TUBING ANCHORS CAN RESTRICT PRODUCTION RATES AND PUMP FILLAGE

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ABSTRACT

When a high fluid level exists in a pumping well, a tubing anchor set some distance above the perforations can cause free gas to collect below the tubing anchor and restrict production from the formation and liquid entrance to the pump. The operator may think that a gaseous liquid column exists from the top of the fluid level down to the pump, when actually, the gaseous liquid column exists from the top of the fluid level down to the tubing anchor, and primarily free gas exists from the tubing anchor down to the pump. The gas that is collected below the tubing anchor causes back pressure against the formation and restricts production from the well. The operator may think that liquid is surrounding the pump and gas separator, when in actuality, very little liquid is in the wellbore below the tubing anchor. Liquid is not available to the pump and gas separator. The paper has field data that shows very little liquid exists around the pump and gas separator in some wells with high fluid levels having tubing anchors.

INTRODUCTION

Pumping systems are installed in wells that are not capable of flowing naturally at the desired or design production rate set by the operator. In these wells the production rate from the formation is controlled adjusting the pump displacement by selecting the pumping speed, stroke length and plunger diameter for rod pumped wells or the pump characteristics and RPMs in centrifugal pumps or progressing cavity pumps. When the pump volumetric efficiency is reduced by any combination of multiple causes the flow rate from the formation decreases as the produced fluids accumulate in the wellbore instead of being delivered by the pump into the bottom of the tubing at the desired rate. This causes the annular fluid level to increase (for a constant casing head pressure) to balance the producing bottom hole pressure (PBHP) that corresponds to the inflow performance characteristics of the reservoir. For this reason it is customary to associate the presence of a high fluid level in a pumping well with a reduction of the volumetric efficiency of the pump.

A frequent reason for inefficient down-hole pump operation is incomplete liquid fillage caused by gas interference. The most effective solution of this problem is to locate the pump intake in the section of the wellbore below the zone or zones of gas entry so as to take advantage of natural separation due to gravity segregation of the gas and liquid phases. **Figure 1** is a simplified schematic of what is defined as a "Natural Downhole Gas Separator" showing the liquid flowing downwards from the perforations to the tubing intake while the majority of the gas flows up through the annulus and to the surface[1]. In this system the efficiency of separation of gas from liquid is controlled by the downward liquid velocity in the annulus between the casing and the tubing. When the annular liquid velocity is less than or equal to about 6 inches per second the majority of the gas is able to overcome the drag forces caused by the liquid's downward motion and flow upwards so that mainly liquid reaches the entry to the pump. As the downward liquid velocity increases, above this 6 inch/second limit, a larger volume of gas is dragged down and into the pump. The pump's liquid displacement efficiency decreases accordingly. The downward liquid velocity is determined by the ratio of the pump flow rate to the annular area. In practical terms, a constant liquid rate of 53.4 Bbl/day flowing in a conduit that has a cross sectional area of 1 square inch results in an average liquid velocity of 6 inches per second. Thus the limit liquid rate for efficient gas/liquid separation can be established for a given casing/tubing diameter combination from knowledge of the annular area. For example a pumping well completed with 5-1/2 inch 17 #/ft casing and 2-3/8 inch 4.6 #/ft tubing the Natural Separator has an annular area of approximately 14.4 square inches which would result in a liquid separation capacity of 768 bbl/day.

WELLBORE PRESSURE DISTRIBUTION IN PUMPING WELLS

Figure 2 is a schematic diagram that illustrates the fluid and pressure distribution in a pumping well which has been completed with the pump intake a few feet below the bottom of the formation perforations. The pump has been operating long enough to have established a steady state condition so that the fluid level and casing head pressure are constant. All the fluids (oil, water and gas) that are entering the well through the perforations are being produced at the surface at a constant rate. We refer to this situation as a producing well at stabilized conditions. The fluid above the pump intake is a mixture of gas and oil while the fluid below the pump intake is primarily brine with very low free gas concentration. The pressure vs. depth diagram on the right side of the figure shows that the producing bottom-hole pressure (PBHP at midpoint of perforations) is equal to the sum of the casing head pressure (Pc) plus the gas column pressure plus the pressure exerted by the gaseous liquid column. The difference between the static reservoir pressure (SBHP) and the producing bottom-hole pressure is the pressure drawdown that corresponds to the stabilized production rate. From this figure it can be seen that for a given casing head pressure the producing bottom-hole pressure reaches a minimum when the fluid level is near the pump intake.

The annular fluid distribution and the corresponding pressures are obtained routinely from the analysis of acoustic fluid level surveys. **Figure 3** shows a typical report generated from fluid level data acquired in a well where the pump intake is set above the perforatons[1]. The analysis includes calculation of the annular gas flow rate (49 MSCF/D) from which the percentage of liquid in the gaseous liquid column (33%) is obtained using the published "S" curve correlation (shown at upper left) and the pressures at the pump intake (PIP=662.7 psi) and at the formation (PBHP=676.9 psi) are calculated using the gradients of the respective fluid columns. In this case, since the pump is set high and the concentration of liquid at the pump intake is only 33% one expects the pump liquid fillage to be about 33% unless an efficient down-hole gas separator is installed with the purpose of reducing the volume of gas in the flow stream entering the pump.

DOWNHOLE GAS SEPARATOR EFFICIENCY STUDY

An efficient downhole gas separator is a separator that provides a pump liquid fillage percentage that is significantly larger than the % liquid present in the wellbore at the pump intake. In a well operated with a rod pump the pump liquid fillage is routinely computed from detailed analysis of the pump dynamometer card. Thus the efficiency of the downhole gas separator can be determined by comparing the liquid percentage from the fluid level survey analysis and the effective displacement from the pump dynamometer card. **Figure 4** shows on the right a cross plot of these variables for a large number of wells completed with different types of separators[1]. The highlighted data point shows that for the well in question the pump liquid fillage, determined from the dynamometer card at the bottom left, is about 62% while the liquid concentration in the well at the pump intake is only 19% as shown in the wellbore schematic at the left. The conclusion is that in this well with the pump set several thousand feet above the perforations and with a very high annular gas flow rate (511 MSCF/D) even though the pump is not 100% full of liquid the separator has increased the liquid concentration by a factor of 3 significantly improving the volumetric efficiency of the pump. This particular well was completed with a commercially available packer type separator which is doing a good job of increasing the pump liquid fillage although not reaching the target of completely filling the pump with liquid.

The diagonal line in the graph of **Figure 4** represents the boundary where the pump liquid fillage is equal to the liquid percent present in the annulus at the pump intake. Points plotted above the line indicate that the liquid fillage for the pumps in these wells is less than the liquid concentration in the annulus. The downhole gas separator installed in these wells is performing poorly and actually is preventing the liquid from entering the pump. Points plotted below the line indicate that the liquid fillage in the pump is larger than the percentage of liquid present in the well. The separators in these wells are performing satisfactorily and are increasing the pump liquid fillage. The points further to the right correspond to the most efficient separators.

These data were obtained during an extensive study of downhole separators that included comparing the pump fillage in wells completed with the pump intake "in the sump" and the pump fillage in wells with the pump intake set high above the perforations and outfitted with different types of downhole gas separators. The pump fillage of the 17 wells with the pump intake in the sump are indicated as triangles in **Figure 4** and they primarily fall in the region of "good separator performance". However a significant number of these wells (6 out of 17) exhibit a pump liquid fillage between 50% and 80% which is much lower than the performance of near full pump expected when the well is completed with the pump intake in the sump. A review of the data also showed that these wells also exhibited a high (several thousand feet) fluid level above the pump.

Based on the previous discussion of the performance of the Natural Gas separator and the pressure and fluid distribution in a pumping well the following can be stated:

Given a pumping system properly designed and operated to match reservoir inflow performance:

- *A high fluid level is caused by reduction of effective pump displacement.*
- *Low effective pump displacement may be due to gas interference*
- *Gas interference is an indication of inefficient downhole gas separation.*
- *Improved separation should result in increased pump displacement and consequently lowering of fluid level.*
- *Best separation is obtained when the pump intake is below perforated interval (Natural Downhole Gas Separation)*
- *Wells completed with the pump intake below the perforations should exhibit near **100%** pump fillage and **low** fluid level.*

The question then becomes:

- *Why is it that the nine wells that show a pump fillage of less than 90% have a **high fluid** level even though the pump intake is **set below** the perforations?*

To try to answer this question, additional tests were performed on several wells. All these wells were operating with pump off controllers. Table 1 summarizes their production performance and characteristics.

To better understand the pump fillage problem a series of fluid level measurements and acquisition of long dynamometer records with the pump operating "on-hand" were performed. **Figure 5** shows an example of the pump fillage observed in a well with the pump intake set 135 feet <u>below</u> the bottom of the perforations and exhibiting a high fluid level consisting of 3193 feet of gaseous liquid column with 28% liquid in the annulus where the gas flow rate was 59MSCF/D. The pump dynamometer on the right side indicates a pump fillage of less than 25 % for the last recorded stroke which corresponds to the steady state condition. The overlay of the surface dynamometer records (on the lower left) and the polished rod load vs. time (upper left) show that for about 10 strokes after starting the pumping unit the pump was practically 100% liquid filled. Then the pump fillage decreased and stabilized at about 25% for the rest of the recorded pump strokes.

This behavior is typical of a well that is "pumped-off" and has the liquid <u>level at or near</u> the pump intake but <u>it is not</u> the behavior expected of a well that exhibits a high annular fluid level. If gas interference were the cause of the low pump liquid fillage then even the first pump stroke would exhibit partial liquid fillage.

Similar tests run in the other wells gave the same indication. In some wells a cyclical behavior was also observed where during several strokes the pump was full of liquid then fillage would decrease for several strokes then increase for some time. This cycle would be repeated continuously while the high fluid level remained constant above the pump.

For the wells in Table 1 that exhibit high fluid levels and significant annular gas flow the following was observed:

- Wells A, D, E, the extended dynamometer tests while pump operates continuously show alternation between full pump and partial pump fillage.
- Wells B, C, H and J, after shutting pump down for several minutes several full pump strokes then changing to partial fillage.

How can the pump be partially filled with liquid and still show a high fluid level when the pump intake is <u>set below</u> the perforations?

One possibility is that the liquid concentration in the vicinity of the pump intake is much lower than the liquid concentration in the upper part of the wellbore due to some obstruction in the annulus that prevents the liquid present in the gaseous column to fall to the lower part of the well against the upwards gas flow. The obstruction in the annulus could be one of several possible sources such as paraffin or scale deposits, a section of collapsed casing or a tubing anchor. Such situation would result in a discontinuity of the fluid distribution and liquid concentration at the depth corresponding to the obstruction. In wells A, D, E and I a tubing anchor is located above the perforations. The particular tubing anchor used in these wells provides a flow area of about 2.9 square inches between the body of the anchor and the casing compared to a flow area of 14.4 square inches between the casing (4.892 inch ID) and the tubing (2.375 inch OD). The small flow area could increase the velocity of the upwards flowing gas to the point where it would be difficult for liquid present in the upper part of the annulus to flow downwards past the depth where the tubing anchor is set. The anchor would essentially act as a choke and also cause an increase of the annular back pressure.

Figure 6 is a schematic representation of this possible type of annular fluid distribution. The annular space below the tubing anchor is principally occupied by gas with the majority of the liquid that is produced through the perforations flowing to the bottom of the well by sliding down the low side of the wellbore. Even in “vertical” wells the wellbore is never perfectly vertical and the heavy fluid (water) accumulates on the low side of the hole and the light fluid (oil or gas) flows on the high side as shown in numerous downhole video recordings[2]. Above the tubing anchor there is a continuous gaseous liquid column to the depth of the acoustically measured liquid level and a gas column extending to the surface. Below the tubing anchor the fluid gradient is basically equal to the gradient of the gas above the fluid level. The pump that is set below the perforations is submerged in the liquid that has fallen to the bottom and has accumulated at a rate corresponding to the liquid production from the formations. When the pump displacement rate exceeds the liquid inflow from the formation then the well “pumps off” while the gaseous fluid column above the tubing anchor remains unchanged. This hypothetical fluid distribution and flow behavior would explain the dynamometer records observed in the eight wells tested.

Hypothesis Verification by Liquid Level Depression Tests

Liquid level depression tests have been used for many years[3] to determine the gradient of annular fluid and the producing bottom-hole pressure in pumping wells. The objective of the test is to obtain a record of the depth of the fluid level as a function of the casing head pressure while the well is pumping at a certain rate. Increasing the casing head pressure causes the fluid level to be pushed downwards in proportion to the casing pressure increase. Thus it is possible to equate the change in level to the change in pressure and estimate the gradient of the annular fluid mixture.

This test is also useful for verification of the hypothetical fluid distribution described in the previous section. If the hypothesis of a discontinuity in liquid concentration were wrong and the gaseous column were continuous from the fluid level to the pump (in spite of the presence of the TA) then the record of fluid level as a function of pressure would be a continuous curve until the liquid level is pushed near the pump intake. If the hypothetical fluid distribution were correct then the fluid level depth as a function of pressure would show a sharp discontinuity when the liquid level is pushed below the depth of the tubing anchor.

The liquid level depression test was performed on these wells as follows:

- Continue pumping at normal SPM
- Close casing head valve or control the pressure with a back pressure valve.
- Continuously monitor casing head pressure as it changes.
- Periodically (15 minutes intervals) obtain fluid level records.
- Plot casing pressure and fluid level vs. time.

A programmable Acoustic Fluid Level instrument[4] was installed on each well and automatic fluid level records and casing pressure were obtained at 15 minute intervals after the casing head valve to the flow line was closed. The pumping unit was kept in operation for the duration of the test.
Figure 7 shows the resulting plot of fluid level and casing pressure vs. time during over 27 hours. Casing pressure increases from 60 psi at the start of the test (6:08PM on 6/10/2013) to 260 psi at a fairly constant rate while fluid level drops from 7500 feet to 9100 feet (1:36AM on 6/11/2013). Fifteen minutes later the fluid level drops 240 feet below the tubing anchor and 45 minutes later is near the bottom of the tubing at
about 10,100 feet where it stabilizes during the rest of the test. This indicates that the wellbore below the tubing anchor was primarily filled with gas and very little liquid as it was postulated in the original hypothesis.

Similar behavior was observed in the tests performed in the other wells that exhibited partial fillage and high gaseous liquid columns above the tubing anchor. **Figure 8** shows the pressure distribution at the beginning of a liquid depression test that was observed in a well that was also outfitted with a bottom-hole pressure sensor. The measured fluid level indicated a gaseous column of about 250 feet above the tubing anchor resulting in a pressure of 124 psi above the tubing anchor. The pressure sensor indicated a pump intake pressure of 180 psi. If the gaseous column were continuous to the depth of the pump intake (set below the perforations) the annulus the pressure at the pump intake should have been about 330 psi as shown in the diagram by extending the gradient line of the gaseous column to the depth of the pump. The much lower actual measured bottom-hole pressure can be explained by considering that there was a column of about 90 feet of liquid above the pump (estimated from dynamometer analysis) and a gas column of about 2100 feet to the bottom of the tubing anchor. The subsequent liquid level depression test verified also in this well that the fluid distribution shown in **Figure 6** was a realistic representation of the annular fluid distribution during normal production.

EFFECT OF THE TUBING ANCHOR ON WELL PERFORMANCE

The tests performed on several wells with the pump intake set below the perforations, completed with tubing anchors set above or within a long perforated interval and exhibiting significant annular gas flow indicate that the tubing anchor is preventing the liquid in the gaseous liquid column from falling to the bottom of the well as shown in **Figure 6**. The figure also indicates that below the tubing anchor the primary fluid is gas and that the producing pressure is controlled by the gradient of the gaseous column plus an additional pressure drop due to flow across the tubing anchor.

The question to be explored is: what would be the pressure distribution in the annulus if the tubing anchor were removed (or located below the bottom of the perforations) while the casing pressure were kept at the same level and the pump operated at a sufficient rate to lower the liquid level near the bottom of the perforations. The pump intake would still be set in the sump so that pump fillage would be maintained to 95-100% using a pump-off controller or a variable speed drive to match the formation inflow and the pump capacity.

Figure 9 is a schematic diagram showing the probable fluid and pressure distribution for this case. The annulus from the surface to the bottom of the perforations would be primarily filled with gas at an average pressure slightly higher than the casing head pressure. Liquid produced from the perforations would flow downwards and accumulate above the pump intake into the sump. The type of flow in the annulus in the section from the top to the bottom of the perforations would be <u>countercurrent liquid and gas</u>, the liquid flowing down and the gas flowing up. For the gas and liquid rates of the wells tested the most probable flow patterns in this region of the annulus could be: segregated downhill liquid (liquid flowing down on low side of wellbore) or annular-wavy with a gas core flowing upwards.

The diagram also shows that the producing bottom hole pressures opposite each zone could be significantly lower that what they were when the tubing anchor was present above the formation as shown in **Figure 6**. Whether this reduction in bottom-hole pressure would result in an increase of the well's production is dependent on the well's inflow performance relation and the ratio of the producing wellbore pressures to the static reservoir pressure of each zone.

SUMMARY

A field study was conducted using fluid level and dynamometer tests to determine why low pump liquid fillage existed in wells with high fluid levels that also had the pump intake set below the formation. Eleven wells were analyzed.

In these wells, that exhibited high fluid levels and dynamometer records with pump fillage varying from full pump to partial liquid, the fluid distribution in the wellbore below the liquid level was not uniform. The wellbore in the vicinity of the pump intake was primarily filled with gas with a minimal volume of liquid.

The presence of a tubing anchor set high above the pump intake is considered to be the main cause of this uneven distribution of fluids in the wellbore.

Fluid level depression tests were used to confirm that free gas can collect below a tubing anchor and prevent the liquid present in the gaseous column above the tubing anchor from falling to the bottom of the wellbore and to the pump intake.

The normally accepted concept that a high fluid level in a pumping well is an indication of poor downhole gas separation or of a restricted pump intake were initially believed to be the problem but the result of the tests show that it was not the case in these wells.

The reduction of annular flow area due to the presence of the tubing anchor in conjunction with a relatively high annular gas flow rate appear to be the physical mechanisms that explain the accumulation of liquid above the tubing anchor and high gas concentration at the pump intake.

Removing the tubing anchor or relocating it below the bottom perforations should reduce the producing bottom-hole pressure when the pump displacement is sufficient to pump the fluid level down near the pump intake.

Depending on the well's inflow performance relation the increased drawdown achieved by removing or relocating the tubing anchor at the bottom of the tubing could provide additional fluid production.

Fluid level depression tests should be run in all wells that suffer from partial pump fillage and exhibit high annular gaseous liquid columns above the pump. This is especially important if they are completed with a tubing anchor set above the perforated intervals.

REFERENCES

1) McCoy, J. N. et al: "Optimizing Downhole Packer-Type Separators", Proceedings of the SWPSC, 2013.
2) http://exprogroup.com/products-services/wireline-intervention/
3) Walker, C. P.: "Method of Determining Fluid Density, Fluid Pressure and the Production Capacity of Oil Wells," US Patent 2,161,733, June 6, 1939.
4) Becker, D. et al.: "Best Practices for Pressure Transient Tests Using Surface Based Measurements", Proceedings of the SWPSC, 2007.

Table 1 – Summary of Field Measurements in Wells with Pump Intake Below Perforations

Well ID	Run Time	BPD	Fillage %	TA 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

Note: "cycles" means pump fillage varies periodically from full to partial liquid

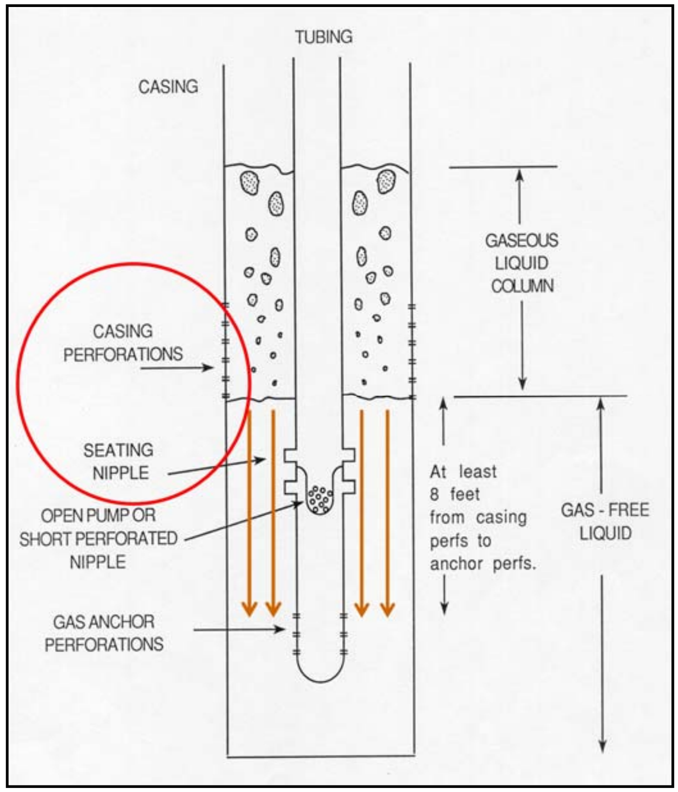

Figure 1 – Pump Intake set Below Bottom of Perforations for Natural Downhole Gas Separator

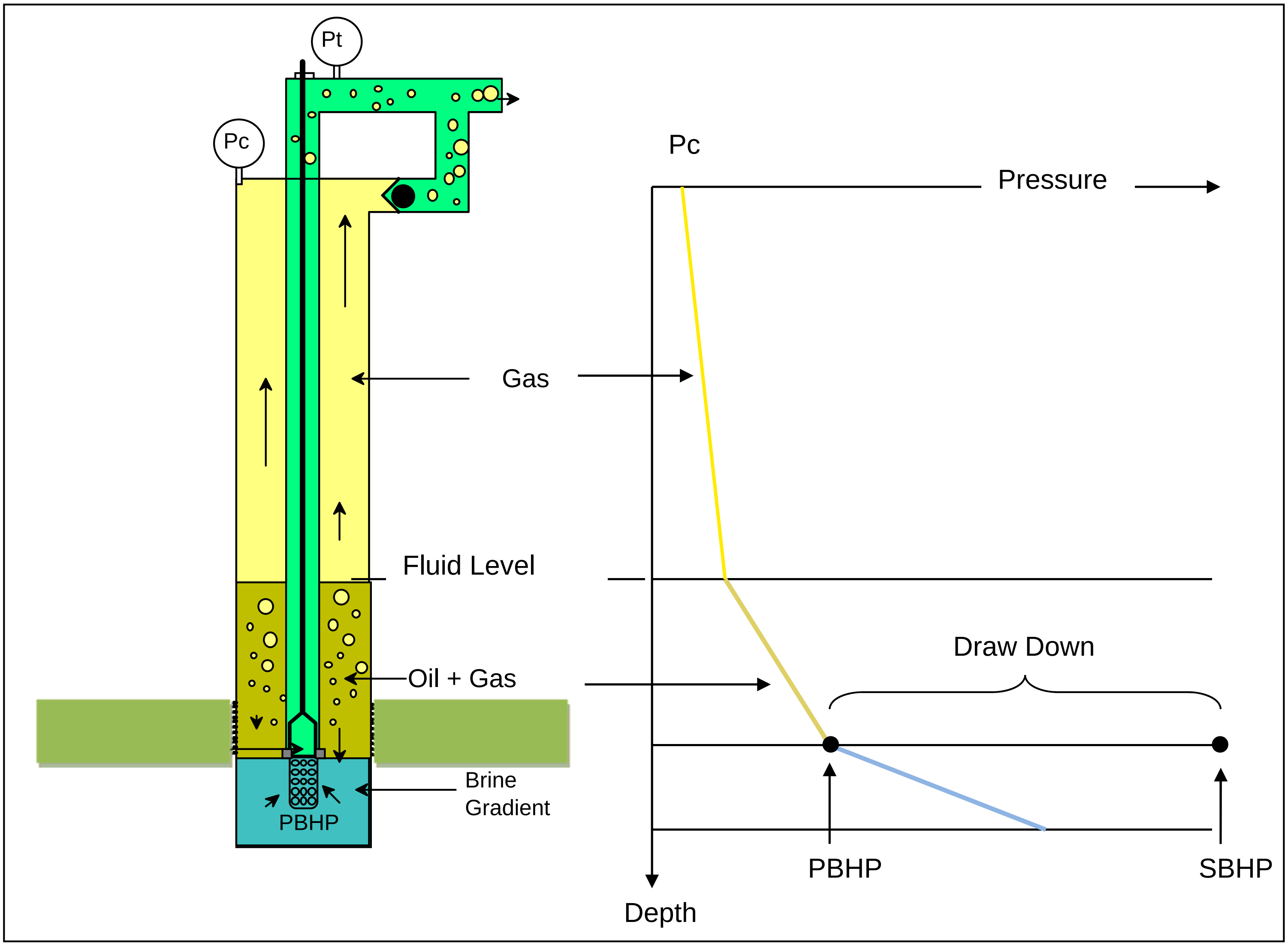

Figure 2 – Pressure Distribution in a Stabilized Producing Pumping Well with Pump Intake Set at Bottom of Perforated Zone.

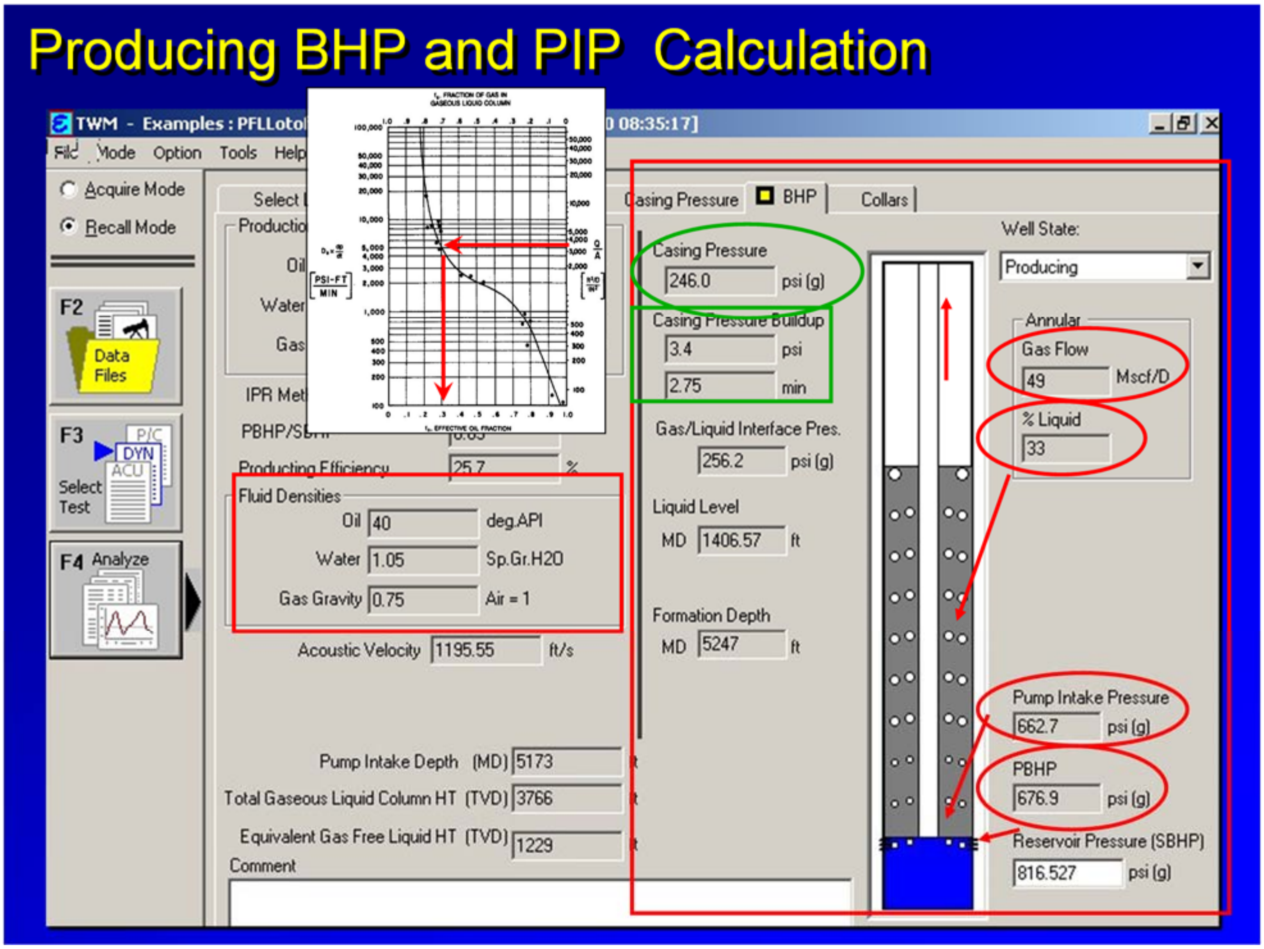

Figure 3– Example fluid level analysis to obtain Gas/Liquid interface pressure, % Liquid at pump, and Pump Intake Pressure (PIP) and Producing Bottom Hole Pressure,(PBHP)

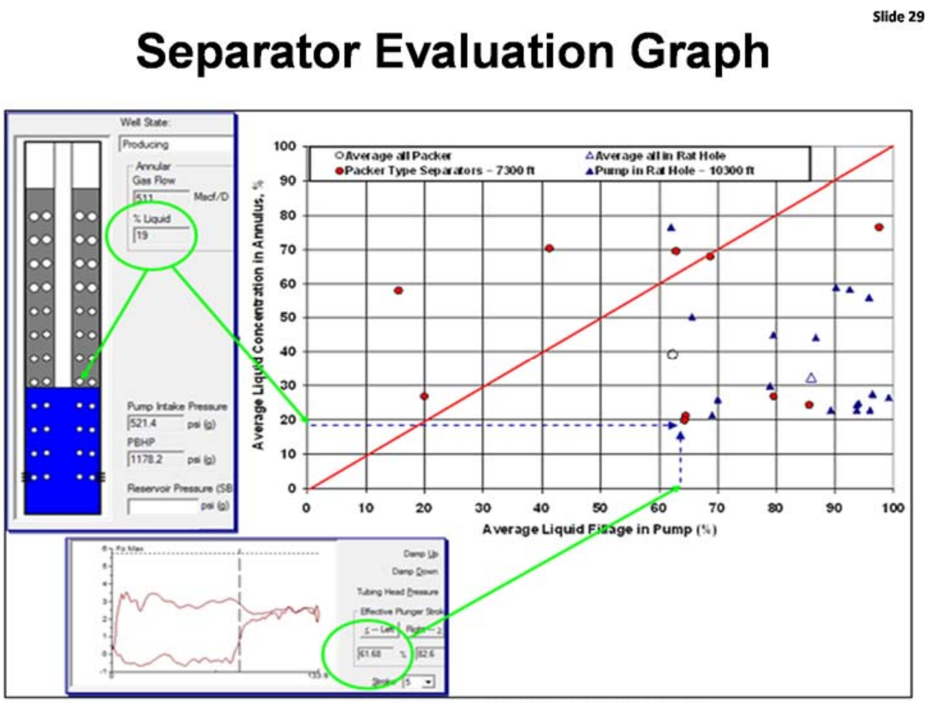

Figure 4 – Downhole Gas Separator Efficiency Evaluation Graph

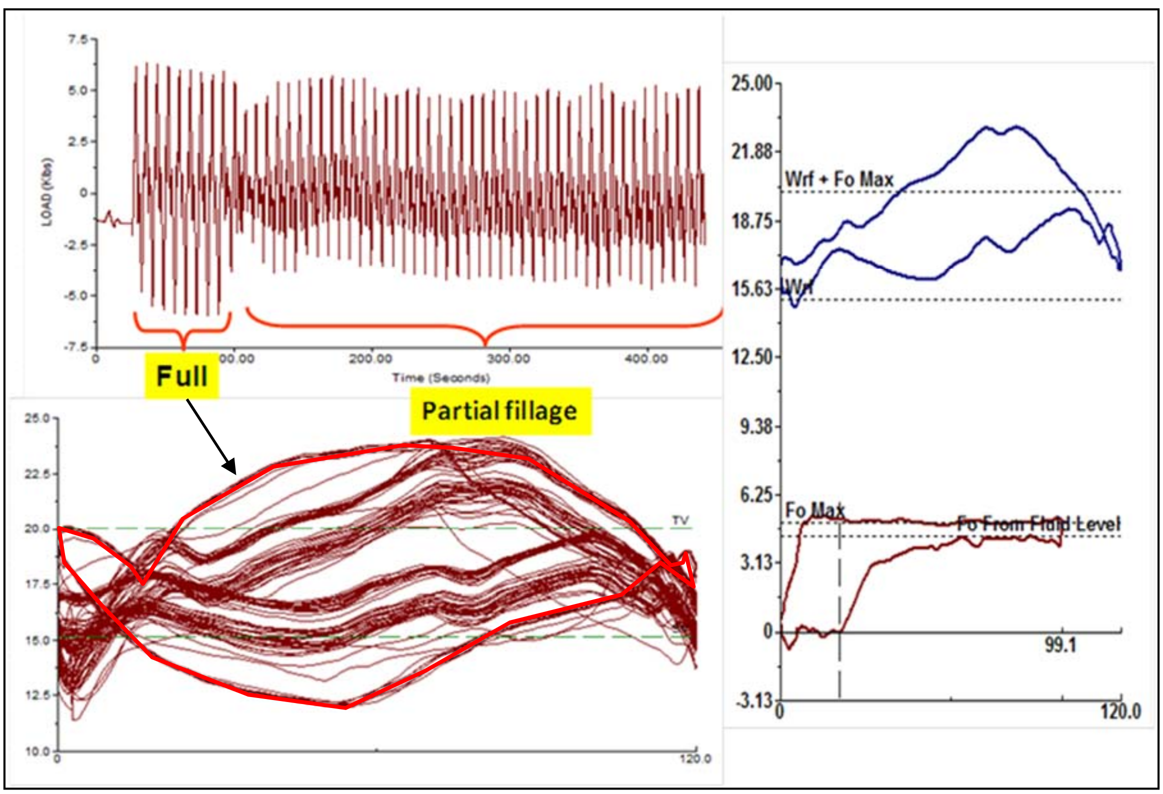

Figure 5 – Typical Long Term Dynamometer Record for Well A Showing Full and Partial Liquid Fillage

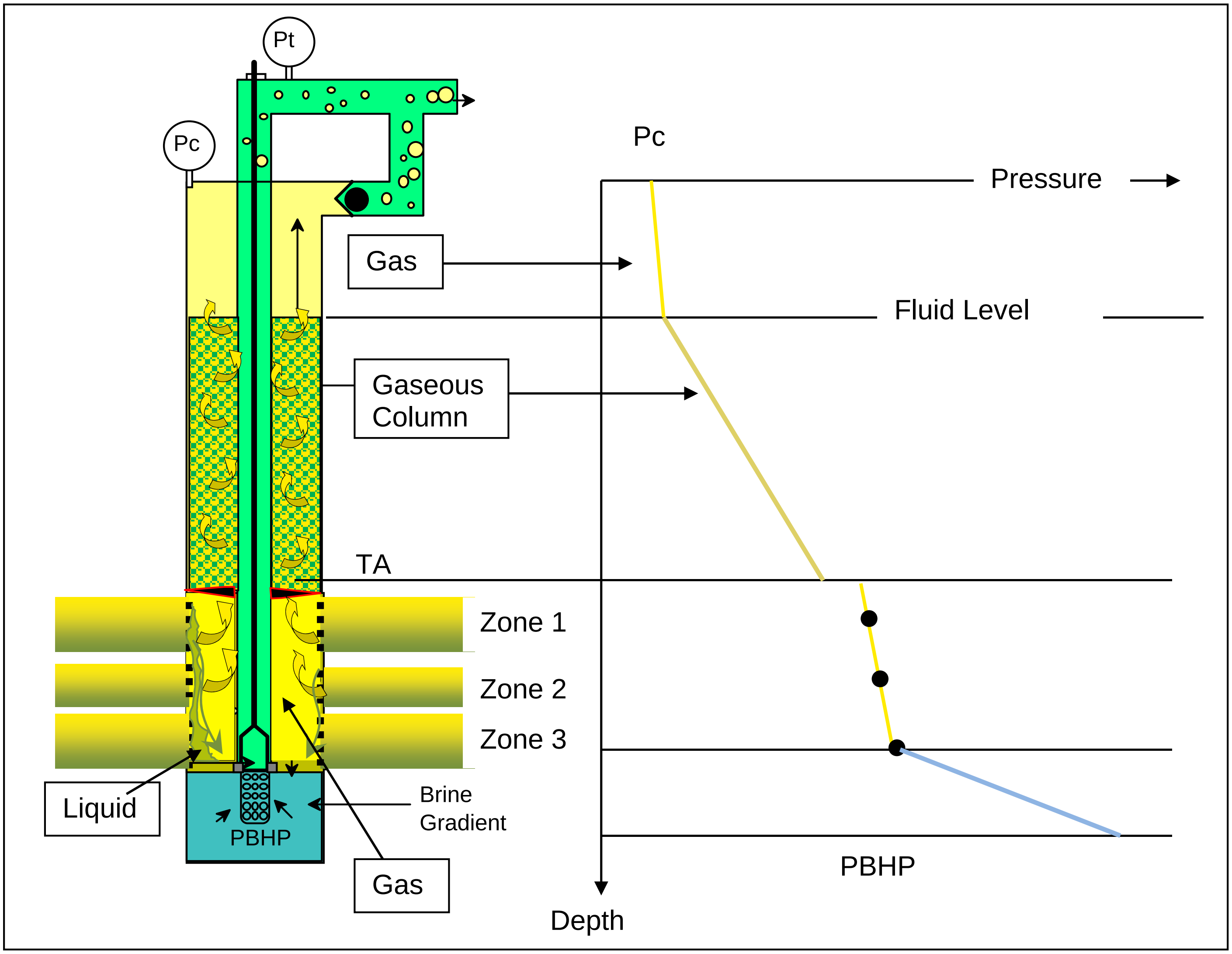

Figure 6 – Postulated Pressure Distribution in Producing Pumping Well with Tubing Anchor set high and Pump Intake Set Below Bottom Perforated Zone.

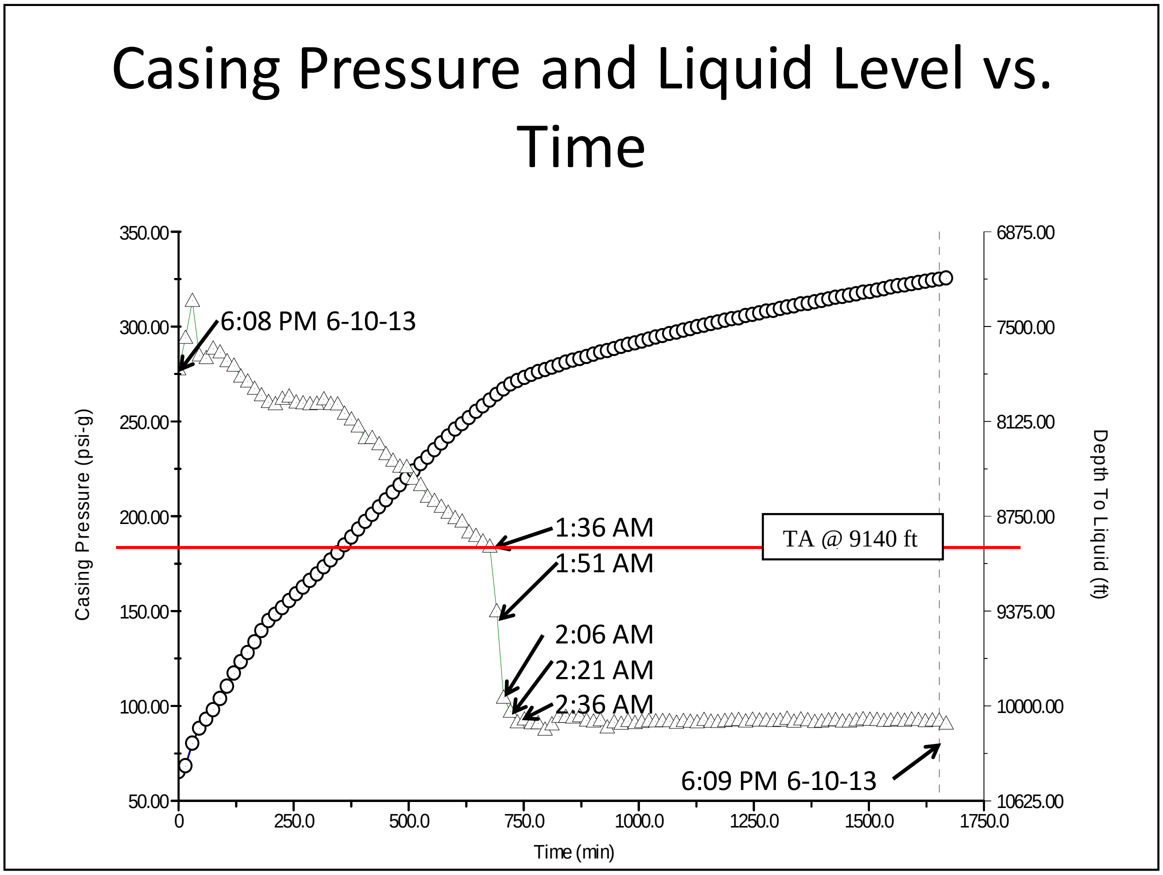

Figure 7 – Casing pressure and liquid level depth as a function of time. Data acquired automatically at 15 minute intervals.

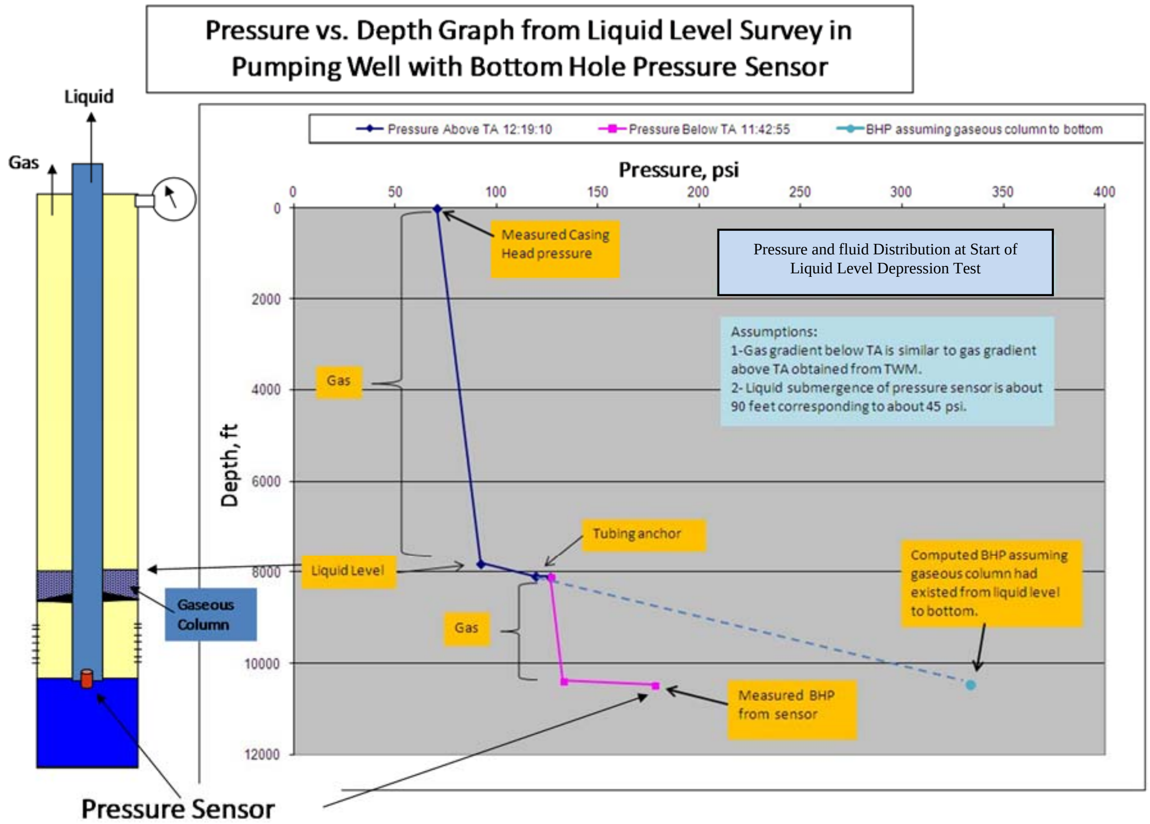

Figure 8 –Measured Pressure Distribution at Start of Liquid Depression Test in Well With Bottom Hole Pressure Sensor

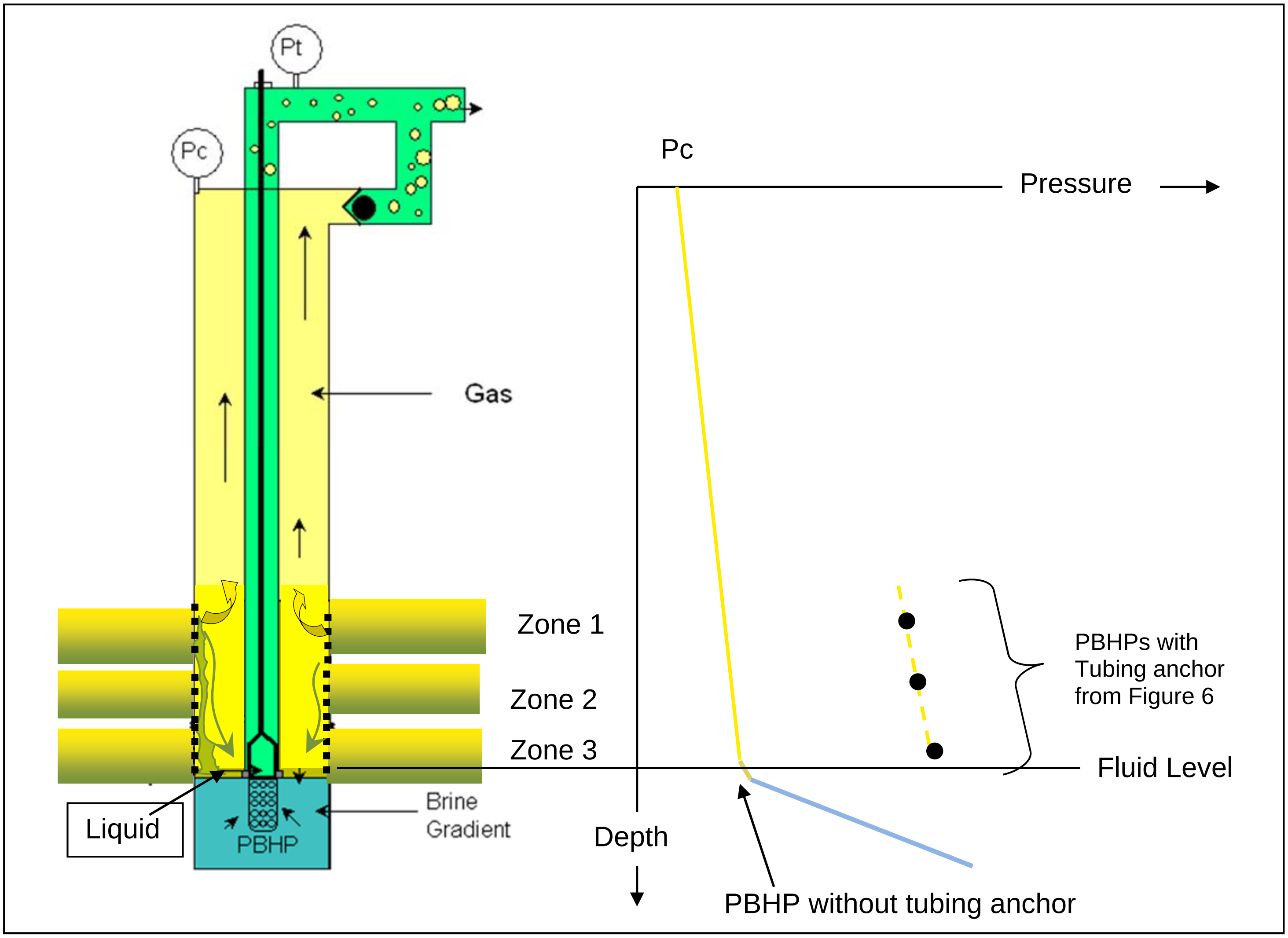

Figure 9 – Postulated Pressure Distribution in Producing Pumping Completed **without** Tubing Anchor and Pump Intake Set Below Bottom Perforated Zone.