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Acoustic Techniques to Monitor and Troubleshoot Gas-Lift Wells

C. Taylor, L. Rowlan, and J. McCoy, Echometer Company

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Abstract

The distance to the fluid level provides beneficial information throughout the life of a gas-lift well. From the initial unloading of the well, to maintaining production, and even into troubleshooting the well, the location of the fluid level plays a crucial role in understanding the well's performance.

Some of the most valuable fluid level shots occur during the unloading process, when the fluid level is compared to the gas injection depth. Fluid levels can be used to help determine whether a problem is occurring within the wellbore or due to equipment malfunction. A quick surface measurement determines valves below the fluid level are not injecting gas. Finding holes in the tubing string and location of any restrictions in the tubing or casing help identify problems impacting production. During a workover, monitoring the fluid levels of a well filled with kill fluid ensures sufficient hydrostatic pressure is maintained against the formation. In gas-lift wells without a packer, producing bottomhole pressures can be accurately measured using an acoustic fluid level instrument. Bottomhole pressure information is useful in designing and operating gas-lift installations and measuring overall producing efficiency[1].

Examples of fluid level shots on gas-lifted wells will be used to demonstrate these concepts. Acoustic fluid levels acquired on gas-lift wells provide a low cost, direct method to observe the well and benefit the operator through knowledge of the well's producing conditions.

Introduction

The distance to the fluid level provides beneficial information throughout the life of a gas-lift well. Fluid level depths are quickly determined with respect to known depths to gas-lift mandrels. The depth to the deepest mandrel uncovered, when check valves are present, is easily identifiable. Holes, restrictions and problem areas in the uncovered sections of the tubing and casing are alerted to by unaccounted reflection kicks. Acoustic shots are used to verify the initial unloading sequence is proceeding by periodic shots taken down the casing as the annular fluid level is depressed passed each mandrel by injection gas. Varying methods of using acoustics are used during troubleshooting regimes to assist in verifying downhole problems.

Determination of Depth to the Fluid Level

The distance to the fluid level in a gas-lift well is determined by analyzing the acoustic signal recorded versus time from a wellbore. The acoustic signal is created by generating a sudden change in pressure at the surface causing a pressure wave to go into the tubing or into the annulus of the wellbore. This pressure wave travels through the wellbore to the fluid level and reflects back to the surface. The depth to the fluid level is determined by relating the recorded echoes on the acoustic trace to the known depth of obstructions along the wellbore. In wells having downhole pumps the most common technique to determine the distance to the fluid level is to count tubing collar reflections. When present in the wellbore additional downhole marker reflections on the acoustic trace are usually seen from anomalies such as liners, gas lift mandrels and/or perforations. For gas-lift wells the most common technique to determine distance to the fluid level is to identify the echoes from each mandrel at their known depth locations. Gas-lift mandrels are excellent downhole markers and are typically used to determine a very accurate distance to the fluid level.

An accurate wellbore schematic is essential when using the echoes from known downhole markers to determine the correct distance to the fluid level. The process of using known marker depths for depth determinations in a wellbore is named the "downhole marker method". When the travelling wave moves past a downhole marker at a known depth, an echo is created because there is a physical change in cross-sectional area within the wellbore. The time on the acoustic trace of each echo reflected from specific anomalies in the wellbore can be identified and can be related to the known depth of a specific downhole marker. To determine the distance to the fluid level, the echo of the marker just above the fluid level

should be identified, then the distance to the fluid level is equal to the distance to the marker times a ratio of the time to the fluid level divided by the time to the marker.

When the downhole marker method for fluid level depth determination is used, a marker is typically selected by the operator. Downhole markers are used to accurately calculate the distance to the fluid level plus other downhole reflectors such as gas-lift mandrels, subsurface safety valves, and possible holes or other problems. Distances are determined by using echoes from mandrels and anomalies at known distances from the wellhead. Using downhole markers account for variations of acoustic velocity changes commonly observed in most wellbores due to variations of temperature, pressure and gas composition as a function of depth.

Acoustic Velocity and Downhole Markers

Echoes from anomalies are identified at known times on the acoustic trace and marker depths are selected directly from wellbore schematics, therefore an accurate acoustic velocity is determined. The time to an echo on the acoustic trace is equal to the Round Trip Travel Time (RTTT) of the pressure wave to travel from the surface to the depth of the anomaly plus the time to travel back to the surface. The average acoustic velocity from the surface to the anomaly can be calculated by multiplying the depth to the anomaly times 2 divided by the RTTT. The number 2 is necessary because the distance to the fluid level is one half of the total distance traveled by the pressure wave.

A more accurate distance to the fluid level can be determined, if the acoustic velocity between adjacent mandrels is determined. The acoustic velocity across the mandrel interval closest to the fluid level, then can be used to estimate the acoustic velocity and distance between the deepest marker that is identified and the fluid level. The calculated depth from the marker to the fluid level is then added to the known depth of the marker for the final distance to the fluid level.

Above the fluid level in the wellbore where gas is flowing or gas is being injected at the surface, the gas is relatively uniform in composition over the entire wellbore volume and an average acoustic velocity is generally representative of the gas in the wellbore. If gas in the wellbore has been shut in for an extended time, gas molecules can segregate by density and significant difference in the composition and acoustic velocity of the gas throughout the wellbore can occur. The acoustic velocity of the gas in the wellbore depends on the composition, pressure and temperature of the gas. Increase in temperature results in an increase in the acoustic velocity. Pressure's impact on the acoustic velocity depends on the value of pressure, for pressures increasing from 0 to 1000 Psia the acoustic velocity generally decreases and acoustic velocity increases as the pressure increases above 1000 Psia. In most wells the acoustic velocity increases as the well depth increases, because temperature in the earth increases as depth increases.

An accurate average acoustic velocity for the wellbore can be determined using an equation of state, if the gas composition, pressure versus depth, and temperature profile are known. This method of determining depth using acoustic velocity depends on the gas being relatively uniform in composition over the entire wellbore.

Since acoustic velocity changes along a wellbore profile, for the downhole marker method to be accurate it is essential to select the marker closest to the fluid level location to determine the average acoustic velocity in the wellbore. For this reason, gas-lift mandrels make excellent downhole markers. Multiple mandrels spaced along a wellbore profile make it easy to identify each marker and to select the marker nearest to the fluid level depth and to determine an average representative acoustic velocity.

Figure 1 displays the acoustic velocity profile for a gas specific gravity of 0.64. Pressure increases left to right along the bottom of the graph, and multiple curves within the graph represent temperature. The acoustic velocity increases with respect to increases of pressure and temperature along the left hand side of the graph. Within the acoustic velocity graph, wellbore conditions have been plotted according to changes measured as the depth of the wellbore increases. At the surface, 0.0 ft, temperature and pressure measurements indicate 70 deg F and 701psi respectively. A plot of these conditions for 0.64 SG result in an acoustic velocity of 1265 ft/sec. As the pressure and temperature increase along with depth, the plotted conditions result in an increase in acoustic velocity. The final plot at the fluid level depth, 10,200.8 ft, with temperature and pressure measured 250 deg F and 956.6 psi respectively, result in an acoustic velocity of 1515 ft/sec.

When choosing the mandrel that will be used as the marker in the fluid level depth determination, essentially the acoustic velocity that will be used in the fluid level depth calculation is being selected. In the above example, the RTTT for an acoustic shot taken from the surface is approximately 16 seconds. Choosing a mandrel marker nearer to the surface, where the acoustic velocity is over 200ft/sec lower than the actual acoustic velocity would result in an error in the final fluid level depth calculation. Choosing the closest mandrel marker to the location of the fluid level will result in the most accurate fluid level depth calculation because choosing that particular marker accounts for the variation of acoustic velocity along the wellbore.

Acoustic velocity can be determined from counting collar echoes, or by identifying downhole markers detected during a shot. Collar echoes can be counted from the surface down to the fluid level, if conditions in the well allow for a sufficient number of collars to be detected. Often, high frequency noise as well as multiple reflections and repeat reflections off mandrels make an accurate collar count impossible.

Noise Present on the Acoustic Trace

Loud high frequency noise is frequently present on the acoustic traces acquired on producing gas-lifted wells. Notice **Fig. 2** where the high frequency noise is masking/hiding the echoes from collars, mandrels, fluid level and other downhole

anomalies. **Fig. 3** displays the same acoustic trace where a special "Low Pass" filter has been used to remove the high frequency noise and the echoes from the anomalies can be seen on the filtered acoustic trace. The source of noise can be determined easily by closing the valve between the microphone and the wellbore. If the acoustic signal showing the well noise remains the same, then the noise is caused either by surface vibrations or by gas leakage from extraneous lines connected on the same side of the closed valve as the microphone. If the acoustic signal showing the well noise decreases when the valve is closed, then the noise source is from inside the wellbore. The microphone is shock mounted, but if the wellhead vibrates excessively, unwanted signals are generated. Wellhead vibration can result from running gas engines, chattering check valves, reciprocating surface equipment, or a compressor supplying the high pressure injection gas. In some cases it may be necessary to eliminate wellhead vibrations to obtain better quality acoustic traces. All other lines leading to the location where the microphone is connected to the wellbore should be closed.

In gas-lift wells the main source of noise is often from down-hole. Acoustic noise can be created from sources such as pressure drops through a choke or gas whistling through an injection valve or just the roar from the high flow rates of injected gas. Downhole noise can also result from tubing and casing leaks. In low pressure wells, the down-hole acoustic noise can be reduced in relation to the anomaly reflections by causing an increase in the wellbore pressure. In gas-lifted wells the wellbore pressure is typically high. If the signal from the fluid level and mandrels is not detected due to excessive surface vibration noise or down-hole acoustic noise, then a larger signal from the fluid level can be obtained by generating a larger initial pressure pulse.

Example of Interval Downhole Marker Method

The acoustic shot trace acquired down the casing annulus of a gas-lift well, shown in **Fig. 2,** displays the raw unfiltered acoustic trace with anomaly echoes hidden in the high frequency noise. Downhole noise from high rate gas injection and whistling valves is the likely cause of the high frequency noise on the acoustic trace. In **Fig. 3** a low pass filter is applied to the acoustic trace to reduce high frequency noise and allow downhole reflectors such as fluid level, gas-lift mandrels, and subsurface safety valve reflection detail to be seen. In **Fig. 4** the time of each anomaly echo has been associated to the depth of the anomaly using the "interval downhole marker method", which determines the acoustic velocity between adjacent reflectors. Shown in **Table 1,** the acoustic velocity between each anomaly has been determined using the RTTT and distance to each anomaly. The distance to the fluid level is determined by using the acoustic velocity between Gas-lift Mandrel 6 and 7 to determine the distance from the known depth of Gas-lift Mandrel 7 to the fluid level. The process of using one downhole marker for depth determination, results in only one acoustic value being used to determine the distance to the fluid level and only the depth of Gas-lift Mandrel 7 being correct because acoustic velocity changes with respect to depth. Using 1 marker to determine distance to the fluid level may be accurate, where the "interval downhole marker method" determines an accurate velocity profile over the entire well bore and the fluid level depth plus each valve's depth is accurately determined along the acoustic trace.

A wellbore profile is created from known valve and marker depths obtained from the wellbore schematic for this well. During analysis, the marker profile is overlaid along the acoustic trace, as represented by the numbered vertical dotted lines. **Fig. 4** demonstrates the results of marker placement. Beginning with the marker highest in the wellbore, each marker is individually moved to the exact time location of its respective reflection kick. The first marker "S," representing the subsurface safety valve (SSSV) located at 1791 ft results in an acoustic velocity of 1170 ft/sec near the surface. By identifying each marker in succession, an acoustic velocity profile for this well is created by calculating the acoustic velocity over each interval between markers until the fluid level is reached. The placement of the final marker "7" for Gas-lift Mandrel 7 located at 6191 ft, results in an acoustic velocity of 1285 ft/sec. The fluid level is located just below Gas-lift Mandrel 7. Using markers to create the resulting acoustic velocity profile yields an accurate fluid level depth calculation of 6253 ft from the surface.

Troubleshooting Using Acoustic Velocity

Knowing an expected value or range for the acoustic velocity of the gas in a particular well or group of wells is important. If the value of the acoustic velocity resulting from the analysis of a fluid level shot is outside of the reasonable range expected for the acoustic velocity for the well, then there likely is a problem. The problem could be due to an incorrectly analyzed acoustic trace or the composition of the gas in the well has changed. These two reasons are discussed for the purposes of troubleshooting.

First, comparing the calculated acoustic velocity to the known range will provide confirmation as to the accuracy of your marker selection and the resulting fluid level depth calculation. In the above example (**Fig. 4**), as each mandrel marker is moved to its respective reflection echo, the acoustic velocity across that interval is calculated concurrently. The acoustic velocity range in this well is approximately 1170 ft/sec – 1285 ft/sec shown in **Fig. 5** and notice how the acoustic velocities determined for each interval follow along a straight trend line. If, for example, a marker's placement yields a calculated acoustic velocity that is unreasonably outside of the 1170 ft/sec – 1285 ft/sec acoustic velocity range or not near the trend line, then the selected marker location should be double checked to verify accurate placement on the acoustic trace.

Further, if the calculated fluid level depth itself seems unreasonable, the marker selected and the acoustic velocity used in the fluid level calculation should be double checked for accuracy.

Second, the acoustic velocity can be used to verify the gas specific gravity and uniform gas composition in the

wellbore. Because the acoustic velocity of a particular gas specific gravity is based on pressure and temperature conditions acting upon that gas composition along the wellbore, the resulting average acoustic velocity calculated can be used to verify the gas specific gravity in the well. A significant increase or decrease in acoustic velocity could indicate an issue with lighter or heavier gases seeping into the wellbore, uniformly changing the gas composition in the well, thereby affecting the overall average acoustic velocity. Identifying wells where the gas acoustic velocity is outside the expected range has allowed the identification of an upper gas zone casing leak. Observing the value of the measured acoustic velocity and comparing the acoustic velocity to an expected value has proven useful in field operations.

Direction of Echo Kick Created by Mandrels

The shape and direction of echoes reflecting from gas-lift mandrels in the wellbore are determined by three main factors: 1) The physical characteristics of the mandrels, 2) Whether the acoustic shot is taken down the tubing or down the casing and 3) Whether the type of shot is implosion or explosion when using a paper strip chart recorder. Many different types of valves and mandrels are manufactured. The shape of the mandrel as well as the space within the mandrel where the valve is located will have an impact on the direction of the resulting acoustic echo.

Acoustic shots taken down the tubing/casing annulus will typically generate downward kick. Once the pressure wave travelling down the casing reaches the outside of the mandrel, which takes up space within the annulus, the travelling pressure wave contracts to fit into the decreased cross-sectional area created by the mandrel occupying space in the tubing/casing annulus. Downward kicks on the acoustic trace acquired down the tubing/casing annulus are the result from the decrease in cross-sectional area at the mandrel, shown in **Fig. 6**.

A pressure wave travelling down the tubing will expand to fill the volume of the side pocket where the valve is housed. **Fig. 7** displays upward kick echoes on the acoustic trace created when the traveling pressure wave expands into the increased cross-sectional area created by the mandrel pocket.

The direction of a reflection kick will also depend on whether the acoustic shot was made using the explosion method or the implosion method when using the gas gun. An explosion shot is generated by filling the volume chamber of a gas gun with compressed gas and “exploding” the shot into the well. An implosion shot is generated using the gas available in the well and “imploding” the shot into the volume chamber of the gas gun. An implosion shot inverses the polarity of the resulting kicks. When software analysis is used, the type of shot (explosion or implosion) is specified and the polarity of the implosion shot is inverted to display the reflected echoes consistently; for example, a downward kick when the acoustic shot is fired, and a downward kick from the fluid level. If a paper strip chart recorder is used to acquire an implosion shot on a well, then the recorded polarity on the paper strip chart is not changed and a shot will result in an upward kick across a decrease in cross-sectional area (such as a fluid level kick), and a downward kick across an increase in cross-sectional area (such as perforations).

Overlay Tubing and Casing Shots for Troubleshooting

Overlaying and comparing tubing and casing shots help identify problems by answering questions.

1) Do the valve and mandrel reflections line up?
   Acoustic shots taken down the tubing and casing on the same well can be overlaid and compared. In **Fig. 8**, the upkicks across the valves in the tubing and the downkicks across the mandrels in the casing are overlaid and compared. The wellbore profile is also overlaid. The reflection kicks on both the tubing and casing shots line up with the mandrel locations visible from the wellbore profile overlay.
2) Are there additional upkicks or downkicks indicating possible holes, restrictions or other problems?
   Once valve and mandrel reflections as well as any other identifiable reflections have been determined, it is easier to identify echoes that could indicate problems in the wellbore.

Echoes from holes will appear as upkicks on the acoustic trace, when the hole is above the fluid level. A hole that is present along the tubing string will appear as an upkick on both the tubing and casing acoustic traces. In **Fig. 9**, an additional upkick is present on both the tubing and casing shots at approximately 1.57 seconds into the shot. Even though the fluid levels depths are different on the shots, the two acoustic traces can still be compared to confirm the presence of a hole in the tubing string. A depth reference line can be moved to the beginning of the upkick across the hole and an accurate depth to the hole of 1083ft from the surface is easily determined.

Fluid Levels During Unloading Sequence

During the initial unloading sequence on a gas-lift well, acoustic fluid levels can be used to monitor the unloading process. Shots down the casing annulus provide a quick look at uncovered mandrels as the annular fluid level is displaced by the injection of high pressure gas into the annulus during the unloading process. As each valve is uncovered, its corresponding reflection kick on the acoustic trace is quickly identified along with the depressed fluid level.

Troubleshooting Problem Wells

Acoustic fluid level measurements can be used to trouble shoot problem wells. **Fig. 10** displays one acoustic technique used to search for holes and restrictions along the tubing string, as well as verify there is no pressure communication between the

tubing and the casing annulus. A total of 20 acoustic shots were taken over a period of 132 minutes. At the beginning of the test, an initial fluid level shot and was taken along with tubing and casing pressure measurements. High pressure gas was injected into the tubing at the surface; the increase in tubing pressure resulted in depressing the fluid level downward in the tubing string. Periodically, acoustic shots were acquired in the tubing to determine distance to the fluid level as a function of the changing tubing pressure. As the tubing pressure increased the fluid level in the tubing was depressed, the acoustic shots displayed echoes reflecting off all uncovered mandrels. Once the forth mandrel was uncovered, the tubing pressure continued to be increased resulting in depressing the fluid level below the end of the tubing. After observing the tubing was clear of obstructions, the tubing pressure was bled off, allowing the fluid level to rise back toward the initial height at the beginning of the test. The process was repeated and gas was injected down the tubing again depressing the fluid level. The casing pressure did not change, the check valves held, and there was no pressure communication between the casing and tubing during this test. **Fig. 11** displays a plot of the fluid level depth compared to the tubing pressure. The height of the fluid column fluctuates and was directly related to the increase or decrease in tubing pressure.

Conclusion

Beneficial information is obtained throughout the life of a gas-lift well using acoustic techniques to determine the distance to the fluid level. Gas-lift mandrels usually provide excellent downhole markers and various techniques can be used to determine distances to anomalies in the tubing string and in the tubing/casing annulus. Identifying reflection kicks across valves and mandrels result in more accurate depth analysis. Varying methods of using acoustics are used during troubleshooting campaigns to assist in verifying downhole problems.

The acoustic velocity of the gas in the well is directly determined from the known distance to the downhole marker and the round trip travel time of the pressure wave reflected from the downhole marker. Knowing the acoustic velocity profile of the gas in the wellbore provides critical information for verifying gas composition and fluid level accuracy.

Holes, restrictions and problem areas in the uncovered sections of the tubing and casing are alerted to by unaccounted reflection kicks. Acoustic shots are used to verify the initial unloading sequence is proceeding by periodic shots taken down the casing as the annular fluid level is depressed passed each mandrel by injection gas. Troubleshooting techniques aid in identifying downhole problems.

References

1. McCoy, J.N. : "Acoustic Determination of Bottomhole Pressures in Gas Lift Wells," paper Petroleum Engineer, August 1976.

Table 1 – Acoustic Velocity from Interval Downhole Marker Method

Code	Description	Depth from Surface (Ft)	Round Trip Travel Time (Sec)	Acoustic Velocity (Ft/Sec)
S	SSSV	1791	3.061	1170
1	Gas Lift Mandrel 1	1893		
2	Gas Lift Mandrel 2	3381	5.642	1232
3	Gas Lift Mandrel 3	4442	7.328	1259
4	Gas Lift Mandrel 4	5002	8.217	1260
5	Gas Lift Mandrel 5	5413	8.868	1263
6	Gas Lift Mandrel 6	5754	9.4	1282
7	Gas Lift Mandrel 7	6191	10.08	1285
8	Gas Lift Mandrel 8	6655		
R	Packer	6700		
	Fluid Level Depth	**6253**	**10.176**	**Avg AV = 1229**

Figure 1 – Acoustic Velocity Profile for a Gas Specific Gravity of 0.64

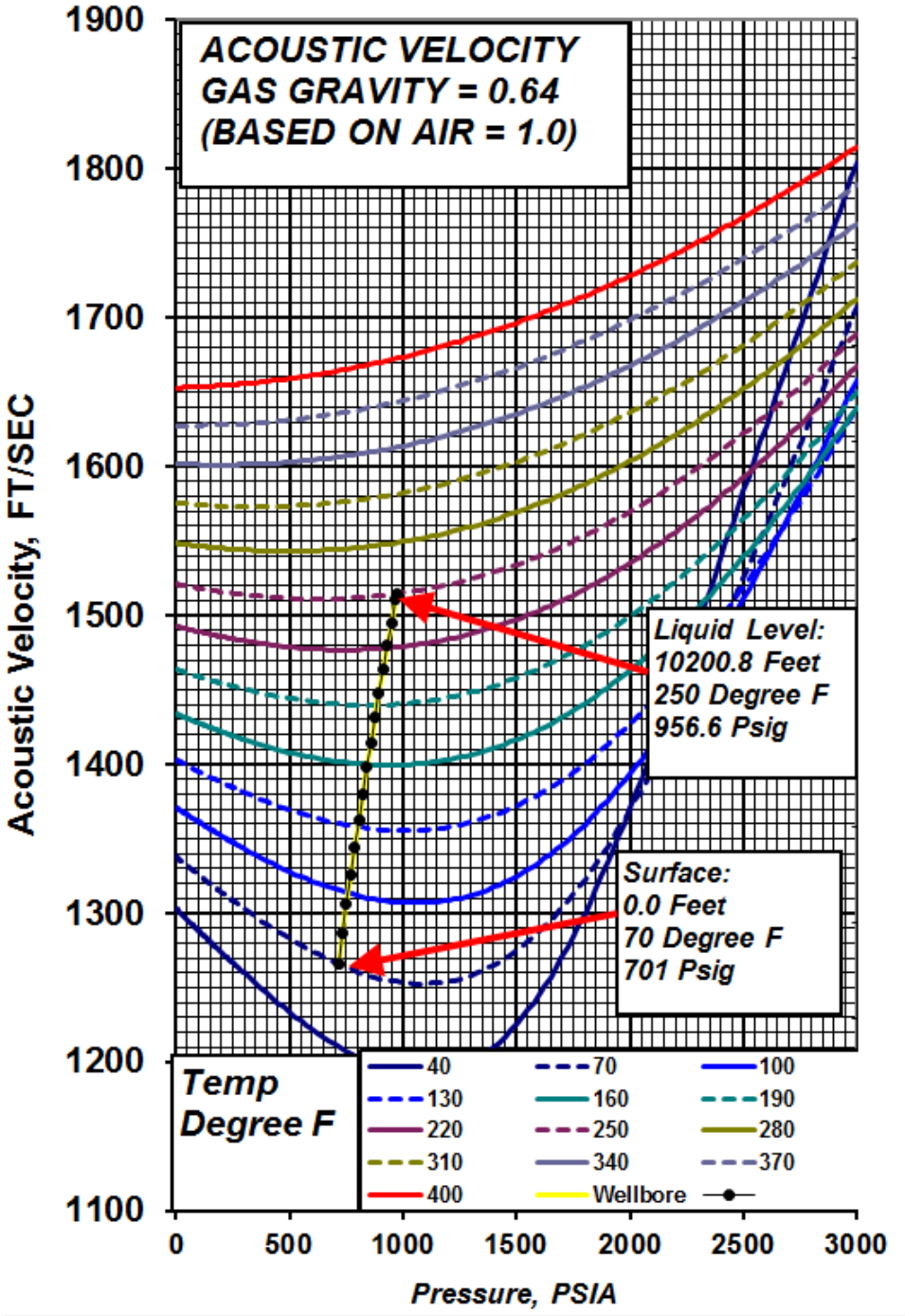

Figure 2 – High Frequency Noise is Masking/Hiding the Echoes

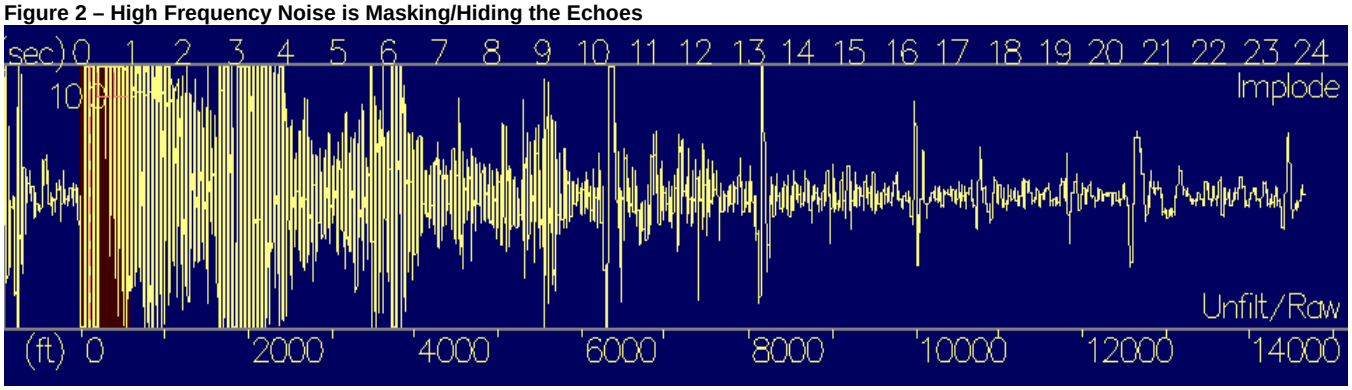

Figure 3 – Special "Low Pass" Filter Used to Remove High Frequency Noise

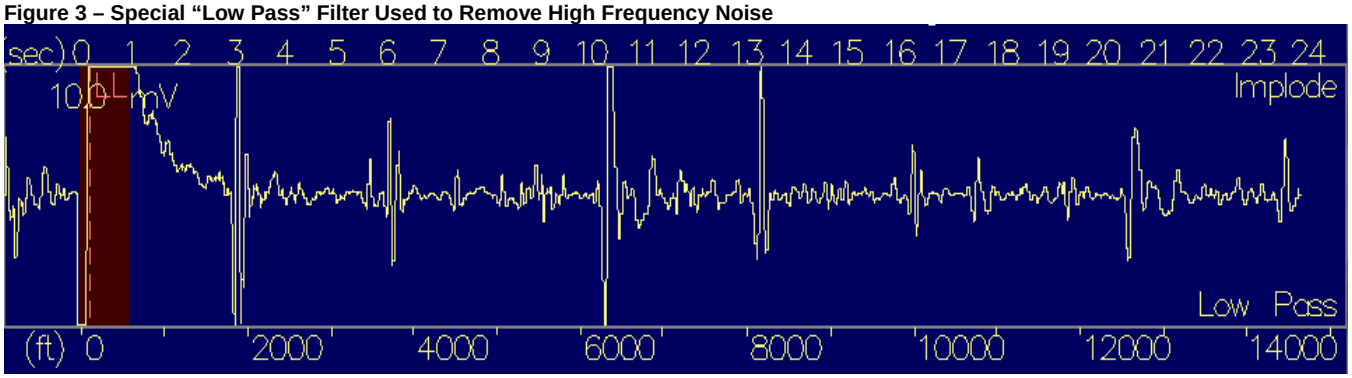

Figure 4 – Acoustic Trace with Anomaly Echo Matched to Anomaly Depth

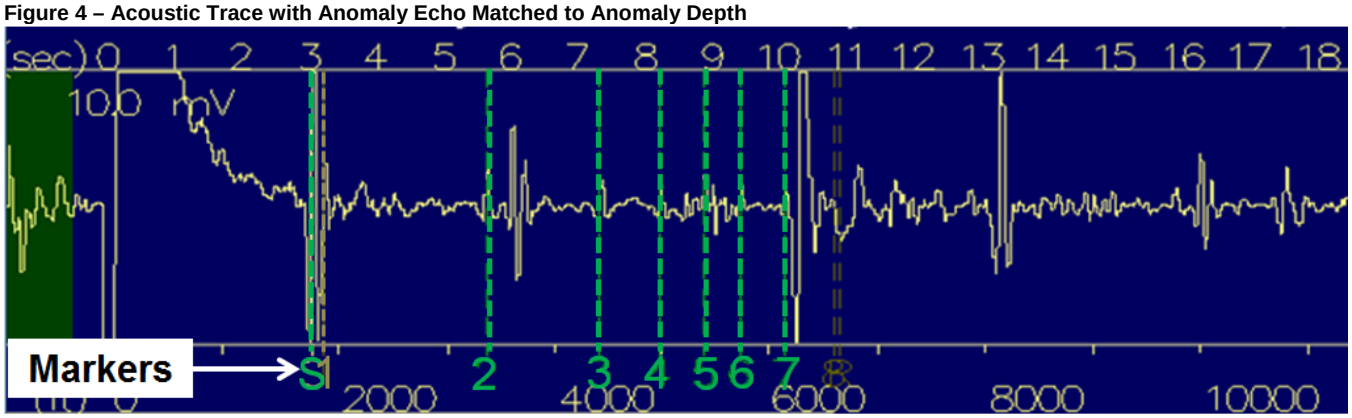

Figure 5 – Reasonable Acoustic Velocity Range for Gas in a Well

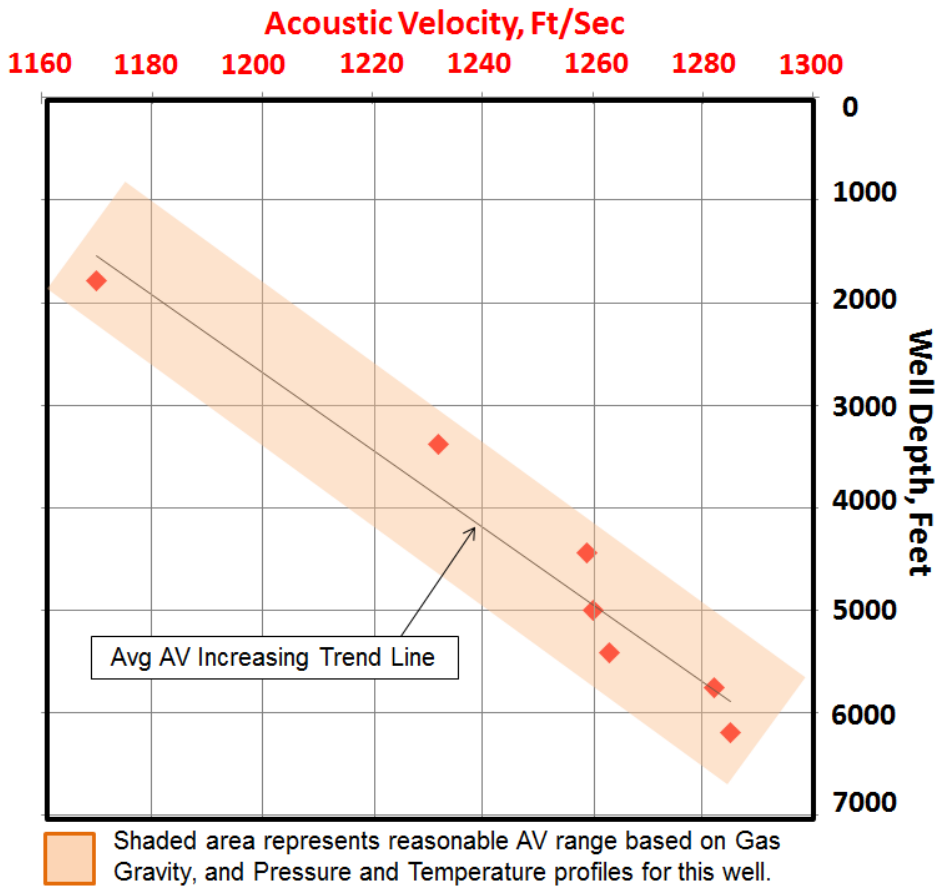

Figure 6 – Casing Shot displays Echo Downkicks at the Mandrel

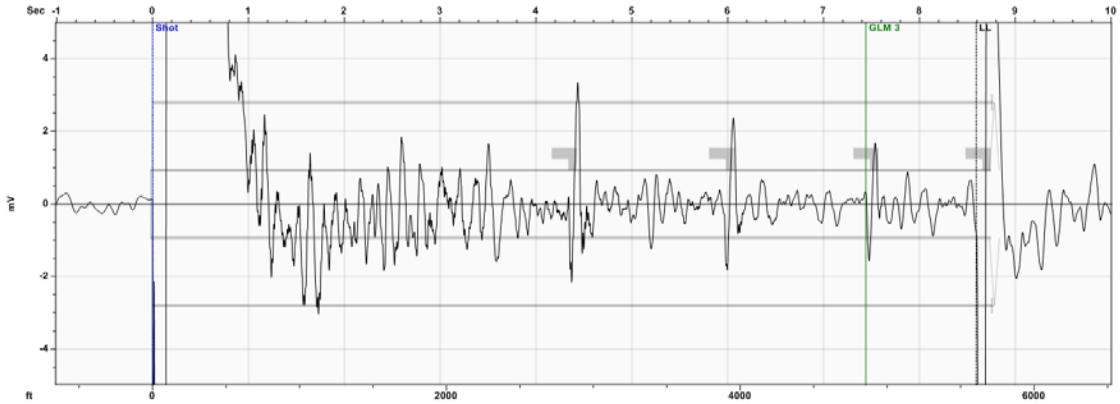

Figure 7 – Tubing Shot displays Echo Upkicks at the Mandrel Pockets

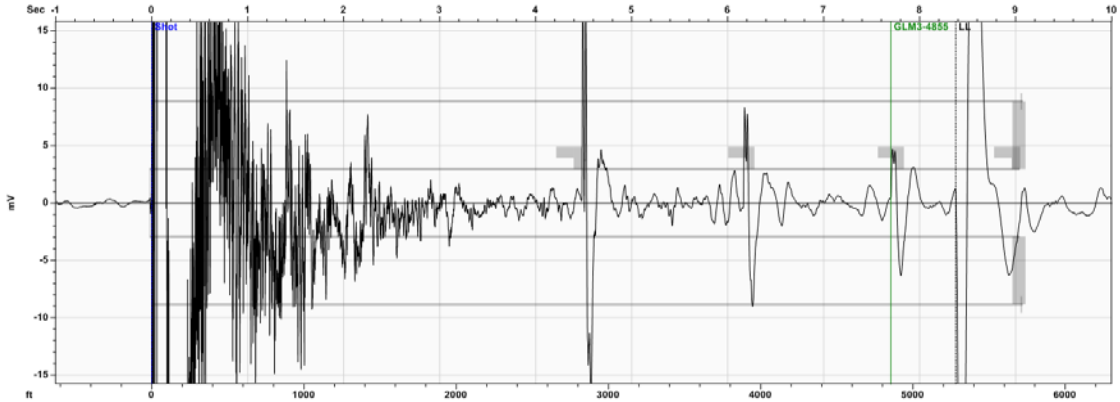

Figure 8 – Overlay of Tubing and Casing Shot Show Echoes Line Up

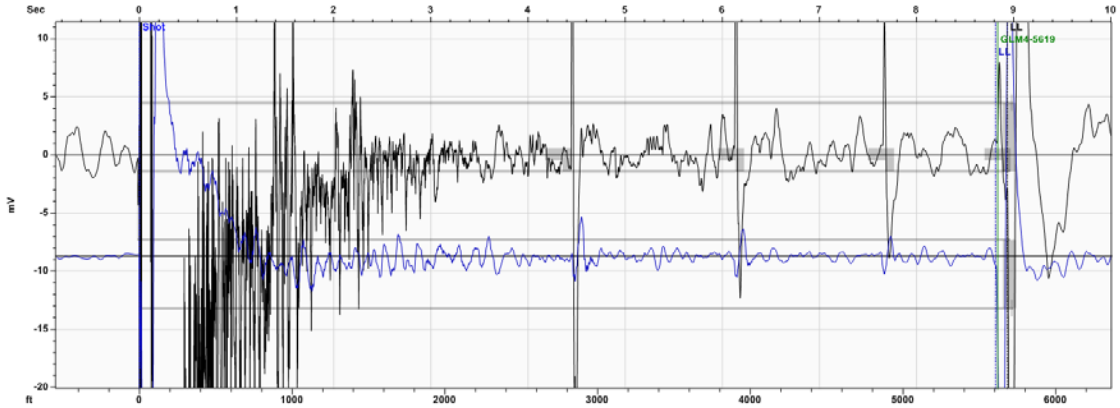

Figure 9– Overlay of Tubing and Casing Shot Show Echo for Hole in Tubing

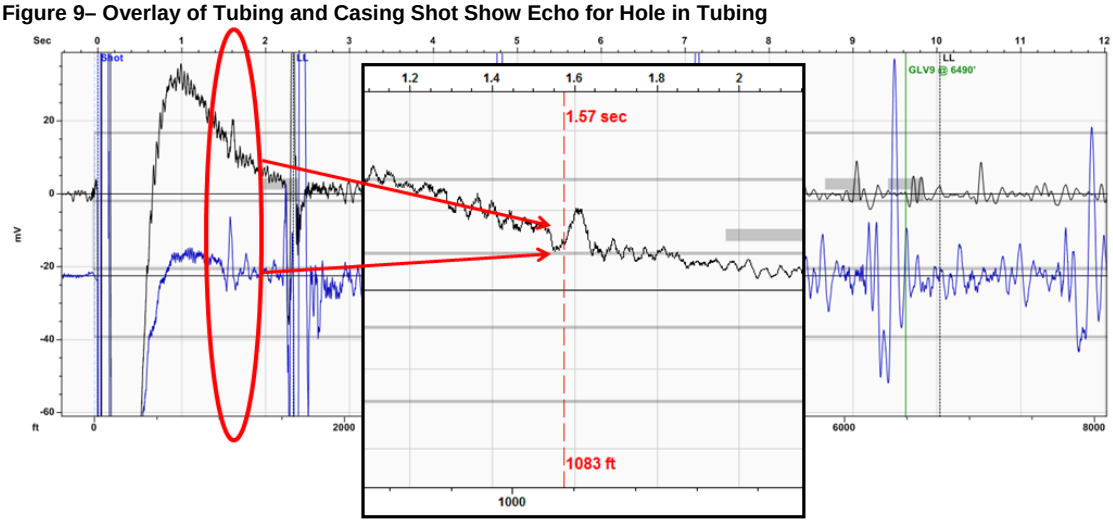

Figure 10 – Troubleshooting Gas Lift Well by Depressing Tubing Fluid Level

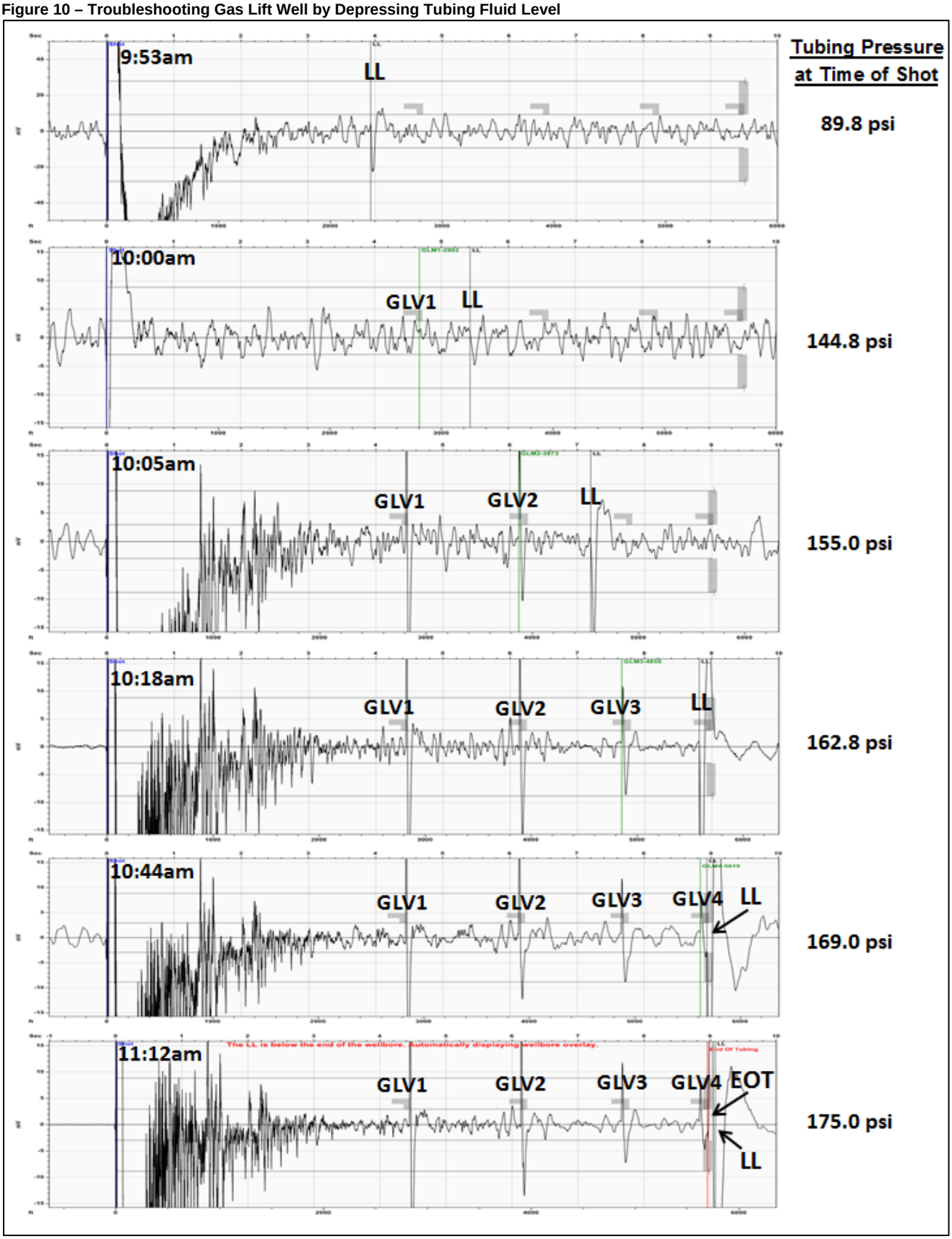
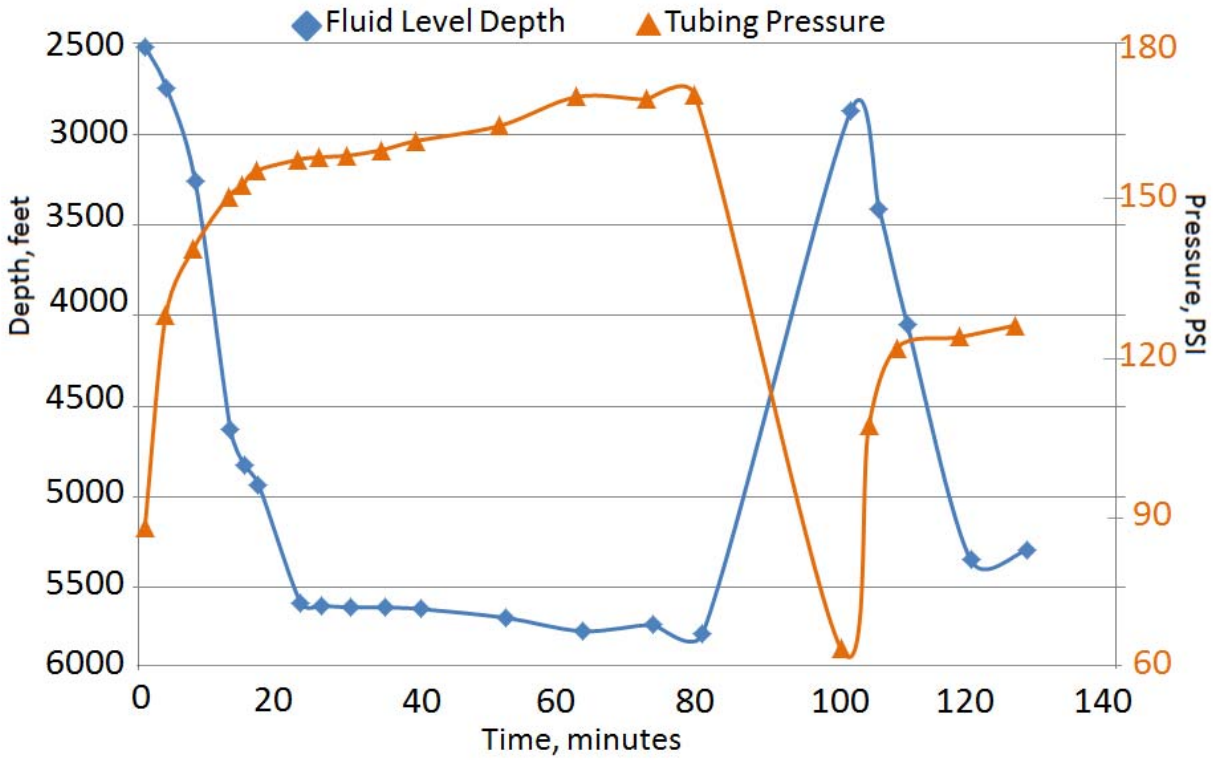
Figure 11 – Depressing Tubing Fluid Level by Increasing Tubing Pressure