International Journal of Recent Engineering Science (IJRES) Volume 7 Issue 1, 1-8, Jan-Feb 2020
ISSN: 2349 – 7157 / doi: 10.1445/23497157/IJRES-V7I1P101

The Effect of Flow Parameters on Liquid Loading and Tubing Lift Performance in a Gas Condensate Well

Godpower Abaku[1], Ifeanyi Samson Nwankwo[2], Bright Bariakpoa Kinate[3]
[1,2,3]*(Department of Petroleum Engineering, Rivers State University, Nigeria)*

Abstract

Liquid loading of gas wells causes production difficulty and reduces ultimate recovery from these wells. Gas wells suffering from liquid loading are incapable of removing the liquid associated with produced gas from the wellbore. This phenomenon is initiated when the upward gas velocity in the well falls below a critical value, and the liquid accumulates at the bottom of the well. This accumulation of liquid decreases production rates and in severe cases kills the well. Several methods have been proposed to predict the onset of liquid loading in gas wells but understanding the influence of flow parameters is significant in solving this problem. In this work, flow parameters such as Tubing wellhead pressure, water-gas ratio(WGR), condensate-gas ratio(CGR), tubing size and the flow regimes are analyzed using PROSPER software to ascertain the effect of these parameters on liquid loading and how production from the gas well can be optimized through the proper selection and control of these flow parameters. Flow and PVT parameters were varied and inputted, and the result shows that an increase in the tubing wellhead pressure results in an increased tendency of liquid loading owning to the corresponding increase in the minimum unloading flowrate. Also, at a tubing wellhead pressure of 1200psig, the gas rate of the well was 90.652MMscf/day, and liquid loading will set in when production declines to 15.911MMscf/day (Turner's rate). Whereas when the tubing wellhead pressure was increased to 1500psig, the production rate declines to 50.627MMscf/day and Turner's limit set at 31.6721MMscf/day. Gases with high liquid contents (high GOR and WGR) also pose more significant tendencies of liquid load up. The sensitivity results of the tubing diameter (ranging from 2.5" to 7.5") show no remarkable effect on the tubing VLP. Hence, the tubing diameter has little or no effect on a gas well liquid load up. To ensure that liquid droplets are continuously and simultaneously transported to the surface, the mist flow regime should be desired and maintained at the wellbore.

Keywords – *Critical Rate, Flow Variables, Flow Regime, Load-up, Turner Limits*

I. INTRODUCTION

Gas condensate reservoirs present an essential source of hydrocarbon reserves and have long been recognized as a reservoir type, possessing the most intricate flow and complex thermodynamics behaviour. They are characterized by producing both gas and condensate liquid at the surface. Gas condensate reservoir with a pressure higher than dew point represents a single-phase fluid, but at certain conditions of pressure and temperature, condensation starts and the reservoir hydrocarbon form two phases. The largest drop occurs near the wellbore area. Most likely, in this zone, the pressure falls below the dew point value, and liquid saturation with sober ends build up [1-3]. Typical retrograde condensate reservoir produces both gas/liquid ratios of approximately 3-150 Mcf/stb, or condensate surface yields ranges from 7 to 333stb/MMscf [4]. The added economic value of produced condensate liquid in addition to the gas production makes the recovery of condensate a key consideration in the development of gas condensate reservoirs. Reservoirs bearing gas-condensates are becoming more common as developments are encountering greater depths, higher pressures, and higher temperatures.

As natural gas is produced from depletion drive reservoirs, the energy available to transport the produced fluids to the surface declines. This transport energy eventually becomes low enough that flow rates are relatively reduced and fluids produced along with the gas are no longer carried to the surface. These liquids accumulate in the wellbore over time and cause additional hydrostatic back pressure on the reservoir, which results in the continued reduction of the available transport energy. In most cases, if this condition is allowed to continue, the wellbore will accumulate sufficient fluids to balance the available reservoir energy entirely and cause the well to die [5]. Most of the pressure drop from condensate blockage occurs within a few feet of the wellbore where flowrates are very high. The condensate bank around the wellbore contains two phases, reservoir gas and liquid condensates. This bank grows as the reservoir declines and progressively impedes the flow of gas to the well, causing a loss of well productivity [6]. Laboratory studies have shown that the oil saturation decreases at production rate in the immediate vicinity of the well, due to capillary number effects (the ratio of viscosity to capillary forces) [7-8].

Consequently, the relative permeability to gas increases, resulting in a recovery of much of the gas mobility lost from condensate blockage. Liquid drop out occurs first near the wellbore and propagates radially away from the well (assuming the well is at the Centre of a radial reservoir) along with the pressure around a pressure drop. When reservoir pressure around a well drops below the dew point pressure, retrograde condensation occurs, and three regions are created with different liquid saturations [9-10].

Liquid load-up in gas wells is not always obvious; therefore, a thorough diagnostic analysis of well data needs to be carried out to adequately predict the rate at which liquids will accumulate in the well. A decision on choosing the minimum gas rate for preventing liquid loading has been the subject matter for researchers [11]. As influenced by so many factors are investigated, in the analysis of the impact of the water content of wet gas, decrease in the wellbore temperature results to decrease in the water gas ratio[12]. Although this subject has been studied the results extensively from previous investigators and the most commonly applied model in the industry still has a high degree of inaccuracy, especially in predicting the minimum gas flow rate required to prevent liquid loading into the wellbore [13]. Hence, this work will explore the influence of flow parameters on liquid loading and tubing lift performance in a gas condensate well.

II. METHODOLOGY

Two unique models have been developed to correspond to the two primary case scenarios of annular flow regime and bubbly flow regimes, respectively [14]. In this work, the liquid-droplet model (typical of bubbly flow) was utilized.

A. The Gas Well Load-up Critical Velocity

Considering a gas well fluid conduit with entrained liquid droplets (condensates) and acted upon by gravitational force (Fg) and drag force, (Fd), the following dynamic equilibrium condition can be established to ensure the condensates (or liquids) are continuously and simultaneously transported to the surface.

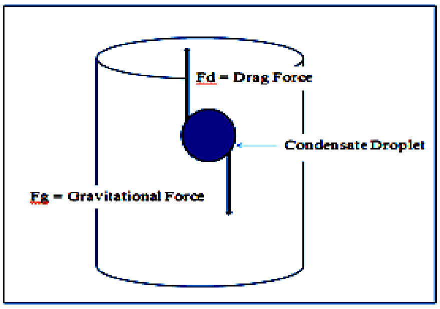

Fig 1: Turner's Liquid Droplet Model

$$Gravitational\ Force, F_g = Drag\ Force, F_d \tag{1}$$

By definition;

$$F_g = \frac{g}{g_c}(\rho_c - \rho_g)\frac{\pi d^3}{6} \tag{1a}$$

$$F_d = \frac{1}{2g_c}\rho_g C_d A_d (V_g - V_d) \tag{1b}$$

Hence for equilibrium, the equation becomes,

$$F_g = \frac{g}{g_c}(\rho_c - \rho_g)\frac{\pi d^3}{6} = F_d = \frac{1}{2g_c}\rho_g C_d A_d (V_g - V_d) \tag{2}$$

By simplifying the above equation and introducing the critical velocity term, Vc defined as the velocity differential between the gas velocity and the drag velocity, that is, $V_c = (V_g - V_d)$, Equation (2) can be simplified as

$$V_c = \sqrt{\frac{4g}{3}\left(\frac{\rho_l - \rho_g}{\rho_g}\right)\frac{d}{c_d}} \tag{3}$$

According to Hinze (1955), the droplet diameter is dependent on gas velocity and can be expressed in terms of dimensionless Weber number, N_{We}. The same investigation showed that the maximum possible liquid droplet exists when N_{We} = 30. In Tuner et al. droplet model, a drag coefficient, Cd=0.44, was shown to be consistent for all cases of turbulent flow conditions.

Introducing these relationships and re-expressing equation (3) above in field units, we will have;

$$V_c = 1.593\frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{\rho_g^{1/2}} \tag{4}$$

Where;

$$N_{We} = \frac{V_c^2 \rho_g d}{\rho_l \sigma}$$

$$d = 30\frac{\sigma g_c}{\rho_g V_c^2}$$

$$1\frac{lb_f}{ft} = 0.00006852\ dynes/sec$$

The equation (4) is Turner's theoretical, critical velocity. The validation of the equation with results from field data shows a remarkable deviation. To accommodate this, a 20% upfront approximation was introduced. Hence, the actual Turner's critical velocity can be estimated using the adjusted critical rate given below

$$V_{c_{adjusted}} = 1.9116\frac{\sigma^{1/4}(\rho_l - \rho_g)^{1/4}}{\rho_g^{1/2}} \tag{5}$$

B. The Gas Well Load-up Critical Rate

In most cases, especially in real field scenarios, it is often more convenient to express the gas well's load up control parameters in terms of the well's critical production rate. This is shown below:

$$V_c = \frac{Q_c B_g}{A} \tag{6a}$$

$$Q_c = \frac{V_c A}{B_g} \tag{6b}$$

Infield units, equation (6b) can be expressed as a function of T, P, and Z since $f(B_g) = f(T, P, Z)$ as follows

$$Q_c = 3.067\frac{V_c P A}{ZT}, \quad MMScf/d$$

$$Q_c = 3.067\frac{V_c P}{ZT}\left(\frac{\pi d_{ti}^2}{4x144}\right) \qquad (7)$$

Table 1: Gas and Condensate PVT Parameters.

S/N	Parameter	Unit	Value/ Range
1	Condensate Density	Lb/ft^3	45
2	Gas Specific Gravity	Lb/ft^3	0.6
3	Gas compressibility factor	-	0.9
4	Isothermal Temperature	°F	120
5	Condensate Surface Tension	dyne/cm	20

Using the data in Table (1), the following modification can be made to equation (5)

$$\rho_g = 2.7\frac{\gamma_g P}{ZT} = 2.7\frac{0.6xP}{0.9x(460+120)} = 0.0031034P \qquad (8)$$

$$V_{c_{adjusted}} = 1.9116\frac{20^{1/4}(45 - 0.0031034P)^{1/4}}{0.0031034P}$$

$$V_{c_{adjusted}} = 4.042542\frac{(45 - 0.0031034P)^{1/4}}{0.0031034P} \qquad (9)$$

C. Gas Well Productivity Model

Gas well productivity Modeling is necessary for investigating the impact of liquid load-up on the well's deliverability. The well's Productivity Index, PI, the IPR and the TPC-IPR models were used in this study to investigate the impact of load-up on the production system diagnostically. The gas well PI can be generated from the following sets of equations

$$q_{sc} = \frac{703x\,10^{-6}k_g h(P_R^2 - P_{wf}^2)}{\mu_g ZT\ln(0.472r_e/r_w)} \qquad (10)$$

Equation (10) above is a modified equation for a stabilized flow at average reservoir pressure. By defining the gas well productivity index, J, Equation (10) can be re-expressed as:

$$q_{sc} = J(P_R^2 - P_{wf}^2) \qquad (11a)$$

$$J = \frac{q_{sc}}{(P_R^2 - P_{wf}^2)} \qquad (11b)$$

$$J = \frac{703x\,10^{-6}k_g h}{\mu_g ZT\ln(0.472r_e/r_w)} \qquad (11c)$$

D. PROSPER Model

PROSPER™ is one of the IPM-Suite package developed by Petroleum Experts. It is a state-of-art industrial tool used in designing and modelling the performance of production systems via nodal analysis. As part of the objectives, the simulation methodologies/options used in this study are presented below in Figure (2).

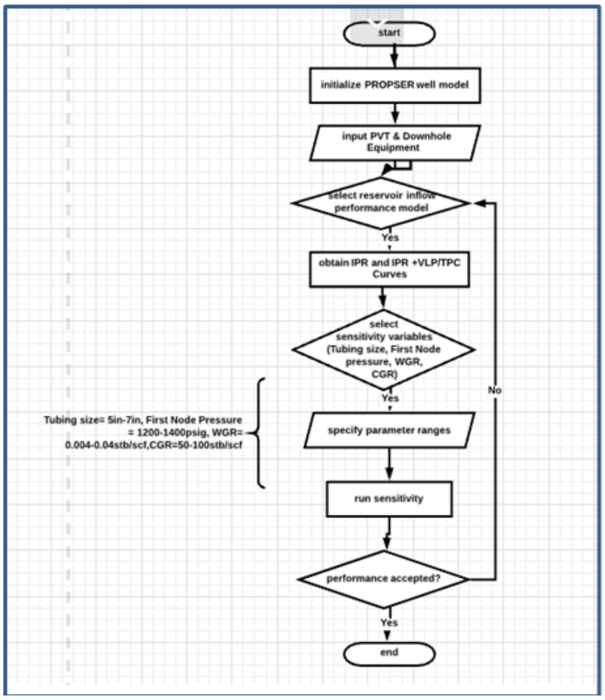

Fig 2: Simulation Flow Chart

III. RESULTS AND DISCUSSION

The results of Figure (3) was developed using sensitivity versus PvD runs. The non-linear inverse relationship shown below can be used to correlate the minimum unloading velocity from the pressure history.

A. Effect of Flowing Wellhead Pressure on Minimum Unloading Velocity

The first node pressure (wellhead flowing pressure) is a very sensitive parameter in production optimization. This is because; wellhead flowing pressure ultimately affects the well's flow rate/velocity. In industrial situations, choking back wellhead flowing pressure has been identified as a way of controlling the production from a well. In this study, the results in Tables(2) to (5) shows the performance of the case study gas well under varying conditions of first node pressure. As the results indicate, as first node pressure increases, the minimum unloading velocity/Turner's limits also increases. The implication is that if a well is excessively choked up, there is a greater tendency of liquid load up as production declines to Turner's flow rate criterion.

On the contrary and provided all other operating parameters are optimized, opening the well to flow could be a strategic way of extending well's economic production life since there is a minimal tendency of the liquid load. In Table (2), the well produces at 90.652MMscf/day at a first node pressure of 1200psig. If this well's operating condition is maintained, liquid loading will set in when production declines to 15.911MMscf/day (Turner's Criteria). On the other hand, the results in Table (5) suggests excessive choking/high-pressure drop at the wellhead, which declines the rate to 50.627MMscf/day with Turner's limit set at 31.6721MMscf/day. If this well is continued at this condition, liquid loading readily sets in at very early life of the well. The corresponding VLP pressure in either situation reveals that, as Turner limit extends, the required Vertical Lift pressure increases.

B. Liquid-Gas Ratio and Tubing Vertical Lift Performance Sensitivity

The phenomenon of liquid loading in producing gas wells cannot be thoroughly analyzed without reference to the source of liquids in the well. The results in Figures (4) and (5) below show that the condensate-gas ratio and the water-gas ratio of the in-situ fluid characteristically determine the extent of Turner's limit. The results show that the more liquid in the gas stream, the higher the minimum unloading velocity and consequently, the more likely the tendency of liquid load up. Figure (6) precisely reveals that condensate rich gas wells will most likely experience liquid-load up. From the ongoing analysis, excessively choking this kind of well is an easy way of bringing it to the end of life.

C. Tubing Size - Tubing Vertical Lift Performance Sensitivity Analysis

From empirical relationships, flow through tubing can be significantly affected by the tubing diameter regardless of the nature of flowing fluid. In real field situations, this relationship holds for most oil wells. However, since gas-well tubing sizes are remarkably larger, the effect of tubing size is not often felt. The result of Figure (7) below validates this industrial practice. As shown in the Figure, the sensitivity results of tubing diameter range from 2.5 in to 7.5 in; there was no remarkable effect on the tubing VLP (or TPC). Hence, for the optimal operating condition, tubing size has little or no effect on a gas well liquid load up.

D. Effect of Flow Regime on Liquid Load up in gas wells

The presence of liquid droplets in a gas stream causes a multiphase flow in the well. To ensure the liquid droplets are continuously and simultaneously transported to the surface, there must be even or near even distribution of the dispersed liquid phase in the gas medium. This can be achieved if the bubbly or mist flow regime is maintained in the wellbore. The result in Table (6) of appendix shows a flow regime tracking versus depth along with the well profile. The results were gotten at an operating first node pressure of 1200psig and Turner's criterion set at 15.9111MMscf/day.

The slug flow regime predicted at bottom hole depth in Table 6 reveals the onset of liquid loading. If this flow regime is allowed to prevail to a significant depth above the bottom hole, actual liquid loads upset in until the well eventually dies. Hence, mist or bubbly flow in the wellbore can be another state of the art technique of overcoming liquid load up in gas wells. This is because; in mist flow, the less dominant phase is almost evenly distributed in the dominant phase such that slip gas velocity, Vsg, equals the slip liquid velocity, Vsl. In the Vsg and the Vsl column of Table (6), at the bottom hole conditions where slug flow exits through a gas column of 59ft, the slip gas velocity, Vsg is far greater than the slip liquid velocity, Vsl. This results in the gas phase slipping over the liquid phase leading to liquid drop out or loading in the well.

IV. CONCLUSION

In this study, the effect of flow parameters (tubing head pressure, WGR, CGR, tubing size and flow regimes) on liquid accumulation was analyzed. From the study, it can be inferred that high pressure at the wellhead leads to a greater tendency of a liquid holdup. This is because as first node pressure increases, the minimum unloading velocity/Turner's limits also increases. The implication is that if a well is excessively choked up, there is a greater tendency of liquid load up as production declines to Turner's flow rate criterion. The sensitivity analysis of WGR and CGR shows that the more liquids are in the gas stream, the higher the tendency of liquid load up.

Contrary to empirical relationships, the study also shows that the effect of tubing size on liquid load-up in a gas well is not often felt even though this relationship holds for most oil wells. The sensitivity analysis ranges from 2.5 in to 7.5in, and there is no remarkable effect on the tubing VLP (or TPC). Hence, for the optimal operating condition, the tubing size has little or no effect on the gas well liquid load up. Finally, the study also analyses and tracts the flow regime along the well profile to determine the predominant flow regime. To ensure that liquid droplets are continuously and simultaneously transported to the surface in a gas well, mist flow regime should be maintained at the wellbore region. The findings in this work are limited to the analyzed operating scenarios.

ACKNOWLEDGEMENTS

We wish to express our profound gratitude to God Almighty. We also wish to acknowledge, Eng. KK.Dune for his supervision and the entire team of Petromario Consults Group, RSUST, who provided the simulation tool (IPM SUIT-PROSPER^{TM}) used in this analysis.

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APPENDIX

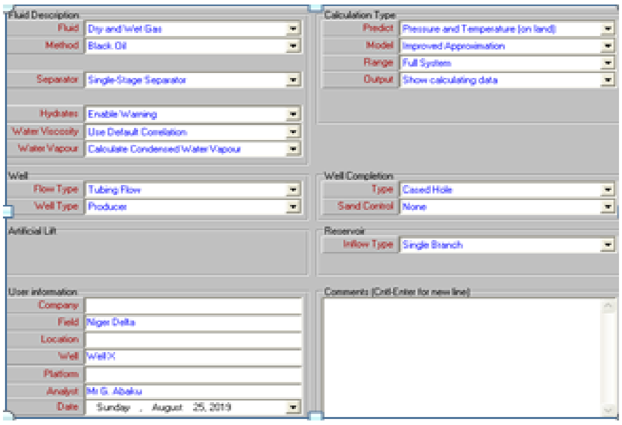


Fig A.1: PROSPER Simulation Option

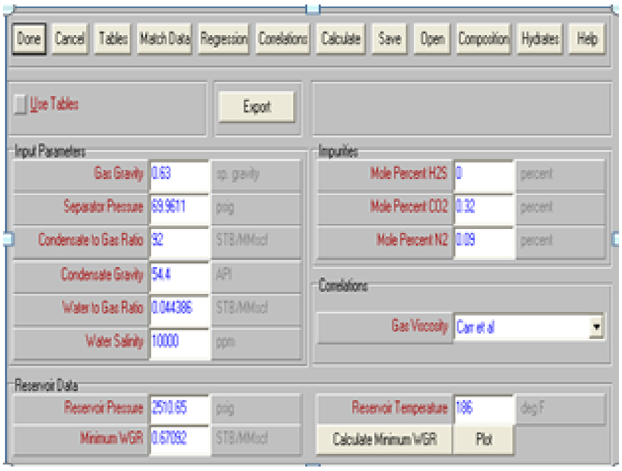
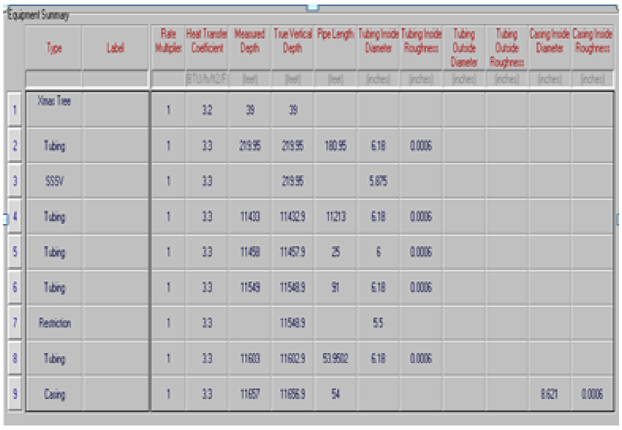


Fig A.2: Fundamental Fluid PVT Properties



Equipment Summary

	Type	Label	Rate Multiplier	Heat Transfer Coefficient	Measured Depth	True Vertical Depth	Pipe Length	Tubing Inside Diameter	Tubing Inside Roughness	Tubing Outside Diameter	Tubing Outside Roughness	Casing Inside Diameter	Casing Inside Roughness
				BTU/h/ft2/F	(feet)	(feet)	(feet)	(inches)	(inches)	(inches)	(inches)	(inches)	(inches)
1	Xmas Tree		1	3.2	39	39							
2	Tubing		1	3.3	219.95	219.95	180.95	6.18	0.0006				
3	SSSV		1	3.3		219.95		5.875					
4	Tubing		1	3.3	11433	11432.9	11213	6.18	0.0006				
5	Tubing		1	3.3	11458	11457.9	25	6	0.0006				
6	Tubing		1	3.3	11549	11548.9	91	6.18	0.0006				
7	Restriction		1	3.3		11548.9		5.5					
8	Tubing		1	3.3	11603	11602.9	53.9602	6.18	0.0006				
9	Casing		1	3.3	11657	11656.9	54					8.621	0.0006

Fig A.3: Downhole Equipment Summary

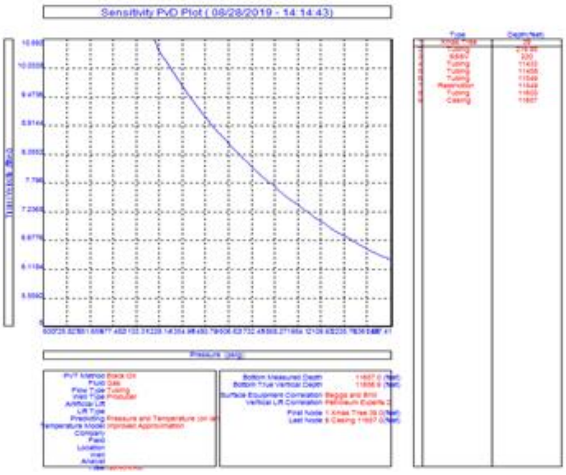


Fig 3: Turner's Critical Velocity versus Pressure

Table 2: System Results at First Node Pressure = 1200psig

Results

		Gas Rate (MMscf/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)	dP Perforation (psi)
T	1	0.15	6033.6	2510.62	0.023438	0
T	2	8.03053	1933.55	2508.94	1.25317	0
T	3	15.9111	1884.71	2507.24	2.48364	0
	4	23.7916	1886.55	2505.51	3.71436	0
	5	31.6721	1906.82	2503.76	4.9458	0
	6	39.5526	1974.78	2501.97	6.17773	0
	7	47.4332	2107.71	2500.16	7.41016	0
	8	55.3137	2203.42	2498.32	8.64331	0
	9	63.1942	2258.29	2496.45	9.87695	0
	10	71.0747	2314.53	2494.55	11.1116	0
	11	78.9553	2374.43	2492.63	12.3411	0
	12	86.8358	2447.47	2490.68	13.5757	0
	13	94.7163	2534.71	2488.7	14.811	0
	14	102.597	2623.82	2486.69	16.0471	0
	15	110.477	2714.78	2484.65	17.2837	0
	16	118.358	2807.57	2482.59	18.5212	0
	17	126.238	2902.16	2480.49	19.7595	0
	18	134.119	2996.4	2478.37	20.9985	0
	19	141.999	3092.23	2476.22	22.2383	0
	20	149.88	3188.11	2474.04	23.479	0

Variables

First Node Pressure 1200 (psig)

Solution

Solution Details

Gas Rate	90.652	MMscf/day
Oil Rate	8340.0	STB/day
Water Rate	60.8	STB/day
Solution Node Pressure	2489.72	psig
Wellhead Pressure	1200.31	psig
Wellhead Temperature	125.00	deg F
First Node Temperature	125.00	deg F
Total Skin	25.00	
Total dP Skin	14.17	psi
dP Friction	-527.22	psi
dP Gravity	-758.87	psi

T - Velocity Less Than Turner Criteria

Table 3: System Results at First Node Pressure = 1275psig

Results

		Gas Rate (MMscf/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)	dP Perforation (psi)
T	1	0.15	6116.03	2510.62	0.023438	0
T	2	8.03053	2058.26	2508.94	1.25317	0
T	3	15.9111	2005.26	2507.24	2.48364	0
	4	23.7916	2003.31	2505.51	3.71436	0
	5	31.6721	2018.96	2503.76	4.9458	0
	6	39.5526	2058.39	2501.97	6.17773	0
	7	47.4332	2190.06	2500.16	7.41016	0
	8	55.3137	2304.48	2498.32	8.64331	0
	9	63.1942	2361.87	2496.45	9.87695	0
	10	71.0747	2414.92	2494.55	11.1116	0
	11	78.9553	2471.51	2492.63	12.3411	0
	12	86.8358	2534.27	2490.68	13.5757	0
	13	94.7163	2618.41	2488.7	14.811	0
	14	102.597	2704.71	2486.69	16.0471	0
	15	110.477	2793.2	2484.65	17.2837	0
	16	118.358	2883.21	2482.59	18.5212	0
	17	126.238	2974.72	2480.49	19.7595	0
	18	134.119	3066.23	2478.37	20.9985	0
	19	141.999	3159.8	2476.22	22.2383	0
	20	149.88	3253.92	2474.04	23.479	0

Variables

First Node Pressure 1275 (psig)

Solution

Solution Details

Gas Rate	81.527	MMscf/day
Oil Rate	7500.5	STB/day
Water Rate	54.7	STB/day
Solution Node Pressure	2491.99	psig
Wellhead Pressure	1274.75	psig
Wellhead Temperature	126.27	deg F
First Node Temperature	126.27	deg F
Total Skin	25.00	
Total dP Skin	12.74	psi
dP Friction	-425.93	psi
dP Gravity	-788.82	psi

T - Velocity Less Than Turner Criteria

Table 4: System Results at First Node Pressure = 1350psig

Results

		Gas Rate (MMscf/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)	dP Perforation (psi)
T	1	0.15	6196.94	2510.62	0.023438	0
T	2	8.03053	2176.03	2508.94	1.25317	0
T	3	15.9111	2123.15	2507.24	2.48364	0
T	4	23.7916	2116.96	2505.51	3.71436	0
T	5	31.6721	2131.43	2503.76	4.9458	0
	6	39.5526	2154.33	2501.97	6.17773	0
	7	47.4332	2271.09	2500.16	7.41016	0
	8	55.3137	2407.49	2498.32	8.64331	0
	9	63.1942	2467.44	2496.45	9.87695	0
	10	71.0747	2518.04	2494.55	11.1116	0
	11	78.9553	2572.14	2492.63	12.3411	0
	12	86.8358	2624.89	2490.68	13.5757	0
	13	94.7163	2704.35	2488.7	14.811	0
	14	102.597	2787.55	2486.69	16.0471	0
	15	110.477	2873.3	2484.65	17.2837	0
	16	118.358	2960.28	2482.59	18.5212	0
	17	126.238	3049.17	2480.49	19.7595	0
	18	134.119	3139.25	2478.37	20.9985	0
	19	141.999	3229.69	2476.22	22.2383	0
	20	149.88	3321.94	2474.04	23.479	0

Variables

First Node Pressure 1350 (psig)

Solution

Solution Details

Gas Rate	67.548	MMscf/day
Oil Rate	6214.4	STB/day
Water Rate	45.3	STB/day
Solution Node Pressure	2495.40	psig
Wellhead Pressure	1350.35	psig
Wellhead Temperature	126.69	deg F
First Node Temperature	126.69	deg F
Total Skin	25.00	
Total dP Skin	10.56	psi
dP Friction	-291.65	psi
dP Gravity	-851.75	psi

T - Velocity Less Than Turner Criteria

Results

		Gas Rate (MMscf/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)	dP Perforation (psi)
T	1	0.15	6277.8	2510.62	0.023438	0
T	2	8.03053	2294.63	2508.94	1.25317	0
T	3	15.9111	2238.85	2507.24	2.48364	0
T	4	23.7916	2232.32	2505.51	3.71436	0
T	5	31.6721	2243.22	2503.76	4.9458	0
	6	39.5526	2265.13	2501.97	6.17773	0
	7	47.4332	2352.5	2500.16	7.41016	0
	8	55.3137	2508.72	2498.32	8.64331	0
	9	63.1942	2567.52	2496.45	9.87695	0
	10	71.0747	2620.17	2494.55	11.1116	0
	11	78.9553	2672.63	2492.63	12.3411	0
	12	86.8358	2726.13	2490.68	13.5757	0
	13	94.7163	2792.69	2488.7	14.811	0
	14	102.597	2873.14	2486.69	16.0471	0
	15	110.477	2955.91	2484.65	17.2837	0
	16	118.358	3040.35	2482.59	18.5212	0
	17	126.238	3126.45	2480.49	19.7595	0
	18	134.119	3213.47	2478.37	20.9985	0
	19	141.999	3302.9	2476.22	22.2383	0
	20	149.88	3392.41	2474.04	23.479	0

Variables

First Node Pressure 1425 (psig)

Solution

Solution Details

Gas Rate	54.795	MMscf/day
Oil Rate	5041.1	STB/day
Water Rate	36.8	STB/day
Solution Node Pressure	2498.44	psig
Wellhead Pressure	1425.12	psig
Wellhead Temperature	126.49	deg F
First Node Temperature	126.49	deg F
Total Skin	25.00	
Total dP Skin	8.56	psi
dP Friction	-195.53	psi
dP Gravity	-876.79	psi

T - Velocity Less Than Turner Criteria

Table 5: System Results at First Node Pressure = 1500psig

Results

		Gas Rate (MMscf/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)	dP Perforation (psi)
T	1	0.15	6358.63	2510.62	0.023438	0
T	2	8.03053	2410.88	2508.94	1.25317	0
T	3	15.9111	2353.44	2507.24	2.48364	0
T	4	23.7916	2344.29	2505.51	3.71436	0
T	5	31.6721	2354.59	2503.76	4.9458	0
	6	39.5526	2374.13	2501.97	6.17773	0
	7	47.4332	2436.73	2500.16	7.41016	0
	8	55.3137	2591.41	2498.32	8.64331	0
	9	63.1942	2668.6	2496.45	9.87695	0
	10	71.0747	2725.93	2494.55	11.1116	0
	11	78.9553	2775.18	2492.63	12.3411	0
	12	86.8358	2826.67	2490.68	13.5757	0
	13	94.7163	2881.88	2488.7	14.811	0
	14	102.597	2959.27	2486.69	16.0471	0
	15	110.477	3039.47	2484.65	17.2837	0
	16	118.358	3121.09	2482.59	18.5212	0
	17	126.238	3205.67	2480.49	19.7595	0
	18	134.119	3290.2	2478.37	20.9985	0
	19	141.999	3376.95	2476.22	22.2383	0
	20	149.88	3465.17	2474.04	23.479	0

Variables

First Node Pressure 1500 (psig)

Solution

Solution Details

Gas Rate	50.627	MMscf/day
Oil Rate	4657.6	STB/day
Water Rate	34.0	STB/day
Solution Node Pressure	2499.41	psig
Wellhead Pressure	1499.86	psig
Wellhead Temperature	127.11	deg F
First Node Temperature	127.11	deg F
Total Skin	25.00	
Total dP Skin	7.91	psi
dP Friction	-139.63	psi
dP Gravity	-859.26	psi

T - Velocity Less Than Turner Criteria

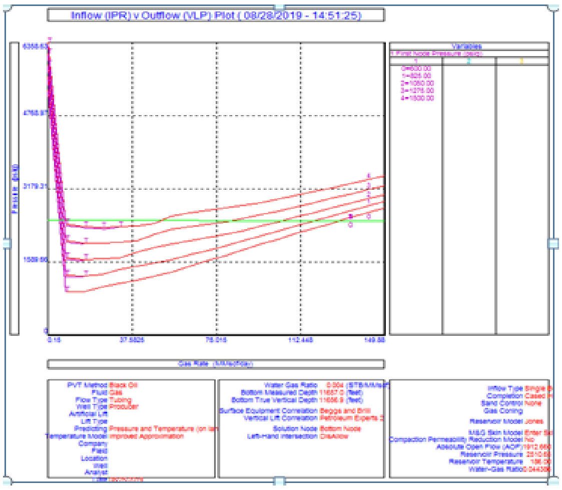


Fig 4: First Node Pressure VLP (or TPC) Sensitivity

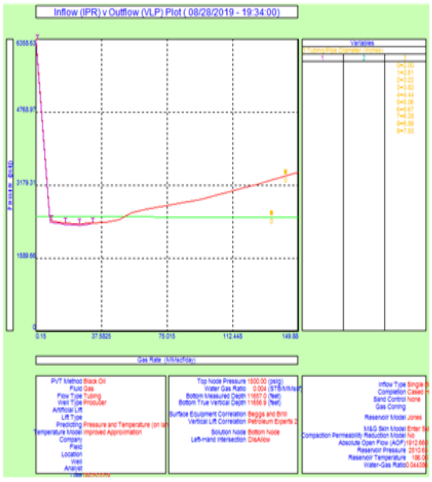


Fig 7: Tubing Size - Tubing Vertical Lift Performance Sensitivity Analysis

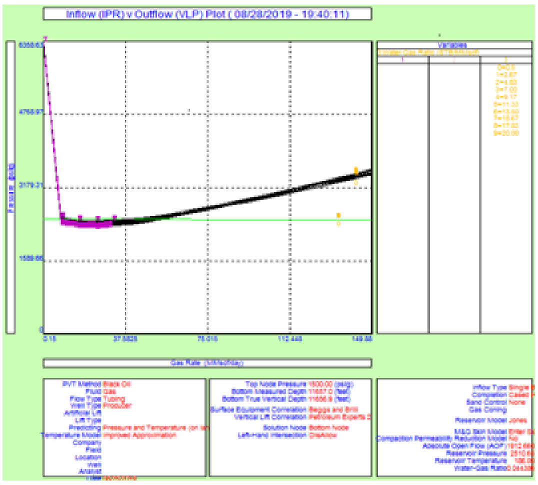


Fig 5: Water- Gas Ratio VLP (or TPC) Sensitivity

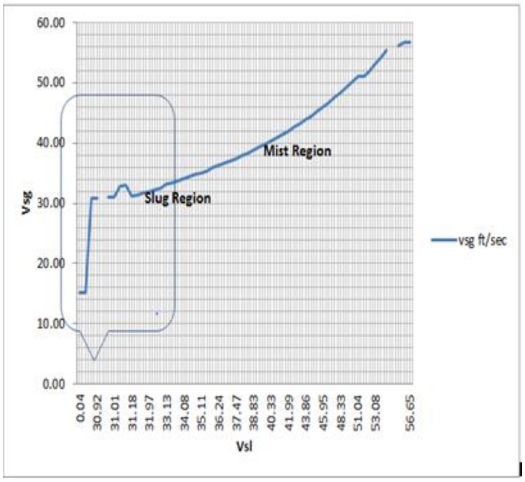


Fig 8: Effect of Gas Slip on Well Profile Flow Regime

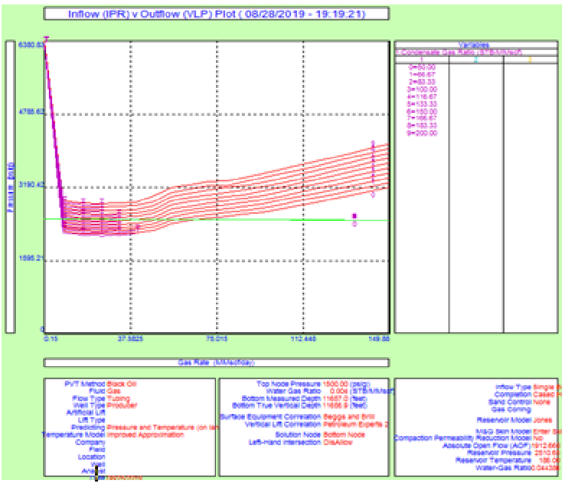


Fig 6: Condensate- Gas Ratio VLP (or TPC) Sensitivity

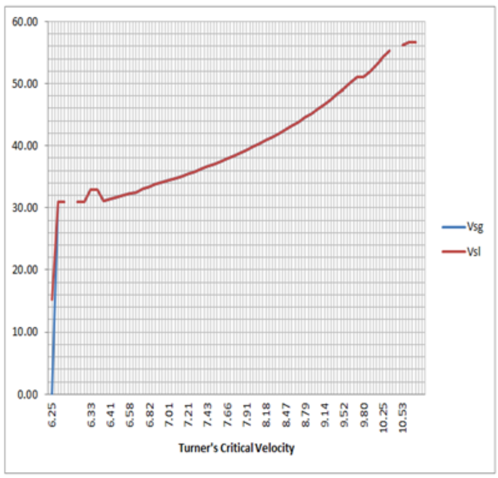


Fig 9: Effect of Gas-Liquid Slip-on Turner's Critical (Minimum Unloading) Rate

Table 6: Flow Profile Variables @Pwh=1200psig

S/N	TVD Ft	PRESSURE psig	TEMP ^{0}F	REGIME	dp/dl Friction psi/ft	dp/dl Gravity psi/ft	Vsl ft/sec	Vsg ft/sec	Turner Cri.Vel ft/sec
1.00	11656.90	2489.72	179.63	-	0.00	0.00			
2.00	11629.90	2487.41	179.55	Slug	0.11	2.19	0.04	15.16	6.24
3.00	11602.90	2485.10	179.46	Slug	0.23	4.39	0.04	15.17	6.25
4.00	11575.90	2481.94	179.36	Mist	1.15	6.62	30.89	30.89	6.30
5.00	11548.90	2478.78	179.27	Mist	2.08	8.85	30.92	30.91	6.30
6.00	11548.90	2478.22	179.27	**Restriction**	2.08	8.85	30.92	30.91	6.30
7.00	11503.40	2472.89	179.10	Mist	3.64	12.61	30.96	30.96	6.31
8.00	11457.90	2467.57	178.93	Mist	5.20	16.37	31.01	31.00	6.32
9.00	11445.40	2466.04	178.89	Mist	5.70	17.40	32.92	32.92	6.33
10.00	11432.90	2464.52	178.84	Mist	6.19	18.43	32.94	32.94	6.33
11.00	11183.70	2435.42	177.92	Mist	14.81	38.88	31.18	31.18	6.36
12.00	10934.50	2406.41	176.99	Mist	23.51	59.16	31.44	31.44	6.41
13.00	10685.40	2377.50	176.05	Mist	32.29	79.27	31.71	31.70	6.47
14.00	10436.20	2348.67	175.10	Mist	41.15	99.21	31.97	31.97	6.52
15.00	10187.00	2319.92	174.14	Mist	50.09	118.98	32.25	32.25	6.58
16.00	9937.80	2291.26	173.16	Mist	59.12	138.57	32.54	32.54	6.64
17.00	9439.50	2234.20	171.19	Mist	77.45	177.25	33.13	33.13	6.76
18.00	9190.30	2205.79	170.19	Mist	86.75	196.32	33.44	33.44	6.82
19.00	8941.10	2177.47	169.17	Mist	96.15	215.21	33.76	33.75	6.88
20.00	8692.00	2149.22	168.15	Mist	105.64	233.92	34.08	34.08	6.94
21.00	8442.80	2121.06	167.11	Mist	115.24	252.45	34.41	34.41	7.01
22.00	8193.60	2092.98	166.07	Mist	124.94	270.80	34.76	34.76	7.07
23.00	7944.40	2064.97	165.01	Mist	134.74	288.96	35.11	35.11	7.14
24.00	7695.30	2037.04	163.94	Mist	144.66	306.94	35.48	35.48	7.21
25.00	7446.10	2009.19	162.86	Mist	154.68	324.73	35.85	35.85	7.28
26.00	7196.90	1981.41	161.78	Mist	164.82	342.33	36.24	36.24	7.35
27.00	6947.70	1953.71	160.67	Mist	175.08	359.74	36.63	36.63	7.43
28.00	6698.50	1926.07	159.56	Mist	185.45	376.95	37.05	37.05	7.50
29.00	6449.40	1898.51	158.44	Mist	195.96	393.98	37.47	37.47	7.58
30.00	6200.20	1871.01	157.31	Mist	206.59	410.80	37.91	37.91	7.66
31.00	5951.00	1843.57	156.16	Mist	217.35	427.43	38.36	38.36	7.74
32.00	5701.80	1816.20	155.00	Mist	228.25	443.85	38.83	38.83	7.83
33.00	5452.70	1788.88	153.83	Mist	239.29	460.08	39.31	39.31	7.91
34.00	5203.50	1761.62	152.65	Mist	250.49	476.10	39.81	39.81	8.00
35.00	4954.30	1734.41	151.46	Mist	261.83	491.92	40.33	40.33	8.09
36.00	4705.10	1707.25	150.25	Mist	273.33	507.52	40.86	40.86	8.18
37.00	4456.00	1680.13	149.03	Mist	285.00	522.92	41.42	41.42	8.28
38.00	4206.80	1653.05	147.80	Mist	296.84	538.11	41.99	41.99	8.37
39.00	3957.60	1626.01	146.55	Mist	308.85	553.09	42.59	42.59	8.47
40.00	3708.40	1599.00	145.29	Mist	321.04	567.85	43.21	43.21	8.58
41.00	3459.20	1572.02	144.02	Mist	333.42	582.39	43.86	43.86	8.68
42.00	3210.10	1545.07	142.74	Mist	345.99	596.71	44.53	44.53	8.79
43.00	2960.90	1518.13	141.44	Mist	358.77	610.82	45.22	45.23	8.90
44.00	2711.70	1491.20	140.12	Mist	371.75	624.69	45.95	45.95	9.02
45.00	2462.50	1464.28	138.79	Mist	384.95	638.35	46.71	46.71	9.14
46.00	2213.40	1437.36	137.45	Mist	398.38	651.77	47.50	47.50	9.26
47.00	1964.20	1410.43	136.09	Mist	412.04	664.97	48.33	48.33	9.39
48.00	1715.00	1383.48	134.71	Mist	425.95	677.93	49.19	49.19	9.52
49.00	1465.80	1356.50	133.31	Mist	440.12	690.66	50.10	50.10	9.66
50.00	1216.70	1329.49	131.90	Mist	454.56	703.16	51.04	51.04	9.80
51.00	1216.70	1329.49	131.90	Mist	454.56	703.16	51.04	51.04	9.80
52.00	967.50	1302.42	130.47	Mist	469.29	715.41	52.04	52.04	9.94
53.00	718.30	1275.29	129.03	Mist	484.32	727.42	53.08	53.08	10.09
54.00	469.10	1248.09	127.59	Mist	499.66	739.19	54.19	54.18	10.25
55.00	220.00	1220.81	126.13	Mist	515.33	750.71	55.35	55.35	10.41
56.00	220.00	1220.43	126.13	**SSSV**	515.33	750.71	55.35	55.35	10.41
57.00	129.50	1210.50	125.58	Mist	521.10	754.83	56.20	56.20	10.53
58.00	39.00	1200.55	125.01	Mist	526.92	758.92	56.65	56.65	10.59
59.00	39.00	1200.55	125.01	**WellHead**	526.92	758.92	56.65	56.65	10.59