Evaluating the Effects of Flow Conditions on Liquid Loading in A Gas Well of a Maturing Gas Field

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Abstract
Gas wells of mature gas field will inevitably produce liquid at some stage of their productive lives. As gas wells mature they produce liquid which flow together with gas. When the flow rate is not enough to sustain the critical velocity liquid condense out which flows as bubbles and later coalesce to slug and fall to the bottom of the well. The accumulated liquid sends back pressure to the reservoir and consequently the well dies. Based on the complexity of flow at later part of gas well life it is necessary to monitor liquid growth in the tubing. In this study operation conditions such as tubing Head flowing pressure, water gas ratio and condensate gas ratio were used to study the impact of operating conditions on liquid loading in gas wells. The study found out that at reduced THP gas flow rate increases. This increased rate might cause erosion of tubing and facilities in the well. At a lower flow rate liquid will not flow to the surface. This condition makes it necessary to have an optimum producing conditions. The sensitivity analysis showed an optimum rate of 120 MMscf/d to unload liquid and also flow rates lower than the Turner rate will cause liquid loading. The well will therefore be managed between the Turner rate and the erosional velocity rate.

Keywords: matured gas well, liquid loading, well performance, optimum flow rate,

1.0 Introduction

Almost all gas wells at some stage during their productive life are subject to produce liquids. The natural flow is expected to produce between 25 %–30 % (Alison & Bill, 2008) of the well's life before production declines as a result of liquid loading. As long as the gas velocity is high enough to entrain the liquid droplets, liquid is carried with the gas as multiphase flow. Below the critical velocity, liquid tends to fall down the tubing and start to accumulate at the bottom of the well. Some correlations (Turner et al, 1969; Coleman et al. 1991; Nossier et al., 1997; Li et al 2001 and Veeken et al., 2003) have been developed for predicting the critical rate required to unload liquid in gas wells. Turner et al (1969) have shown that this critical velocity is a function of the flowing wellhead pressure, type of liquid, temperature and conduit size. King (2005), in an analysis of impact of water content of wet gas has shown that decrease in the wellbore temperature results in decrease in the water gas ratio.

A great amount of energy is expended in vertical lift phase in moving gas in a mature gas well from the reservoir to the surface. The vertical lift of gas well flowing above dew point may not be of concern to the production engineer but when the well starts to produce liquid or produce below dew point it becomes necessary to be apprehensive of the multiphase flow. When the flow rate fluctuates between stable and unstable conditions or better expressed as erratic, the vertical performance needs to be maintained to the natural flow, this requires efforts to modify the prevalent conditions to remove unnecessary restriction to proper flow, if the erratic flow performance is ignored, flow might cease and the well stops producing. It becomes good practice to optimize flow to prolong the life of the well.

The lifting efficiency of a gas well, becomes important as the well matures, when liquids starts to build up in the well bore. To handle this effectively, the production engineer should be mindful of the flow conditions with the view of modifying the conditions to achieve an optimum production. The choice of minimum gas rate for preventing liquid loading or unloading the well has been the subject of many researches (Park 2008). Old gas producing fields suffer declining reservoirs pressure and in low-pressure gas wells, liquids accumulation in the tubing has been prevalent issue. In mature gas wells liquid vapour produced together with gas condense as gas rises and expands along the tubing. This liquid must be removed. Not only is there reduction in productions, there is also lost of revenue. This study evaluates the impact of operating conditions on the productivity of maturing gas wells. Such operating conditions include flowing tubing head pressure, flow area, water gas ratio and condensate gas ratio. It is aimed at using operating variables to minimize the effect of liquid loading to prolong the productive life of the well. The accumulated liquid will exert a back pressure that will restrict reservoir inflow performance. Therefore the goal is to identify and resolve liquid loading as early as possible.

Two models have been applied in the evaluation of the onset of liquid loading, the droplet reversal model (Turner et al 1969) and Film reversal model Barnea (1987) although the mechanism of liquid loading is fairly understood, petroleum industry is still in search of reliable predictive model (Park, 2008.)

In this study, a production system comprising of reservoir with a static reservoir pressure, a vertical wellbore with a dynamic producing bottom hole pressure and surface facilities are considered.

2.0 Materials and Methods

The inflow performance relation can be expressed as the production index. In liquid loaded wells, the productivity of the reservoir is not constant but decreases as the drawdown increases. This result in a non linear inflow relation shown in Figure 1. The difference between IPR Q_{max} and PI Q_{max} give the loss in production due to liquid loading. The PI curve shows the trend of a gas well producing above dew point and IPR curve depicts the trend of a gas well producing below dew point after some production.

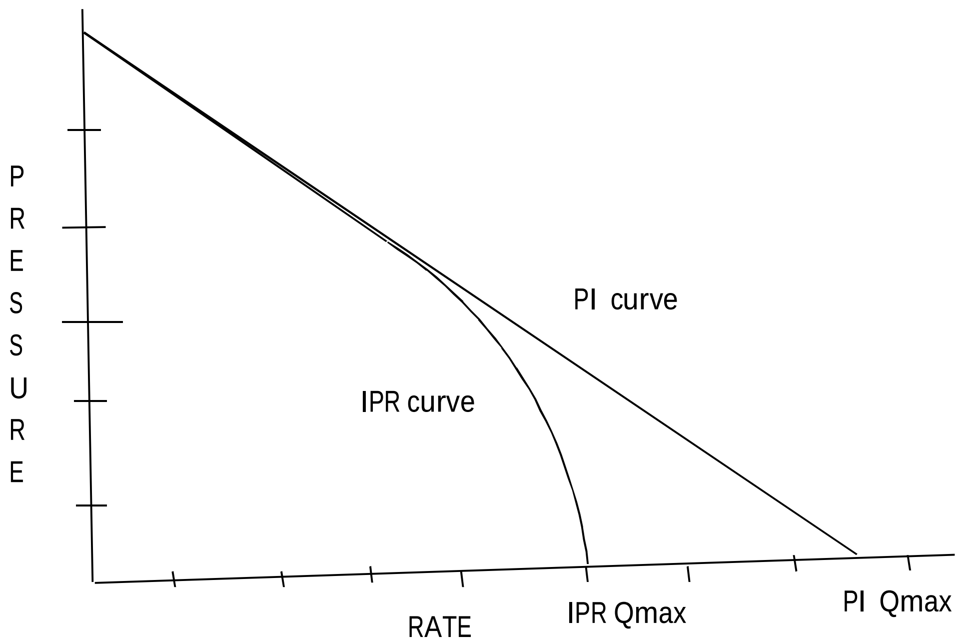

Figure 1 Production index and inflow performance curves describing the relationship between pressure and rate

The fluid flowing from the reservoir into the wellbore overcomes the tubing head pressure, hydrostatic pressure due to the flowing fluid mixture, friction force due to flow in the tubing and any other energy losses that depends on the types of flow pattern in the tubing before it comes to the surface. The flowing bottom pressure is taken as the tubing intake pressure required to flow the fluid mixture to the surface. Tubing intake pressure is a function of liquid rate and gas-oil ratio when the values of the well depth, pipe diameter and tubing pressure are constant. The tubing intake pressure relates the vertical lift performance as shown in Figure 2

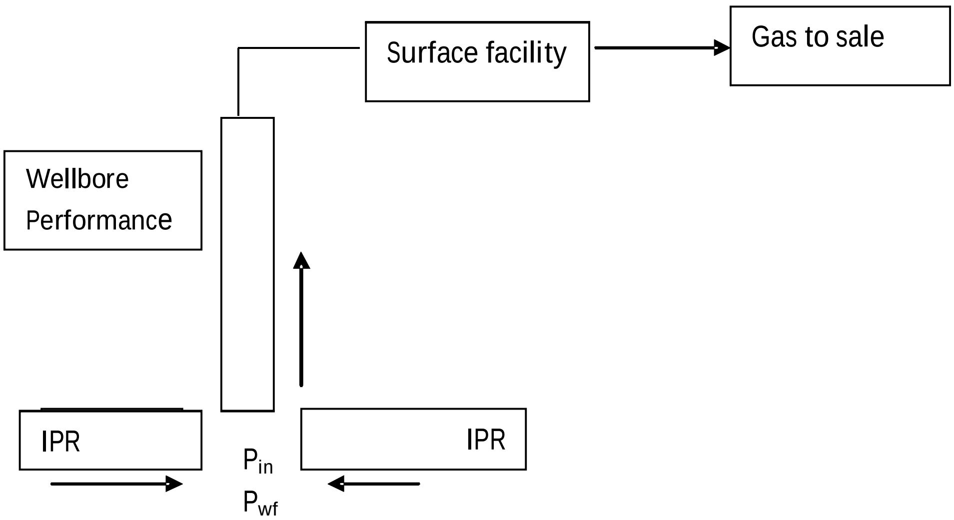

Figure 2 : Flow Performance of a Typical Gas Well

Vertical lift performance represents how the fluid flows inside the tubing that would create a specific trend of pressure drop along the flow conduit. Below the dew point pressure two phases are encountered in the system, liquid and gas. Liquids in gas wells can be caused by gas phase condensing to liquid water or condensate and /or connate water/aquifer water which often accumulate at the bottom of the well. This will happen at low well head temperature and at low rate or low lift velocity. In a two phase system, the plot of tubing head pressure and flow rate will often present a J-shaped curve as a result of the stable and unstable flow conditions. Decreasing gas velocity result to four flow regimes (Brown 1983) encountered in a flowing gas well – mist flow, annular flow, slug and bubble flow regimes. Slug and bubble flows cause liquid loading problems. A gas well may go through any or all of the flow regimes during its life time (Lea, 2003). In the wellbore pressure and the critical gas flow rate are functions of pipe diameter, fluid properties liquid – gas ratio and temperature among other things. critical rate is the rate required to sustain the critical gas velocity. If the gas rate is above the critical gas flow rate the flow is friction dominated which means that the frictional pressure drop will largely affect the total pressure drop in the tubing. Pressure drop increases as the gas rate increases. As a result of relatively high gas velocity liquid hold up will be small and no liquid accumulation will be formed. The flow in this situation will be stratified-wavy flow and the system will be stable. On the other hand, if the gas flow rate is below critical rate the flow becomes gravity dominated. Gravity pressure drop now becomes more than frictional pressure drop and the total pressure drop increases as gas flow rate decreases, thereby resulting to liquid fall back to the bottom of the well. The flow pattern is determined by the velocity of gas and the liquid phase and the amount of each phase at any given point in the system. Other causes of liquid loading

1. Decrease in well production due to decrease in reservoir pressure

3.1. Liquid loading starts when rate decreases below minimum unloading rate

Some of the signs of liquid loading are : variation of the decline curve from the normal PI curve Figure 2, when there is heavier gradient, when there is erratic production and increase in decline rate, decrease in tubing pressure with increase in casing pressure, and annular heading. Liquid loading occurs when the gas velocity is not sufficient to lift liquid. However it could be attributed to older wells with low gas volume when the pressure of the reservoir is depleted

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and the wells are making more water. The conditions for liquid loading to occur is a function of gas flow rate and liquid rates including the mechanical and pressure constrains.

Erosion velocity

High flow rate has the tendency of causing wear and tear on the tubing and surface facilities as a result of repeated impact on the walls of the facilities. This erosion damage is caused by the continuous bombardment of the liquid and solid particles (Khamehchi et al., 2014). In the study potential erosion problem was avoided by setting a limit.

Table 1: PVT and Reservoir Data

Parameters	Values	Parameters	Values
Gas specific gravity	0.63	Reservoir permeability, mD	2500
Separator Pressure, psi	69.9611	Reservoir thickness, ft	194
Condensate Gas Ratio (CGR), stb/MMscf	92	Drainage Area, ac	600
Condensate gravity, API	54.4	Dietz shape factor	4
Water Gas Ratio (WGR) stb/MMscf	0.044386	Well bore radius, ft	0.61458
Water Salinity ppm	10000	Perforation Interval, ft	58
Mole Percent H_2S, %	0.0	Skin	25
Mole Percent CO_2, %	0.32		
Mole Percent N_2, %	0.09		

Table 2: Inflow Performance Relationship Model

Reservoir model	**Darcy**
Mechanical Geometrical skin model	Enter skin by hand
Deviation and partial P. skin model	Wong-Clifford
Reservoir pressure, psi	2510.65
Reservoir temperature, ^oF	186
Water Gas Ratio, stb/MMscf	0.044386
Condensate Gas Ratio, stb/MMscf	40
Compaction permeability reduction model	No

Table 3: Well Equipment

Equipment	MD (ft.)	Size (in)	I.D (in)
Xmas Tree	39		
Tubing	220	7	6.18
SSSV			5.875
Tubing	11433		6.18
Tubing	11458		6
Tubing	11549		6.18
Restriction			5.5
Tubing	11603		6.18
Casing	11657	9-5/8	8.621

Nodal system analysis approach was used to study liquid loading in gas well. Nodal analysis divided the system into two subsystems; the inflow and outflow subsystems. The PVT data in Table 1 was used to build the black oil PVT model while the reservoir data was used to construct the inflow performance curve.The curves of inflow performance and outflow performance meet at a point which defines the optimal operating conditions of bottom hole pressure and flow rate. This flow rate is the liquid flow rate. This nodal analysis is done with a simulator Petroleum Expert soft ware. The well configuration considered for this study is as shown in Table 2 and Table 3 - well depth of 11657 ft, water gas ratio of 0.44386 stb/MMscf, tubing head pressure of 1,300 psi and reservoir pressure of 2,510.56 psi. The well has open completion. The maximum flow rate and erosion velocity of 140 MMscf/d and 130 MMscf/d respectively were used as constrain in the flow analysis. After matching the simulated data, sensitivity analysis was done to verify the impact of tubing head pressure THP, water gas ratio, WGR and condensate gas ratio, CGR on liquid loading.

3.0 Results and Discussion

The following figures represent the results of the sensitivity analysis performed to study the effects of varying the Tubing Head Pressure, Water Gas Ratio and condensate gas ratio.

Inflow Performance Relationship

The IPR was generated using data in Tables 1 and 2. From the plot the absolute open flow potential is 1,990 MMscf/d. The IPR relation depicts a decline in production as a result of condensation of liquid Figure 4.

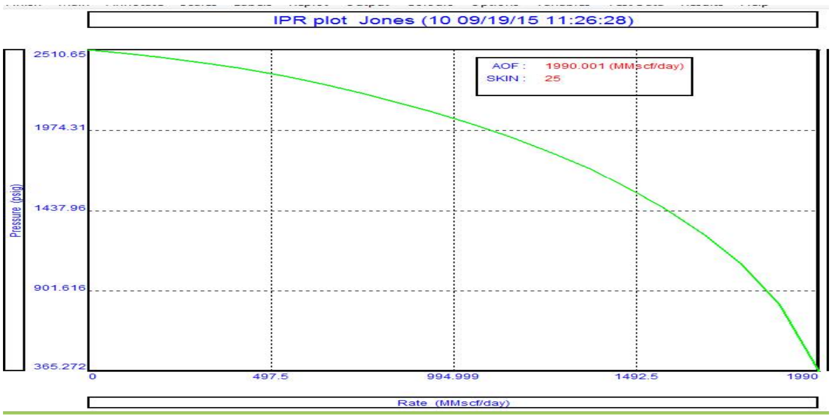

Figure 4: Inflow Performance Curve

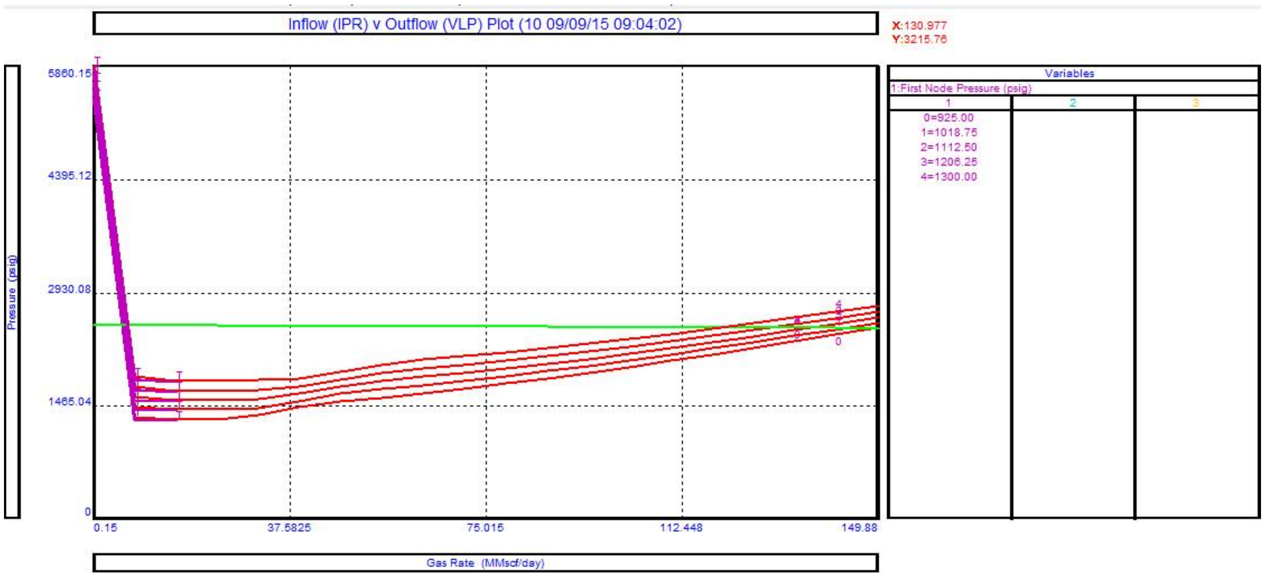

Figure 5: The sensitivity Result of Tubing Head Pressure

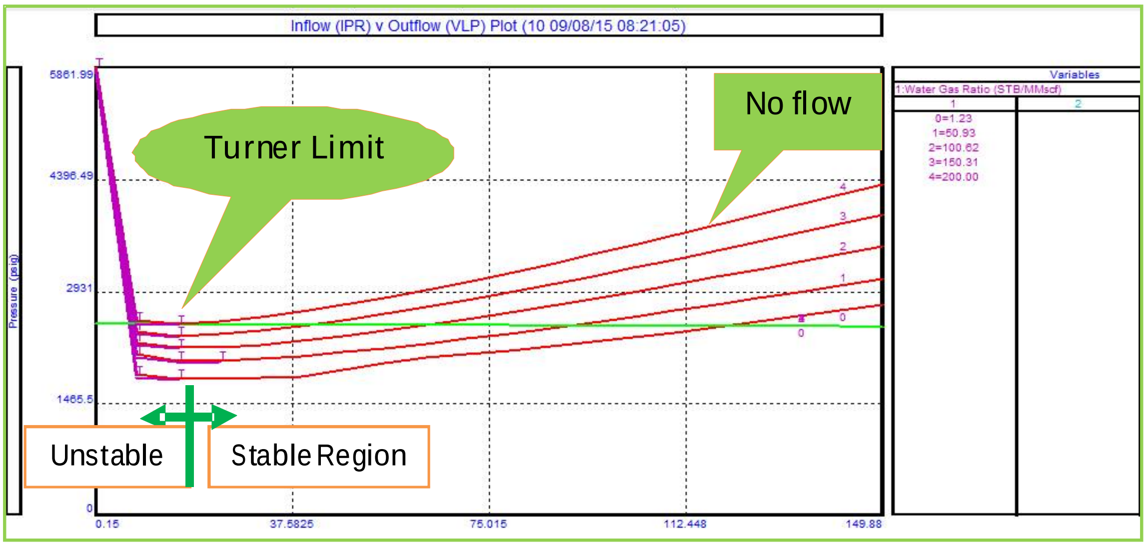

Figure 6: The sensitivity Result of Water Gas Ratio

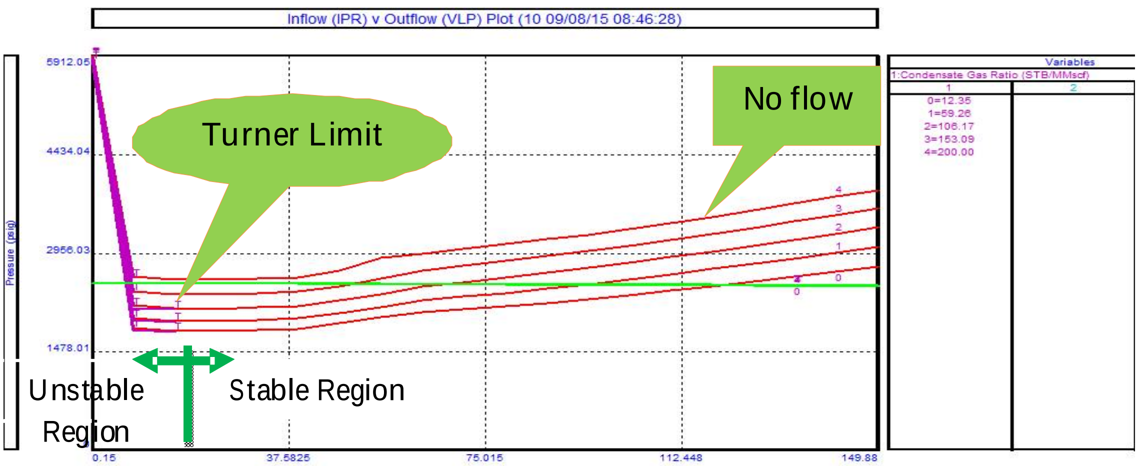

Figure 7: The sensitivity Result of Condensate Gas Ratio

.Table 4: Relationship Between the Operating Variables and Flow Rate to Determine Optimal Liquid Unloading Rate

THP (psi)	Bottom Hole Flowing Pressure (Psi)	Rate(MMscf/d)
925	2475.1	149.63
1018.75	2476.71	143.64
1112.5	2478.52	136.86
1206.25	2480.54	129.16
1300	2482.85	120.29
Water Gas Ratio (stb/MMscf)		
	Bottom Hole Flowing Pressure (Psi)	Rate(MMscf/d)
1.23	2482.85	120.29
50.93	2490.36	90.35
100.62	2496.79	63.41
150.31	2501.76	41.56
200	No Flow	No Flow
Condensate Gas Ratio (stb/MMscf)		
	Bottom Hole Flowing Pressure (Psi)	Rate(MMscf/d)
12.35	2482.85	120.29
59.26	2488.23	93.85
106.17	2493.69	66.98
153.09	2496.87	49.64
200	No Flow	No Flow

Effect of Tubing Head Pressure

With constant WGR of 1.2345 stb/MMscf and CGR of 12.345 stb/MMscf, a sensitivity analysis was run to investigate the effect of THP on liquid loading. This was carried out by varying the values of the Tubing Head Pressure (THP). Five tubing head pressures were taken to study the effect. The values are 925 psia, 1,018.75 psia, 1,112.00 psia, 1,206.25 psia and 1,300.00 psia represented with line 0 to 4 respectively. It was observed that gas rate produced from the intersection of the IPR and VLP curve show that tubing head pressure of 1300psia has the lowest flow rate 120 mmscf/d which is lower than the maximum flow rate and the tubing erosional rate indicated in Figure 5. The maximum withdrawal gas rate and erosional flow rate limit is at 140 MMscf/d and 130 MMscf/d respectively. This can be taken as the optimum gas rate, it will not cause erosion of the tubing. It is observed from the analysis that the liquid loading rate of 15.9 MMscf/d remained stable in all simulation runs. Beyond the turner limit the gas flow rate is unstable. The gas velocity in the well bore is affected by the flowing tubing pressure. The smaller the tubing head pressure the higher the lifting velocity but the choice of the tubing head pressure is controlled by the erosional velocity. It is observed that decrease in tubing head pressure at constant temperature causes an increase in the liquid gas ratio. The stable operating point can be found within 1,200 psi-1,300 psi. Above 1,300 psi, further analysis will yield tangible result but due to the critical FTHP limit of 1,308.3 psia, it was not carried out.

Effect of Water Gas Ratio

With the same constant values of THP 1,300 psia, WGR1.2345 stb/mmscf and CGR 12.345 stb/mmscf, a sensitivity analysis was run to investigate the effect of Water Gas Ratio on liquid loading. WGR was varied from 1.2345 stb/MMscf to 200 stb/MMscf at 5 different linear number spacing. It was observed that at 200 stb/MMscf of WGR, there was no flow due to the fact that the well has been loaded with water and cannot flow to the surface again. The first four flow is acceptable as they fall within the safe operating point of the well (Figure 6). Based on this study it is advisable not to allow the water gas ratio to exceed 100 stb/mmscf because it will reduce the flow rate to about 63 MMscf/d. The WGR value of 1.23 stb/MMscf will cause the well to produce at rate of 120 MMscf/d. This well will operate effectively with WGR between 1.234 stb/MMscf to 100 stb/MMscf. Considering the energy available to the well and the erosional velocity rate WGR value of 1.234 stb/MMscf could be suggested as optimal value. The study showed that an increase in WGR gives a corresponding decrease in flow rate.

Effect of Condensate Gas Ratio

Wet gas well may drop heavier components in the tubing at low pressure as the well flows. This necessitated the study on CGR. With the same parameters constant, CGR was varied from 12.345 stb/MMscf to 200 stb/MMscf at 5 different linear number spacing. Figure 7 shows the inflow performance. It was observed that at a CGR of 200 stb/MMscf, the well didn't flow as a result of liquid loading. When the condensate Gas ratio was reduced step by step from 150 stb/MMscf to 12.345 stb/MMscf a good result was obtained and an optimal value of 12.3453 stb/MMscf.

4.0 Conclusion

From this study, it is found that the gas velocity in the well bore of the studied gas well is affected by the flowing tubing head pressure, water gas ratio and condensate gas ratio. For this well, Table 1, the optimal operating condition would be a tubing head pressure not below 1300 psi, water gas ratio of 1.23 stb/ MMscf and Condensate gas ratio of 12.36 stb/MMscf. This will give an optimal flow rate of 120.29 MMscf/d and a corresponding flowing bottom hole pressure of 2,482.85 psi. An increase in water gas ratio or condensate gas ratio will cause a decrease in the flow rate and hence a decrease in the flow velocity. This operating condition will be a guide to control the on-set of liquid loading and management of the well as the flow rate decline due liquid accumulation.

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