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Acoustic Liquid Level Testing of Gas Wells

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Abstract

Initially Gas Wells usually flow at sufficiently high rates to remove all liquids from the wellbore. When the gas flow rate decreases below critical rate[1] some intervention such as compression, surfactants, and/or velocity strings is required. At a later time when either reservoir pressure and/or gas flow rate is sufficiently reduced, then other means of artificial lift (usually such as plunger lift, gas lift, or sucker rod lift) must be added to maintain production. Acoustic fluid level testing can be used to investigate the producing condition of a gas wells. Developments in digital acoustic fluid level technology have resulted in the operator being able to undertake fluid level measurements and use this technology to investigate the status of his gas wells. The act of acquiring a fluid level on a gas well is an inexpensive and non-intrusive process. Examples of acoustic tests are presented, where the test are performed on shut-in or flowing above or below critical flow rate gas wells with or without surfactant treatments acquired down the tubing or the tubing/casing annulus.

Techniques for acoustic liquid level analysis are discussed for gas wells where unusual conditions exist such as very shallow liquid levels, very deep liquid levels, noisy wells, high bottomhole temperature, and low or high surface pressures. Some gas wells have gas lift mandrels, liners, multiple zones of perforations, tubing holes, flush pipe and other conditions which result in the acquisition of difficult to interpret acoustic traces. This paper describes analysis techniques used to determine the distance to the liquid level in gas wells with these unusual conditions. The analysis is based on data obtained at the surface without entering the wellbore and yields accurate representation of the conditions existing on the surface, within the wellbore and within the reservoir.

Introduction

The principal objective of the acoustic measurements in a flowing gas well is the determination of the quantity of liquid that is resident in the tubing (or annulus when the tubing is used for deliquifying the wellbore by means of a pump) and whether the liquid is uniformly distributed over the length of the well as a mist or annular flow pattern or has fallen back, accumulating towards the bottom of the well.

In the first case when the gas flow rate is above critical rate, when the liquid is uniformly distributed, the gas velocity is sufficient to continuously carry liquid as a fine mist or small droplets to the surface, establishing a relatively low and fairly uniform flowing pressure gradient. In the second case when the gas flow rate is below the critical rate the gas velocity is not able to carry liquid to the surface, accumulating liquid in the lower part of the well. The flowing pressure traverse in the well bore will show two different gradients, a light gas gradient above the gas/liquid interface and a heavier gradient in the lower section of the well below the gas/liquid interface. The gradient of this fluid below the gas/liquid interface is controlled by the gas flow rate through the liquid with zero net liquid flow as the gas bubbles or slugs of gas percolate through the liquid and only the gas flows to the surface.

Knowledge of the flowing gradient and fluid distribution in the well is important in determining the back pressure acting on the formation if there is liquid loading in the tubing. When gas velocity drops below critical rate, production rates are reduced by liquid accumulation in the tubing and removal of this liquid requires application of a deliquifiyng technique such as installation of plungers, pumps, redesign of the flow string to increase gas velocity or addition of surfactants reduce the gradient.

The acoustic test is designed to determine which flowing gradient conditions exist in a well by performing a series of fluid level and surface pressure measurements while the flow at the surface is stopped for a length of time sufficient to identify the behavior and distribution of the fluids in the tubing or tubing/casing annulus. The advantages of acoustic test over wireline flowing pressure surveys include lower costs, equipment is very portable, and lower risks since measurement tools are not introduced into a flowing well.

Flowing Gas Well Applications

The acoustic fluid level test is used to determine the tubing pressure distribution in a flowing gas well, by a momentary shut-in of the flow during the duration of the test. The measured values are then used to determine the extent of liquid loading of the well and may be used to optimize the production performance.

Shooting a fluid level down the tubing of a flowing gas well can be of benefit to the gas well operator. Analysis of the acoustic fluid levels acquired on gas wells can be used to determine 1) the amount of liquid loading on the formation, 2) the approximate gas rate into tubing, 3) the equivalent gradient of the gaseous liquid column in the tubing, and 4) the flowing bottom hole pressure at the end of the tubing and the bottom of the perforations. Fluid level instruments can be used to inexpensively identify liquid loading and determine the severity of the loading for gas wells.

The fluid level test data should be analyzed as it collected at the well, the goal for the person performing the test should be to answer the well performance questions. An acoustic test acquired on a flowing gas well can be used to answers the following well performance questions:

1. Is gas flowing? At what rate?
2. What is the depth to the top of the liquid in the tubing and/or casing?
3. What is the percentage of liquid in the fluid column?
4. How does the liquid level drop as the gas flow decreases?
5. How much liquid is in the tubing above the tubing intake?
6. What are the producing and static BHP's?
7. How much is the flow rate restricted due to back pressure from liquid loading?
8. Does tubing gas/liquid pressure push liquid out of tubing?
9. What is the maximum production rate available from the well?

Flowing gas wells may be grouped into one of three different categories 1) above critical rate, 2) below critical rate, and 3) shut-in. When the gas well is flowing at a gas rate less than the Critical Rate, then an acoustic fluid level test acquired down the tubing will usually show a liquid level echo. If the gas well is flowing gas at a rate greater than the Critical Rate, then the gas/mist interface will be at the surface and the initial fluid level shot will often not show a liquid level echo in the tubing. If the gas well is shut-in for an extended period of time, the high pressure gas often accumulates in the tubing and displaces all liquid out of the tubing. In a shut-in gas well the fluid level shot into the well will often show echoes from the bottom of the tubing, the perforations, and a liquid level echo very near the bottom of the perforations. Using a portable fluid level instrumentation permits the operator to quickly conduct a simple cost effective test and immediately identify underperforming liquid loaded gas wells. The information obtained from analyzing a series of fluid level shots down the tubing on a flowing gas well provides critical data in analyzing the well's performance.

Hardware Configuration

The most common well head attachment for flowing gas well measurements includes an acoustic gas gun with microphone and pressure transducer connected to the tubing through a fully opening valve connection above the swab valve or at the point of connection of the tubinghead pressure gage. The ease of use, low cost and reliability of gas guns have resulted in widespread use of this type of acoustic pulse generator. In many cases acoustic test are also preformed down the tubing/casing annulus. The most common technique to generate an acoustic pressure wave in the gas well is to use the well's pressure to implode into the gas gun external volume. Sudden expansion of gas from a volume chamber into the well or from the well into the gas gun generates the acoustic pulse. At low well head pressures (generally less than 200 psi) an external pressure source is required to charge the gas gun volume chamber to a pressure greater than the well pressure to perform an explosion mode acoustic test. In most cases, compressed CO2 or N2 gas is loaded into the gas gun volume chamber. Best results are obtained when shooting through a ½ inch fully open valve replacing any needle valves that may be present. A gas gun with a working pressure rating that exceeds the well pressure should always be used. A valve in the wellhead attachment is opened rapidly, either manually or electrically, resulting in a pressure pulse being generated in the well's gas. The acoustic pulse travels through the gas in the wellbore and is partially reflected by changes in cross sectional area. The remaining energy is then reflected by the gas/liquid interface at the depth of the liquid level. These reflected signals travel back to the surface of the well where they are detected by the microphone. If the liquid level echo is not detected, then a larger pressure difference or larger volume chamber should be used to increase the energy contained in the initial pressure pulse.

The microphone in the gas gun converts the reflected acoustic signal into an electrical signal consisting of a series of pulses, which correspond to the sequence of reflections from changes in cross-sectional area in the well bore. The microphone creates electrical signals from the reflected signal from downhole anomalies; these signals are digitized and stored as an acoustic trace for analysis. The acoustic trace, pressure signals, along with the well data can be recalled and analyzed to determine the distance to the liquid level and the pressure profile in the well.

Depth Determination to the Liquid Level

To determine the distance to a liquid level reflection on an acoustic trace usually requires three steps. The first step is to identify correctly the echo on the acoustic trace that reflected from the liquid level. The second step is to determine the elapsed time from the beginning of the shot to the echo from the liquid level. This elapsed time is usually referred to as the

round trip travel time, because the pressure wave released from the gas gun traveled from the surface down to the liquid level and back to the microphone in the gas gun connected to the well at the surface. The third step is to use one of three different depth determination methods to determine the acoustic velocity of the gas in the well and to convert the round trip travel time, RTTT, into distance.

Direction of Kick of the Reflected Acoustic Signal

The direction of kick (deflection or polarity) of the reflected echo indicates enlargements and reductions in the cross sectional area of the annulus (or internal diameter of pipe if shooting down tubing). For an explosion shot, downhole anomalies which reduce the cross sectional area of the annulus result in compression reflections and are displayed as downward kicks. Such anomalies would be liners tops, tubing anchors, paraffin/scale deposits, subsurface safety valves, or the liquid level. Downhole anomalies that increase the area of the wellbore result in rarefaction reflected waves and are displayed as upward kicks. Such anomalies include perforations, open hole, sliding sleeves, parted casing, parted tubing and the end of the tubing. If an implosion pulse is used to create the acoustic trace, then the responses will be reversed from those of an explosion pulse, but software allows the selection of implosion type of pulse and the digital trace is flipped over by software so implosion and explosion acoustic traces on the same well appear identical.

For the explosion pulse the liquid level is recorded as a downward kick. If the liquid level is a few joints below a perforation, then the acoustic trace would first display an upward kick at the perforations, and then display a kick down as the traveling wave is reflected from the liquid level, possibly followed by another upward kick due to the traveling wave again passing by the perforations. When the liquid level is below a liner top, the acoustic trace will show a downward kick at the liner and a downward kick at the liquid level, then an upward kick as the traveling wave exits the restricted liner back into the larger diameter unlined casing.

Fig.1 displays an acoustic trace acquired by shooting down the tubing of a gas well. The liquid level down kick is selected correctly at a RTTT of 11.664 seconds. The repeat echo of the liquid level is displayed at a RTTT of 23.35 seconds, which is double the time of the first liquid level echo. The upkick at a RTTT of 7.78 seconds is due to a hole in the tubing and the repeat echo at RTTT of 15.553 seconds is due to the traveling wave coming back up the wellbore past the hole the same distance from the liquid level. Then the last upkick at a RTTT of 19.465 seconds is caused by the repeat echo of the liquid level signal again encountering the increase in cross-section at the hole. Direction of kick on acoustic traces is often used to trouble shoot gas well having problems, thereby identifying an upkick which does not belong at a certain location on the acoustic trace and may indicate a reflection from an unexpected hole in the tubing.

Counting Tubing Collars

By default, the computer software automatically locates the most probable liquid level echo and then processes tubing collar reflections from the beginning of the acoustic blast to the echo of the liquid level and obtains the reflected collar frequency or number of joints per second (acoustic velocity if average joint length is known). Some wells will have an acoustic trace that may be very difficult to interpret, because of the presence in the wellbore of liners, gas lift mandrels, multiple zones of perforations, paraffin, odd length of joints, poor surface connections and other conditions. When shooting down the tubing/casing annulus the tubing collars echoes are usually easy to detect; this is because the casing pressure is high since the casing valve is usually closed and all gas and produced liquid are flowing into the tubing. In gas wells when shooting down the tubing, the tubing collar recesses on the inside of the tubing are sometimes difficult to detect. An acoustic shot down the tubing/casing annulus is usually a good technique to estimate the acoustic velocity of the gas in the tubing. For flowing gas wells if there is no packer and the tubing/casing annulus is open to the formation and the casing valve is closed, then the liquid level should be expected to very near the tubing intake. In gas wells where the default automatic collar count does not result in accurate distance to the liquid level, then other analysis techniques may be used such as identifying an echo from a known down hole marker or using the gas composition or gas gravity to determine the acoustic velocity.

Downhole Marker

When the lengths of tubing joints vary considerably, so that an average joint length is not representative, some operators have installed an over-sized tubing collar (marker) to serve as an acoustic reflector at a known reference depth. When other acoustic reflections are identified on the acoustic trace, such as those generated by gas lift mandrels, liner tops, crossovers where the tubing diameter changes, tubing anchors, perforations; the known depth of these anomalies can be used to calculate the distance to the deeper liquid level. **Fig. 2** shows the analysis method “Downhole Marker” being used to determine depth to liquid level echo at a RTTT of 2.633 seconds in a coal bed methane gas well with three zones of perforations (1369-71; 1530.5-33.5; 1807.5-09.5). The upkick from all three sets of perforations are easily seen on the acoustic trace. The echo from the top perforation is located at a RTTT of 1.921 seconds at a known 1369 feet in depth from the surface to the top of the perforation. To use the downhole marker technique, a movable indicator is placed onto an echo kick such as the perforations, nearest to the liquid level kick... The operator sets the movable indicator on the top of the known perforation and enters the distance from the surface to the acoustic reflector. The program will calculate the distance to the indicator located at the liquid level or other anomaly of interest by comparing the ratio of elapsed times on the acoustic trace to a ratio of their depths. For example **Fig. 2** shows an anomaly detected in the annulus above the liquid level, as indicated by a strong reflected rarefaction (up kick) acoustic pulse recorded at 1.921 seconds. The anomaly was displayed at the same time in all acoustic traces

collected while testing the well; it is recommended practice to acquire more than one (1) acoustic trace when testing a well. The anomaly corresponds to the increase in area of the annulus volume at the depth of 1369 feet at the perforations. A strong reflected compression (down kick) acoustic pulse recorded at 2.633 seconds indicates the depth to the top of the liquid level is (2.633/1.921)*1369 = 1876 feet from the surface. **Fig. 2** is a typical acoustic trace for gas wells dewatered using progressive cavity pumps, electric submersible pumps, or sucker rod pumps, where the gas is produced up the annulus and the pump intake is set in a rat hole below the bottom of the perforations. The acoustic velocity of 1425 ft/sec determined from this downhole marker analysis correlates to a gas having a specific gravity of 0.6. The acoustic velocity or gas SG determined from an acoustic fluid level analysis can be used as a quality check, these values should be compared to results form other wells and there should be reasonable agreement.

Acoustic Velocity

Another technique to determine the distance to the liquid level is for the operator to input the acoustic velocity and then measure the acoustic roundtrip travel time to the liquid level. The velocity can be obtained from prior data obtained in the field, from charts of acoustic velocity as a function of gas gravity, pressure and temperature, or calculated by a computer program that uses gas properties or composition. Acoustic velocity charts are available free of charge by downloading a paper[2] from the internet that displays the acoustic velocity of various hydrocarbon gases at various pressures and temperatures. Also, the acoustic velocity can be determined from a representative sample of gas obtained from the well. After the acoustic velocity is determined or estimated, the acoustic wave round-trip travel time from the initial pulse to the liquid level reflection is read directly from the acoustic trace. The round-trip travel time is divided by two and multiplied by the acoustic velocity to calculate the depth to the liquid level.

When the specific gravity or the composition of the gas is accurately known, then the velocity of sound in the gas can be calculated. Free, downloadable software programs, AWP2000[3] and TWM[4]; provide the operator the ability to select from four options to calculate the acoustic velocity at a known pressure and temperature using: 1) gas specific gravity, 2) gas composition analysis, 3) depth markers, or 4) tubing joint collar reflections. **Fig. 3** shows the entry of 0.5977 gas SG into one of the free programs used to calculate an acoustic velocity of 1412.19 ft/sec and the corresponding depth of 8451 feet to the liquid level. The value of acoustic velocity determined from this equation of state is very dependent on both the temperature and pressure in the well; extra effort should be made to ensure representative values of bottomhole temperature are input when using the acoustic velocity analysis method to determine depth... In deep, hot, gas wells the high bottomhole temperature can have a significant impact in determining the accurate distance to the liquid level.

Determination of BHP from Fluid level Measurement

When analyzing the acoustic data acquired in a gas well producing below critical rate, the gradient of the gaseous column below the liquid level is computed using the Echometer annular "S" curve[5]. The percent liquid in the gaseous liquid column is obtained from this generalized empirical correlation ("S" curve) developed from field data acquired in pumping oil wells under stabilized conditions, with a constant gas flow rate through the gaseous liquid column having net zero liquid flow. This S correlation is applicable to stabilized flow in gas wells producing below Turner critical rate with some confidence as long as the flow regime is not disturbed. The Echometer annular S-curve does not calculate an accurate gaseous column gradient after the surface valve is closed for an extended period of time. The Echometer annular S-curve does not calculate the correct gaseous column gradient for well flowing in the mist flow regime or for gas wells being treated with surfactants where light stable foam is lifting liquids from the well. The annular "S" curve gives a reasonably accurate estimate of the gaseous liquid column when the liquid loaded bubble or slug flow regime is not disturbed and a stabilized gas flow from the well exists...

Determining pressure below the liquid level depends on the gas flow rate, the pressure; and the type of liquid (oil, condensate and/or water) in the gaseous column. The gradient of the gaseous liquid column depends on stabilized conditions existing in the well and is computed from the flow rate of gas through the liquid, the pressure, flow area of the pipe, temperature, oil and water gravities, and assuming that the liquid has not been treated with a surfactant. The gradient of fresh water is .433 psi/ft, which is approximately equal to a height about 2 feet per psi. If gas flows through the liquid and the pressure at the bottom of the well remains the same, then the fluid column grows taller due to the gas lightening the gradient of the mixture. As the gas flow rate increases, then the % liquid decreases to approximately a minimum of 20% until the gas rate becomes too high and the high gas velocity starts to form a mist and carry the liquid out of the well. For 1 psi of pressure at the bottom, the gas free water column will stand approximately 2 foot tall, if you add gas below critical rate then the liquid level can stand up to 5 times higher to approximately 10 feet per psi (gradient is approximately 0.08 psi/ft). If surfactant is added, foam is formed and the density of the gaseous liquid column is reduced further lightening the gradient by approximately 1/3 and the column will stand approximately 3 times higher to up to 30 feet per psi. In all of these cases it is usually easy to shoot through the gas to the gas/gaseous liquid column interface and see a liquid level kick.

Fig. 4 shows the results from acquiring fluid level down both the tubing and casing on a gas well being treated by continuous injection of surfactant down the casing annulus. The well operates with the casing valve closed and a casinghead pressure of 150.9 psi. The liquid level in the annulus is at the tubing intake (as expected) where the pressure is 179.4 psig due to the additional gas column pressure. The fluid level shot down the tubing shows a fluid level 2150 ft from the surface and a pressure of 95.6 psi. The fluid below this point is estimated to consist of 24% liquid that corresponds to a gradient of

(.24*.433) =0.104, based on the gas flow rate through the fluid in the tubing. The pressure at the tubing intake is assumed to equal the pressure in the casing of 179.4 psig, obtained from the casing shot. The height of the gaseous liquid column in the tubing is (6040-2150) = 3890 feet. The average gradient of the gaseous liquid column in the tubing is (179.4 – 95.6)/ 3890 = 0.022 psi/ft. In this well treated with surfactant, the actual tubing fluid gradient of 0.022 psi/ft is much less than the 0.08 psi/ft gradient computed by the software.

Fluid Level – Gas Flow above Critical Rate

In gas wells where the gas flow rate is above the Critical Rate the liquid level is usually at the surface. Any liquid being produced with the gas or condensing due to temperature and pressure changes is usually uniformly distributed in the tubing. The gas velocity carries all the liquid as a fine mist or small droplets to the surface and a relatively light-uniform flowing pressure gradient is established in the tubing. At the stabilized undisturbed flowing condition the fluid level is at the surface and the tubing is filled with a mist.

When the gas flow rate is above the critical rate; acoustic surveys consisting of several fluid level shots has shown[6] that a uniform light mist flowing gradient exist in the tubing string from the liquid level down to the bottom of the tubing. To analyze this type of gas well, the gas flow at the surface is shut-in and series of acoustic fluid level surveys are acquired as the surface pressure increases. Analysis of these fluid levels shots can be used to determine the tubing fluid gradient and the flowing bottom hole pressure. A plot of the gas/liquid interface pressures and height of the gaseous liquid column determined from the series of fluid level shots will usually fall along a straight line indicating a constant pressure gradient exists below the gas/mist liquid level interface. The change in pressure and the change in height of the gas/liquid interface from at least two fluid level measurements can be used to calculate the gradient below the fluid level. Extrapolation of the pressure at the gas/mist interface to a zero height of the gaseous liquid will give a reasonably accurate estimate of the producing bottom hole pressure.

Fluid Level – Gas Well Shut-in

Use of acoustic surveys to determine the static shut-in pressure is an accepted and accurate practice. Using acoustic fluid level instruments to determine static bottom hole pressure provides advantages over downhole gauges in that the equipment is compact, light weight, and portable. Fluid level instruments are frequently used to inexpensively determine the shut-in static reservoir pressure for gas wells as opposed to traditional wire line methods, which are more intrusive and costly. In a shut-in gas well liquid is often pushed out of the wellbore and the liquid level is usually identified at or near the bottom of the perforations. If a pump is to be used to remove the liquid loading the gas well, then the pump intake should be set below the static liquid level and preferably below the bottom of the perforations; in the rat hole. If the well is to be produced using a velocity string, plunger lift or surfactant, then the tubing intake should be set above the static liquid level or the gas well will be difficult to unload.

If the static bottomhole pressure is to be determined from the static fluid level, then any special considerations for a particular production method must be included in the calculation. The downhole marker method is the most appropriate technique to determine distances in a shut-in gas well and it is important to record the measured depth to all known down hole reflectors such the depth to gas lift valves/mandrels, all zones of perforations, the subsurface safety valve, crossovers and liners. The most accurate depth to the static liquid level is determined by identifying and using the reflection from the down hole anomaly that is closest to the liquid level.

Wellbore configuration including tubing and casing size, average joint length, and tubing intake depth should be used in the static calculation. If the wellbore is deviated, then the deviation survey must be used in the calculations to determine pressures based on true vertical depths. To calculate the fluid gradients of the liquids, both oil and water production rate and the corresponding gravities should be known. In deep wells the bottom hole temperature has a significant impact on the acoustic velocity and the pressure gradient, errors will result if default values for temperature are used in the calculation. The static bottom hole pressure is often reported at the bottom of the producing interval, but if the static bottom pressure from a fluid level survey is compared to the results from a wireline pressure bomb, then the depth for computing the static pressure from the fluid level should be at the same depth as the wireline bomb.

Fig. 5 displays the well bore schematic for an offshore well and the corresponding acoustic trace obtained through the tubing. An accurate wellbore schematic is essential for interpretation of the acoustic record shot inside tubing since all components that exhibit changes of internal diameter will generate echoes of the acoustic pulse. Knowing the depth to each item allows a very accurate estimation of the acoustic velocity in each section of the wellbore and the user can pinpoint the depth to the liquid level. **Fig. 5** shows the relationship between the acoustic record and the tubing description from the wellbore diagram. When a subsurface safety valve is present, there will be numerous repeats of the echo generated by the change in internal diameter (when shooting down the tubing) or external diameter when shooting down the casing. The amplitude of the repeated echoes decays exponentially, as seen in the figure above, so that it is generally possible to view echoes generated at greater depth from other features of the flow string and the liquid level. If the liquid level were very high, it is possible to confuse its echo with the repeats from the safety valve. Identifying the liquid level echo can be accomplished by making the liquid level move, through changes in the pressure conditions, over a period of time.

Three wells in the North Sea had wireline conveyed pressure bomb surveys and static fluid level surveys performed at the same time. Initially when the static pressures determined from the two methods were compared the differences were in excess

of 100 psi, this error was due to incomplete wellbore information and calculations using default values in the static fluid level bottom hole pressure determination. After inputting the correct representative well information and reprocessing the acoustic fluid level calculations, then the difference between the wireline conveyed bomb static pressures and the acoustic fluid level static values were only a few psig.

Fluid Level – Gas Flow below Critical Rate

Acoustic fluid level measurements in a gas well flowing below critical rate determine the amount of liquid that has accumulated in the tubing and at the bottom of the well. The fluid level survey determines the depth to the fluid level and the pressure distribution in a flowing liquid loaded gas well. The acoustic fluid level survey is acquired down the tubing while the well's flow at the surface is momentarily shut-in. Analysis of the survey is used to determine the back-pressure acting on the formation, due to liquid loading in the tubing. .

In flowing gas wells where the gas velocity is below critical rate the liquid accumulates in the bottom of the tubing. A fluid level shot down the tubing will usually show a liquid level echo below the surface of the well. The flowing pressure gradient will show two values, a very light gas gradient above the gas/liquid interface and a heavier gaseous liquid gradient below the gas/liquid interface. Below the liquid level the flow is characterized as zero net liquid flow with gas bubbles or slugs percolating through the liquid and upon exiting the gaseous liquid surface the gas flows the remaining distance up the tubing to the surface.

In a liquid loaded well flowing below critical rate the first few acoustic fluid level measurements yield the most accurate estimate of the gaseous liquid column gradient and the flowing bottom hole pressure. After a liquid loaded well is shut-in for a period of time, surface pressure increases, and gas flow rate decreases as the pressure on the formation increases; then the flow regime below the liquid level in the tubing is disturbed and liquids previously held up by gas flow begin to fall; the additional liquids increase the gradient at the bottom of the tubing. Acoustic fluid level surveys acquired while the liquid is falling may result in flowing bottom hole pressures that are not accurate. When shooting fluid levels on a liquid loaded gas well the act of shutting the flow valve at the surface of the well for a long time period or running tools on a wire line will disturb the flow regime and can result in calculating inaccurate bottom hole pressures.

To determine the percentage of liquid in the tubing below the gas/liquid interface it is recommended that one or two fluid level measurements be undertaken shortly after stopping the flow at the surface. These measurements should be used to relate the depression of the gas/liquid interface to the increase in wellhead pressure. In wells with a significant percentage of liquid in the flow stream, the gas flow rate is 20 % or more below the Turner critical gas flow rate, only a few measurements will be required to establish the gaseous column gradient and to compute the PBHP. In these gas wells, shooting a fluid level down the tubing to determine %Liquid and PBHP produces similar satisfactory results as shooting down the casing annulus on a well pumping liquid up the tubing. One acoustic test is probably sufficient, but the operator should acquire two shots at the well: One acoustic test to shoot the well and a second acoustic test to verify/confirm the results from the first shot.

Acoustic Determination of Liquid Loading in a Gas Well

A fluid level survey down the tubing can be used to confirm that a well is liquid loaded. The results from the fluid level analysis determines the back pressure on the formation due to liquid load, plus predicts the possible increase in the gas production if the well is unloaded.

Fig. 6 displays the fluid level on a liquid loaded gas well. The current 265 MscfD average gas flow rate is below the Turner critical rate of 980 MscfD. This critical gas flow rate is calculated at the intake pressure of the 2.441 inch internal dimension tubing. The 265 MscfD is also below Turner's critical rate for the 358 psig wellhead pressure. **Fig. 7** plots gradients resulting from the analysis of the **Fig. 6** single fluid level shot down the tubing of this flowing liquid loaded gas well. The line labeled Liquid Gradient displays the gradient of the gaseous liquid column determined using the Echometer "S" curve. Based on the analysis of the acoustic fluid level shot there is 8630 feet of gaseous liquid in the well. The difference between the Liquid Gradient and the Gas Gradient line represent the "Back Pressure on Formation" at the 11261 foot tubing intake depth. The 385 psig gas/liquid interface pressure at the 2704 foot liquid level is extrapolated using the gaseous liquid gradient to the producing bottom hole pressure of 1080 psi ay 11261 feet. The "S" curve gradient is used to calculate an equivalent 1664 feet of gas free liquid is applying 622 psi of back pressure on the formation.

At a glance alternate tubing sizes can be evaluated to determine if the critical gas flow rate could be exceeded allowing the well to flow in an unloaded state with a smaller diameter string. The gas rate is determined at the intersection of a simple Vogel inflow curve modeling the flow from the formation intersecting with the outflow curves for each specific tubing size. The predicted status shows that this well would continue to flow at the current liquid loaded state with 1.995 and 1.5 inch ID tubing. If the Turner or Coleman critical rate is greater than the existing flow rate for any tubing size, then the well's predicted status stays loaded. But tubing strings with a 1.25 inch internal dimension and smaller would result in a sufficiently high gas velocity for the well to flow above critical in an unloaded state. With a 1.25 inch velocity string the well would continuously flow at 313 MscfD, resulting in a 48 MscfD increase in the gas production rate.

A single acoustic fluid levels "shot" down the tubing in flowing gas wells can be used to determine: 1) Amount of liquid in the bottom of the tubing, 2) Backpressure on the formation due to liquid, 3) Gas flow rate into the tubing, 4) Equivalent fluid gradient below the liquid level, 5)Flowing bottom hole pressure, 6) Feasibility of using various lift methods to remove the liquid loading and 7) Incremental Gas Flow Rate if Liquid Loading Removed. In a liquid loaded well the annular "S" Curve

predicts a reasonably accurate gradient of the gaseous liquid column and is a good technique to determine flowing BHP, and liquid loading.

Summary and Conclusions

Acoustic fluid level measurements are easily performed in flowing and shut in gas wells either through the tubing or the casing or both, depending on the type of completion and production method.

Gas production through tubing without packer

Acoustic fluid level measurements are performed in the casing first then through the tubing. The casing record generally shows good collar echoes that are used with an accurate average joint length to automatically calculate an accurate average acoustic velocity of the casing gas.

Since the well produces with the casing shut in, the liquid level is generally at the depth of the tubing intake; or below when there are multiple perforated zones below the end of the tubing. The annulus pressure at the depth of the tubing intake is computed very accurately as the sum of the wellhead casing pressure and the pressure due to the gas column based on the real gas equation of state and the gas gravity determined from the acoustic velocity.

When the tubing intake is set below some of the perforated intervals the casing acoustic trace should display echoes (upkicks) from the open perforations and these upkicks can be used as downhole markers to determine the distance to the liquid level. Occasionally, the multiple echoes from the perforations impede clear detection of the fluid level.

When shooting down the tubing if collar recesses can be detected, then the acoustic velocity should be reasonably close to the acoustic velocity determined from the casing. Tubing collar recesses from standard EUE upset 2 7/8 inch tubing are usually good reflectors and often are automatically counted (just like counting collars down the casing). Where echoes from 2 3/8 inch tubing collar recesses are usually more difficult to identify and other methods to determine the acoustic velocity may need to be used (such as using the acoustic velocity determined from the casing fluid level measurement).

Use the acoustic trace acquired down to casing to determine an accurate acoustic velocity, and then the gas gravity can be used as an estimate when performing an acoustic test down the tubing. The gas in the casing can be slightly different composition than the gas in the tubing, but using the gas gravity from the casing gas is often a reasonable method to determine the acoustic velocity and distance to the liquid level in the tubing.

An acoustic test on the casing annulus usually shows that there is no casing pressure buildup, and incorrectly concludes that no gas is flowing through the liquid below the tubing intake. If there is gas flowing up the casing, then the casing acoustic test will calculate too heavy of gradient below the tubing intake and too high of flowing bottom hole pressure. To determine the proper gradient in the larger diameter casing below the end of the tubing, the operator may want to modify and increase the casing pressure buildup until the gas glow rate calculated from the hand entered pressure and time match with the actual gas flow rate produced from the well up the tubing. The shot down the tubing is used with the tubing pressure build up to estimate the gas flow rate and the gradient of the fluid in the tubing and below the end of the tubing. The shot down the tubing usually gives the most accurate bottomhole pressure because the software assumes no gas flow when the casing valve is closed with the well flowing up the tubing.

Gas production through tubing with packed casing annulus

Fluid level measurements are performed only through the tubing unless there are reasons to suspect the presence of holes in the tubing or the casing.

The absence of echoes from the tubing couplings recesses makes determining the depth to the liquid level more difficult. If good tubing collar reflections are present and sufficient pressure is used to generate the acoustic shot, then tubing collar recess reflections may be counted deep into the well; counting collar reflections is usually the most accurate method to determine acoustic velocity or depth in a well.

When echoes from downhole markers are visible near the liquid level, these echoes should be used to determine a representative acoustic velocity and then to compute the distance to the liquid level.

The absence of echoes from downhole markers or from tubing recesses requires estimating the acoustic velocity from gas gravity or gas composition. Calculating the depth to the liquid level using gas specific gravity or composition is often the least accurate depth determination analysis method, because the actual composition of the gas in the well is unknown and/or the actual bottom hole temperature is not representative.

Gas production through casing with liquid pumped through tubing

Acoustic fluid level measurements for these types of gas wells are taken through the casing/tubing annulus. The acoustic fluid level measurements are interpreted and analyzed in the same manner as for pumping oil wells.

Data Quality Control

A recommended practice is to always acquire at least two (2) acoustic fluid level records when shooting the casing and two shots each time a connection is made to the well. The two acoustic traces should be examined and the operator should verify that the two acoustic traces are nearly identical. The acoustic velocity determined from all depth determination methods should be in the same range. If an echo from the top of a perforation can be identified near the liquid level, then using this perforation as a downhole marker is usually the most accurate method to determine depth. Do not shoot through a needle valve when an acoustic test is performed on the tubing or casing, if possible shoot through a hole size of 1/2" or larger.

References:

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3. Echometer Company, "Download AWP2000 Software", WWW.Echometer.com\software\index.html
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6. SPE 100663, "Acoustic Liquid-Level Determination of Liquid Loading in Gas Wells", O.L. Rowlan, SPE, J. N. McCoy, SPE, Echometer Company, A.L. Podio, SPE University of Texas

Figure 1 – Acoustic Trace Acquired down the Tubing Showing Upkick from Hole in Tubing

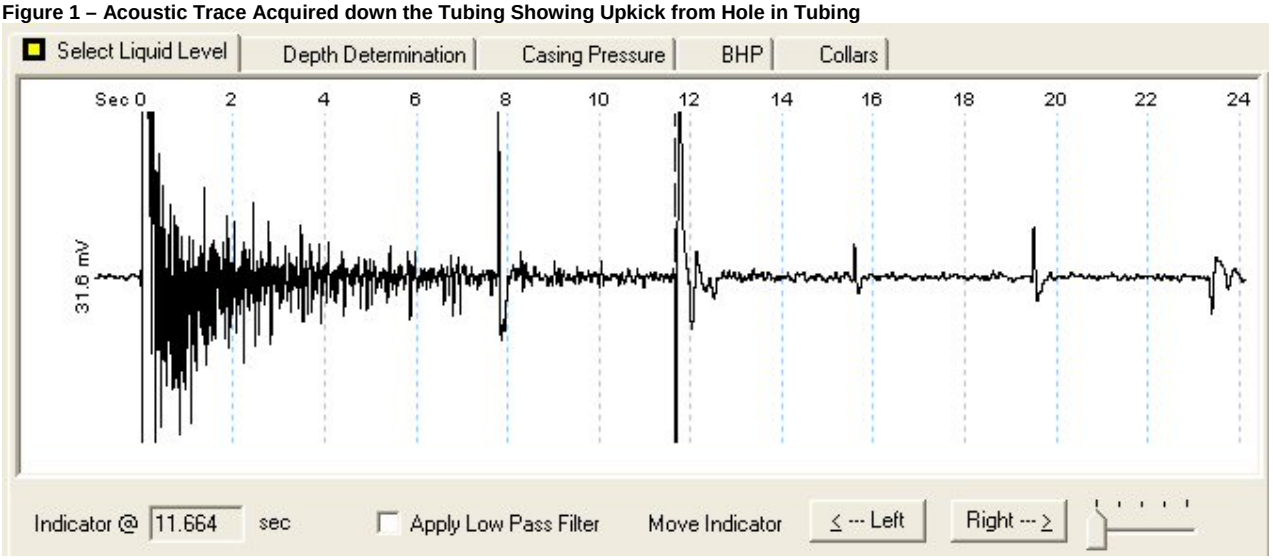

Figure 2 – Downhole Marker Using Known Perforation Depth to Determine Distance to the Liquid Level

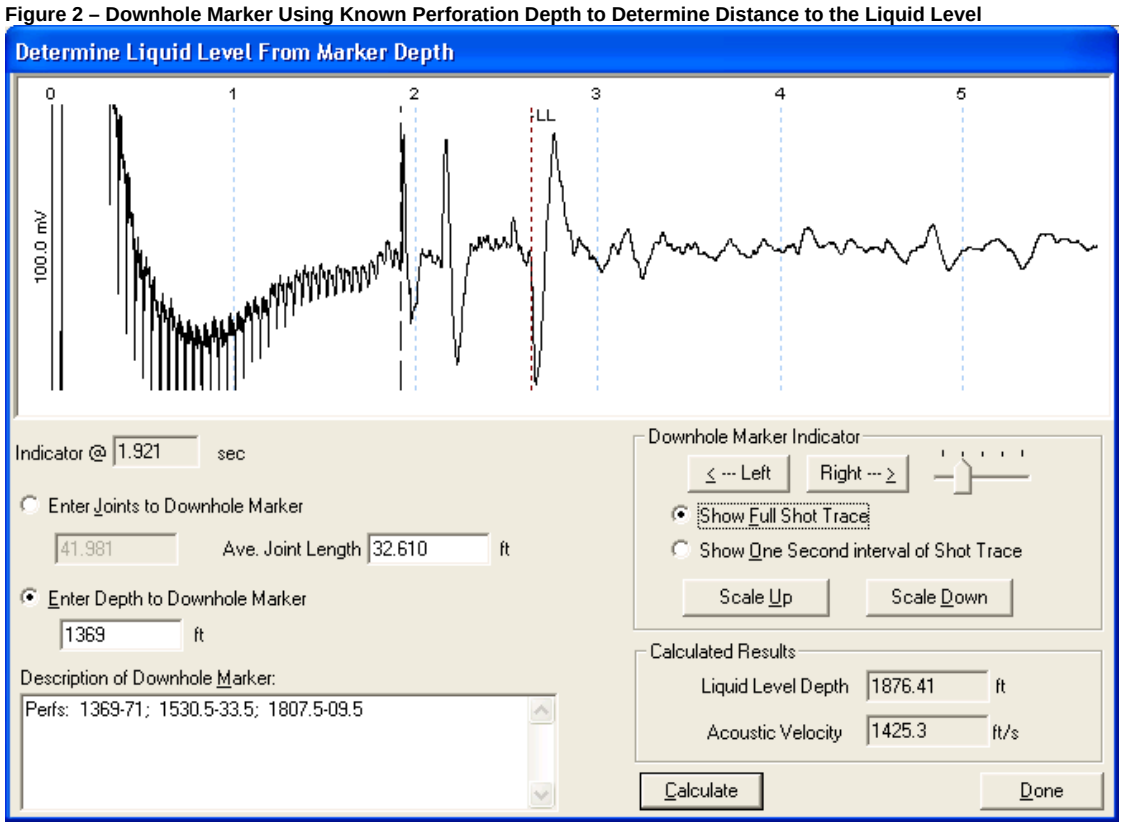

Figure 3 – Acoustic Velocity Determined from Gas Gravity

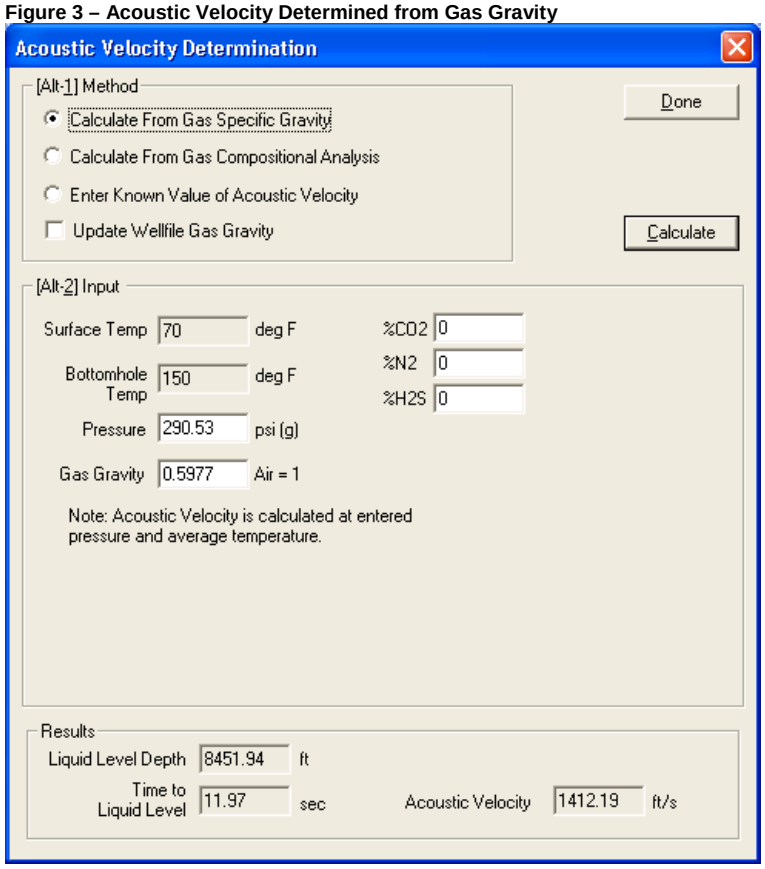

Figure 4 – Fluid Level Results on Gas Well Treated with Surfactant

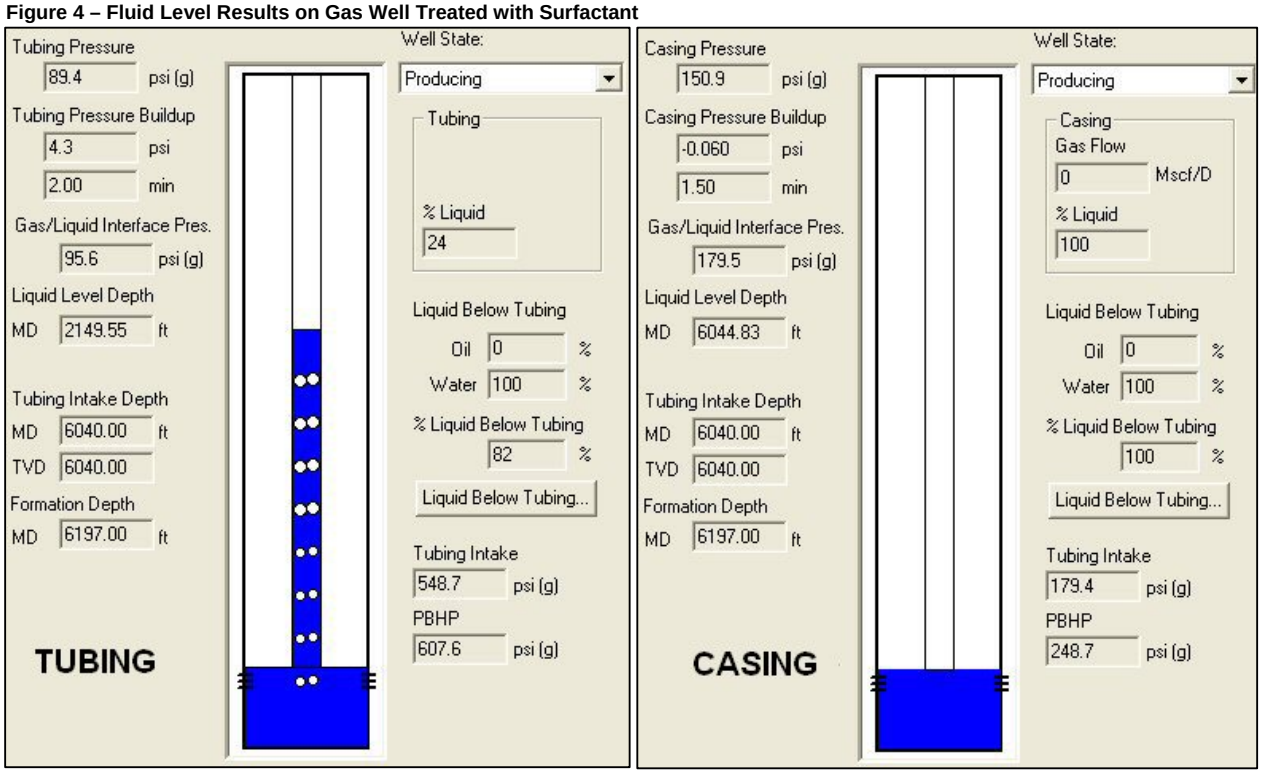

Figure 5 – Offshore Wellbore Schematic and Corresponding Acoustic Trace

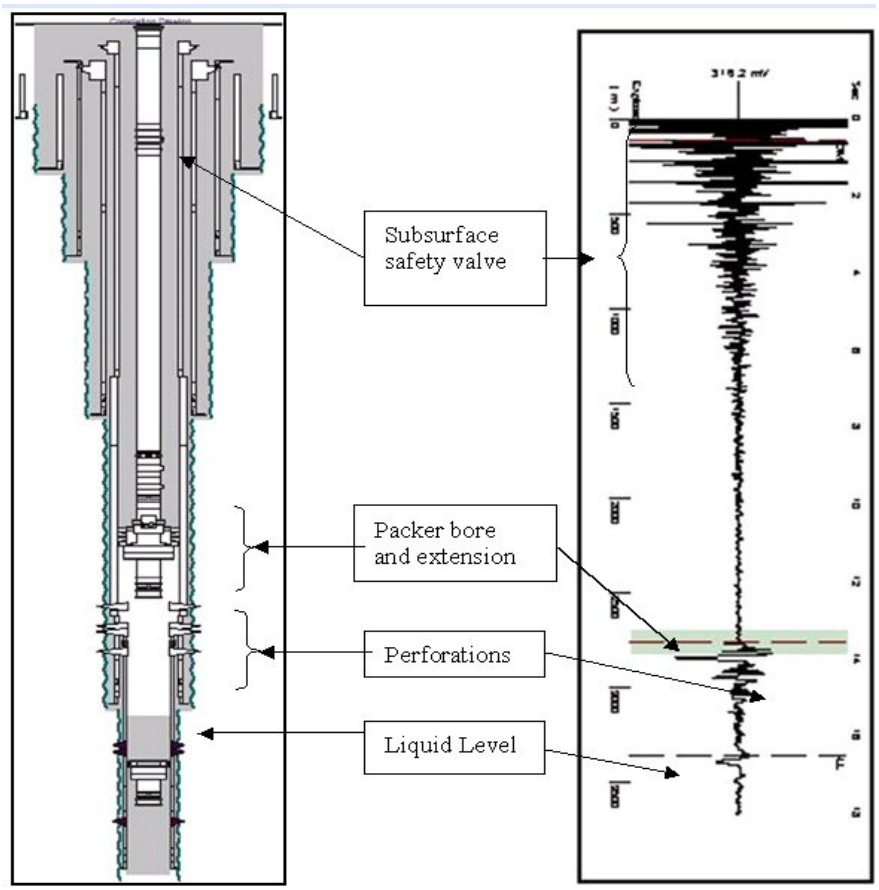

Figure 6 – Acoustic Test Acquired on a Liquid Loaded Well

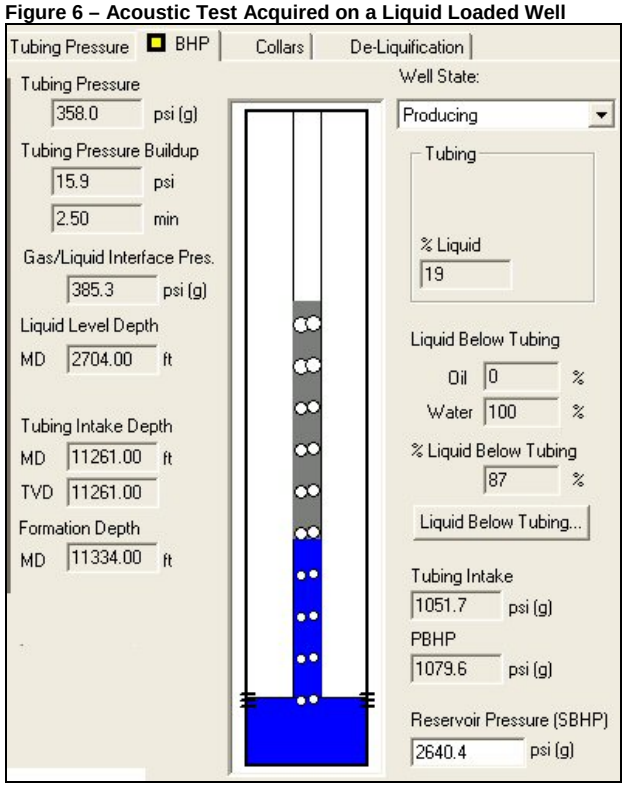
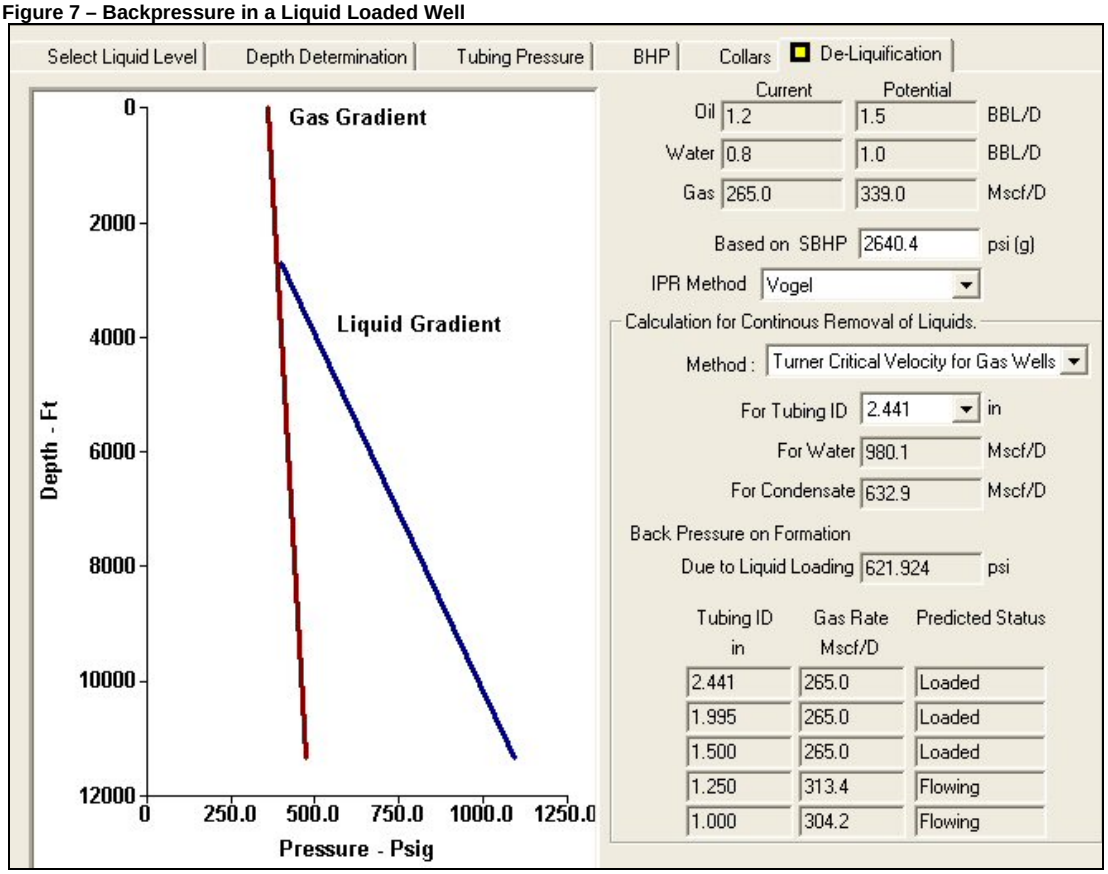
Figure 7 – Backpressure in a Liquid Loaded Well