Journal of Mining and Earth Sciences

Website: http://tapchi.humg.edu.vn

Prediction of liquid loading and affecting factors on liquid loading in gas wells

Tien Van Tran [1,*], Quan Le Vu [1], Trung Quoc Le [1], Thinh Van Nguyen [2]

[1] Vietnam Petroleum Institute, Vietnam National Oil and Gas Group, Vietnam
[2] Faculty of Oil and Gas, University of Mining and Geology, Hanoi, Vietnam

ARTICLE INFO

Article history:
Received 12 Sept. 2017
Accepted 15 Nov. 2017
Available online 29 Dec 2017

Keywords:
Gas well
Liquid loading
Critical Velocity

ABSTRACT

In a gas well, liquid loading is one of the most important technical problems impacting on production rate. If it is not supervised and given any treatments measure, the liquid will be accumulated in the bottom hole of the well. Therefore, it will prevent the gas moving into the bore hole. Moreover, a lower gas production rate implies a lower gas velocity which will ultimately stop the production. Liquid loading is characterized by the critical gas velocity which is the minimum gas velocity to lift the liquid to the surface. In this paper, we simulate and predict the liquid loading in well X, Nam Con Son basin, Vietnam by using an experiment and modeling approach to recommend some suitable treatment methods for this issue. The results showed that the risk of liquid loading may happen in well X, Nam Con Son basin when gas rate continues to fall because the current gas production rate (2.885 MMscf/d) is quite close to critical gas rate (2.217 MMscf/d). On the other hand, the results showed obviously affecting factors on liquid loading including tubing diameter, wellhead pressure, reservoir pressure and productivity index. When there is an increasing of wellhead pressure and tubing diameter the risk of liquid loading happens quickly. On the contrary, if reservoir pressure and PI increase, the liquid loading will be unlikely to occur.

1. Introduction

In gas well production, when the reservoir pressure decreases to below dew point pressure, gas will be transferred from a single phase (gas) to 2 phases (gas-liquid). Liquid loading, by definition, is inability of a gas well to remove liquids that are produced from the wellbore (Yashaswini, 2012).

The produced liquid will accumulate in the well and create a static column of liquid, therefore creating a back pressure against formation pressure and reducing production until the well ceases production. Therefore, prediction and treatment this problem are very essential to improve the efficiency of production in gas wells.

2. Liquid loading in gas wells

*Corresponding author
E-mail: quanlv@vpi.pvn.vn

2.1. Gas - condensate reservoir

The gas-condenstate reservoir is a special hydrocacbon composite, where there are more light components than heavy components. Phase diagram of a gas-condensated reservoir showing in Figure1 illustrated that during production, when the pressure decreases to a critical value (dew point), components in hydrocacbon composite will be condensated and transferred from gas phase to liquid droplets. This process is called retrograde condensate. Retrograde gas-condensate reservoirs typically exhibit gas-oil ratios between 3,000 and 150,000 scf/STB (oil-gas ratios from about 350 to 5 STB/MMscf) and liquid gravities between 40 and 60^{o}API (Lal, 2013).

2.2. Liquid loading in gas wells

In gas well production, the liquid of reservoir will move from wellbore to surface always consists water and liquid hydrocacbon carried along with the gas from reservoir to wellbore, as well as, amount of heavy component of gas phase will be condensated in the near wellbore and in the bottom hole when the decline of reservoir pressure is below saturation pressure. Figure2 presents the change in gas flow rate during liquid loading occurrence. This process is usually represented by 4 main flow regimes such as annular-mist flow, transition flow, slug flow and bubble flow. At the first period stage of production, the gas stream will be carried along with liquid droplets to the surface. This process happens when high velocity of gas stream delivers kinetic energy to liquid droplets. High velocity of gas stream will create a mist stream when carry along with liquid droplets which is distributed along the tubing wall. However, when the velocity of gas decreases to a certain value after a long time of production, liquid droplets will fall back to bottom of the hole due to the effect of gravity and these liquid droplets will accumulate in the bottom hole, which would increase pressure gradient as well as increasing the hydrostatic pressure in the bottom hole. This process transferred from annular-mist flow to slug flow and then to bubble flow regimes. This lead to a reduce sharp of production rate and make difficulties for production operating. When the gas velocity falling, liquid will continue to accumulate and create liquid slug in the bottom hole to prevent the gas move in the well and ultimately stop the production.

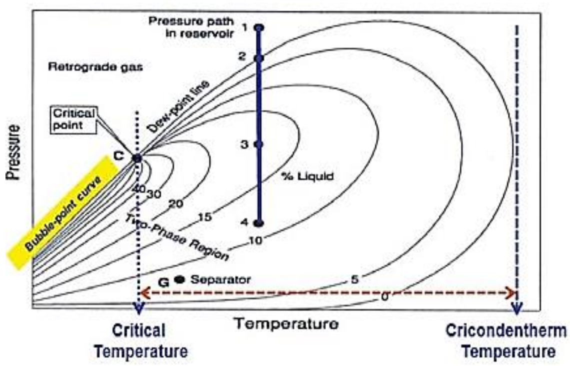


Figure 1. Phase diagram of a gas-condensate reservoir (Le Vu Quan, 2016).

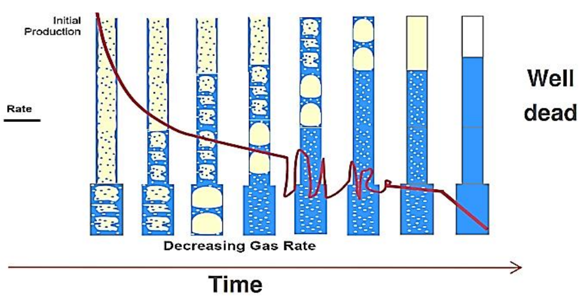


Figure 2. Schematic representation of liquid loading (Lea et al., 2013).

3. Critical velocity

3.1. Prediction model for critical velocity (Turner droplet model)

(Turner et al.,1969) proposed two physical models for removal of gas well liquid. The models are based on: the liquid film movement along the walls of the pipe and the liquid droplets entrained in the high velocity gas core (Yashaswini, 2012). By analysis a large database of production gas wells, Tuner found that a force balance performed on a droplet could predict whether liquids would flow upwards (Drag forces) or downwards (Gravitational forces). If the gas velocity is above a critical velocity, the drag force lifts the droplet, otherwise the droplet fall and liquid loading occurs. In practice, the critical gas velocity is generally defined as the minimum gas velocity in the tubing string required to move droplets upward.

The theoretical equation for critical velocity V_t to lift a liquid drop is.

$$v_t = \frac{1{,}593\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{\sqrt{\rho_g}} \quad (ft/sec) \qquad (1)$$

where:

v_t - Terminal velocity of liquid droplet (ft/s),

σ- Surface tension (dynes/cm),

ρ_l- Liquid phase density (lbm/ft^3),

ρ_g- Gas phase density (lbm/ft^3).

Turner's expressions (with 20% upward adjustment to fit field data) in field units are

$$v_{c,w} = \frac{5{,}304(67 - 0{,}0031P)^{1/4}}{\sqrt{0{,}0031P}} \qquad (2)$$

$$v_{c,cond} = \frac{4{,}03(45 - 0{,}0031P)^{1/4}}{\sqrt{0{,}0031P}} \qquad (3)$$

Although critical velocity need to be under control but almost people usually more concern to gas rate factor of gas wells. These equations can be transferred easily to become critical gas rate from critical gas velocity.

Critical gas rate can be calculated as follows:

$$Q_{(MMscf/d)} = \frac{3.067 \times P \times Vc \times A}{(T+460)z} \qquad (4)$$

where:

T - Wellhead temperature (^{o}F),

P - Wellhead pressure (psi),

V_c - Critical velocity (ft/s),

A - Tubing section (ft^2).

By contract, from equation (4), critical velocity is also calculated as follows:

$$V_c = \frac{Q \times (T+460) \times z}{3.067 \times P \times A} \qquad (5)$$

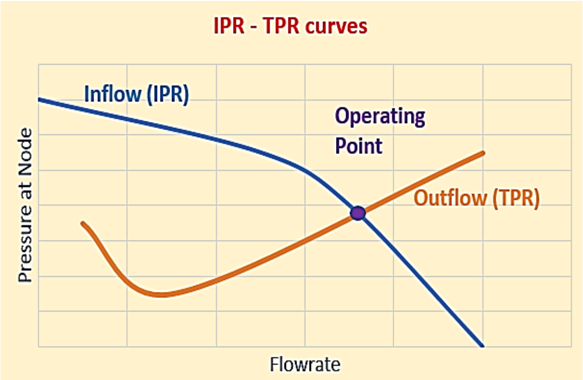


Figure 3. Typical nodal analysis curves.

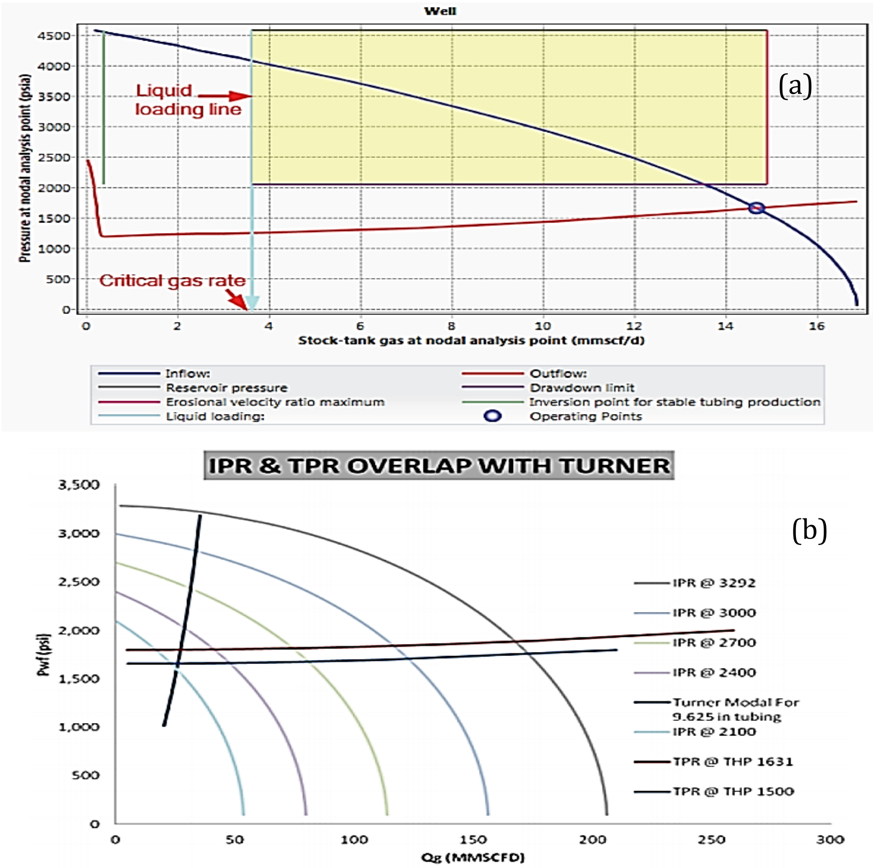


Figure 4. (a) Liquid Loading line on NA system (Schlumberger, 2007); (b) IPR & TPR overlap with Turner (Yashaswini, 2012)

As the equation (5), critical gas rate is very dependent on wellhead pressure and tubing section in gas well production. These factors are directly proportional to critical gas rate.

3.2. Determination of critical gas velocity to prevent liquid loading - Nodal analysis Mothed (Nodal Analysis)

Nodal analysis divides the system into two subsystems at a certain location called nodal point. One of these subsystems considers inflow from reservoir to the nodal point selected (IPR) while the other subsystem considers outflow from the nodal point to the surface (TPR). Each subsystem gives a different curve plotted on the same pressure- rate graph. These curves are called the inflow curve and the outflow curve. The point where these two curves intersect denotes the optimum operating point where pressure and flow rate values are equal for both of 2 curves (see Figure 3 for illustration).

The liquid loading gas rate line can be displayed on the Nodal Analysis (NA) system plot where the X-axis is conFigured to display gas rate. Figure 4 shows that for every point on the outflow curve, the value of the liquid loading velocity ratio is calculated and the liquid loading gas rate line is plotted at the specific rate where the liquid loading velocity ratio is equal to 1. PIPESIM calculates a Liquid Loading Velocity Ratio (LLVR), which is the minimum lift velocity (terminal/critical velocity) divided by the fluid velocity. A LLVR > 1 indicates a liquid loading risk because the fluid is flowing at a velocity lower than the minimum velocity required to lift the liquids and prevent loading).

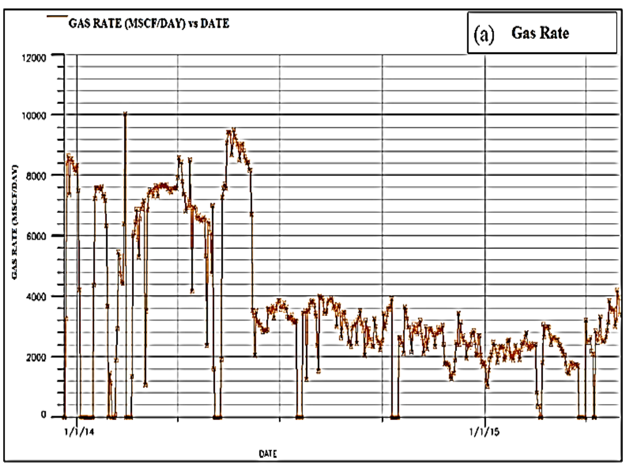
Figure4b represents the TPR at tubing head pressure points intersect with the IPR on the left-hand side of intersection of IPR and Turner (or Liquid loading line in Figure 4a), liquid loading occurs.

4. Liquid loading prediction in a well in Nam Con Son basin

4.1. Gas critical velocity of a gas well

Well X was perforated at Middle Miocene MMF30 in Nam Con Son Basin, the perforated depth was about from 3990 to 4020 mMD and it is a high pressure, high temperature reservoir. This well has been produced since 13th December 2013. However, the gas rate has decreased significantly from around 8 MMSCF/D (225 MSCM/D) to 2.1 MMSCF/D (60 MSCM/D) at the same choke size during production as showing in Figure5. The production performance showed that this well may be affected by liquid loading in short time. Therefore, it is necessary to study whether liquid loading occur in this well or not.

For answering above question, we conducted the study for this well using Pipesim software. Well X model was built to predict future production rates and determine a critical gas rate to prevent well loading. Input datas entered into gas well model in Pipesim software including tubing parameter, downhole equipment, casing datas, completion datas and compositional fluid model (Table 1 & 2 and Figure6).



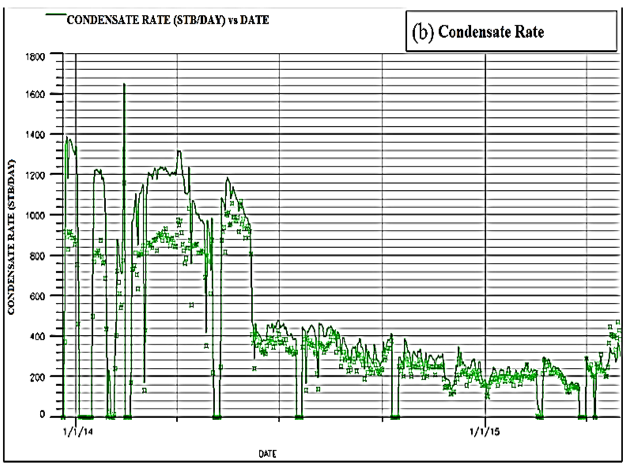


Figure 5. Production performance of Well X (Le Vu Quan, 2016).

Table 1. Parameters of well X.

Well	Unit	Well-X
Reservoir		MMF-30
Property of Fluid		
Compressibility, *Zi*		1.31
Dew point pressure	psia	7091
Condensate-gas Ratio	stb/MMscf	221.8
Gas formation volume factor (B_g)	Rcf/scf	0.00312
Oil gravity (separator condition)	g/cm³	0.3534
CO_2 Component	%	5.07

Table 2. Composite of fluid.

Components	Mole %
CO2	5.07
N2	0.21
C1	75.51
C2	5.21
C3	3.21
iC4	0.84
nC4	1.15
iC5	0.49
nC5	0.4
C6	0.55
C7+	7.36

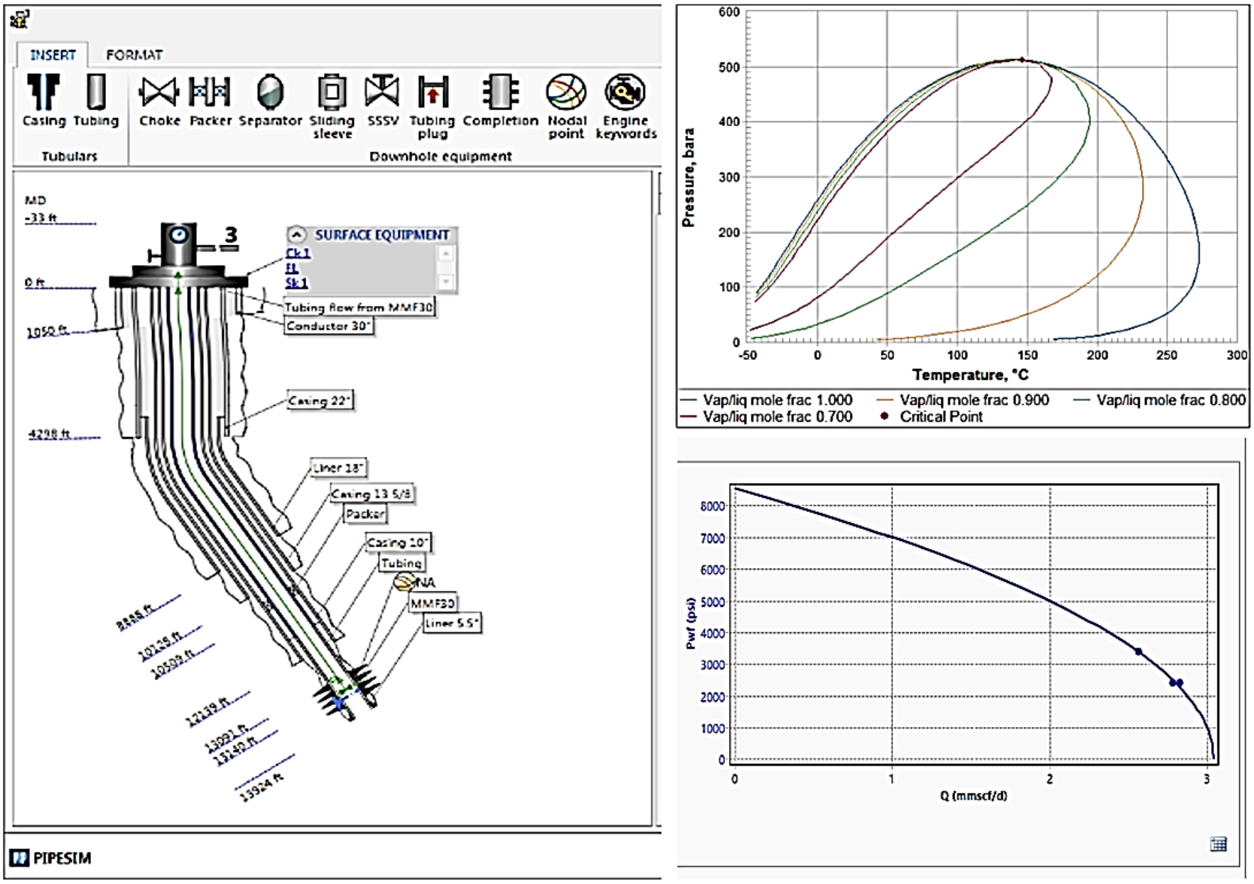


Figure 6. Building the NA model of Well X.

The Nodal Analysis Model is built on Pipesim software with Nodal point at the bottom hole for predicting critical gas rate to prevent liquid loading (Figure6).

Figure7 shows the result of Nodal Analysis with actual production data (WHP = 1100 psi). The operating gas rate is 2.885 MMscf/d as well as critical gas rate is 2.217 MMscf/d. Application of Equation (5), the critical gas velocity is calculated, it is about 4.5 ft/s. For this well scenario, we can see that the operation flowrate (2.885 MMscf/d) is very close to the critical gas rate to avoid liquid

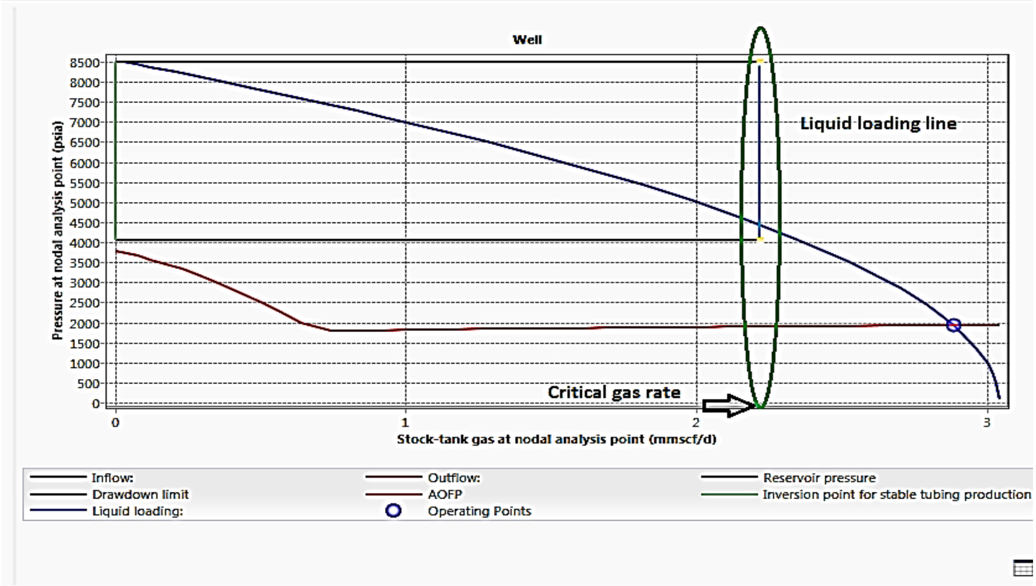


Figure 7. Result of Nodal analysis of Well X.

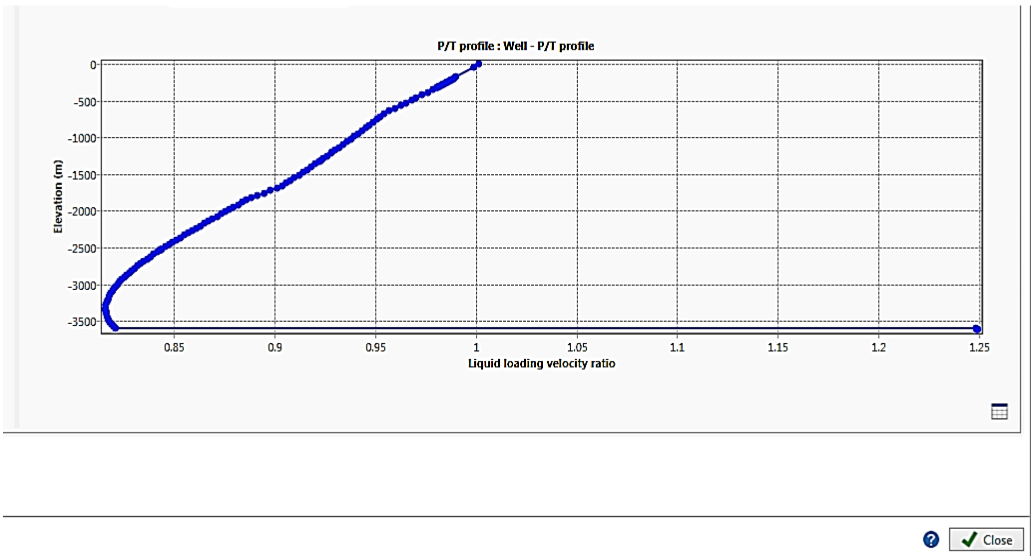


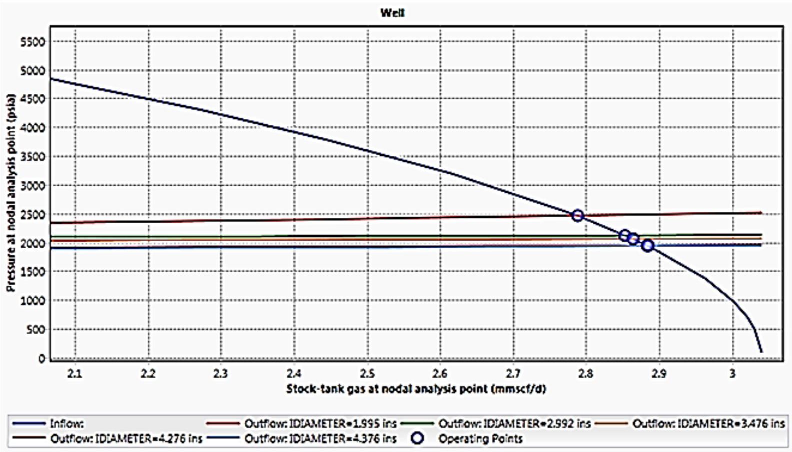
Figure 8. Liquid loading velocity ratio along the tubing.

loading, so there is a great risk of liquid loading at these conditions (Figure7).

The analysis result of liquid loading velocity ratio emulation also verifies that within the outflow section, where the liquid loading is calculated (consisting of the tubing section of the casing up to mid-perforation), the maximum liquid loading velocity ratio at the critical gas flow of 2.217 MMscf/d, is approximately equal to 1. We can show that the LLVR increase more as decreasing trend of tubing deep. At the bottom hole, LLVR is only 0.8, however it is equal to 1 at wellhead (Figure8). This means the liquid loading is more likely happenned near wellhead due to the decreasing pressure which lead to decrease the velocity of gas stream.

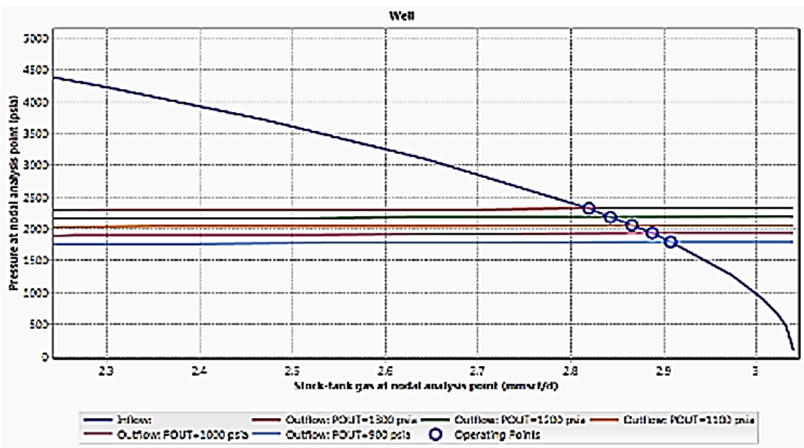
4.2. The affecting factors on critical gas rate

In this paper, we also estimate the affecting factors on liquid loading. Based on Turner's theory and Nodal Analysis (Figure4a & 4b), it is obviously show that the smaller gap between operating point and critical point is, the more possible liquid loading occurs. Hence, there are more parameters which have effect on liquid loading through impacting on TPR curve (such as tubing diameter, wellhead pressure) and IPR curve (such as Gas productivity index, Reservoir Pressure). This will recommend suitable production design to optimize gas rate and production time to prevent liquid loading



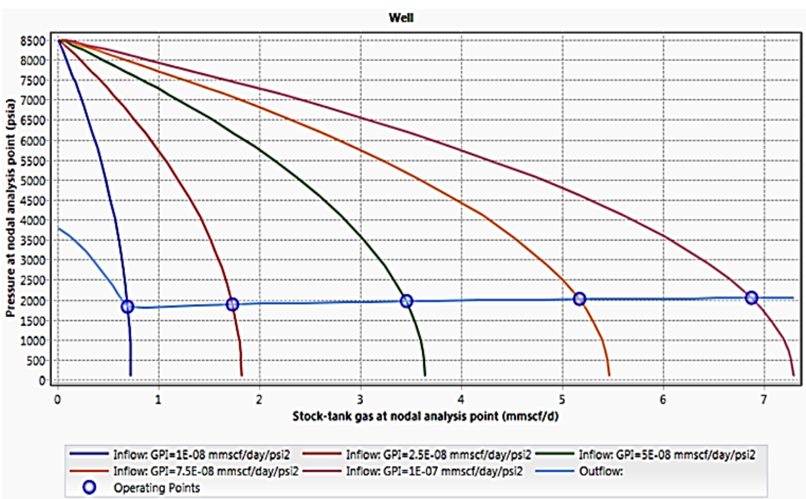
OD	ID	Operating gas Rate	Critical gas rate	Difference
in	in	mmscf/d		
2 3/8	1.995	2.79	0.859	1.931
3.5	2.992	2.853	0.879	1.974
4	3.476	2.864	0.882	1.982
5	4.276	2.883	2.214	0.669
5.5	4.376	2.885	2.217	0.668

Figure 9. The effect of tubing diameter on critical gas rate.



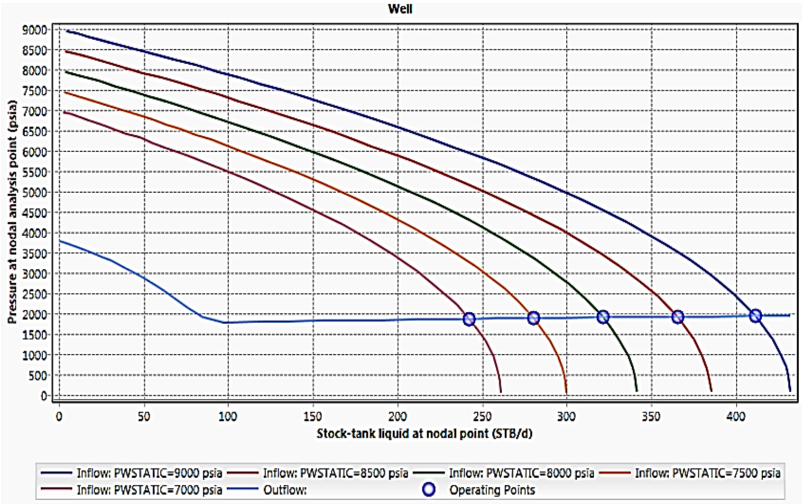
Outflow pressure	Operating Rate	Critical gas rate	Difference
Psi	mmscf/d		
1000	2.907	2.234	0.673
1100	2.889	2.217	0.672
1200	2.862	2.199	0.663
1300	2.838	2.18	0.658
1400	2.812	2.16	0.652

Figure 10. The effect of Wellhead Pressure on critical gas rate.



Gas PI	Operating Rate	Critical gas rate	Difference
mmscf/d/psi2	mmscf/d		
1.00E-08	0.696	0.535	0.161
2.50E-08	1.736	1.334	0.402
5.00E-08	3.457	2.656	0.801
7.50E-08	5.17	1.592	3.578
1.00E-07	6.879	2.112	4.767

Figure 11. The effect of Gas Productivity Index (PI) on critical rate.



Reservoir Pressure	Operating Rate	Critical gas rate	Difference
Psi	mmscf/d		
9000	3.218	2.473	0.745
8500	2.856	2.194	0.662
8000	2.514	1.932	0.582
7500	2.194	1.685	0.509
7000	1.894	1.455	0.439

Figure 12. The effect of Reservoir Pressure on critical gas rate.

These results are showed as following Figures and tables:

- Tubing diameter (Figure9);
- Wellhead Pressure (Figure10);
- Productivity Index (PI) (Figure11);
- Reservoir Pressure (Figure12).

As the results, wellhead pressure and/or tubing diameter increases, the possibility of liquid loading is more likely to happen because operating gas rate is very near critical gas rate. Similarly, factors affect to the IPR curve such as productivity index and reservoir pressure will impact on liquid loading. If PI and Reservoir pressure decrease, liquid loading will occur easily.

5. Solutions to prevent the liquid loading in the gas well

Based on affecting factors on liquid loading, we recommend some solutions to deal with this issue as follows:

- Inflow performance relationship (IPR) depends on productivity index and reservoir pressure, hence, we can keep reservoir pressure and PI as high as possible for decreasing risk of liquid loading. Treatment near the wellbore is the best measure to increase PI. Moreover, some methods to maintain the reservoir pressure may be also applied, such as, produce with a suitable rate or CO_2 injection into depleted gas reservoir.

- Similarly, tubing performance relationship (TPR) can be changed through modification of wellhead pressure and tubing diameter. When wellhead pressure is demoted to a certain value is possible to decrease the risk of liquid loading because the difference between wellhead and bottom hole pressure is higher lead to increase the gas velocity. Decreasing tubing diameter (Tubing diameter of well-X is 5.5 inch now) also lead to increase the gas velocity. In addition, we can use the velocity string with smaller diameter for improving gas stream velocity.

6. Conclusions

In a gas field, production rate decreases over time and may eventually stop production completely due to liquid loading, so studying liquid loading is more and more important. We use Turner Droplet model to predict liquid loading by interesting Turner curve with IPR and TPR as explained above. The result of Well-X's shows that great risk of liquid loading can occur when the operating rate (2.885 mmscf/d) is very close to critical gas rate (2.217 mmscf/d) which starts to liquid loading happen. Predicting the time and condition where liquid loading starts helps us to take early measures to prevent this problem. And there are many factors impacting on liquid loading as well as several measures are suggested to prevent liquid loading as the result of this study, for instance, decreasing the wellhead pressure/ tubing size and applying some moths for increasing PI and Reservoir pressure.

References

Lal, R. R., 2013. Well Testing In Gas-condensate Reservoir, *Master Thesis*, Stanford University.

Le Vu Quan, 2016. Studying characteristic reservoir and optimal production of gas-condenstate fields in Nam Con Son basin, *Report on State Project*, 2016

Lea, J.F., Nickens, H.V., Wells, M.R., 2008. Gas Well Deliquification (Second Edition). *Gulf Professional Publishing*.

Schlumberger, 2007. PIPESIM User guide version 2017.1.

Turner, R. G., Hubbard, M. G., and Dukler, A. E. Analysis and Prediction of Minimum Low Rate for the Continuous Removal of Liquids from Gas Wells. *Journal of Petroleum Technology*, 1969. pp. 1475–1482.

Yashaswini, D. N., 2012. Prediction of Liquid Loading in gas wells, *SPE 155356*.