TROUBLESHOOT ROD PUMPED WELLS USING TUBING FLUID LEVEL SHOTS

John Sparks, COG OPERATING LLCU
Lynn Rowlan, Echometer Company

ABSTRACT

If no pump action or no production to surface, then a recommended practice is to shoot a fluid level down the casing annulus and also shoot a fluid level down the tubing. Distance down the tubing is determined by using the average acoustic velocity obtained from the casing shot. DO NOT use the tubing average joint length to interpret the down tubing fluid level, because inside the tubing, rod couplings are spaced at the length of the sucker rods.

Analysis of the acquired data can determine such things as: If there is a hole in the tubing. Additional tubing back-pressure may be required if tubing liquid was unloaded by significant amount of gas produced up the tubing. Tubing pressure buildup measurement determines the amount of gas flowing up the tubing, tubing percent liquid, and the effectiveness of the dowhole gas separation. Difficult to interpret tubing shots may indicate that the well has "paraffined-up". Tubing shots acquired at uniform time intervals can show ineffective pump operation, where "pumping up" the tubing occurs too slowly. Down tubing fluid levels are effective tools when troubleshooting shooting a shut-in sucker rod pumped well suspected of having no pump action.

INTRODUCTION

Over the last few decades in the oil and gas industry, the practice of shooting fluid levels has become a well-known mainstay to daily operations and the benefits received from shooting fluid levels justifies their continued use. 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. 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 and to determine if the current artificial lift method needs to be modified to increase production from the well. Another, much-lesser-known facet of shooting fluid levels is shooting fluid levels inside the tubing (instead of just inside the casing annulus). Shooting a fluid level inside the tubing is a valuable trouble-shooting technique used on wells that have either stopped producing altogether, or production rate has drastically decreased.

The concept of shooting fluid level down tubing was proposed while attending an advanced dynamometer troubleshooting seminar. Over time this technique has been applied successfully on many wells operated by many different companies. After hearing of this novel idea, a concerted effort was made to apply this practice in the field on any well having drastically reduced production rates. This paper will expound on the practice and promote the value of shooting fluid levels inside a well's tubing in order to troubleshoot several different types of problems.

SHOOT A FLUID LEVEL

Analysis of the fluid levels acquired on the well down the casing and down the tubing is the first step in trouble-shooting a well having a possible hole in the tubing. Typically a gas gun is attached at the surface to the well through a fully opening valve. The gas gun contains a pressure transducer, microphone, and a volume chamber with some type of valve mechanism used to fire the shot and to suddenly release the differential pressure created between the well and the volume chamber. Both the acoustic signal from the microphone and readings from the surface pressure transducer are digitally acquired. Pulse generation is performed by attaching a volume chamber to the wellhead and generating the acoustic pulse with a sudden release of a gas into the well (compression gas pulse) or by releasing gas from the well into the volume chamber (rarefaction gas pulse). To "Shoot a Fluid Level" the valve mechanism in the gun is suddenly opened; the release of differential pressure creates a pressure wave that travels down the tubing or casing depending upon where the gas gun is attached to the well. The echoed acoustic signal detected by the microphone is digitized and stored by software to become the acoustic trace. Special digital filters are used to process the digitized acoustic data to improve collar reflections or enhance echoes from large anomalies. Software automatically locates the liquid level. Software automatically determines the number of collar reflections from the surface to the liquid level and processes collar reflections to determine the average joint per second (acoustic velocity). Manual inspection of the automatic processing is recommended to verify the software processing of the acoustic trace is correct. When other acoustic reflections are identified on the acoustic trace, such as those generated by holes in tubing, gas lift mandrels, liner tops, crossovers where the tubing diameter changes, tubing anchors, perforations; then the distance to an anomaly can be determined by multiplying the round trip travel time, RTTT, to the anomaly times the average joint per second frequency times the average joint length. Caution should be used inputting the correct average joint length when shooting the tubing and casing because the coupling echoes are detected in tubing shots and tubing collars are detected when shooting down the casing annulus. When trouble-shooting holes in tubing the acoustic trace is normally manually analyzed and the liquid level indicator can be moved to the echo created by the hole, when the hole is above the liquid level. Only echoes from anomalies above the liquid level are present on the acoustic trace and no echoes are created from anomalies below the liquid level.

The reflected signal from downhole anomalies, collars and liquid level is recorded in the acoustic digital data. The acquired acoustic trace can be manually or automatically analyzed using software to determine accurate distance to the liquid level or determine the accurate distance to an echo from a hole in the tubing. For a well that is shut-in due to a possible hole in the tubing, it is common to discover the fluid level to be very close to the surface in a well having high bottom hole pressure. The recorded acoustic trace on a well having a high fluid level usually includes a large number of repeating fluid level echoes and repeating hole echoes. Care must be taken to identify the deepest liquid level echo which is not a repeat of a previous echo. The initial signal reflected from the liquid level or a hole may be hidden in the noise generated from creating the fluid level shot because high amplitude noise is created by the sudden release of pressure differential between the gas gun and the well. Less pressure differential should be used in the gas gun in wells where high fluid levels are encountered because excessive energy in the shot can hide echoes or the amplitude at the beginning of the acoustic signal may be so large that safety devices inside the microphone can clip the output of the microphone. No acoustic signal from the well is present over the section of the acoustic signal where clipped. On shallow liquid levels when the round-trip travel time between the surface and the liquid level is less than 1.0 second, the operator may be required to select the liquid level echo manually. The operator can position a marker using software at the echo from the liquid level or at an echo from a hole to determine the RTTT and distance. At least 80% of the collar echoes should be counted to determine an accurate acoustic velocity and determine an accurate distance to an anomaly. When the distance to the liquid level from the gas gun is far, then an increased pressure charge into the volume chamber may be required to create a quality acoustic trace. In general shallow liquid levels require a low pressure charge, while deep liquid levels often require a high pressure charge.

If gas is flowing up the casing annulus or tubing, then the surface pressure will increase because the surface valves are closed and the closed valve trap gas the flowing toward the surface. The surface pressure buildup rate, distance to the fluid level, and the configuration of the wellbore are used to determine the tubing or casing gas flow rate. The surface pressure buildup rate should be acquired while the artificial lift equipment continues to operate undisturbed with the surface flow valve closed for a time period of approximately 2 minutes. The increase in surface pressure (dP) and the time period (dT) is recorded. The ratio of dP/dT is used to determine the gas flow rate and the gradient of the gaseous liquid column[1] using the Echometer S-curve. Multiplying the height of the gaseous liquid column by the gradient of the gaseous liquid column determines the pressure exerted by the gaseous liquid column. A fluid level shot is performed on a well to determine the producing bottomhole pressure, distance to liquid, and the gas flow rate. When the measured surface pressure builds up, dP/dT is increasing, then gas is assumed to be flowing into the tubing and/or into the casing annulus.

Direction of Kick of the Acoustic Signal

The direction of kick of the reflected echo indicates enlargements and reductions in the cross sectional area of the annulus (or internal diameter of pipe when 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 on the acoustic trace. Obstructions in the wellbore that would display as a downkick are liners tops, tubing anchors, paraffin/scale deposits, blockages or the liquid level. Downhole anomalies that increase the area of the wellbore result in rarefaction reflected waves and are displayed as upward kicks. Obstructions in the wellbore that would display as an upkick are hole in tubing, 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 inverted by software so the 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 hole in the tubing, then the acoustic trace would first display an upward kick at the hole, and then display a down kick as the traveling wave is reflected from the liquid level, possibly followed by another upward kick due to the traveling wave moving back past the hole. Identifying the direction of the kick of an echo is an important step in determining the type of the anomaly and troubleshooting a well problem.

Fig.1 displays an acoustic trace acquired by shooting down the casing annulus. The liquid level down kick is selected correctly at a RTTT of 11.116 seconds. Direction of kick of echoes on the acoustic traces is used to trouble shoot sucker rod pumped wells having problems. A representative well bore schematic should be used to identify all changes in cross-sectional area along the wellbore. Echoes on the acoustic trace from any change in cross-sectional area should be expected on the acoustic trace at the depth of the anomaly, if the anomaly is above the liquid level. Identifying an unexpected upkick on the acoustic trace at a certain time on the acoustic trace can mean that there is a hole in the tubing. The upkick at a RTTT of 7.389 seconds is due to a hole in the tubing or casing. There is no anomaly shown on the wellbore schematic of this well to indicate an increase in cross-sectional area of the well bore and an upkick echo should NOT be expected at this time/location/depth.

Troubleshooting Procedures

A well is normally turned off upon arrival, if the well is suspected of no pump action or no production to surface. Acquire two (2) fluid level shots down the casing and verify the acoustic traces appear the same on both shots. Acquire two (2) fluid level shots down the tubing and verify the acoustic traces appear the same on both shots. Since the shut-in well is normally quiet the casing tubing collar echoes are normally very clear. The acoustic velocity determined from counting tubing collar reflections from the casing annulus should be used to determine distance for the tubing shot. DO NOT use the average tubing collars joint length to determine distance on the shot acquired down the tubing! Remember that inside the tubing of a rod-pumped well, the presence of rod couplings skews the analysis and that's why it's necessary to use the acoustic velocity obtained in the casing fluid level analysis. Analysis of the acquired acoustic traces can determine the following:

1. Whether or not the well has a hole in the tubing.
2. If the well has kicked
    a. Excessive gas flow has unloaded the tubing liquids
    b. Backpressure adjustment is required to apply more tubing pressure.
3. Is gas flowing up the tubing? Determined by dP/dT greater than 0 from the pressure buildup test.
4. The buildup test also helps to determine the % liquid in the tubing, thereby helping determine the effectiveness of the downhole gas separation equipment. For example, if the %liquid inside the tubing is low and the tubing fluid column is gassy, then the bottom hole assembly is ineffective at gas separation.
5. Tubing shots can sometime indicate if the well is "paraffined up" because the presence of a lot of paraffin will make a tubing shot almost impossible to interpret.
6. Tubing fluid level shots made at regular intervals can show the operator if a well is truly "pumping up." A leaky pump can display a pump card filled with liquid, but the fluid level shots can show the liquid level is traveling up the tubing very slowly.

Tubing Leaks

The first and most basic use of shooting fluid levels down the tubing can show an operator if his well has developed a hole in the tubing. This is a very simple process whereby one can begin by shooting a fluid level down the casing. Immediately afterward, the 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. There are a few things that need to be taken into consideration when shooting fluid levels down the tubing, because the process is a little more difficult than the "garden-variety" casing fluid level shots…

Shooting the fluid level inside the tubing usually requires 50 to 65% less charge pressure into the gas gun than is normally required to create the casing shot. Less charge pressure is required for two reasons:

1. The tubing shot is usually made through a 1" bleeder valve and,
2. The space inside the tubing is more restricted by the sucker rod couplings than by the tubing collars inside the casing annulus.

The presence of sucker rod couplings in the tubing makes the method of determining distance from "counting collars" impossible, if the average tubing joint length is used. Therefore, the method of using the casing average acoustic velocity to determine distance to the anomaly echo should be employed. Sometimes 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 if 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 checked for an upkick from the tubing hole appearing on both traces at or near the same depth. The liquid level marker is moved to the beginning of the upkick from the hole on the tubing shot and to the beginning of the upkick from the hole on the casing shot. **Fig. 2** is the overlay plot comparing the acoustic traces acquired on well BKU #554 down the casing and tubing, where the upkick echo from the hole can be seen. Determining the distance to the upkick from the hole in the tubing:

- **Fig. 3** rod couplings frequency down the tubing of 19.46 Jts/Sec *25 ft/joint *0.541seconds RTTT = 263 ft to the hole. The tubing pressure at the time of the shot is 48.8 psi(g).
- **Fig. 4** tubing collars frequency down the casing of 14.96 Jts/Sec *32.15 ft/joint * 0.539 sec RTTT = 259 ft to the hole. The casing pressure at the time of the shot is 46.9 Psi(g).

The distance to the hole determined by counting rod coupling versus tubing collar echoes is within 4 foot. The casing acoustic velocity was determined to equal 973 ft/sec and the 0.002 second difference in RTTT between the 2 shots is approximately equal to 1 foot difference in depth to the hole. 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 foot when counting the rod couplings. Software creates a simple process to zoom into a short time interval along any portion of the acoustic trace. **Fig. 2** compares two acoustic traces by overlaying the portion of the acoustic traces from the surface to the hole.

In the vast majority of sucker rod wells where this “shoot down the tubing” process has been used, the hole in the tubing is usually found to be very deep in the well. So, it is normal to not see the upkick on the acoustic traces from the hole. 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 allows equalization of the two fluid levels to usually take place.

Experience 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.

Fig. 5 is an overlay plot of two acoustic traces acquired down the casing on a rod pumped well where there is a hole in the tubing at 4056 feet from the surface and no liquid is being produced to the surface. The echo from the hole on both acoustic traces is located at 9.08 seconds from the surface. While pumping, a fluid level shot was acquired at 1:48:12 PM. The echo from the hole is displayed as a down kick due to produced liquid discharging from the hole and the liquid discharge is partially filling the wellbore at the hole to create a decrease in cross-section area. With the pump turned off for 50 minutes, a fluid level shot was acquired at 2:38:35 PM. The echo from the hole is displayed as an upkick since all of the liquid in the tubing had enough time to drain out of the split tubing joint thereby creating an increase in cross-section area in the wellbore at the hole. When the pump is producing liquid up the tubing an echo from a hole can be masked or hidden due to liquid filling the tubing at the hole. A recommended practice is to shut the pump down for a period of time to allow any liquid in the tubing above the hole to drain out of the tubing and allow the echo from the hole visible on the acoustic trace.

Fig. 6 shows an abnormally low pump card load of 1355 lbs. The fluid level is 6583 feet from the surface and the pump card loads should be near the 3774 lbs fluid load calculated from the differential pressure acting on the 1.25 inch diameter plunger. The hole in the tubing is 4056 feet from the surface and the pump is lifting liquid up the tubing approximately 2500 feet to discharge out the tubing hole into the casing and circulating liquid back down the casing to keep the pump filled with liquid. The 3744 lbs calculated pump card height is equal the load required to lift the liquid from the pump intake pressure to the surface. The hole in the tubing is 4056 feet from the surface and pump card load on the upstroke is too low because the pump only lifts the liquid approximately 35% of the distance to the surface to discharge out the hole. The reduced height of the pump card can be used as an indicator of a possible hole in the tubing when the net lift shown by the pump card height is much less than fluid load required to lift the liquid to the surface determined from the fluid level. The full pump card also indicates that there is not a problem with the pump and valves appear to be operating correctly.

Pressure Test the Tubing

When a tubing fluid level shot and a casing fluid level shot indicates a hole in the tubing, HIT, a recommended practice is to confirm the HIT by either calling a pump truck or a hot oiler and determine if the tubing can be "loaded." The tubing pressure test is done by shutting down the well (usually on the downstroke) and pumping clean treated water into the tubing. The downstream flowline valve is closed to ensure the water being pumped will indeed go down the tubing and not down the flowline. The tubing is usually pressured up to 500 psi(g) and the pressure is held for a period of time. If a hole in the tubing is small and near the surface, then a good pump truck can often increase the water injection rate (barrels/minute) to increase the tubing pressure to 500 psi(g). But if a hole is present, then the tubing pressure will very quickly leak off (30 seconds to a minute). A "collar leak," however will not leak off as fast as a HIT. A single leaking tubing collar can take as much as 10 minutes to leak off 500 psi(g) of pressure.

Quite often, gassy wells will flow off, or "unload" the tubing because foreign material of some kind becomes trapped between the ball and seat of the tubing back pressure valve, BPV. The foreign material causes the ball and seat to leak. While pumping a quick method to check for foreign material is to screw in the stem of a BPV several turns and then shut the well's tubing/flowline valve and allow pump action to increase the surface pressure. Once the tubing pressure has increased to 300-400 psi, then open the flowline valve. If the back pressure valve holds the pressure, then the ball and seat are providing a seal and no foreign material is impeding the seal between the ball and seat. If after opening the flow line and the pressure quickly leaks off, then the back pressure valve should be disassembled and repaired.

To examine the BPV requires the well to be shut down, isolate the valve and bleed off any and all remaining pressure on the valve or inside the valve. Once this is done, the valve can be taken apart and all parts can be examined for wear and/or damage. Many operators will often replace the factory balls and seats in the BPV with balls and seats from the pump shop that don't wear out as fast or will change the ball/seat metallurgy to be better suited for the well's viscosity and causticity of fluid.

Another "valve" that can leak is the surface casing check valve. There are many brands on the market, but most employ a flapper that shuts against a seat to only allow the casing to flow in one direction—down the flowline. When a casing "check" fails, a well can have all the visible signs of pumping, even showing a back pressure valve that is operating properly. But a leak in the surface casing check valve can result in none of the produced fluids going to the tank. The well's production is "circulating" where fluid that is being pumped up the tubing is leaking past the flapper and falling right back into the casing annulus of the well. When a HIT or leaky surface casing check valve is suspected, then a recommended practice is to always test both for a pressure leak. The procedure to test a check valve is to apply pressure on the downstream side of the valve and determine if the pressure leaks back into the upstream side of the valve. Prudent operators design their surface piping so that this test is simple to perform. Such designs that allow a quick pressure test of the surface check valve will prevent costly workovers due to a misdiagnosed downhole problem. HIT and a leaky surface casing check valve have many of the same symptoms, but with a HIT the tubing will not pass a pressure test of the tubing.

Wells That "Kick"

In recent years with the advent of 2000-3000 foot long multi-zone perforated intervals plus many new horizontal wells, the industry has experienced a great increase in the number of gassy wells with high producing bottom-hole pressure. Excessive amounts of gas produced up the tubing can "unload the tubing" and the horizontal can often surge-flow and "kick" large quantities of gas up the tubing or the casing. After "unload the tubing" occurs and the Lease operators discover the well not producing to the tank, then the operator may suspect the well has a hole in the tubing or foreign material has stuck open a valve in the pump. Usually additional back-pressure on the tubing is required to prevent unloading of the tubing due to excessive gas pumped into the tubing. Pump action can usually be restarted by loading the tubing with water. Frequent interaction by the operator with wells that "unload the tubing" is often required. Identifying that tubing fluids are being unloaded is an important step in the process of properly operating the well and justifying that increased backpressure should be applied to the tubing.

After "unload the tubing" occurs shooting a fluid level down the casing and shooting a fluid level inside the tubing can provide the operator with an inexpensive diagnosis of what has happened to his well. Results from this test normally show that the well has a very high fluid level inside the casing annulus, which tends to make the well to “want” to flow up the tubing. The casing fluid level shot can be used to determine how high and how gaseous the column of fluid is inside the casing. The 2 minute casing pressure buildup test can be used to determine how much gas is flowing up the casing. After proper manual collar selection, the acoustic velocity is determined from counting tubing collars, then the acoustic velocity can be used to determine distance in the subsequent shots down the tubing.

The next step to “shoot the tubing” in the process of troubleshooting the well will require turning off the pumping unit. When shooting down the tubing on a well suspected of “unload the tubing”, the recommended practice is to not disturb the well and an accurate picture of the conditions inside the tubing can be obtained. Do not open the tubing valve “blowing down the tubing” pressure. The recommended practice is to preserve the initial condition of the well to obtain the highest quality data. Blowing down the tubing pressure changes the conditions in the tubing. Do not shut the flowline valve until just a few seconds before acquiring the tubing fluid level shot. Leave the well in the condition discovered by the Lease operator. Once the fluid level shot is acquired inside the tubing, the downstream valve is left closed for the tubing pressure buildup test. After switching the software default to identify the gas gun was attached to the tubing, the percent of liquid in the tubing, the percent gas inside the tubing, plus how much gas is flowing up the tubing is determined.

Wells that “kick” and unload the tubing fluids usually have the following traits… Unlike wells that have deep tubing leaks where the tubing/casing surface pressures “equalize”, wells that kick are just the opposite. When a well has unloaded the tubing fluids, it is common to observe a very high fluid level inside the casing, but to observe a deep fluid level inside the tubing. (Also, if a back pressure valve is in use on the tubing, and/or a choke on the casing, then the tubing and casing pressures will not be close together, as when the pressures are nearly equal when there is a tubing leak.) Also, in these situations, the liquid column inside the tubing will almost always be very gaseous, with only 15 to 20% of the column being liquid. Results from the dP/dT test will indicate that significant amount of gas is flowing up the tubing. The combined analysis of the data from the tubing fluid level shot indicates that the downhole gas separation performance is poor; too much gas is being allowed to be produced up the tubing. When the well is found in the state of “unload the tubing”, then additional back pressure on the tubing is required. Better downhole gas separation is critical to trouble free operation of the well. Do not underestimate the value of this information! The operator should take action based on analysis of the results from the fluid level shot down the tubing on a very gassy well. When the data collected on the well is properly interpreted and acted upon, gassy wells can be economic to operate, if production can be maintained without continuous intervention.

Difficulties

One of the biggest “monkey wrenches” in shooting and interpreting tubing fluid level shots is the presence of one of the oilfield’s worst enemies: paraffin. Shooting fluid levels down tubing packed with paraffin usually provides unreliable results. The presence of moderate to severe amounts of paraffin inside a well’s tubing will make shooting of the fluid level inside the tubing untrustworthy, if not impossible. If the well has a known history of paraffin buildup, plus the well is overdue for a treatment for paraffin then be cautious of using a tubing fluid level shot to diagnose and troubleshoot the problems discussed in this paper. Experience is beneficial when interpreting the results from shooting down the tubing on wells that may have a paraffin problem. If a well is suspected of having paraffin in the tubing, and the tubing acoustic trace exhibits unclear, “mushy” data, and anomalies with no clear fluid level, then it may be “time to call the hot oiler”. Cleaning paraffin out of the tubing is one technique that can be used to make fluid level shots have value in wells with paraffin.

Documenting Fluid Movement

Successive tubing fluid shots in **Table 1** show the pump installed in the well was under-performing and was not pumping sufficient liquid per stroke into the tubing. **Fig. 7** the dynamometer pump card shows good pump action, but liquid was not being pumped into the tubing due to a leaky pump. The pump card shows tubing movement and a valve test on this well could have shown high plunger/barrel leakage (if performed). The fluid level shots down the tubing were used to make the determination on whether or not the pump in this well is truly pumping.

After 53 minutes of continuous pumping a fluid level was acquired on the casing and the distance to the liquid level was determined to be 7300 feet from surface. Thirty-four minutes after taking the casing fluid level shot, there was still no fluid to the surface at the tubing bleeder valve, despite the fact that each pump stroke appeared to be filled with liquid. With no pump slippage at 120 barrels per day pump displacement, the pump should have been filling approximately 3 foot of tubing/sucker rod annular volume per each stroke. **Fig. 8** fluid level acquired inside the tubing at 01:4828PM determined the fluid level was 727.7 feet from the surface, using the acoustic velocity of 1192 ft/sec obtained from the casing fluid level shot.

Liquid was expected to quickly appear at the surface due to the display of relatively good dynamometer cards. With fluid only 727.7 feet from the surface the initial diagnosis was that the well had likely kicked and unloaded a lot of the tubing liquid, but fluid should soon be at the surface. Thirty-one minutes later with no fluid to surface, the next tubing fluid level shot showed fluid to be 672.9 feet from surface. The fluid level inside the tubing had only risen 55 feet in 31 minutes, rising at a rate of 1.736 feet/minute.

Based on experience from watching other wells "pump up", there definitely was something wrong with the pump. A visit to the pump shop on the next day discovered that we had mistakenly run a pump with a PAP plunger in this 10,955 foot deep well. With high differential pressure acting across the PAP plunger, lost pump displacement due to slippage accounts for the very slow rise of liquid in the tubing. Initially the well had a high fluid level with low differential pressure acting across the PAP plunger, so the production from the well was good. As the well was produced, the lowered fluid level increased the pressure acting across the plunger and pump slippage increased. When the liquid level was drawn down to 7300 feet from surface, then the pump displacement could not exceed the amount of slippage past the plunger and the pump could no longer lift fluid to the surface. No matter what the "cards" look like, if the fluid level shot down the tubing shows the pump is not bringing fluid to the surface, then it's time to call the pulling unit. Using an acoustic instrument and shooting fluid levels down the tubing, even without a pump card, an operator can still "make a good call" without incurring the additional expense of a pump truck and determine whether or not his well needs to be pulled.

CONCLUSIONS

If no pump action or no production to surface, then a recommended practice is to shoot a fluid level down the casing annulus and also shoot a fluid level down the tubing. Distance down the tubing is determined by using the average acoustic velocity obtained from the casing shot. Once the casing fluid level and the tubing fluid levels are properly analyzed, then the tubing and casing acoustic traces can be overlaid and checked for an upkick from the tubing hole appearing on both traces at or near the same depth. The reduced height of the pump card can be used as an indicator of a possible hole in the tubing when the net lift shown by the pump card height is much less that fluid load required by fluid level for the pump to lift liquid to the surface. When the data collected on the well is properly interpreted and acted upon, gassy wells can be economic to operate if production can be maintained without continuous intervention. Monitoring the fluid level in the tubing over time can be used to determine if the pump action is filling the tubing with liquid. Shooting a fluid level inside the tubing is a valuable troubleshooting technique used on wells that have either stopped producing altogether, or production rate has drastically decreased.

1. McCoy, J.N., Podio, A.L. and Huddleston, K.L.: "Acoustic Determination of Producing Bottomhole Pressure," paper SPE 14254 presented at the 1985 SPE Annual Technical Conference and Exhibition, Las Vegas, NV, Sept. 22-25.

Table 1 – Successive Fluid Level Shots

Shot	Time	RTTT (Sec)	Distance to Liquid (ft)	Elapsed Time (min)	Rise Ft/min
Casing	01:14:56PM	12.248	7300.0	0	-
Tubing	01:48:28PM	1.221	727.7	33.533	-
Tubing	02:20:03PM	1.129	672.9	31.583	1.736
Tubing	03:51:06PM	0.973	579.9	91.050	1.021

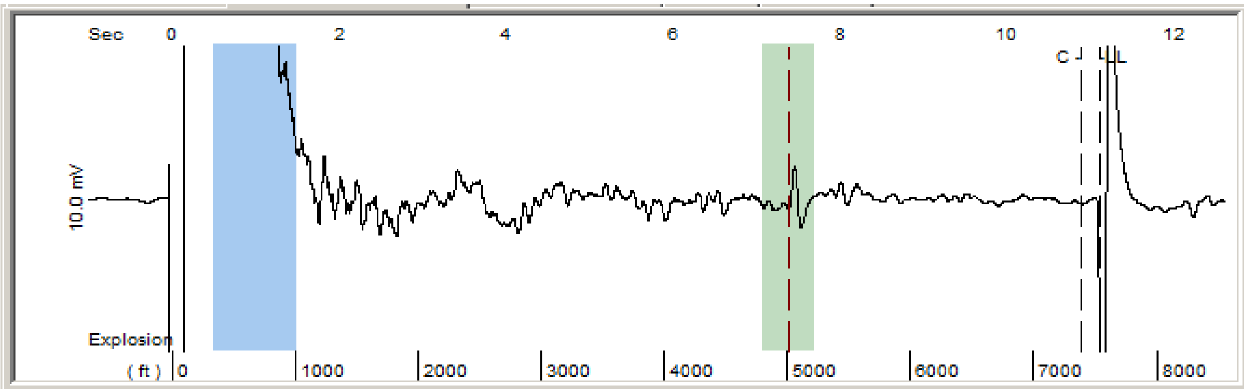

Figure 1 – Upkick on Acoustic Trace from a Hole in the Tubing

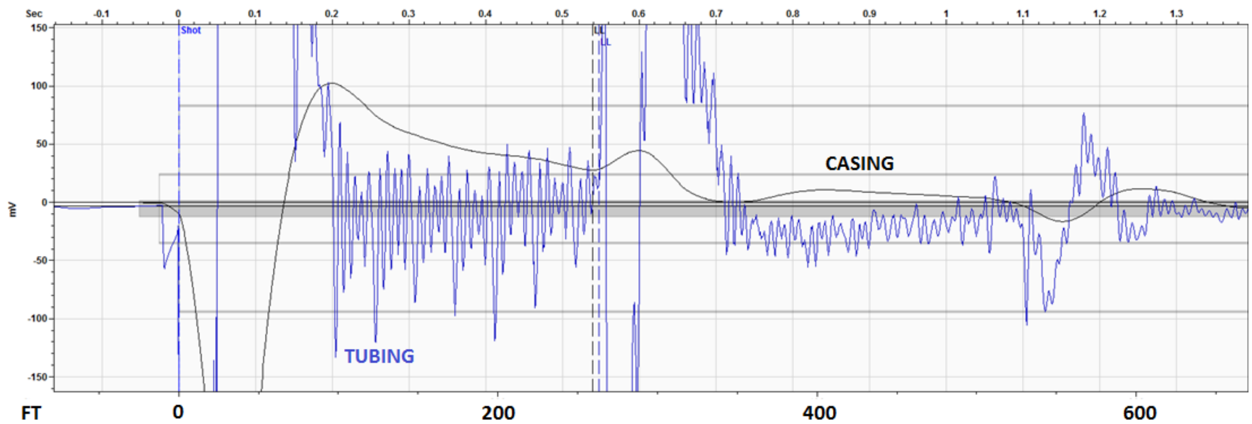

Figure 2 – Comparing Hole in Tubing Echo Overlay of Low Pass Filter Casing Shot to Raw Tubing Shot

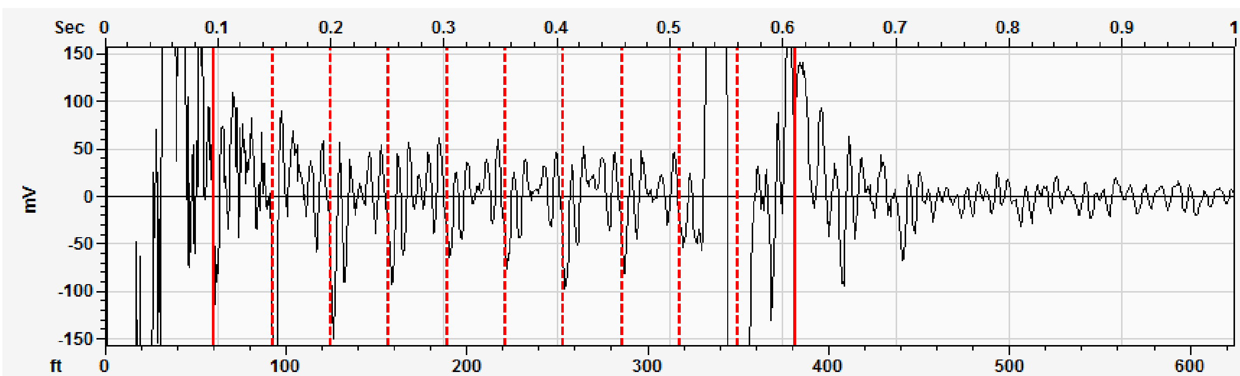

Figure 3 - Rod Couplings Frequency in Tubing of 19.46 Joints/second at 25.0 feet/joint

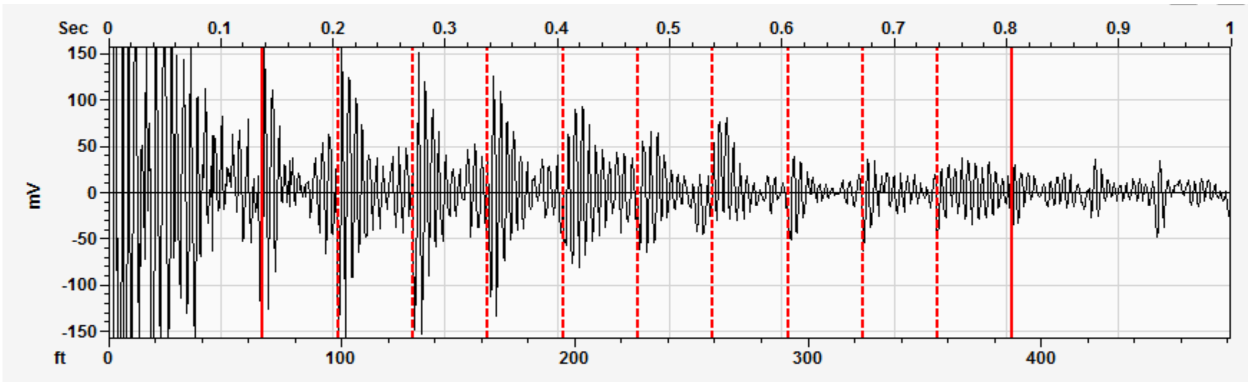

Figure 4 - Tubing Collars Frequency in Casing of 14.96 Joints/second at 32.15 feet/joint

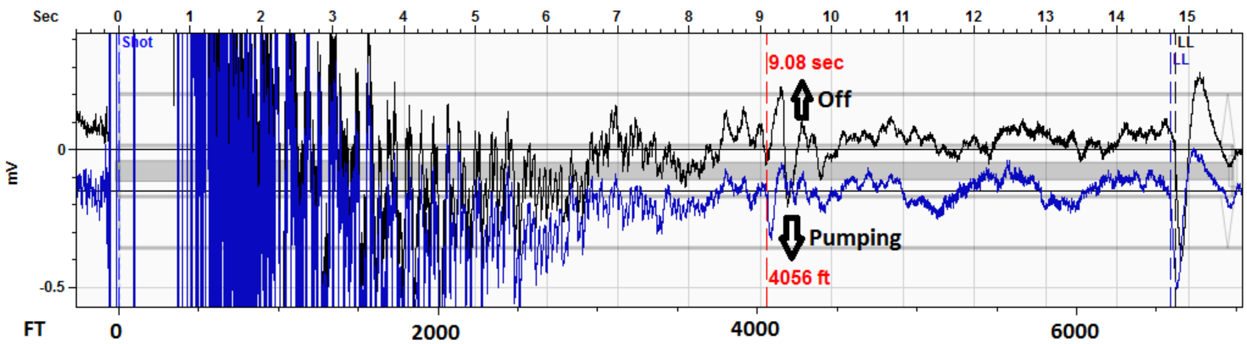

Figure 5 – Hole in Tubing Shown as Up Kick when Pump Off and Down Kick when Pumping

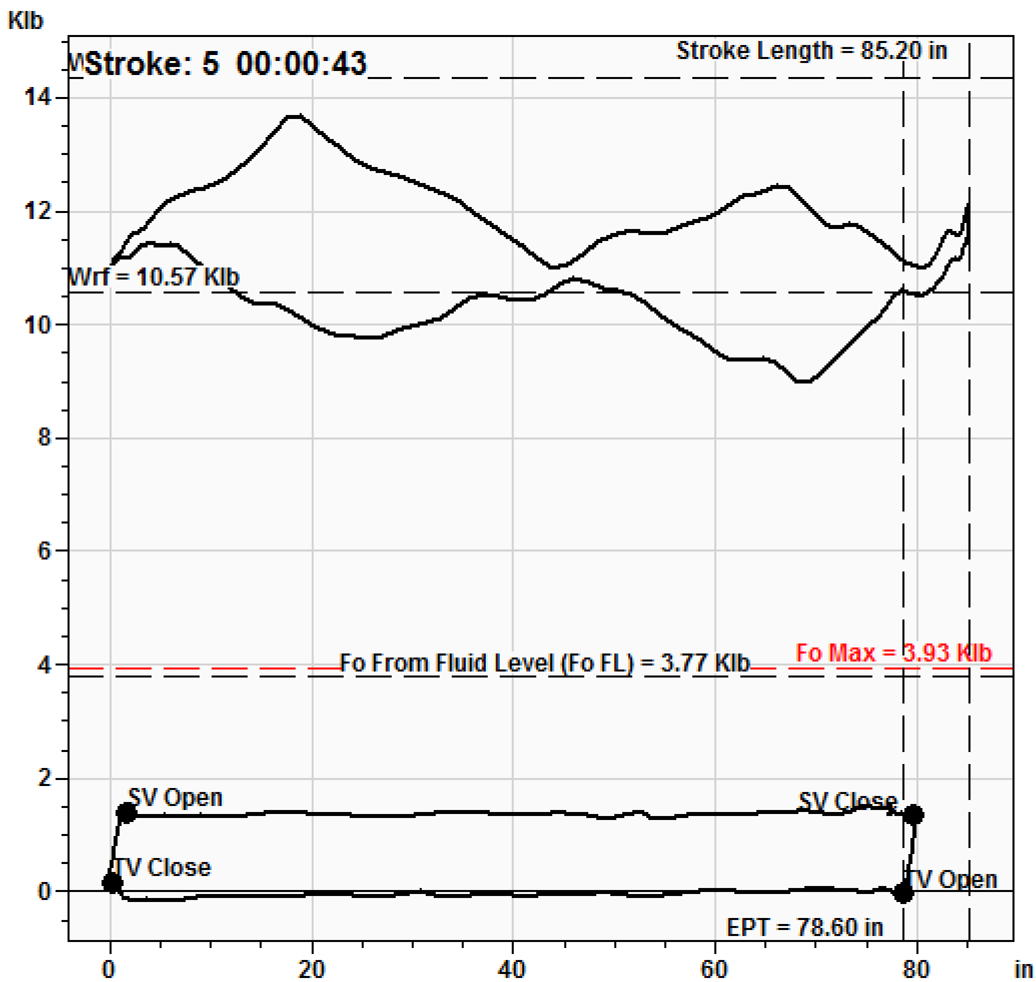

Figure 6 – Pump Card Abnormal Loads Due to Lifting Liquid out a Hole and Not Lifting to the Surface

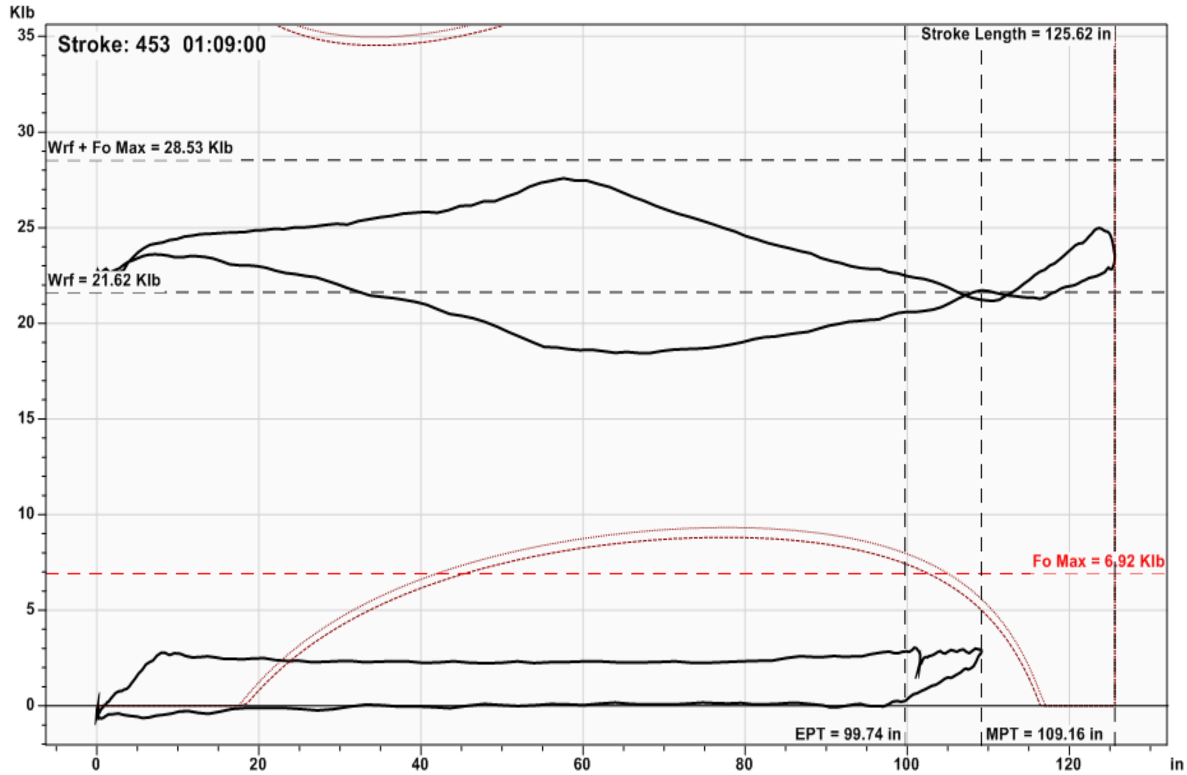

Figure 7 – Good Pump Action and Not Lifting to the Surface Due to Leaky Pump

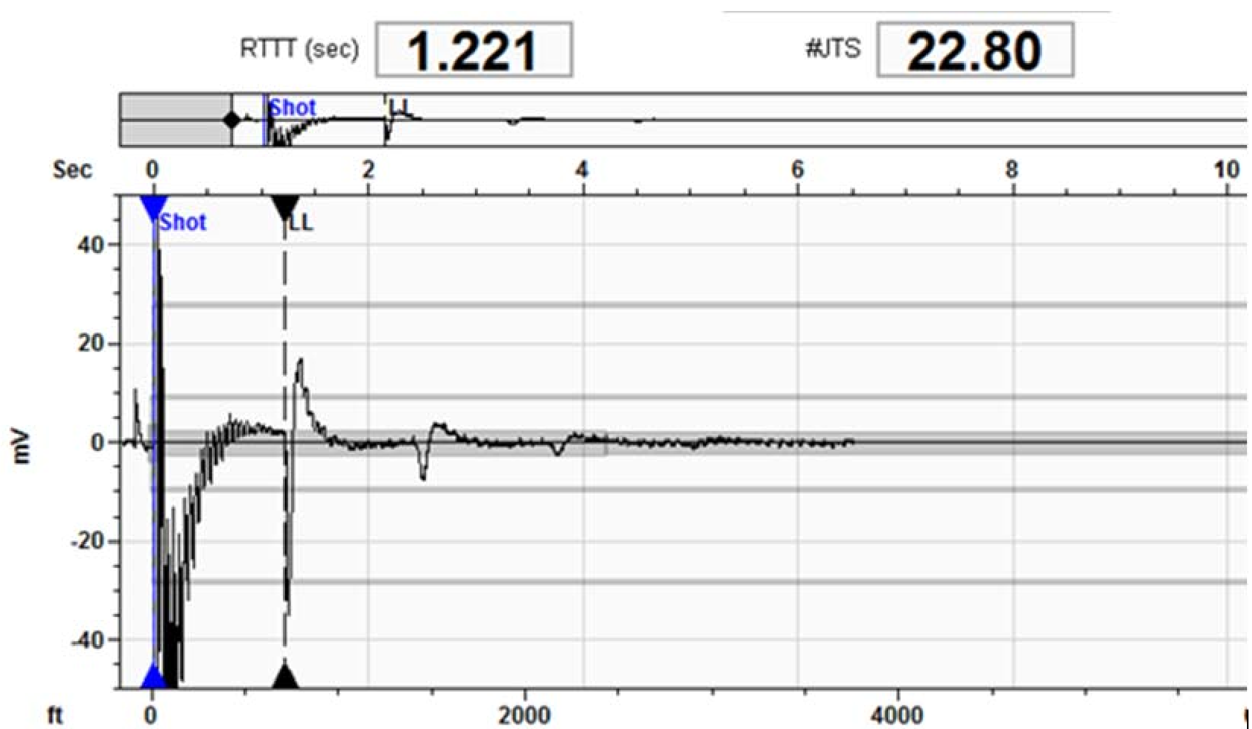

Figure 8 – Fluid Level in Tubing