996; Kanu, Mach, & Brown, 1981; Nishikiori, Redner, Doty, & Schmidt, 1989; Schmidt, Doty, Agena, Liao, & Brown, 1990).

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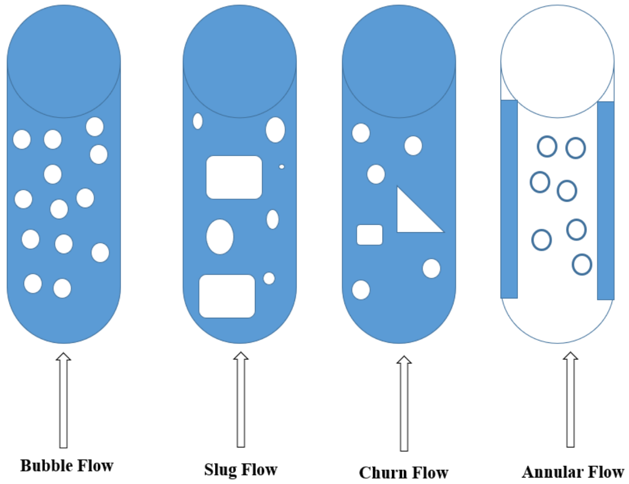

Figure 1 Flow Pattern in Multiphase Flow (Reproduced from Ansari, Sylvester, Shoham, & Brill (1990))

However, the GLPC, albeit as simple as it looks, is known and proven to be highly repetitive where changes in production dynamics will require different GLPC curves. As operating pressure changes in a highly dynamic range, exact alteration of GLPC curves for every change are not operationally and economically feasible due to possibility of oil flow rate deteriorating and its adverse effect into reservoir dynamics. Therefore, a new approach is required to deliver another point of view in reducing uncertainties in GLPC forecast and production modeling.

Current development of fundamental researches related to multiphase fluid behaviour in gas lift system is not commonly encountered recently, namely due to the relatively established operational procedure of gas lift system, providing less incentive to perform researches in uncharted territories. Multiphase flow research, however complicated it may sound, does provide a new perspective in previously thought to be well understood phenomenon such as liquid loading and slugging phenomenon, rendering new comprehension and more detailed mapping of the problem itself.

The application of mechanistic modeling, an approach that identifies pattern, timed changes, routine alterations of a dynamic system, has never been prominently applied in the aspects of petroleum engineering, mainly due to its complicated nature. Many researches related to mechanistic modeling have only been limited to basic researches in fluid flow in pipes (Barnea, 1987; Taitel & Barnea, 1990; Taitel & Dukler, 1976). It is known that mechanistic modeling often requires high understanding in fluid physics, as well as rigorous mathematical process. However, mechanistic modeling does offer more realistic model due to its nature of observation-based model, where the parameters observed can be quantified easily from patterns and occurrences, coupled with mathematical modeling.

Several models are currently available for multiphase flow model in pipe, namely the Taitel & Dukler (1976) and Taitel, Bornea, & Dukler (1980) model for general applications of surface pipeline system and downhole casing/tubing system. These models basically laid the foundation for Ansari, Sylvester, Shoham, & Bill (1990)'s model which defines flow patterns into four distinct flow patterns, shown on Figure 1, which laid good foundation of flow pattern mapping.

The four distinct flow patterns shown above can be a powerful tool in defining suitable flow pattern for gas lift operations. However, these flow patterns have to be quantified in order to increase its utility value. The study is extended by Shoham (2006) in developing a simple chart to determine flow pattern region as a function of superficial liquid velocity and superficial gas velocity, named as Flow Pattern Map. Therefore, the concept of superficial liquid velocity is then introduced to the pattern mapping, rendering a Flow Pattern Map (FPM) for simple, versatile use of flow pattern dynamics in gas lift optimization.

This research is a continuation of previous researches where a new hypothesis that Flow Pattern Map (FPM) can be a powerful tool to complement GLP curves as gas lift optimization media. The aim of this research is to extend the applicability of FPM into all production tubing sizes available in the market, in order to prove the hypothesis that minor correction factor is needed to adjust the optimum injected gas rate based on the FPM.

METHODS

GLP curves taken from Z-1 Well in Indonesia, in which the data are shown on Table 1, is then taken as a reference study for proving the effectivity of FPM.

Table 1 Z-1 Well Data

Parameters	Value		Units	Remarks
Tubing	OD	2.875	In	
	ID	2.441	In	
Oil Density	ρ_l	876	kg/m^3	
Gas Density	ρ_g	0.9	kg/m^3	
Gravity Constant	g	9.8	m/s^2	
Oil Viscosity	μ_o	2.32	cP	
Gas Viscosity	μ_g	0.01442	cP	
Slug Length	L_E	2.53	m	(Moissis & Griffith, 1962)
Gas SG		0.75		
Reservoir Pressure	P_r	1000	psi	
Reservoir Temperature	T_r	200	^{0}F	

Based on the data provided in Table 1, a typical Flow Pattern Map (FPM) is constructed for Well Z-1. The results, shown in Figure 2, confirmed the hypothesis that GLP curves and FPM can complement each other, evidenced by the location of the optimum gas injection rate. Shoham (2006) stated that the most stable flow in multiphase flow should be located in churn flow, where injected gas affects mixture density the most by forming unstable slugs that are able to carry most liquid droplets.

Figure 3 illustrate the calculation procedure of correction factor needed for tubing size in order to achieve the optimum gas rate.

In this study, a total of 51 tubing specifications are used to verify the prior hypothesis. The tubing data are taken from Tenaris Pipe Body Performance Catalogue (2011) which is a highly accepted standard in tubing and casing modeling. The tubing outside diameter (OD) ranges from 2”-5.5”, therefore increasing the relevance of this study to application in oil and gas industry.

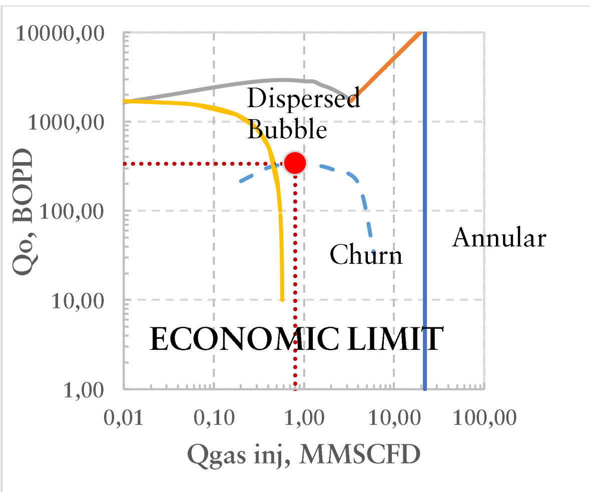

Figure 2 Flow Pattern Map of Z-1 Well

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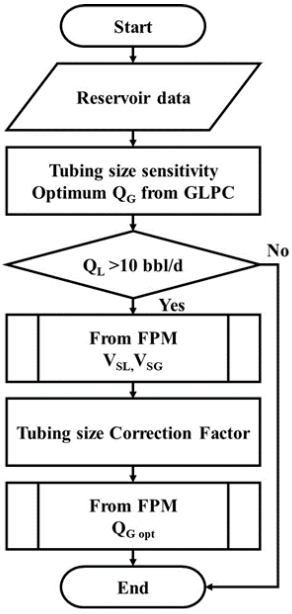

Figure 3 Flowchart of tubing sensitivity for correction factor

The parameter slug length, L_E, shown on table 1 is given as a function of tubing ID where the L_E is approximated to be 8- 25 times the tubing ID (Moissis & Griffith, 1962). Slug length should be around 8 times the tubing ID when the flow is near the transition of bubble to slug flow and should be around 25 times tubing ID near the transition to churn flow from slug flow. Hence the slug length is to be 25 times the tubing ID. Should there any indication of deviated and horizontal wells, the slug length should be calculated as a function of well segment, which is beyond the scope of this research. The well is assumed to be producing 100% liquid without any associated gas dissolved in the oil component. The sample of constructed FPM is shown on Figure 4. In this paper, the other three flow pattern transitions, which are the bubble to slug and two dispersed bubble transitions, are omitted. The limitation of this work is the churn flow that is considered as the only optimum flow pattern.

RESULTS AND DISCUSSION

Previous work done by Shoham (2006) indicated that the hypothesis of flow pattern map utilization for gas lifted wells holds true for all tubing sizes. However, changes in optimum injection rate, as evidenced by the adjacent dashed lines on the FPM, should be corrected as a function of tubing size. Therefore, a regression analysis is performed to analyze the behavior of a novel correction factor in determining the optimum amount of gas injected, in which the bullet marks define the correction factors and the dashed lines are the regression line, shown on Figure 5.

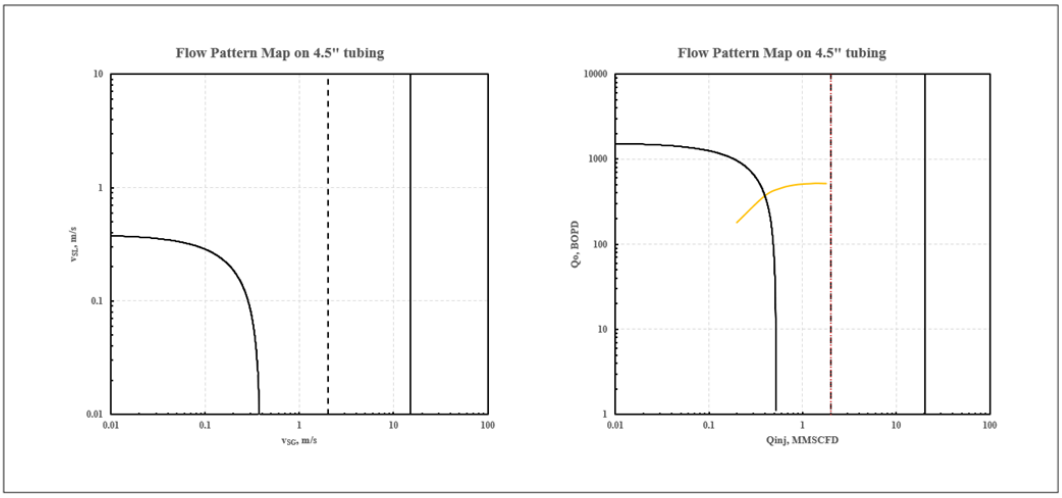

Figure 3 Example Calculation of FPM for Various Tubing Sizes. Figure on The Right Indicates GLPC Placement in FPM

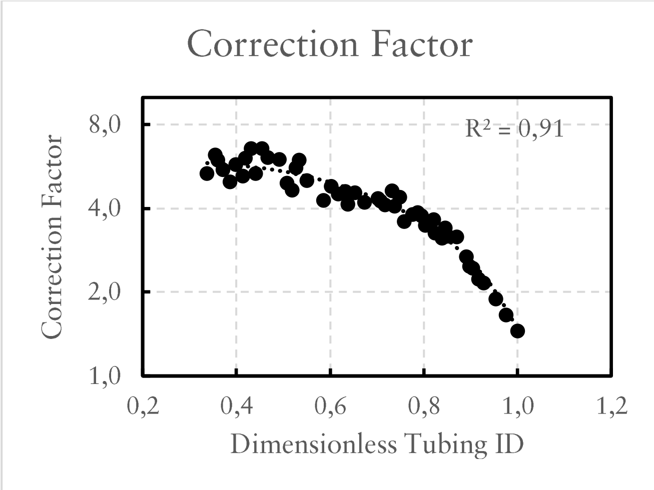

Figure 4 Tubing Size Correction Factor

In order to increase the utilization of the Figure 6, it is then decided to perform a non-dimensionalization analysis of the tubing ID, therefore the tubing size can be calibrated against the available sizes for any suppliers, shown on Figure 7.

The Figure 6 employs dimensionless tubing ID as the x-axis, therefore should there be any different tubing specifications are used, the equation can still be used without any uncertainties in accuracy. This benefits engineers in situations where more complex field cases are presented, such as hundreds of gas lift wells with multiple of tubing sizes. Engineers can use the curve conveniently to determine the optimum gas lift injected by utilizing the flowchart shown on Figure 6. The correction factor itself is denoted in the following equation, with the estimated MSE of 0.20 MMSCFD.

$$CF = -8.30 * \left(\frac{d_{int}}{d_{max}}\right)^2 + 4.53 * \left(\frac{d_{int}}{d_{max}}\right) + 5.23 \quad (1)$$

Where

CF = Correction Factor, dimensionless

d_{int} = Tubing ID of Interest, in

d_{max} = Maximum Tubing ID Available, in

Q_L = Minimum liquid rate, bbl/d

Field Case Verification

The following field case of X-1 well, an offshore marginal well in Indonesia is taken to verify the validity of the method. The field data is summed on table 2.

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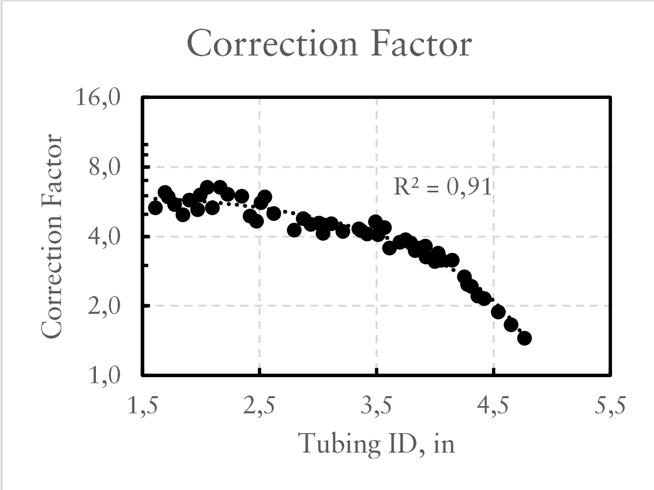

Figure 5 Dimensionless Tubing Size Correction Factor

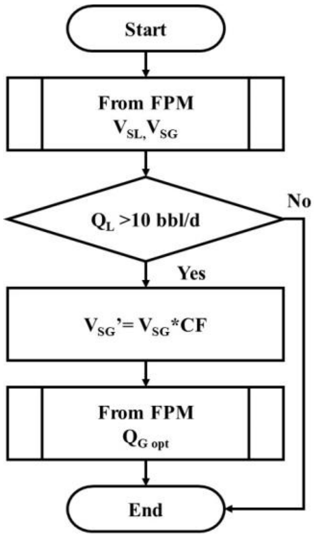

Figure 6 Flowchart of Correction Factor Application

Based on the previously available data on Table 2, a GLP curve is then constructed, shown on figure 8.

Table 2 X-1 Well Production Parameters

No.	Parameter	Values
1	Well Name	"Well SPE-7"
2	Reservoir Pressure (Psi)	956.3
3	Formation GOR (scf/stb)	600
4	Killing Fluid Gradient (psi/ft)	0.465
5	TVD/MD of Mid Perf. (ft)	4794/5700
6	Packer Depth Estimation (ft TVD)	4700
7	Prod.Casing Outer/Inner Diameter (in)	7/6.538
8	Tubing Outer/Inner Diameter (in)	3.5/
9	Max. Kick Off Pressure available (psia)	670

10	Water cut (%)	20
11	Injectivity index (bbl/psiday)	6.1
12	Gas specific gravity	0.77
13	FTP (psi)	120
14	Ambient/BH Temp. (°F)	80/170
15	Available Gas Lift Valve Port Size	0.1875;0.25;0.3125

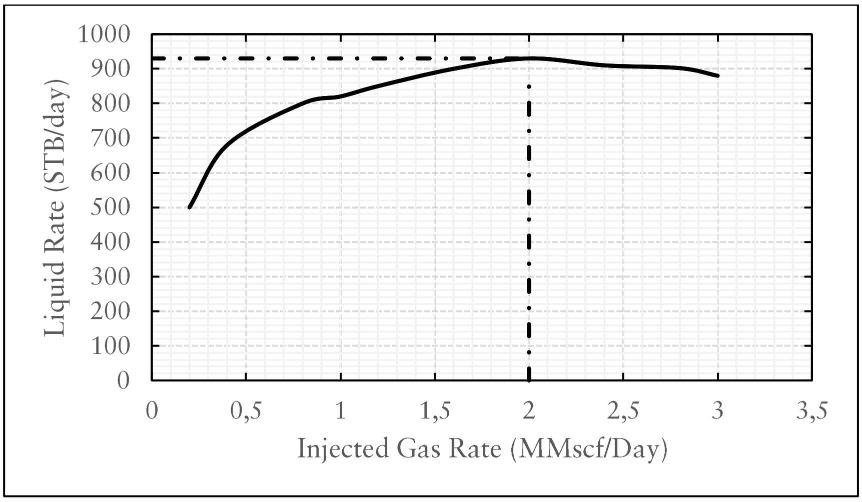

Figure 7 GLP Curve for X-1 Well

A computer program is generated to calculate the optimum gas injection rate based on the FPM approach, shown on table 3, indicates that the optimum injection rate difference is minimum, only yielding 0.1 MMSCFD difference in gas rate.

Table 3 Results of FPM Calculation for X-1 Well

Input	Tubing	ID	In	2.991
		OD	In	
	P_{res}		Psi	954.00
	T_{res}		°F	170.00
Output	v_{sg}		m/s	0.34
	CF			6.72
	v_{sg}'		m/s	2.27
	Opt G_{inj}		**MMSCFD**	**1.90**

CONCLUSION

This research presents a novel implementation of mechanistic modelling for gas lift optimization. A new correction factor is presented in order to perform quick estimation of optimum injected gas amount as a function of tubing size, therefore further works are needed to extend this work into multi-wells and multi-fields analysis to gain the full range of the correction factor analysis. The correction factor can be used for every production tubing size available in the market, therefore its utilization can be really helpful in multi-well gas lift optimization.

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