TROUBLESHOOT OIL AND GAS WELLS USING ACOUSTIC LIQUID LEVEL SHOTS

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ABSTRACT
Shooting fluid levels has become a well-known practice in support of daily production operations. The practice of shooting fluid levels is so well-known, in fact, that the term, "shooting fluid levels" is assumed to mean checking the fluid level to determine if a well is producing the maximum fluid potentially available from the formation. The most common use of an acoustic liquid level instrument is to measure the distance to the liquid level in the casing annulus of a well having a downhole pump. Shooting fluid levels inside the tubing (instead of just inside the casing annulus) is common practice in flowing gas wells. Fluid level both inside the tubing and inside the casing annulus is a valuable trouble-shooting technique used on wells that have either stopped producing altogether, or production rate has drastically decreased.

Analysis of acquired fluid level shots can determine if there is a hole in the tubing. Tubing shots acquired at uniform time intervals can show ineffective pump operation, where down hole liquid level rise in the tubing occurs too slowly. Tubing shots acquired at uniform time intervals can also be used use gas pressure buildup provided from the well or a high-pressure source to displace the liquid level down the tubing or casing and see the echo from a hole when no longer covered with fluid. Fluid levels shots are effective tools when troubleshooting oil and gas wells. Many fluid level examples will be presented that discuss how tubing and casing shots are acquired and analyzed to determine hole-in-tubing on all types of oil and gas wells.

Introduction
Acoustic fluid level tests are performed successfully to analyze and troubleshoot producing oil and gas wells throughout the world[1]. An acoustic fluid level trace is created by a sudden release of differential pressure between the acoustic instrument and the wellbore. When the pressure differential is released the explosion of pressure change is created and can be described a "BANG!" the shot is fired. The shot in effect creates a traveling wave from the acoustic instrument into typically the gas at the connection into the wellbore. The pressure wave propagates through the gas at a speed of sound called the acoustic velocity of the wellbore gas. A portion of the traveling wave/sound wave/pressure wave is reflected by solids or liquids in the path of the wave. Echoes created inside a wellbore when reflected by changes in diameter of tube have a relationship to the size of the wellbore diameter change, the greater the change in diameter the larger is the amplitude of the reflected wave. More energy (differential pressure) is required to create a quality acoustic trace as more changes in the wellbore cross-section restrict the propagation of the traveling wave. Each change in cross-sectional area (above the fluid level) reflects a pressure wave back to the microphone/differential pressure detector in the acoustic instrument. The recorded acoustic trace as a function of trip travel time, RTTT, displays all of the echoes from the changes in cross-section of the wellbore down to the fluid level. Software normally displays the acoustic trace showing echoes as vertical +/- spikes (signals) along the horizontal RTTT timeline axis. Where time 0 is the initial blast created by the sudden release of the differential pressure from the acoustic instrument, then a series of repeating small echoes from tubing or casing collars. On the right side of the acoustic trace is displayed a low frequency (wider) echo created by the fluid level. The recorded signal (acoustic trace) corresponds to the differential pressure pulse traveling from the acoustic instrument's microphone to the fluid level and then back to the surface. Fig. 1 shows an acoustic trace timeline above the acoustic trace with RTTT 0 identifying time shot is fired, the high frequency echoes are from collars and the fluid level, LL, is located at a RTTT of 1.37 seconds.

To create a high-quality acoustic trace, then usually 200 Psi or greater pressure is needed to fire the shot. Pressure range on the annulus can range from 0-15000 psia, depending on the pressure rating of the acoustic instrument selected. The quality of the acoustic recording is determined by well conditions and the energy contained in the acoustic pulse. To get an adequate acoustic record, the signal to noise ratio should always be maximized. If needed, in order to get a larger acoustic pulse and a better signal, use a higher differential pressure between the wellbore and in the volume chamber of the acoustic instrument. Low surface casing pressure can be a problem when shooting wells, but we recommend that you add more pressure in the acoustic instrument to send out a stronger acoustic pulse if the distance to the liquid level is deep in the well. For deep fluid levels more pressure in the volume chamber is better. Frequently on deeper wells the acoustic trace is acquired with greater than 600 psi charge pressure. The compact and remote gas gun is rated for 1500 psi and you can use Nitrogen gas can be used to create a large pressure charge, when CO2 vapor pressure does not provide sufficient pressure. For some types of acoustic instrument, a volume chamber that is 3 or more times larger than normal can be attached, so that the initial acoustic blast will contain a high amount of energy and contain sufficient energy to travel far in a deep, noisy, low pressure well. The energy you release into the wellbore is directly proportional to the volume chamber size and the amount of differential pressure. At very low wellbore pressures a high differential pressure charge is required for the traveling wave to travel from the surface and reflect back to the microphone in the acoustic instrument. Past experience has shown when the surface pressure is a negative 5 psig the quality of the acoustic trace is acceptable, if the liquid level is less than 6000' from the surface. Sound does not travel in a vacuum, below -8 psig sound (traveling wave) does not travel very well, but a high-pressure charge near the working pressure of the acoustic instrument will usually create a quality acoustic trace. The acoustic instrument should be attached to the wellbore through a fully opening valve. Preferably, the distance between the acoustic instrument and the wellbore should be 3 feet or less. Also, all the connections from the acoustic instrument and the wellbore should be 1/2 inch or larger without using a needle valve. Do not permit a U tube to exist in these connections or a liquid trap may occur.

The well should be operating in stabilized conditions to acquire a quality fluid level for accurate determination of the distance to the liquid level and then accurate bottom hole pressure. The knee of fluid level echo should be correctly identified. The default method to determine the distance to the liquid level is to count tubing collar echoes and the correct average tubing joint length should be used. Accurate up to date wellbore schematic is important to associate the known depth to each mechanical device installed in the well to its corresponding echo. The wellbore deviation survey is required convert the measured depth of the acoustic trace into true vertical depth and to compute pressures in the wellbore. Measurement of casing pressure is required for accurate calculation of downhole pressures. Measurement of casing pressure change versus elapsed time is required to calculate annular gas flow rate and annulus liquid fraction below the fluid level. The tubing and casing size is required for calculation of annular gas rate. The oil, water and annular gas densities are required for calculation of pressure gradients. Acoustic fluid level measurements should be repeated whenever excessive acoustic noise is present and fluid level echo is not clearly identifiable, but in any event the operator should always acquire 2 shots in order to identify random noise on the acoustic trace.

Types of acoustic instruments, gas gun, are certified for use with well head pressures and working pressures of equipment should not be exceeded. There are types of acoustic instruments can be used on wellheads in the explosion (pressure from gun discharged into well) mode when the well pressure is low and does not permit satisfactory operation in the implosion (pressure from well discharged into gun) mode. **Fig 2** shows the direction of kick of the echo shown on the acoustic signa for a liquid level and perforations. On the acoustic trace the direction of the reflected echo kick indicates enlargements and reductions in wellbore cross-section. Display of acoustic traces are based on creating the traveling wave using an explosion shot, where any echo from a reduction in the cross-sectional area of the wellbore are displayed on the acoustic trace as downward kicks. When the wellbore suddenly decreases in cross-sectional area, then the echoes from wellbore decreases are displayed as a down kick. Down kick echoes can be created from liners tops, tubing anchors, paraffin/scale deposits, blockages, liquid level and reduced annular cross-section filled/partially filled form liquid being pumped up tubing out the HIT into the casing annulus. Wellbore cross-sectional area increase echoes are displayed as upward kick, caused by hole in tubing, HIT, perforations, open hole, open sliding sleeves, parted casing, parted tubing, end of tubing, and the repeat echo of the pressure wave leaving a liner top and entering a larger pipe traveling back to the surface (**Fig. 3** shows typical down kick echo #1 from the casing Liner Top @ 4533 feet, then ~2.5 seconds later echo #2 from the LL, followed ~2.5 seconds by the repeat echo #3 as the traveling wave is leaving the smaller diameter liner top and entering a larger diameter casing.) Implosion created acoustic trace are inverted in amplitude by software, then the displayed echoes will have the same direction as echoes as created by explosion shops. Both acoustic traces created by explosion or implosion shots will have the echo displayed as if acquired using an explosion shot; i.e. liquid level displayed as down kick and increase in wellbore cross-section are displayed as am up kick. By the operator of software for acoustic instrument selecting Pulse Type: Explosion OR Implosion then wellbore decreases will be displayed as downward kicks and increases as upward kicks.

The focus of this paper is to present the idea that an acoustic instrument can be used to shoot a fluid level in a wellbore to find a hole in the tubing. A common practice is to shoot a fluid level to determine the distance to the liquid level in the casing annulus. A much-lesser-known technique is to shoot fluid levels inside the tubing (instead of just inside the casing annulus) and use the up kick to troubleshoot the well and identify the depth a hole in the tubing.

Determining Distance Along an Acoustic Trace

The acoustic trace is created by the sudden release of the differential pressure from the acoustic instrument and the signal is digitized and stored by the software. Normally, the computer software locates the liquid level and then processes collar reflections between one and two seconds from the beginning of the acoustic blast to obtain the reflected collar frequency rate. The computer processes this digitized acoustic data to accent collar reflections. The software program automatically counts the number of collar reflections from the surface to the liquid level and determines the liquid level depth. When the lengths of tubing joints vary considerably, so that an average joint length is not representative, some operators have placed an over-sized tubing collar (down hole 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 depth to the deeper liquid level. This technique is to locate a movable indicator on a marker such as the liner top **Fig. 3**, when the liquid level is below the liner top. The operator places the movable indicator on the top of the known liner top at the known distance from the surface, then the distance to the liquid level and other echoes on the acoustic trace can be determined. Displaying the acoustic trace together with the wellbore diagram provides an enhanced analysis method for determining accurate distance to the liquid level or other echoes on the acoustic trace.

The acoustic instrument becomes a powerful troubleshooting tool since on the acoustic trace the direction of the reflected echo indicates a well bore cross-sectional area enlargement or reduction by overlaying the acoustic trace over a wellbore schematic allows for a quick visual confirmation of each echo belonging to a change in the cross-section of the well. This Downhole Marker method allows the display of the acoustic trace with round trip time travel to each anomaly echo associated to the measured depth to the anomaly. Wellbore schematic overlay with the acoustic trace showing distance to the liquid level provides beneficial information with respect to the pump and complicated well bores.

Another technique to determine the distance to the liquid level is for the operator to input the acoustic velocity [2] and then measure the acoustic roundtrip travel time to the liquid level. The acoustic velocity can be obtained from prior data obtained in the field, from plots of acoustic velocity, from a gas analysis, or calculated from a computer program that uses gas properties or composition.

Hole-in-Tubing - Electrical Submersible Pump

For ESP well #3 the technician was called to acquire a fluid level on this electrical submersible pumped well. The reason for the request was the oil production was down 40 barrels per day. Don Villines[3] stated, “Too often fluid level information is only used to locate distance to the top of the liquid level.” An acoustic fluid level test is a diagnostic test performed on an oil or a gas well, proper analysis of the acquired acoustic and pressure data will aid in the diagnosis of the well’s problem. Diagnosis of the acoustic fluid level shot showed that there was a hole in the tubing. At a minimum the damaged tubing joint must be replaced to correct the problem, where the hole in the tubing circulated produced liquid back into the casing annulus resulting in a drop in production from the well.

Initial observation from the operator was “I have a casing leak.” The oil production rate had decreased by 40 barrels per day. The technician was called to shoot a fluid level; **Fig.1** displays the acoustic trace shot down the tubing/casing annulus acquired on the electric submersible pump, ESP, while pumping fluids up the tubing. In **Fig. 1 – Liquid Discharging Out Hole into Casing – ESP Well** there is an unexpected echo displaying a down kick on the acoustic trace at 1.37 seconds of elapsed round trip travel time from the surface to the decrease in the wellbore cross-section at the pin hole and back to the surface. The echoes from 21.78 joints of tubing were used to determine the distance of 666 feet to the down kick created by liquid discharging from the inside the tubing through a pin hole into the casing annulus. A portion of the liquid being produced to the surface was discharging through a hole in the tubing and this liquid decreased the cross-sectional area of the annulus. When the ESP is shut-in the discharge of liquid stops and the down kick disappeared. The depth to the hole in the tubing was determined by counting tubing collar echoes. In some ESP wells the cable bands can make counting tubing collar echoes more difficult. After pulling the tubing string the depth in the tubing determined by counting collars was within 4 inches of the actual pin hole found by visually inspecting the pulled tubing joints. Acoustic liquid level instruments can be used to easily look into the well and diagnose downhole problems. Use of fluid level data is a valuable tool to use in the diagnosis of problems encountered in this operating ESP well. Dynamometer and fluid level can be used to determine if the well is producing as much oil and gas as possible without incurring excessive operational problems. The ESP can be diagnosed and the artificial lift technician can determine if the downhole pump is operating as expected.

Hole-in-Tubing – Sucker Rod Lift

Dynamometer and fluid level can be used to determine if the well is producing as much oil and gas as possible without incurring excessive operational problems. The pump can be diagnosed and the artificial lift technician can determine if the downhole pump is operating as expected. Dynamometer and Fluid level data will point out opportunities for well improvement, more production, lower power cost, more effective and fewer pulling jobs. Dynamometer data will quickly confirm success and failure in operational changes. When the recommended changes to the well are completed, new data should be collected in a few weeks once the well is operating under stabilized conditions. The artificial lift technician should use the acquired fluid level and dynamometer data re-read the recommendations from the previous analysis of the well's data and notice if the well performance has changes as planned. The analysis step to evaluate the recommended changes is called the follow-up step of the analysis. Following-up on recommendations is how production technicians learn from their successes and failures; and their role changes from a data collector to a knowledgeable well analyst and expert well problem diagnosticians.

Fig. 4 displays the overlay of 2 casing annulus acoustic traces acquired approximately 50 minutes apart with echoes from a hole in the tubing identified using marker of a dashed red line at a RTTT of 9.184 seconds. The top acoustic trace was acquired at 01:48:12 PM while pumping and the down-kick is created by liquid pumped up the tubing then discharging out of the hole in tubing into the casing annulus. The bottom acoustic trace was acquired at 02:38:35 PM when the pump had been off for the 50 minutes following the previous shot and the up-kick is created by the increase in cross-sectional area at the hole since all the liquid in the tubing above the hole had time to drain into the casing annulus. These acoustic traces demonstrate that a hole will not show an up-kick echo if liquid is filling the hole. The width of the echo created by the hole in the tubing is relatively wide because the echo was created fairly large hole from a split tubing joint located at 4052 feet from the surface.

In addition to identifying a hole in the tubing by an up-kick on an acoustic trace, then also a hole in tubing can also be identified using data acquired using a dynamometer by comparing the height of the pump card, Fo to the theoretical height of the pump card based on the Fo from the Fluid Level. Usually, the pump card shape is filled completely with liquid signifying the sucker rod pump and valves are functioning properly, but the down hole pump card load determined from the dynamometer data is much lower than the theoretical height of the pump card based on the Fo from the Fluid Level. The Fluid Load, Fo, calculated from the pump intake pressure, P_i, determined from a fluid level shot and the pump discharge pressure, P_d. The Fluid Load from the Fluid Level is equal to the Differential pressure acting across the plunger cross-sectional area, A, shown by **Eq. 1**:

$$Fo = A(Pd-Pi) \qquad \text{…. Equation 1}$$

Usually, a "hole in tubing" pump card shape is completely filled with liquid signifying that the sucker rod pump and valves are functioning properly, thereby liquid is being pumped up the tubing, then out the hole, then back down to fill the pump. No liquid is being lifted to the surface all produced liquids from the pump are being circulated. When the hole in the tubing is above the liquid level in the casing, then the down hole pump card fluid load, Fo, determined from the dynamometer data is much lower than the theoretical height of the pump card based on the Fo from the Fluid Level. The theoretical Fluid Load from the Fluid Level is 2960 Lbs. **Fig. 5** shows the abnormal low 1311 Lbs. pump card loads due to lifting liquid from the pump intake pressure of 152 psig to the hole in tubing at a depth of 4052 feet.

The pump intake pressure (pump card) is 1496 psi, the pump intake pressure (fluid level) is 152 psi, if the fluid level is correct then the fluid load that the pump is applying to the rods should be near FoMax. This means the pump intake pressure calculated from the pump is too high, because the pump is lifting fluid to the hole in the tubing and not to the surface. The equations used to calculate pump intake pressure assumes the fluid load applied to the rods will lift the fluid to the surface tubing pressure, but in this well the fluid is being lifted 2514 feet and out a hole back into the well bore. A good indicator of a hole in the tubing is a full pump with little fluid load being applied to the rods and a lot less fluid than the pump displacement getting into the tank. There was no production into tank, but pump displacement was 95 barrels per day.

A fluid level shot down the tubing may be required to troubleshoot a possible hole in the tubing in a Sucker Rod lifted well if there is no production to the surface. The first step in the process is to first shoot a couple of fluid level down the casing. Next the gas gun is disconnected from the casing valve and connected into the tubing valve; the fluid level is acquired inside the tubing using the same procedure as shooting a fluid level inside the casing. When shooting down the tubing there are additional issues that need to be considered:

1. There is very little benefit or NO benefit when shooting a liquid level down the tubing, if the sucker rod pump is producing liquid to the surface. If the liquid level is at the surface, then the acoustic trace may not display anything of value, just a lot of noise and no liquid level.
2. Shooting the fluid level inside the tubing usually requires 50 to 65% less charge pressure into the gas gun volume chamber than required to create the casing shot.
3. The tubing shot is usually made through a 1" bleeder valve and a restriction in the area from the gas gun can restrict pressure from leaving the gas gun into the well, Too high charge pressure may result in clipping of the acoustic signal and excessive noise.
4. The cross-section area inside the tubing is more restricted by the sucker rod couplings and sucker rods than by the tubing collars inside the casing annulus.
5. Shooting fluid levels down tubing packed with paraffin usually unreliable results
6. The presence of sucker rod couplings in the tubing makes the method of determining distance from "counting collars" NOT accurate, if the average joint length of the tubing length is used. Recommended practice is to use acoustic velocity method when shooting down the tubing. Use the casing average acoustic velocity to determine distance inside the tubing. Counting sucker rod couplings echoes can be used to determine distance instead of using tubing collars echoes for distance, but the average joint length must be changed from that of the tubing to that of sucker rods; 25 feet for steel rods or 37.5 feet for fiberglass rods are present. Using the acoustic velocity determined from analyzing the casing shot is recommended option for determining the acoustic velocity in the tubing. This option is generally the easiest and most accurate method for determining distance down the tubing.

Once the casing fluid level and the tubing fluid levels are properly analyzed, then the tubing and casing acoustic traces can be overlaid and analyzed to determine if the up kick from the tubing hole appearing on both traces is at or near the same depth. The liquid level marker is moved to the beginning of the up kick from the hole on the tubing shot and to the beginning of the up kick from the hole on the casing shot. **Fig. 5** shows the dashed LL line positioned at the up kick are a close match and the distance to the hole in tubing is 263 feet from the surface in well BKU #554. The tubing shot shows the high frequency collar echoes and the casing shot is displayed using a low pass filter which removes all of the high frequency signal from collar echoes from the casing acoustic trace. In the down tubing shot, the rod coupling echoes are present on the acoustic trace; rod coupling echoes are usually seen when shooting down the tubing. To determine the correct acoustic velocity for the steel sucker rod string the average joint length must be changed to 25 feet when counting the rod couplings. Software creates a simple process to zoom into a 2 second time interval near the beginning of where the shot was fired. **Fig. 5** compares two acoustic traces by overlaying the portion of the acoustic traces from the surface to the hole.

In most sucker rod lifted wells where this "shoot down the tubing" process has been used, the hole in the tubing is usually found to be near the pump where rod on tubing wear is a typical problem. If the hole in the tubing is below the liquid level, then normally the up kick on the acoustic traces from the hole is not seen. Rod on tubing wear often creates a hole in the lower portion on the tubing string and the tubing leak is usually deep, but the presence of a deep hole in the tubing tends to allows equalization of the two fluid levels to usually take place.

When the tubing hole is below the liquid level in the casing and no liquid is produced to the surface, then experience[4] has shown that if the tubing fluid level and a casing fluid level are within a thousand feet of each other, then the first step in diagnosing a tubing leak has been established. The second condition usually seen in conjunction with the first step is the tubing and casing pressures are often within one half of one psi of the same value. For example, acquired fluid levels inside the tubing and casing of a well are determined to be within 1000 feet of each other and the casing pressure is 78.6 psi and the tubing pressure is 78.7 psi, then a tubing leak would be strongly suspected. To further verify the possibility of a hole, several surface dynamometer cards would be acquired on the well to check for pump action. Deep tubing leaks always produce "flat cards," while a well with a shallow tubing leak will often produce full pump cards, but will never lift fluid to the surface. Another test to verify a hole is to operate the pumping unit for 30 minutes to an hour time period, then stop pumping and quickly re-shoot the tubing fluid level. If the fluid level inside the tubing has not risen, then there is likely a hole in the tubing. After pressure testing the tubing and confirming the hole, then the well service company should be called to pull the well and repair the tubing.

Hole-in-Tubing – Flowing Gas Wells

Using an acoustic fluid level instrument to shoot down the tubing and the casing to see an up kick at the same depth is fairly common for gas wells, plunger lift wells and gas lift wells. When gas fills the casing annulus and gas fills the tubing from the surface down to or past the hole in the tubing, then overlaying the tubing and casing acoustic trace is the same process as previously discussed for sucker rod lifted wells. Answering the question is the gas well flowing above Turner critical velocity or liquid loaded should be determined, before undertaking the process of using an acoustic fluid level instrument to troubleshoot a gas well and look for a hole in the tubing.

Liquid Level measurements are used to determine the fluid and pressure distribution in a flowing gas well[5] generally doing the surveys in the tubing, while the well flow is momentarily shut-in during the acquisition of the acoustic fluid level trace. 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. In **Fig. 7** at a gas flow rate of 820 MscfD the gas flow rate falls off the decline curve. The operator was requested to open the sliding sleeve and commingle two zones increase gas flow rate and return flow rate in the apparently liquid loaded well. When the sliding sleeve was opened the gas rate did not increase. Liquid loading is NOT the issue because the Turner critical rate was determined to be 320 Mscfd and the flowing gas well at a rate of 820 MscfD had NOT fallen off the decline curve due to liquid loading.

Fig. 8 shows a sequence of 5 fluid level shots acquired on the well to identify that the gas well had a hole in the tubing. The gas well was still flowing at 250 Mscfd up the tubing and the casing valve was closed. For a gas well flowing above critical rate or liquid loaded when the casing valve is closed and the well produces free gas at the tubing intake, then gas accumulates in the casing annulus and pushes out all liquid down to the end of tubing, EOT. Shots 1 through 3 were acquired down the casing annulus. Shot 1 does not show an up kick on the acoustic trace from a hole but does shows the liquid level in the casing to be approximately 700 feet above the EOT. With the tubing intact and casing valve closed, then these 700 feet of fluid should NOT exist in the casing annulus above the EOT. If the casing annulus liquid level is not at the EOT then 1 or more of the conditions exist in the casing annulus:

1. Acoustic Trace may not be Correctly Analyzed
2. Too Many Perforations OR Not Enough Energy in Shot
3. Gas May be Flowing up Casing Annulus

If gas is flowing up the casing annulus, then 1 or more of these conditions may exist:

1. Cross Flow into Another Perforated Interval
2. Surface Casing Valve Leaking
3. Flowing into Hole and up Tubing

If free gas is being produced and the surface casing valve is closed, then gas will fill from the closed valve to the EOT. In a gas well with gas flowing up the tubing and a high fluid level exist in the casing annulus above the EOT then usually a hole exists in tubing. The process to identify if there is a hole in the tubing is to shut-in flow form the well, depress the liquid in the tubing and casing with the increasing surface pressure. First take casing shot at equal time steps until a up kick appears on a casing acoustic trace, then move the gas gun to the tubing and shoot fluid levels down the tubing and confirm the up kick from the tubing and casing shots identify a hole in the tubing at the same depth. Procedure to use and acoustic instrument to identify the depth to a hole in tubing in a gas well:

1. You must shoot down both tubing and tubing/casing annulus
2. Shoot tubing/casing annulus while well is flowing up tubing (the Fluid Level should be near tubing intake or below perforations (If no Hole))
3. If you see a up kick that is not the perforations OR if you see a high fluid level in the tubing/casing annulus, then shut-in the well, continue to shoot casing annulus looking for down kick due to liquid leaking from hole in tubing back into annulus.
4. Increasing Pressure pushes liquid down, and after shooting fluid levels for a while the high casing fluid level should be pushed deeper into the well and the hole should be uncovered.
5. After 1-2 hours of shooting tubing and casing annulus an up kick from hole should be seen at the same depth on both shot down tubing and shots down casing.

6. OR shut-in well over night, then come back in morning to shoot well when pressure is high and fairly easily seen up kick from the holes…. But be cautious because the liquid may be pushed below the EOT and a casing shot and tubing shot will display an up kick at the EOT.

Fig. 8 shot #2 was acquired after ~15 minutes elapsed and a slight up kick on the casing acoustic trace is seen. Shot #3 was acquired after ~30 minutes elapsed and a very distinct up kick on the casing acoustic trace is seen. Shots #4 & #5 were acquired down the tubing after moving the acoustic instrument from the casing to the tubing. The time between shots continues at 15-minute time intervals. Distinct up kicks are seen on both acoustic traces. A hole in the new tubing string was identified at a depth of 4325 feet from the surface. After the tubing with the hole was replaced, the gas well returned to flowing at 1000 Mscfd above the Turner critical rate.

Based on experience with gas wells in many fields DO NOT be surprised if more than 10% of the wells the wells that are classified as being liquid loaded in actuality are not liquid loaded but holes in the well's tubing. When a hole is created in the tubing then the result is a significant drop in gas production. The surface tubing and casing pressure are NOT equal when there is a hole in the tubing, because a gassy column of fluid is held above the hole in the tubing with a corresponding increase in casing pressure to maintain a =n equal pressure in the tubing and casing at the tubing hole. When there is a hole is the tubing with a closed casing valve, then a casing fluid level "high" above the EOT likely indicates a HIT. Acoustic shots acquired at uniform time intervals can be used to monitor the liquid level in the wellbore and identify where down hole liquid level movement by surface pressure change shows a problem.

When gas wells are shut-in, the liquid that was suspended in the wellbore by the gas flow, falls back and accumulates in the bottom of the well and this liquid will be pushed out into the formation by the high-pressure gas collecting in the wellbore during the after-flow period. While in shut-in oil wells the liquid level generally rises above the formation until the pressure from the gas and the liquid column in the wellbore equalizes with the reservoir pressure, in gas wells the opposite usually happens especially when the volume of produced liquid is small compared to the produced gas. In these gas wells, the high-pressure gas may push all of the liquid out of the well bore over the period of time the well is shut-in. However, it is not possible to know when the wellbore is completely dry unless a liquid level measurement is made to verify that all the liquid has been displaced back into the formation or measure the height of the liquid column above the formation depth. Use of acoustic surveys to determine the static shut-in pressure is an accepted and accurate method. In a shut-in well fluid level instruments can be used to inexpensively determine if there is a problem in he tubing, because the wellbore is filled with high pressure gas and fluid level shots are easy to acquire and analyze. Shut-in gas wells typically are quiet and there is no noise on the acoustic trace created by flowing gas.

Hole-in-Tubing – Gas Lift Wells

A Hole in tubing of a Gas Lift well can be identified using the same technique as discussed for identifying holes in tubing for Gas Wells. Gas lift valves and mandrels are installed in the well at depths set in the gas lit design. Wireline retrievable mandrels and Conventional gas lift with the gas lift valve attached to the outside of the tubing are usually seen as down kicks at the depths specified in the gas lift design on acoustic traces acquired down the casing annulus. Acoustic fluid shots acquired down the tubing where wireline retrievable valves are installed are usually of excellent quality where up kicks are displayed when shooting down the tubing and the tubing is filled with gas past the side pocked mandrel. Tubing and casing acoustic traces on gas lift wells are usually easy to overlay, identify the valve depths and identify the depths to the side pocket mandrels. In conventional gas lift installations, the valve ports on conventional wells are not as easy to identify when shooting a tubing fluid level. Overlaying the tubing and casing acoustic trace is a good process to identify unexpected up kicks and identify the location to a hole in the tubing.

The Dual Shot Acoustic Technique[6] is used to troubleshoot Gas-lift Wells by looking for pressure communication between tubing and casing. One gas gun is fired, sending a pressure wave down the tubing. Simultaneously, a second gas gun listens to the casing. Both microphones are attached to the same input to record the acoustic signal. The tubing microphone is disconnected immediately after creating the traveling pressure wave at the surface of the tubing, and the microphone on the casing detects signals that pass through defective valves or checks or holes in the tubing. The acoustic signal is created in the tubing, then holes and malfunctioning check and gas-lift valves pass the pressure wave into the casing.

The Dual Shot is a special process where 2 acoustic instruments are used simultaneously to shoot fluid level down one side of the tubing while listening on the other side of the tubing where no acoustic noise should exist. When the acoustic instrument that is listening detects an acoustic signal, then communication between the tubing and casing annulus on the gas lift well has been identified. Acoustic Signal is created in tubing by firing a fluid level shot, then holes in tubing, malfunctioning check valves, or malfunctioning gas lift valves pass pressure wave through the leak into casing. For calculating depth to the leak, then use an average of the Tubing and Casing Acoustic Velocities determined by firing prior fluid level shots down the tubing and the casing shots. Following is the Dual Shot method:

1. Displace liquid out of Tubing down to the operating valve.
2. Fire Shot using Remote Fire Gun on Tubing. Disconnect Tubing microphone cable after Shot is fired.
3. Listen and Record Shot using Compact Gas Gun on Casing.
4. Watch for Kick identifying communication between Tubing and Casing.
5. Using the average of the Tubing and Casing Acoustic Velocities, calculate the Depth to the Kick.
6. Using the Wellbore Schematic or Overlay, identify the Problem Valve

See Fig. 9 for the schematic on a dual shot. Fig. 10 displays the dual shot acquired using the listening acoustic instrument, plus the tubing and the casing shot acquired prior to the acquisition of the dual shot.

Conclusion

Using an acoustic fluid level instrument is a low cost, quick method to troubleshoot an oil or gas well and to identify the presence/location of a hole. Displaying the acoustic trace together with the wellbore diagram provides an improved ability for analysis the trace to identify a hole in the tubing. On the acoustic trace use the direction of the reflected echo to identify each well bore cross-sectional area enlargement or reduction. When analyzing the acoustic trace. The echo from a hole will not be seen on and on an acoustic trace if the hole is below the liquid level or liquid is in the tubing or in the casing filling the hole.
acoustic traces presented in this paper demonstrate that a hole will not show an up-kick echo if liquid is filling the hole. Hole in the tubing often is first indicated by a drop in production.

For a rod pumped well a good indicator of a hole in the tubing is a full pump with little fluid load being applied to the rods and a lot less fluid than the pump displacement getting into the tank. Usually, the height of the pump sard drops fairly quickly when the hole becomes large enough to cause all of the liquid to recirculate out the casing that is discharged by the pump. Tubing shots in sucker rod lifted wells are usually of no value when liquid is being produced to the surface since the liquid level is located at the surface. There was no production into tank, but pump displacement was 95 barrels per day. Fluid levels shots are effective tools when troubleshooting oil and gas wells.

Frequently when flowing gas wells are converted to anther lift method, the reason is a hole in the tubing. Fluid level both inside the tubing and inside the casing annulus are valuable trouble-shooting technique used on wells that have either stopped producing altogether, or production rate has drastically decreased. Often this problem is created by a hole in the tubing. This paper presents the low-cost non-intrusive method of using an acoustic instrument to identify holes in the tubing.

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Nomenclature:

Fo - Fluid load applied to Rods by plunger - Lbs
S - Surface Stroke Length - Inch
A = plunger area, square inches
Pd = Pump Discharge pressure, psi
Pi = Pump Intake pressure, psi

Figure 1 – Liquid Discharging Out Hole into Casing – ESP Well

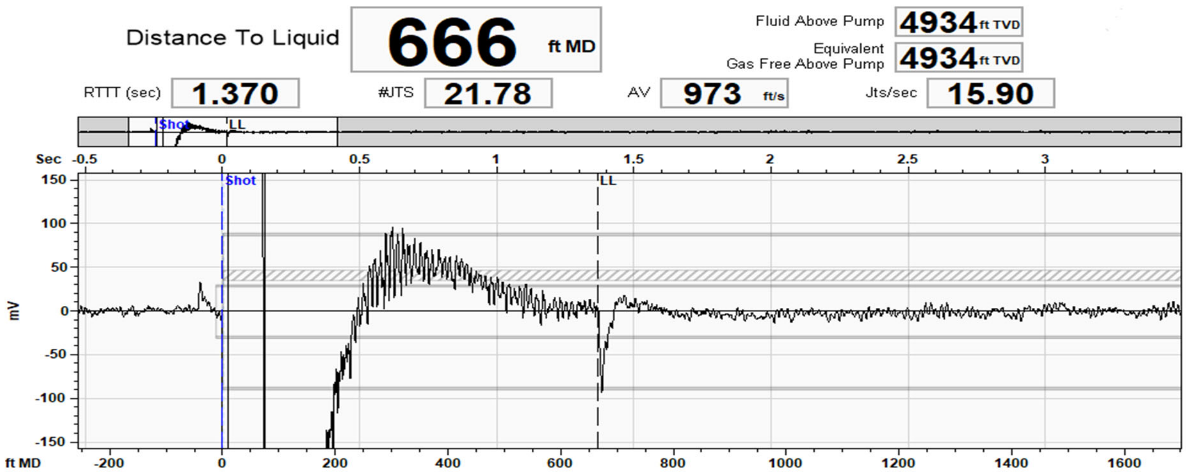

Figure 2 – Upkivk and Down Kick Echoes – Sucker Rod Lifted Well

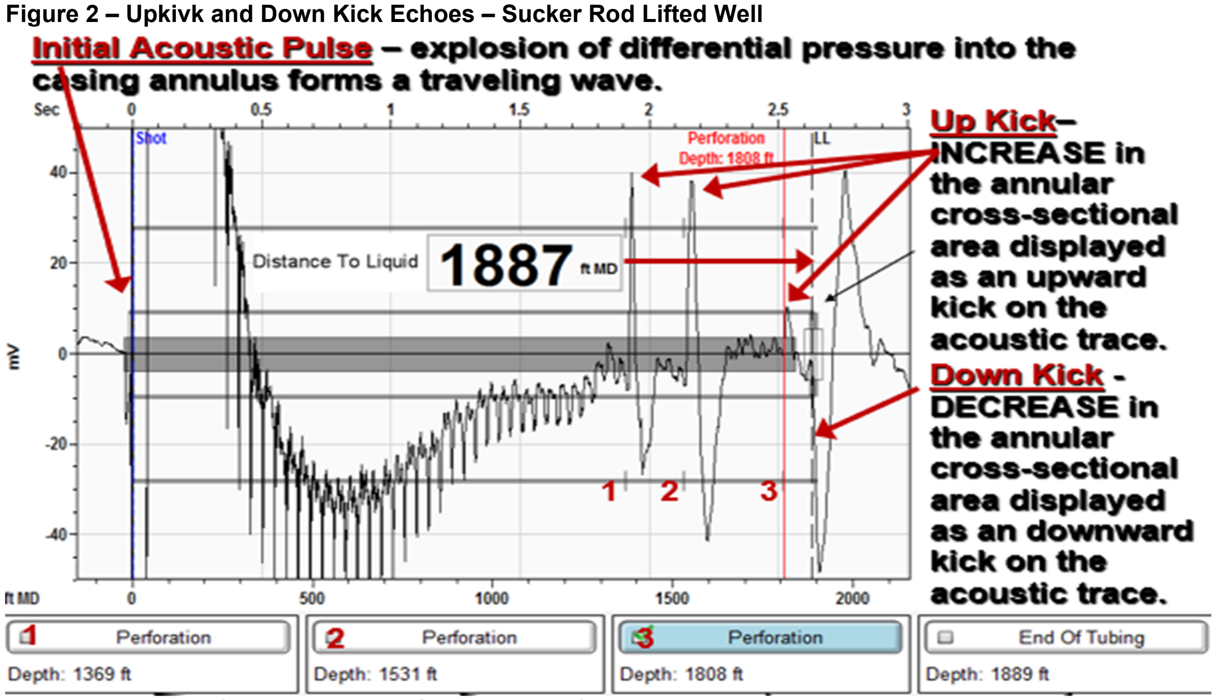

Figure 3 – Echoes from Liner Top – Sucker Rod Lifted Well

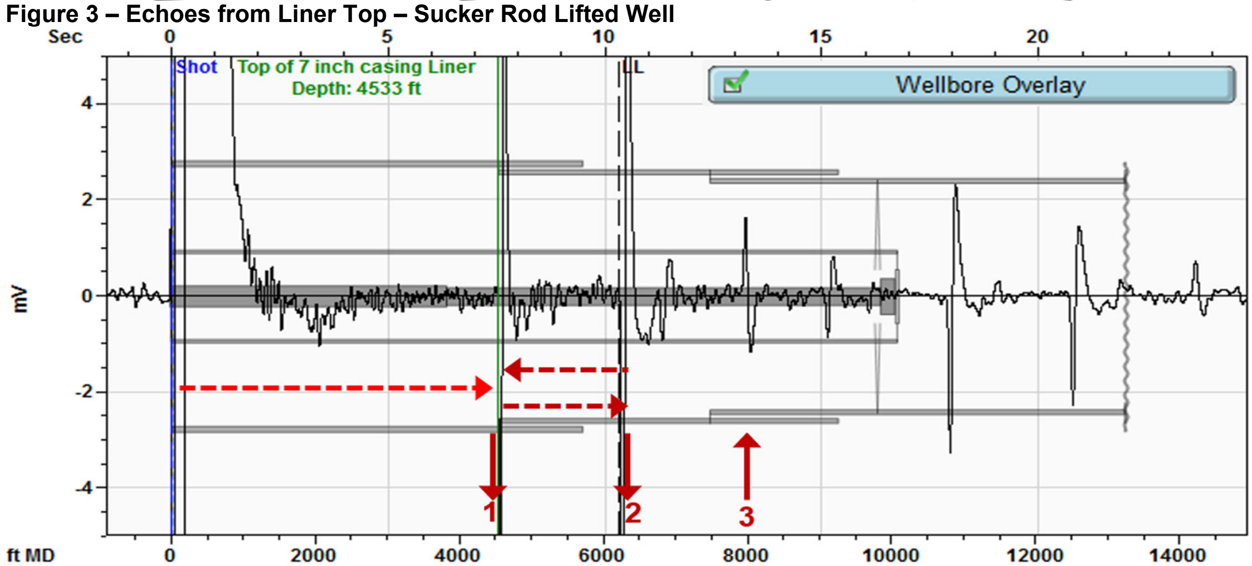

Figure 4 – Echoes from Leak Tubing Hole – Sucker Rod Lifted Well

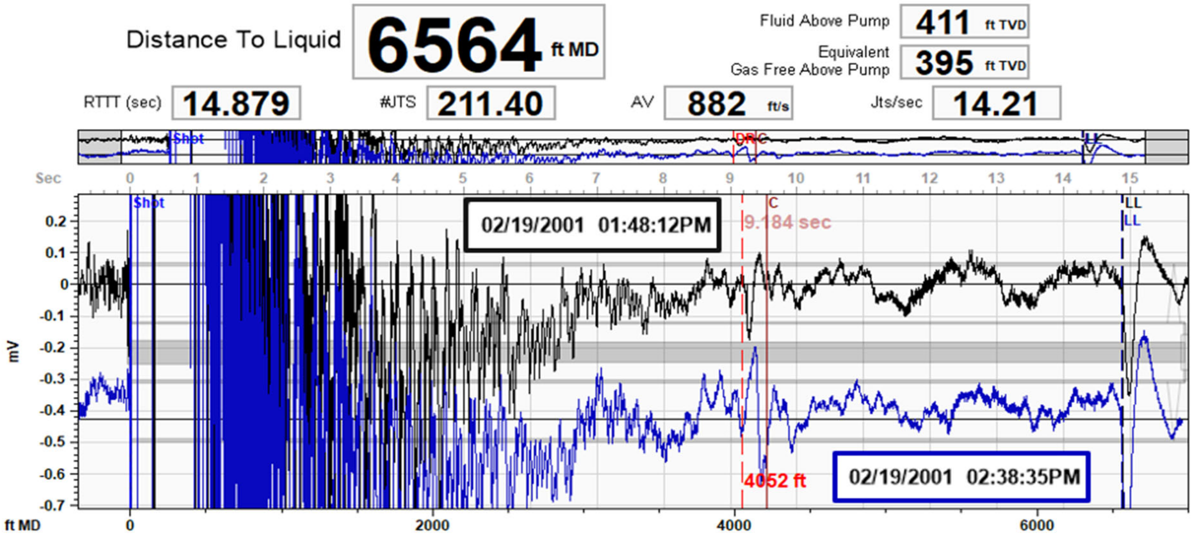

Figure 5 – Dynamometer Card for Leak Tubing Hole – Sucker Rod Lifted Well

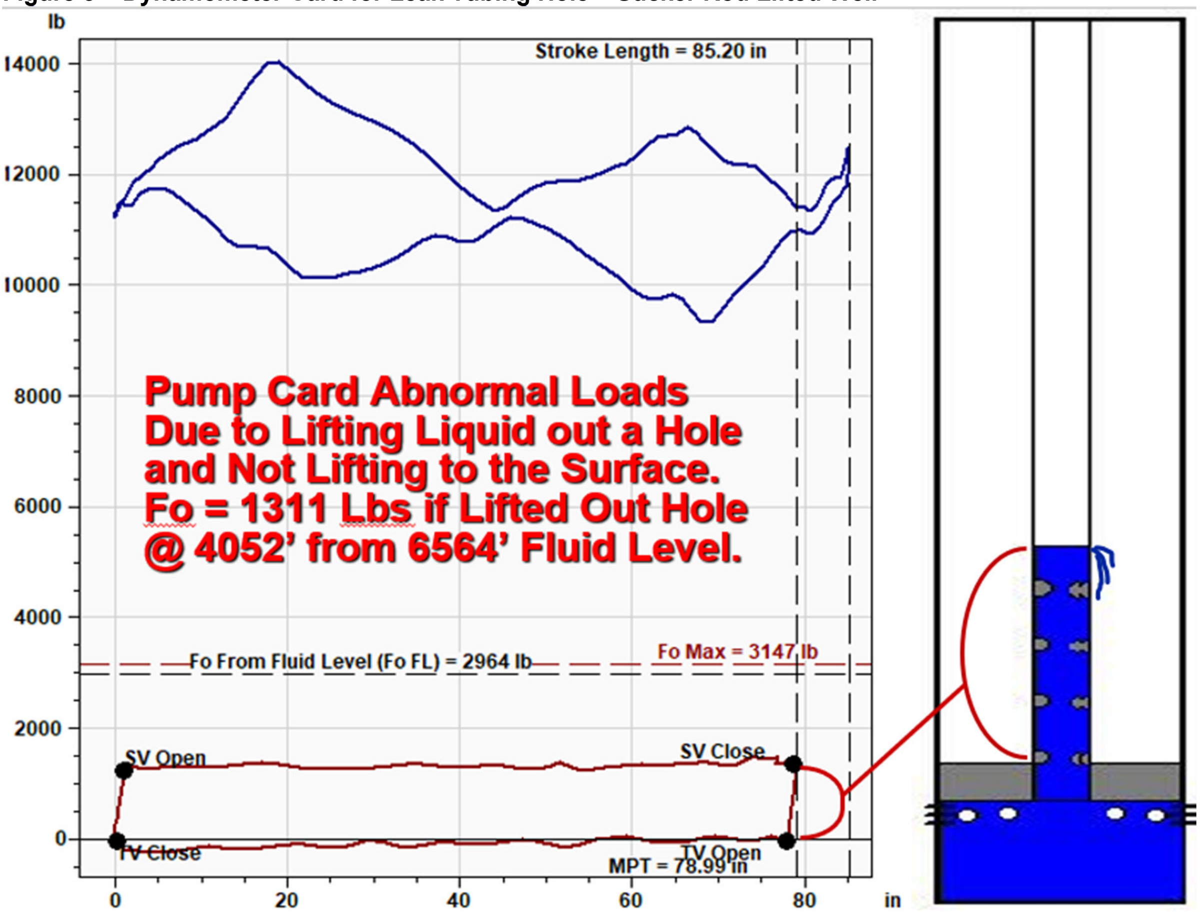

Figure 5(continue) – Dynamometer Card for Leak Tubing Hole – Sucker Rod Lifted Well

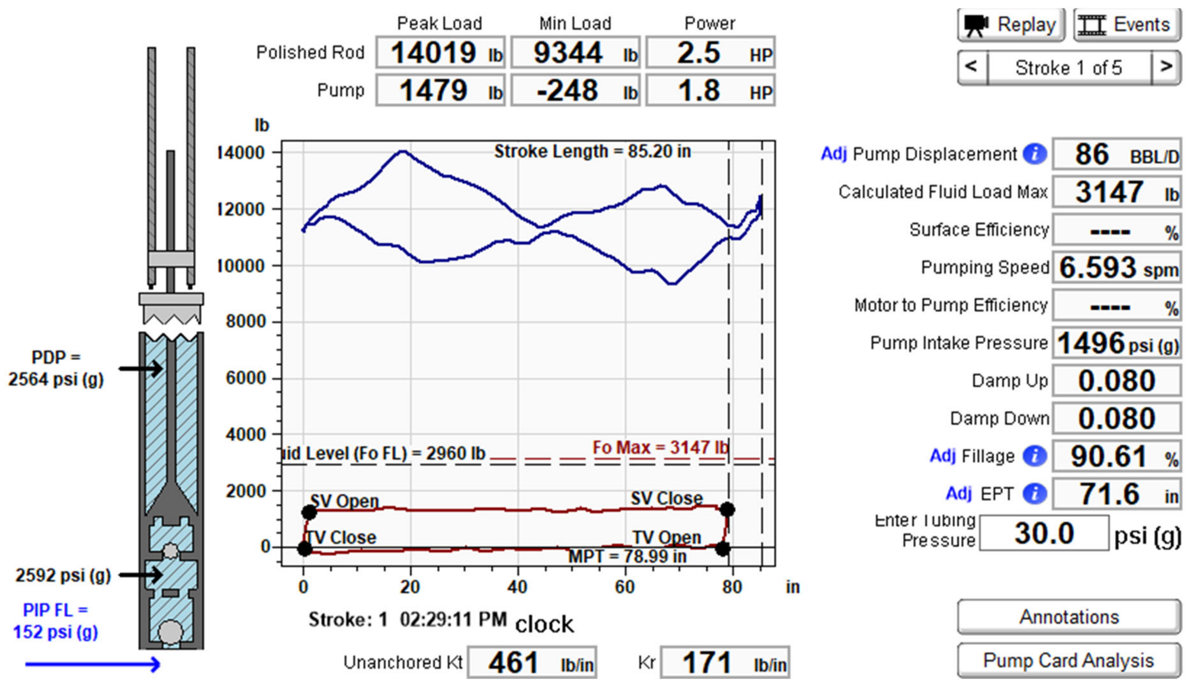

Figure 6 – Overlay Shot Down Tubing to Shot Down Casing – Sucker Rod Lift

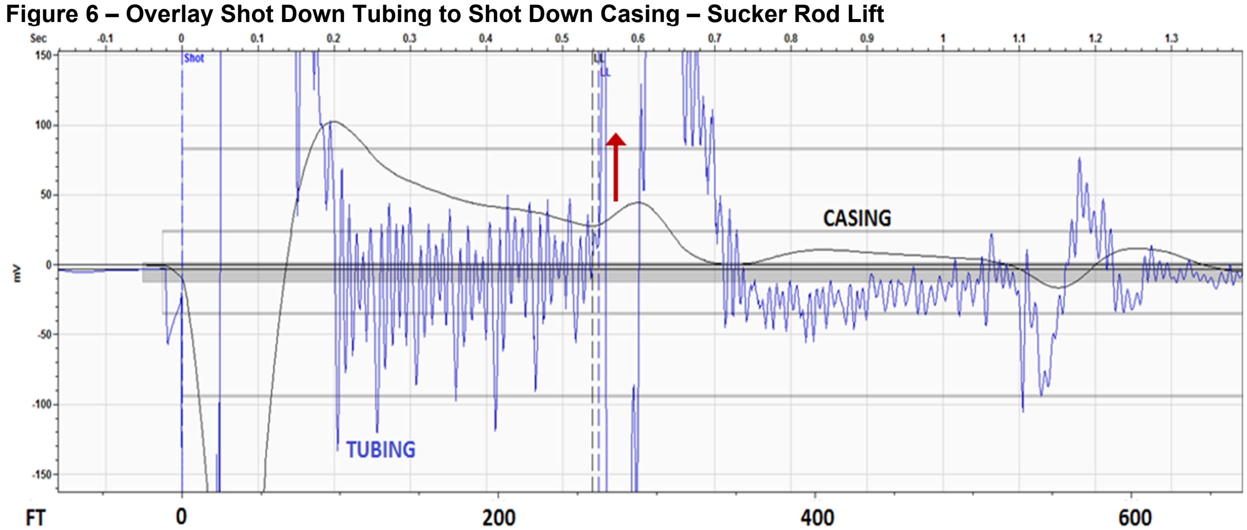

Figure 7 – Flowing Gas Well Develops Hole in Tubing

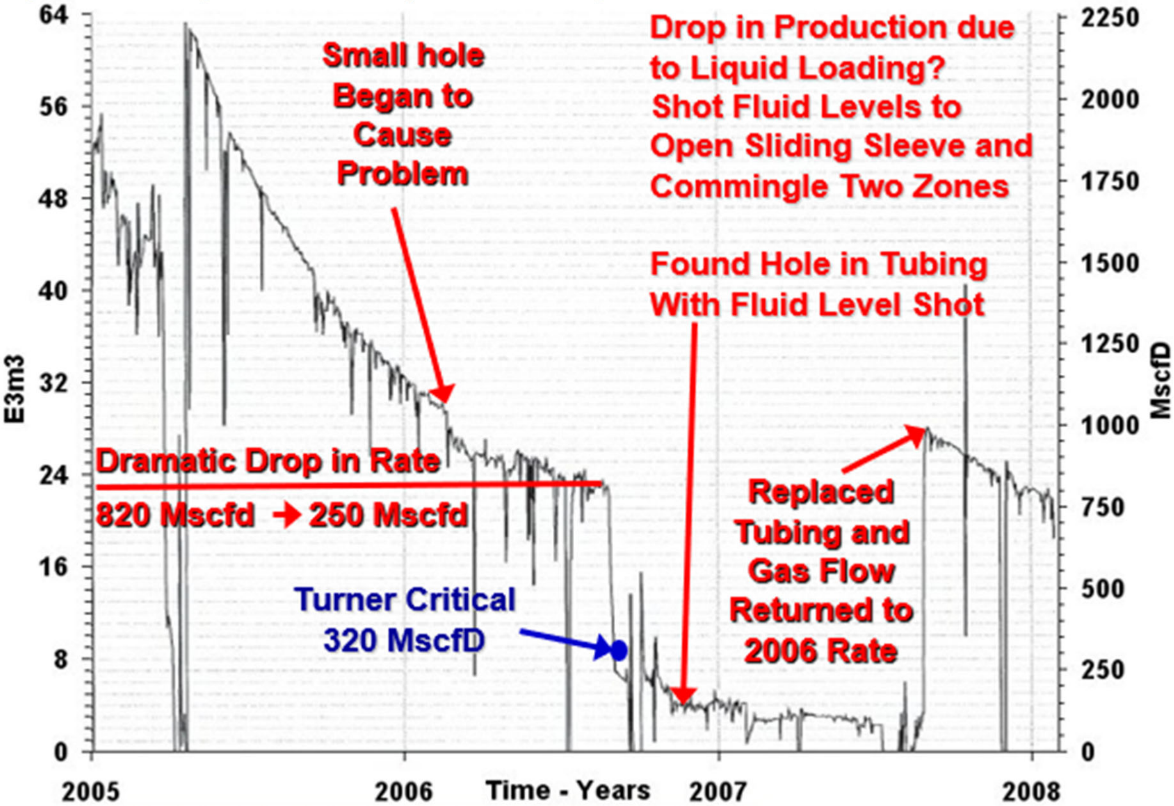

Figure 8 – Series on Casing then Tubing Fluid Level Shots Used to Identify a HIT

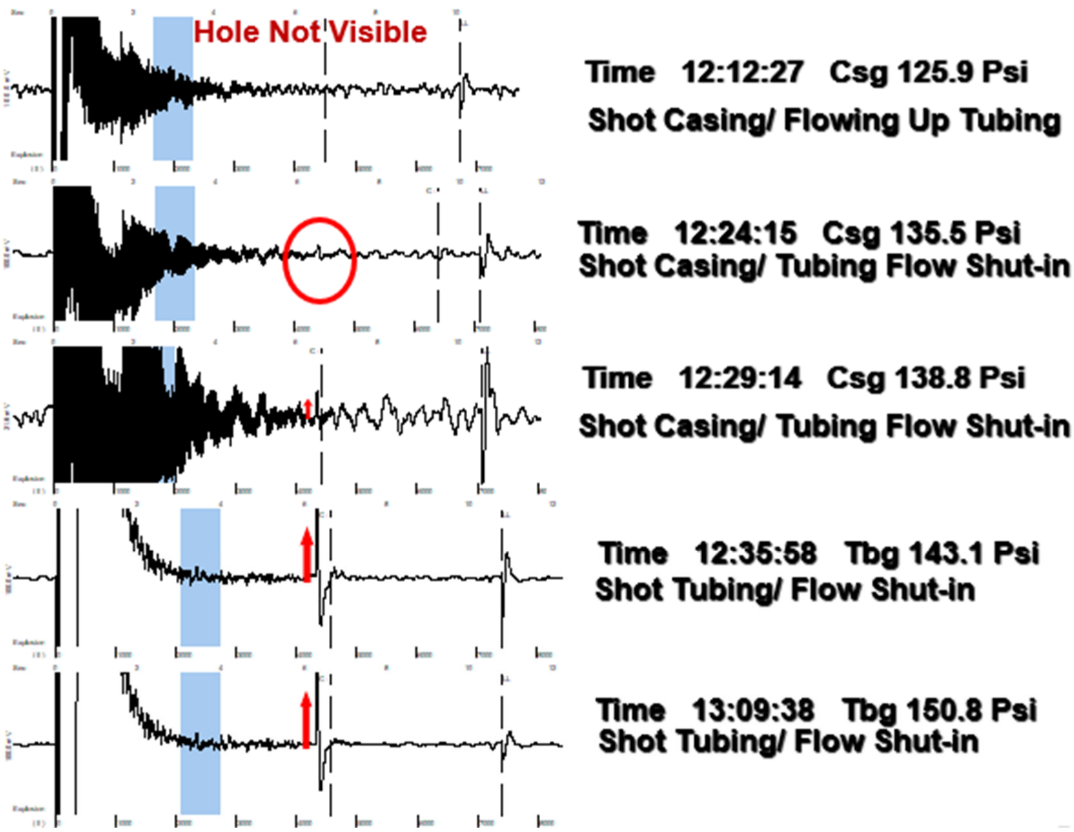

Figure 9 – Dual Shot Schematic

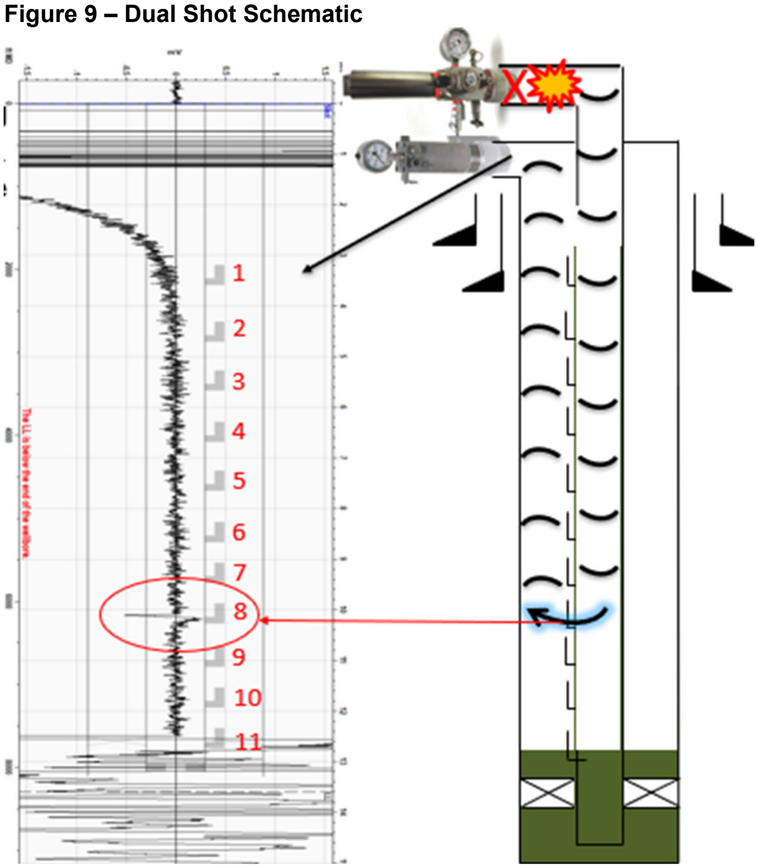

Figure 10 – Dual Shot Acoustic Trace