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Tubing Anchors Can Reduce Production Rates and Pump Fillage

James N. McCoy, O. Lynn Rowlan, Carrie A. Taylor*, Echometer Company
A.L. Podio, University of Texas

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Abstract

Modern completion techniques have greatly increased the production rate capability of wells. Many wells have the potential to produce more liquid and gas, but the use of tubing anchors in certain wellbore locations chokes the gas flow up the casing and results in increased back pressure against the formation that restricts production from the well. A gaseous liquid column can form above the tubing anchor and cause high pressure in the gas below the tubing anchor that restricts the liquid and gas flow from the reservoir.

Often times, low pump fillage and low production rates are blamed on a poor gas separator when actually the separator is operating efficiently and is separating the liquid from the gas. In the condition described, all of the liquid in the wellbore below the tubing anchor falls to the pump and is being removed by the pump. The problem is that high pressure in the gas column below the tubing anchor is restricting production from the well. Additional production is available if the high pressure that is restricting production from the formation is removed. The accumulation of a gaseous liquid column above the tubing anchor when constant low pump fillage is observed indicates that liquid exists above the tubing anchor when only free gas exists from the tubing anchor down to the pump. Limited liquid production falls down the casing wall while the casing annulus is almost completely filled with gas if the pump is set below the formation⁶.

Field testing using automated fluid level measurement equipment to perform liquid depression tests verifies that a gaseous liquid column exists⁹ above the tubing anchor and a gas column exists below the tubing anchor in wells with high fluid levels, low pump fillage, and with the tubing anchor located above the pump. This field data was acquired on several wells and is shown to verify the above analysis of the well's performance. This fluid distribution condition is not generally known.

Locating the tubing anchor below the pump prevents this condition and will improve production in these wells.

Introduction

When a naturally flowing well is no longer capable of performing per its desired or designed production rate, artificial lift methods are installed to improve performance and increase production. To optimize rod pumped well performance, pumping system designs ideally match pump displacement to the inflow of fluids from the formation by controlling pumping unit speed, stroke length, plunger diameter and pumping unit runtime. Sufficiently matching fluid inflow from the formation to pump displacement will typically keep fluid levels a few hundred feet above the pump intake. When the fluid level is located just above the pump intake, the majority of producing bottomhole pressure (PBHP) then comes from the pressure exerted at the gas/liquid interface which results in a lower back pressure against the reservoir, yielding a higher drawdown and better production. Generally, high casing pressure

and/or high fluid levels are the main causes of high producing bottomhole pressures which decrease the production from the reservoir resulting in a decline in production reaching the surface.

Producing Bottomhole Pressures Impact Well Performance

Fig. 1 below displays the analysis of a typical fluid level shot, with casing pressure buildup rate, PBHP and Pump Intake Pressure (PIP) calculations, as well as the potential production available as determined by the Vogel Inflow Performance Relation (Vogel IPR) curve, which compares PBHP to Static Bottomhole Pressure (SBHP) or reservoir pressure. In order for an accurate IPR determination, the current PBHP and well test must be obtained and SBHP must be representative of current reservoir conditions. To accurately determine SBHP, the well must be shut in for a sufficient period of time for the fluid level and casing head pressure to stabilize.

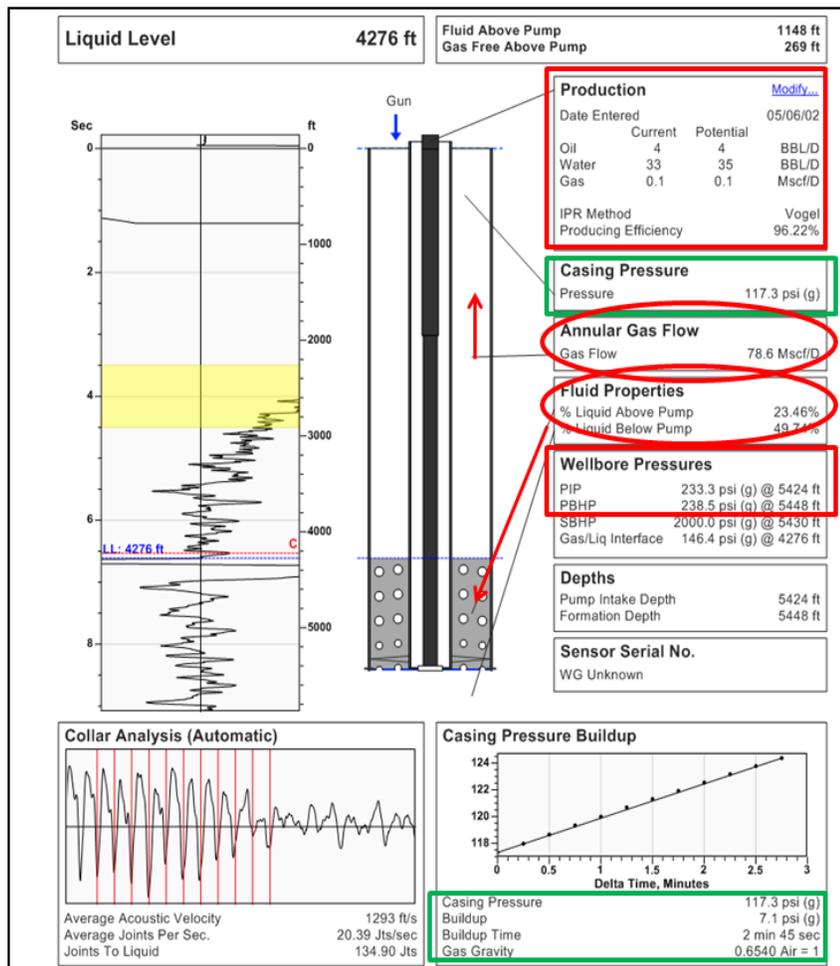


Fig. 1: Example fluid level analysis to obtain Gas/Liquid interface pressure, % Liquid above the pump, Producing Bottomhole Pressure (PBHP) and Pump Intake Pressure (PIP)

When producing bottomhole pressure increases enough to cause the flow rate from the formation to decrease, measures should be taken to determine the major cause of high producing bottomhole pressure and adjustments should be made to the pumping system to lower producing bottomhole pressure and increase production. For example, a high gas free fluid level on a producing well will increase PBHP, which in turn decreases the drawdown on the formation, slowing the desired inflow performance from the reservoir. When a high fluid level exists and pump volumetric efficiency is high³, meaning maximum effective plunger travel is utilized and full pump loads are produced to surface, adjustments can be made to the pumping system, i.e. Increasing pumping unit speed or

increasing pump size, to lower the fluid level to the pump intake thereby lowering the producing bottomhole pressure and increasing inflow from the formation. However, when a high fluid level exists and pump volumetric efficiency is low due to a mixture of fluid and gas at the pump intake, indicating incomplete pump fillage due to gas interference⁷, further measures must be considered to deal with the problem of gas separation below the pump. Low pump fillage due to gas interference causes produced fluids to accumulate in the wellbore rather than being delivered by the pump into the bottom of the tubing at the desired rate. The annular fluid level then increases and expands into a high gaseous liquid column.

The most effective solution for incomplete pump fillage due to gas interference is to locate the pump intake below the gas and fluid entry zone of the formation^{1,2,3}. Consider the schematic diagram seen in **Fig. 2** below.

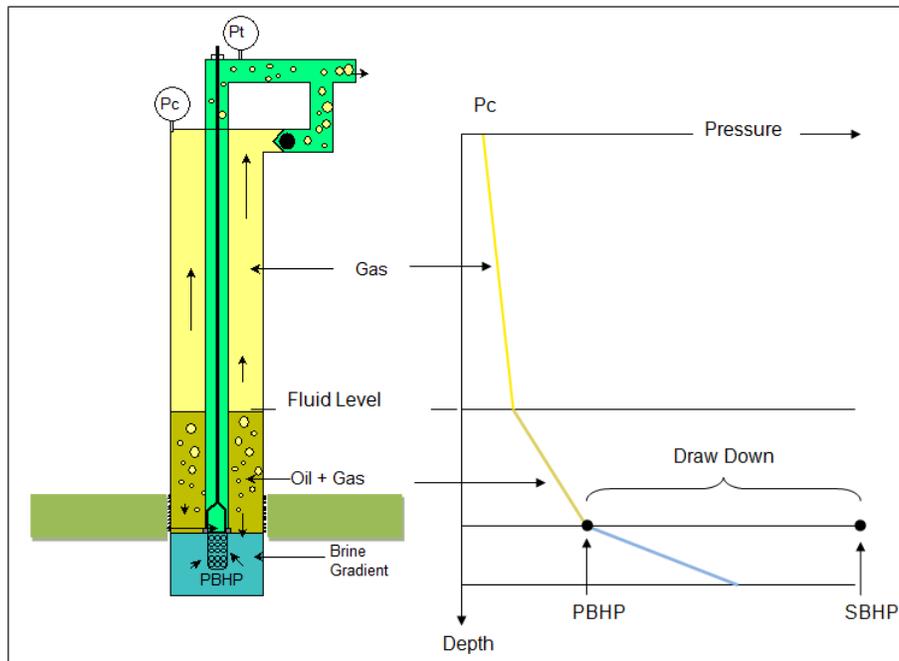


Fig. 2: Wellbore Pressure Distribution in a Stabilized Producing Well Using Natural Gas Separator

Fig. 2 illustrates the relation of wellbore pressure distribution of a producing well operating in a stabilized condition, with the pump intake set a few feet below the fluid entry zone. The fluid level and casing head pressure are constant, and all fluids (oil, water and gas) entering the wellbore are being produced at the surface at a constant rate. A gaseous liquid column (oil and gas) exists above the pump intake, while fluid below the pump intake is primarily brine with very low free gas concentration. The diagram on the right hand side of the schematic displays the pressure vs. depth relationship of the casing head pressure (P_c), the gas column pressure and the fluid column pressure to the stabilized producing Drawdown capabilities ($SBHP - PBHP$) of the well. It can be deduced from the diagram that for a given casing head pressure (P_c), a fluid level just above the pump intake results in a lower producing bottomhole pressure ($PBHP$) and a higher drawdown on the formation ($SBHP$)⁵.

Downhole Gas Separation

All gas separators for rod pumped wells work on the basic principle of gravity separation. A “Natural Downhole Gas Separator” shown in **Fig. 3** below takes advantage of natural separation due to gravity segregation of the gas and liquid phases when the pump intake is set below the fluid entry zone^{4,6}. Utilizing natural gas separation, liquids flow downward from the perforations to the tubing intake while the majority of the gas flows up through the annulus and to the surface.

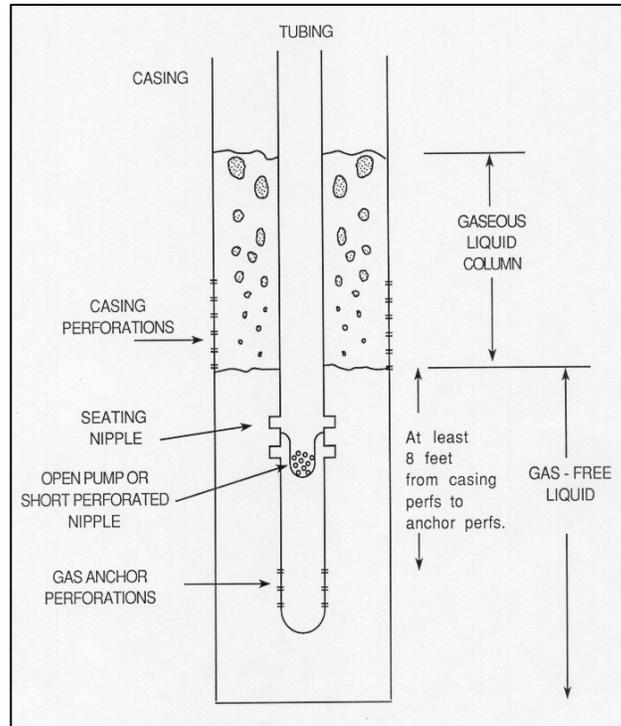


Fig. 3: Natural Downhole Gas Separator – Pump Intake Set Below Fluid Entry Zone

The ability of the gas to efficiently separate from the liquid in any gas separation system is dependent upon the downward liquid velocity in the casing annulus¹. Downward annular liquid velocity less than or equal to 6 inches per second¹⁰ allows the majority of gas entering the wellbore from the formation to overcome drag forces from the downward flowing liquid and move upward so that mainly liquid is present at the pump intake. When downward liquid velocity exceeds 6 inches per second, gas is unable to effectively separate from the liquid and the gas separator's efficiency is greatly reduced. Gas separation failure causes a larger volume of gas to be dragged into the pump, resulting in decreased volumetric efficiency. The downward liquid velocity can be determined by comparing a ratio of the pump flow rate to the annular area. For example, the liquid separation capacity of a pumping well completed with 5-1/2 inch 17#/ft casing and 2-3/8 inch 4.6 #/ft tubing, with the pump intake set below the fluid entry zone (Natural Downhole Gas Separator) and an annular area of 14.4 square inches results in a liquid separation capacity of 769 BBL/D.

The most effective downhole gas separators locate the pump intake below the lowest gas entry point. Gas is not pulled down to the pump perforations unless the liquid velocity is greater than 6 inches per second. Maximum annular capacity is utilized when a pumping system is designed using a Natural Downhole Gas Separator because nothing can be run in the wellbore that will provide more separation area than the annulus itself.

Downhole gas separation is one of the biggest problems in medium and high volume producing wells. Fluid is present in the annulus, but due to the gas producing from the formation, low pump fillage due to gas interference limits production capabilities and overall well performance. Often the pump intake is set above the formation and other gas separation options must be considered.

The key to choosing and installing an efficient downhole gas separator is to choose a separator that will maximize the area used for separation. An efficient downhole gas separator will increase the pump liquid fillage percentage over the percentage of liquid present in the wellbore at the pump intake. Setting the pump intake above the fluid entry zone³ in a well will create difficulties with gas separation, but a number of gas separators exist to assist in increasing pump fillage and production of fluids to the surface.

Field Study of Downhole Gas Separator Effectiveness

Often times, low pump fillage and low production rates are blamed on a poor gas separator when actually the separator is operating effectively and is separating the liquid from the gas. Proper gas separator selection, when the pump intake is above the formation, must take into account casing annulus gas production rate and the well's net pump capacity (Pump Displacement – Pump Slippage). The percentage of pump liquid fillage on rod pumped wells is routinely computed from downhole pump dynamometer card analysis. Fluid level and dynamometer measurements can be performed to determine gas separation effectiveness by comparing the fluid level survey analysis of gas flow rate and percent liquid in the annulus, and the effective pump displacement from the downhole pump dynamometer card.

Using fluid level and dynamometer analysis comparisons for a number of producing wells in the Sprayberry Trend located in the Permian Basin in West Texas, an effectiveness study was performed to measure the performance of wells completed with both natural and packer-type gas separators^{2,4}. In **Fig. 4** below, the performance evaluation graph on the right hand side plots the percentage of liquid in the annulus from the fluid level survey to the percentage of effective pump fillage from the dynamometer pump card⁶. The symbols indicate the type of downhole gas separator installed in each well. The diagonal line represents the boundary where the percent liquid in the annulus at the pump intake is equal to the percent pump fillage. Wells with the pump intake set high above the fluid entry zone have been completed with Packer Type separators and are indicated by circles. Wells using a Natural Gas Separator with the pump intake below the fluid entry zone or “in the Rat Hole” are indicated by triangles.

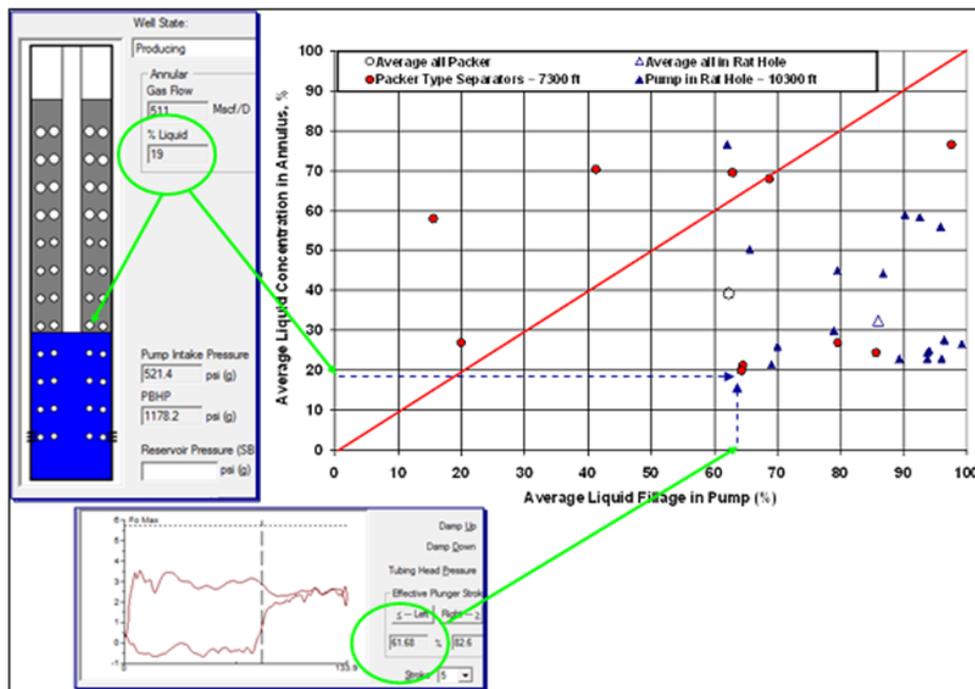


Fig. 4: Field Study Evaluation Graph of Gas Separator Performance

To the left of the graph in Fig. 4, the fluid level survey and dynamometer pump card measurement for one of the evaluated wells, typical for the region, is shown. This well, located in the Wolfberry Formation near Big Spring, Texas, USA, has a formation depth of 10,400 feet, a gas/oil ratio (GOR) of 3,941 (SCF/B), with a water cut of 43.1%. The fluid densities are 41.2 degree API gravity oil, 1.035 specific gravity water, and .831 gas gravity.

The casing pressure buildup measurement from the fluid level survey equates to a very high gas flow rate of 511 MSCF/D and a low 19% liquid concentration in the annulus above the pump intake. The percent liquid concentration is the calculated percentage of liquid present in the annular gaseous liquid column⁵. The effective pump fillage computed from the dynamometer measurement is approximately 62%. While pump fillage does not reach a desired 100%, 62% pump fillage on this well with the pump set several thousand feet above the fluid entry zone where the liquid concentration is a low 19% indicates the downhole gas separator is effectively increasing the liquid concentration in the pump by a factor of 3. The packer-type gas separator on this well is significantly improving pump volumetric efficiency.

Viewing each variable on the graph similarly, wells plotted above the diagonal line had poor gas separation resulting in low pump fillage percentages compared to the liquid concentration available in the annuli. The gas separators are even preventing fluids from reaching the pump. Wells plotted below the diagonal line had a pump fillage percentage that was higher than the percent liquid concentration in the annulus, indicating good gas separation and improved production. Wells plotted furthest to the right correspond to the highest percentage pump liquid fillage and the most efficient gas separators.

What If Natural Downhole Gas Separation Doesn't Work?

As previously discussed, the best gas separation performance is obtained by locating the pump intake below the gas entry point due to the fact that the largest separation area is achieved by using the casing annulus. The highest pump volumetric efficiency (100% pump liquid fillage) would be expected on wells using a Natural Gas Separator. However, of the 17 wells shown in Fig. 4 which were completed with the pump intake below the fluid entry zone, 9 have between 60% and 90% pump liquid fillage and maintain fluid levels several thousand feet above the pump – further indication of low effective pump displacement and questionable gas separation.

Further testing and evaluations were performed on ten additional wells in the Wolfberry Formation (**Table 1** below) exhibiting the same performance and with similar wellbore characteristics as those tested in the downhole gas separator effectiveness study described in the previous section. The testing was done to better understand why natural downhole gas separation performance was much less effective than expected.

Well ID	Run Time Hrs/Day	Produced BBL/D	% Pump Fillage	Tubing Anchor Above Perforations
A	10	22	28-100 cycles	Y
B	3	21	15	N
C	4	30	30	N
D	20	67	12-75 cycles	Y
E	11	71	22-100 cycles	Y
F	24	190	100 constant	N
G	24	81	100 constant	N
H	10-24	82	37	N
I	4-6	26	30	Y
J	24	165	100 constant	N

Table 1: Summary of Production Performance and Wellbore Characteristics of Wells Using Natural Gas Separation

With initial concentration on wells in Table 1 exhibiting low run times and low pump fillage, long term dynamometer measurements were acquired along with a series of fluid level surveys with the pump operating “on-hand” rather than by Pump Off Controller (POC). The dynamometer pump card and fluid level measurement comparison in **Fig. 5** below displays dynamometer results from Well B listed in Table 1. The pump intake is set 135

feet below the fluid entry zone. Setting the pump intake below the perforations or “in the rat hole” is considered the most effective form of downhole gas separation.

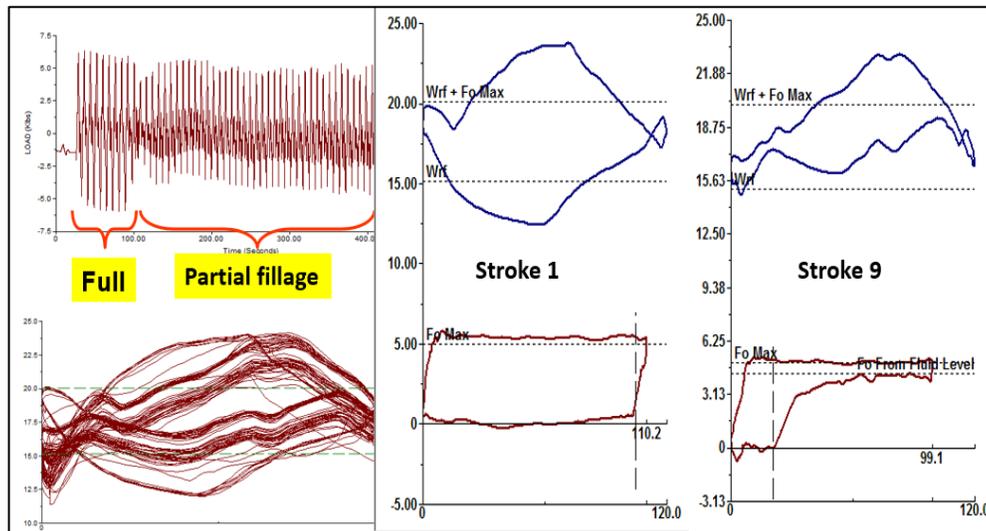


Fig. 5: Well B Dynamometer Measurement - High Fluid Level and Natural Gas Separation

The following observations were made from the measured data acquired on Well B:

- The fluid level analysis showed a high fluid level due to a gaseous liquid column extending 3193 feet above the pump.
- 28% liquid concentration existed in the casing annulus at the pump intake with a 59 MSCF/D gas flow rate measurement from the casing pressure buildup during the fluid level survey.
- The high pump fillage (near full pump at almost 100% pump liquid fillage) observed when the pumping unit was started up lasts only 10 strokes.
- Pump liquid fillage drops immediately to approximately 25% where it stabilized for the remainder of the dynamometer survey.

With the high fluid level and with the pump set below the perforations, it is most interesting that the pump is not filled with liquid. The stabilized 25% pump fillage of the dynamometer card is characteristic of a well that is pumped off⁷ (suggesting there is not sufficient liquid in the annulus to fill the pump barrel). Sufficient liquid to fill the pump should be available, as shown by the high gaseous liquid column remaining constant above the pump. Fluid level and dynamometer surveys performed in other wells yielded similar conclusions. Repeating cyclical pump liquid fillage behavior (full pump liquid fillage decreasing to partial liquid fillage then increasing again) observed in some of the wells occurred even though no cycle change in the liquid level occurred during the time of the dynamometer survey.

Summary of initial tests and observations of wells in Table 1:

- Wells A, D, E – Long term dynamometer tests observed cyclical full to partial liquid pump fillage, constant high fluid level.
- Wells B, C, H, I – Long term dynamometer tests observed a full pump for a few initial strokes at pumping unit start-up then dropping and stabilizing at low partial liquid fillage, constant high fluid level.
- Wells F, G, J – Testing proved to be consistent with 100% constant pump fillage.

Another reason for low volumetric efficiency, or partial liquid fillage, is incomplete pump fillage due to some type of flow restriction⁷. In a restricted flow scenario, annular fluids are obstructed from entering through the pump intake at a sufficient rate to fill the pump barrel with liquid during the plunger upstroke. Possible sources of annular obstructions include scale, paraffin, sand, rust or even obstructions caused by mechanical configurations creating a “choked pump”. Any of these possible obstructions would restrict fluid from flowing from the wellbore into the pump. A comparison of the wellbore schematics while searching for similarities of the wells’ downhole designs showed a tubing anchor located above the fluid entry zone in wells A, D, E and I. The tubing anchor common in these wells provided a small 2.9 square inch flow area as compared to the large annular 14.4 square inch annular flow area used as the Natural Gas Separator in the wellbore.

Further analysis of the data, while considering the common factor of a tubing anchor above the pump, resulted in the following possible scenario:

The tubing anchor and the gaseous liquid column combine to create a choke mechanism that regulates gas flowing up the casing annulus. Gas accumulates beneath the tubing anchor, where sufficient gas flowing up the annulus is regulated to maintain the gaseous liquid column above the anchor, plus free gas fills the annular volume below the anchor to the pump. The pressure at the tubing anchor controls the gas column contained in the annular volume between the anchor and the pump. High pressure in the free gas column between the tubing anchor and the pump inhibits the inflow of fluids from the formation, resulting in a “pumped off” diagnostic pump card shape.

Fig. 6 illustrates the annular fluid distribution both above and below the tubing anchor, and the scenario is further described in the following paragraphs.

Fluid enters the wellbore from the formation. The pump is set below the fluid entry zone for natural gas separation of liquid and gas. The separated gas rises past the tubing anchor in the annulus to the surface. A vapor condensate is created from the cooling hydrocarbon gases as they rise toward the surface. Fluid entering the wellbore from perforations above the tubing anchor plus these condensed liquids cannot fall past the tubing anchor to the pump intake and will accumulate on top of the tubing anchor. The accumulated liquid sitting on top of the tubing anchor increases the fluid gradient of the gaseous liquid column⁸ above the tubing anchor “plate.” As the fluid gradient increases, the separated gas from the formation fluids begins to accumulate below the tubing anchor until the annular space below the tubing anchor and extending to the pump is almost completely filled with gas. Thus the gradient below the tubing anchor is essentially equal to the gradient of a gas column. Regulated flow of free gas which has accumulated below the tubing anchor now maintains the gaseous liquid column above the tubing anchor.

Liquid produced through the perforations slides down the casing wall on the low side of the wellbore and falls to the pump set below the fluid entry zone. The pump removes the accumulated fluids until the pump displacement rate exceeds the liquid inflow from the formation and partial liquid fillage occurs. Even though the well appears to have “pumped off,” the gaseous liquid column above the tubing anchor remains constant. This fluid distribution behavior correlates to the fluid level survey and dynamometer measurements observed on the field tested wells.

Thus, a tubing anchor located above the pump provides a means for gas to accumulate between the tubing anchor and the pump caused by back pressure from the gaseous liquid column above the tubing anchor. The choking mechanism of the tubing anchor and the gaseous liquid column choke the gas flow up the casing which results in increased back pressure against the formation and restricted flow into the wellbore.

A second condition exists when the tubing anchor and the pump are set above the perforations. The problem occurs when high pressure gas below the tubing anchor preferentially fills the pump with gas and the restricted fluid inflow at this high pressure.

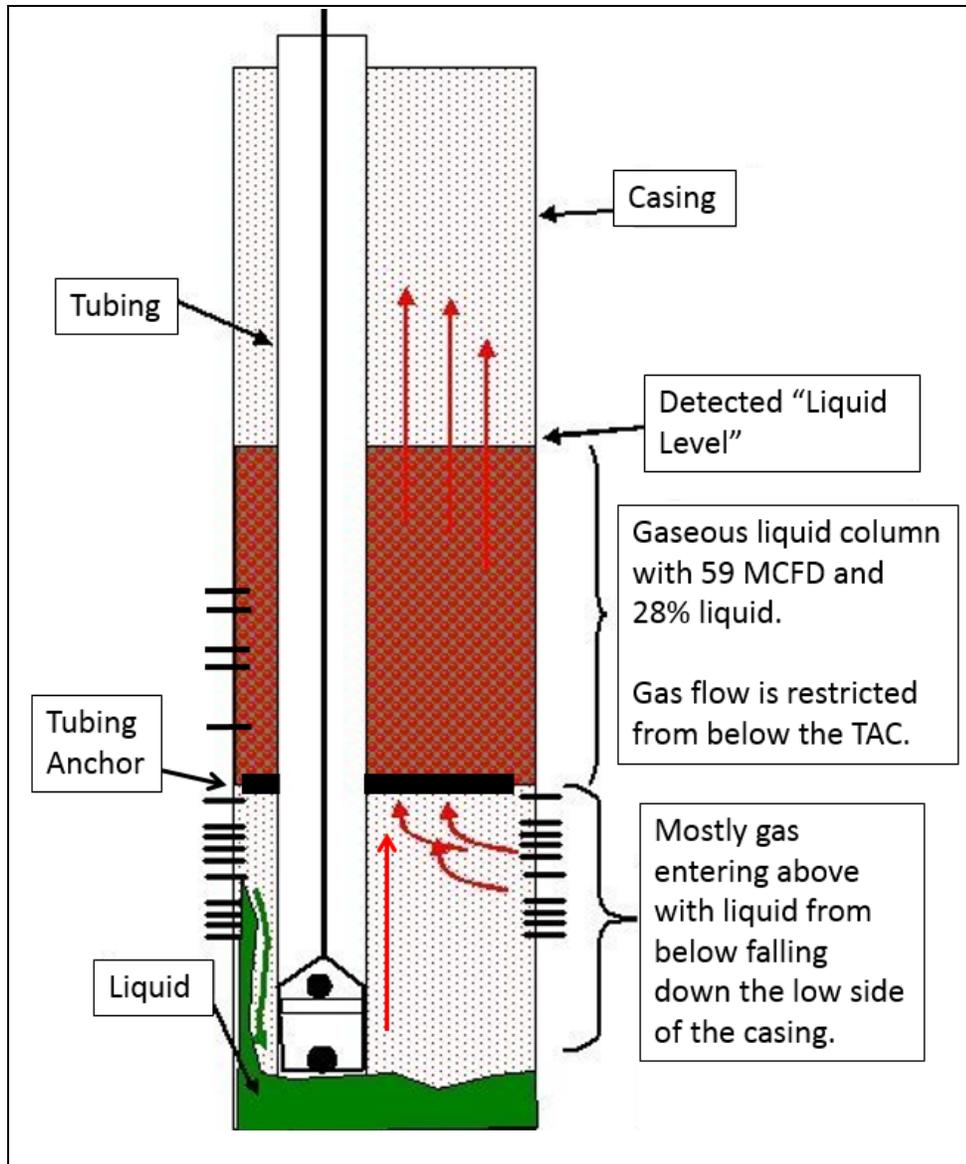


Fig. 6: The Tubing Anchor and Gaseous Liquid Column Combine to Create a Choke Mechanism

Liquid Level Depression Tests Confirm Choke Mechanism Hypothesis

Proof of the existence of the accumulated free gas column below the tubing anchor was needed to confirm the problem created by the tubing anchor location above the pump. Liquid level depression tests are widely used to determine the annular fluid gradient and producing bottomhole pressures in pumping wells¹⁰. Fluid level measurements as a function of casing head pressure are obtained while the well is pumping at a constant rate. Increasing the casing head pressure depresses the fluid level proportionate to the casing pressure increase. The annular fluid gradient can then be estimated by equating the change in fluid level depth to the change in casing head pressure.

In order to confirm the existence of the accumulated gas column between the tubing anchor and the pump, the absence of liquid needed to be verified. The liquid level depression test would confirm either 1) a continuous

gaseous liquid column extending all the way to the pump intake, or 2) a sharp drop due to a liquid free gas column as the fluid level is pushed below the depth of the tubing anchor.

The procedure for the liquid level depression tests was as follows:

1. Perform fluid level and dynamometer measurements to verify the liquid level is above the tubing anchor and confirm that incomplete pump fillage is occurring.
2. Shut down the well for 10 minutes. Upon restarting, if the pump is full for only a few strokes then changes to incomplete pump fillage while the annulus maintains a liquid level above the tubing anchor, then the liquid level depression test should be performed on the well.
3. Close the casing valve to build casing pressure and depress the liquid level. Continue to pump the well.
4. Obtain fluid level measurements every 15 minutes as the casing head pressure builds and the liquid level is depressed.
5. Acquire 4-5 additional shots after the liquid level is depressed past the tubing anchor to continue monitoring of the liquid level.
6. Run additional shots until the liquid level is stabilized.

Wells B, E and H from Table 1 were selected for monitoring using the liquid level depression test. Automatic fluid level depths and pressures were obtained in 15 minute intervals using an automated fluid level instrument⁹ once the casing head valve to the flow line was closed. The pumping unit continued operating during the entire test.

Fig. 7 below shows the 800 minute resulting plot from the liquid level depression test performed on Well B. At 2:21AM, the liquid level is at the tubing anchor located at 9140 feet. Fifteen minutes later at 2:36AM, the liquid level is at the pump intake depth of 10,181 feet. The liquid level depression test verifies the existence of a gas column with very little liquid below the tubing anchor.

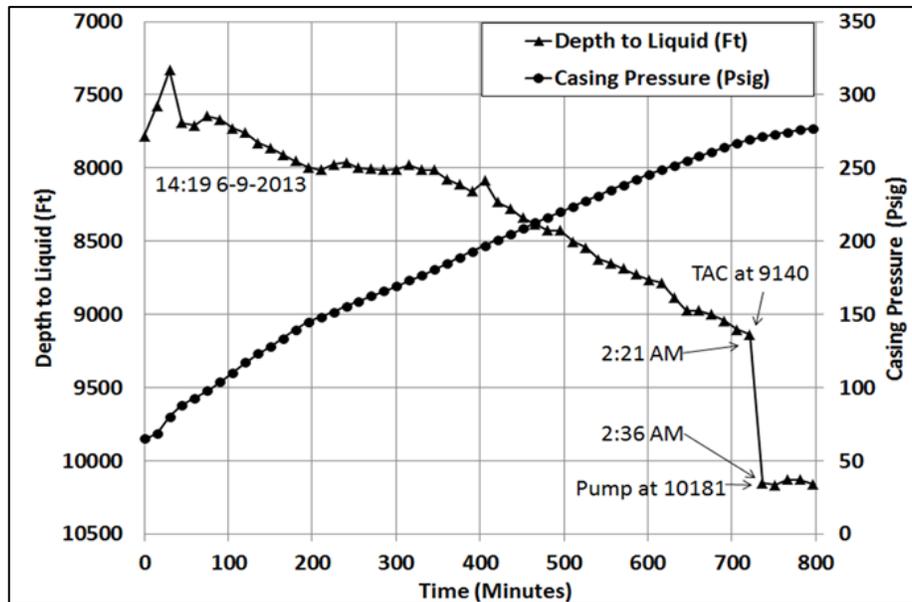


Fig. 7: Example 1 – Summary of Liquid Level Depression Test, Well B

Fig. 8 below shows the resulting plot of the casing head pressure and the depth to the liquid level versus time, summarizing the liquid level depression performed on Well H. At time 6:33:40PM, the liquid level is at 7659 feet and approaches the tubing anchor located at 7908 feet. Thirty minutes later, the liquid level has depressed approximately 250 feet and is at the tubing anchor. Ten minutes after the liquid level depressed past the tubing anchor, the liquid level has dropped almost 2700 feet to the pump intake depth of 10,599 feet where it stabilizes for the remainder of the test. This indicates that the area of the wellbore below the tubing anchor was filled with gas and very little liquid.

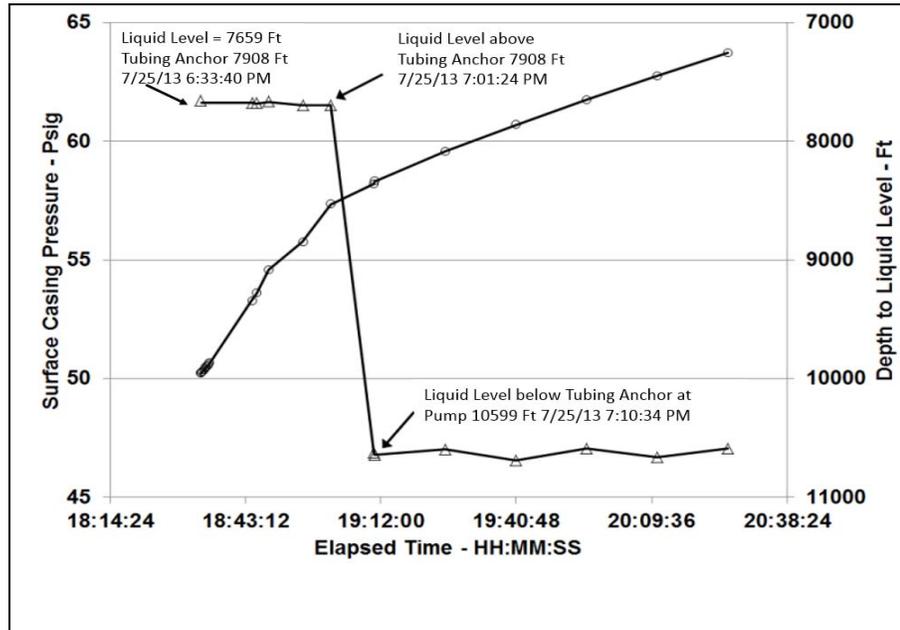


Fig. 8: Example 2 – Casing Pressure vs. Liquid Level Depth as a Function of Time, Well H

Similar behavior was observed in the liquid level depression test performed on Well E.

Tubing Anchors are Unexpected Problems

The combination of the tubing anchor and the gaseous liquid column causing gas to accumulate below the tubing anchor all the way down to the pump is an unexpected problem that the industry does not realize may exist in a significant number of wells. Rather than an effective separation of gas and liquid produced from the formation, the high pressure created from the accumulated gas below the tubing anchor restricts liquid inflow from the formation and forces gas directly into the pump. As a result, wells exhibit incomplete pump fillage and a restriction of inflow from the formation caused by back pressure created by the accumulated gas column and gaseous liquid column.

The first dilemma is determining how this problem can be detected.

Identify the problem:

- Natural Gas Separator or properly sized gas separator below the pump but incomplete pump fillage and high fluid level maintained above the tubing anchor.
- Pump liquid fillage increases to near full when restarting the pump after an extended shut down period.
- After restarting the pump the liquid fillage decreases and remains constant or oscillates between partial and full.

When these symptoms have been observed it is recommended that a liquid level depression test be undertaken, as described earlier in this paper, until liquid level falls below the tubing anchor depth. This test will validate the presence of the flow restriction caused by the tubing anchor.

It should be noted that although in the examples described in this paper the distance between the tubing anchor and the pump intake was several thousand feet, this is not a requirement for the tubing anchor to create additional back pressure. A similar problem may exist whenever the pump is set above the formation and is outfitted with a downhole gas separator that is located only a few joints below the tubing anchor. This is the recommended configuration used by operators when installing a downhole gas separator. The presence of the flow restriction caused by the tubing anchor could create a high concentration of gas at the separator intake and reduce pump liquid fillage. Gas accumulation below the tubing anchor indicates that it may be more efficient to install the tubing anchor below the downhole gas separator.

The second dilemma is determining whether the fluid and pressure distribution due to the presence of the tubing anchor and a high gaseous liquid column is causing a reduction in well production. The answer is dependent on the well's inflow performance characteristics. The liquid level depression test at the point when the fluid level drops below the tubing anchor gives a very good estimate of the existing producing bottomhole pressure. In the example shown in Fig. 7 when the casing head pressure reaches a value of 275 psi and the liquid level is at the pump intake the producing bottom hole pressure was estimated at 325 psi. If the 325 psi producing bottomhole pressure is high in comparison to the static bottomhole pressure, then the well is not being drawn down and high pressure gas is restricting inflow.

Recommendations:

Whenever it has been determined that the present location of the tubing anchor relative to the pump intake and the formation is causing a reduction in well flow (based on analysis of well's inflow performance) the following alternative solutions may be considered:

1. Locate both the tubing anchor and the pump intake below the bottom most perforations or producing formation. An On-Off tool may be used to secure the tubing below the fluid entry zone.
2. When the pump intake cannot be set below the formation, install a properly sized downhole gas separator¹ with the separator intake located above the tubing anchor. When the downhole gas separator is located above the tubing anchor, then the separator tensile and shear strength must be sufficient to allow setting the tubing anchor by tensioning or rotating the tubing string.
3. Use a packer type separator that includes a tubing anchor so that the tubing anchor cannot be a restrictor to gas flow.
4. Do not increase casing pressure with the intent to displace the fluid level below the tubing anchor. High casing pressure contributes to the problem of low productivity due to its impact on the PBHP.
5. The performance of a particular separator design that is below a tubing anchor should be compared to a predictive simulation to determine if it is operating normally. If the separator is not performing as predicted and there is a tubing anchor installed in the wellbore, a liquid level depression test will confirm whether the placement of the tubing anchor has contributed to restricted inflow from the formation.

Each of these alternatives have to be evaluated with regard to the specific well conditions of pressure and flow rate, the production of solids, corrosion and scaling problems and overall cost.

Conclusion

The combination of the tubing anchor and the gaseous liquid column causing gas to accumulate below the tubing anchor all the way down to the pump is an unexpected problem that most operators may not realize exists. The tubing anchor and the gaseous liquid column combine to create a choke mechanism that regulates gas flowing up the casing annulus. Gas accumulates beneath the tubing anchor, where sufficient gas flowing up the annulus maintains the gaseous liquid column above the tubing anchor and fills the annular volume below the anchor to the pump⁸. High pressure created from the accumulated gas below the tubing anchor reduces liquid flow from the formation and forces gas directly into the pump. As a result, wells exhibit incomplete pump fillage and a restriction of inflow from the formation due to the back pressure created by the accumulated gas column and gaseous liquid column. A liquid level depression test confirms the existence of an accumulated gas column between the tubing anchor and the pump. Liquid level depression tests should be run in all wells that suffer from partial pump fillage and exhibit a high annular gaseous liquid column extending above a tubing anchor installed above the pump. Gas accumulation below the tubing anchor indicates that it may be more efficient to install the tubing anchor below the downhole gas separator.

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