APPLYING DATA FROM FLUID LEVEL SHOTS TO OPTIMIZE CHEMICAL TREATMENT PROGRAMS

Shawn Dawsey
Downhole Diagnostic, LLC

ABSTRACT

Data from fluid level shots can be very valuable in optimizing the chemical treatment program. Just because chemical is being introduced into the well does not mean it is effectively getting downhole (or getting downhole at all). This paper will discuss the five different methods of chemical treatment (Truck Treating, Continuous Treatment, Cap Strings, Solid Time-Released Chemical Subs, and Chemical Squeezes) and how data obtained from fluid level shots can help determine the best chemical treatment method for a well. Monitoring/optimizing the performance of slip-streams, treating 'flumping' wells, and analyzing how to treat wells with large pads of fluid above the pump will be discussed. High gas flow rate wells that potentially make enough gas to lift liquids out the annulus (above the Critical Gas Velocity) will be looked at, along with some discussion of oil vs water soluble corrosion inhibitors. Fluid level shots see what is happening in the annulus and thus can be the basis for ensuring chemical treatment practices are appropriate for the specific conditions.

INTRODUCTION

Nearly all wells have some sort of chemical treatment program with the goal of economically extending run-life and minimizing downhole failures related to general corrosion, bacterial pitting, paraffin or scale deposits, etc. A good chemical program will analyze the chemistry of the well fluids/gasses (pH, scaling tendency, ppm of corrosive gasses, bacterial counts, etc.) and it will also analyze the condition of the downhole equipment/failures pulled out during routine pulls and use this information to determine the most appropriate chemicals needed to mitigate these issues. The goal is to economically extend run-life and the most common chemicals introduced are corrosion and scale inhibitors.

However, just because an appropriate chemical is being introduced into the well does not mean the well is effectively being treated. The chemical must get downhole and into the pump/tubing to effectively treat the inside of the tubing (and sucker rods for a rod pumping well). **Flumping wells (flowing + pumping**; i.e. wells that are producing up the tubing but also flowing/heading liquids up the backside) present a unique challenge to getting the chemical downhole and appropriate measures must be taken to ensure the chemical actually gets downhole and into the tubing. Due to the top of the fluid level being at (or right below surface), the gas/liquids flowing up the annulus will try to push the chemical staight down the flowline to the tank battery, and the downhole equipment will not receive chemical protection.

There are five different methods for introducing chemical into the well: Truck (Batch) Treatment, Continuous Treatment, injection down a Capillary String, installing Solid Time-Released Chemical Sticks in chemical subs at the bottom of the tubing, and a Chemical Squeeze into the formation. The most common methods are Continuous Chemical injection and Truck Treating for their low cost and simplicity of application. However, if a well is flumping, the operator needs to evaluate their chemical treatment method as these two methods are not likely adequate for getting the chemical 'down-and-around'.

Data acquired from fluid level shots can help diagnose what is going on in the annulus to optimize chemical treatments. Slip-streams (on continuous treatment wells) need to be shut off before a fluid level shot and the operator should first observe if they are actually slipping any fluid (which is needed to carry the chemical downhole). If the top of the fluid level is close to or at surface, steps need to be taken to ensure the chemical actually stays downhole and is not pushed down the flowline. If the well regularly holds a large pad of fluid above the pump (which will be all oil if it is running in steady-state conditions), then water-soluble inhibitors might be preferred as oil soluble inhibitors might get bound up in the oil column and not make it to the pump. If the fluid level is low and/or near the pump, oil soluble inhibitors can be used with confidence. Also, fluid level shots approximate the gas rate flowing up the backside, and if the gas rate is above the Critical Gas Rate, the chemical can be lifted out of the well on continuous treated wells and additional CP will need to be held to prevent this from happening.

This paper will discuss the five different ways of chemically treating wells and tie in how data from fluid level shots can help guide the decision process of how to best treat a well. Also, it will explore simple operational changes that can be made to overcome issues related to flumping or proper slip-stream operation.

OVERVIEW OF CHEMICAL TREATMENT METHODS

The two most common forms of chemical treatment are Truck Treating and Continuous Treatment. With **Truck Treating (Batch Treating)**, a chemical truck (Figure 1) comes to the well (for example, weekly) and pumps several quarts/gallons of chemical down the backside and then pumps 3-5 barrels of flush water behind it to push the chemical downhole. It is hoped this chemical will provide adequate protection till the chemical truck comes back to introduce more chemical the following week. Batch treatments are fine for corrosion inhibitors (which bind to the metal) but not usually considered adequate for scale/paraffin inhibitors which need to be constantly introduced into the system so there is adequate concentration to prevent scale/paraffin precipitation. [One caveat to this last statement: there are small solid pellet forms of chemical that can be pumped on the batch treatments which are designed to be time-released, so these could be used for scale/paraffin treatment.]

With **Continuous Treatment**, a chemical tank and pump are on location and they are constantly introducing chemical to the annulus throughout the day (e.g. one-quart to one-gallon+ per day; Figure 2). The small amounts of chemical being introduced need assistance to fall down the casing annulus to the top of the fluid level, and then they need further assistance to migrate through the pad of gaseous liquid residing above the pump intake so the chem can make its way into the pump/tubing. To assist the chemical getting downhole, these wells should have a Slip-Stream that takes some fluid from the tubing and “slips” it to the backside to mix with the chemical and help it make its way downhole. The slip fluid is very important in this method of treatment, but usually the slip-stream is rarely given enough attention and it usually is not functioning properly (I have much more to say about this in a later section).

The next three forms of chemical treatment methods are more specialty and not as commonly employed. A **Capillary String** (Cap String) is thin spooled tubing, usually 3/8" stainless steel, that is ran into the well at the same as the production tubing and it is banded to the outside of the tubing (Figure 3). The end of the Cap String is usually tied directly into a sub right below the seating nipple or pump intake and chemical is continuously injected from surface down the Cap String into the pump intake. The benefits of a Cap String is that you can ensure the chemical gets downhole to the pump intake (even if the well is flowing large volumes of liquid up the backside), but there are several downsides to its application that makes operators hesitant to use it. First, it is usually only needed on wells that flump or hold very large fluid columns above the pump. Second, it is expensive and adds fishing risks. Installing a Cap String on a 10,000’ well will cost about $30,000 (for the Cap String, bands, and added rig time). Cap Strings can part when trying to set tubing anchors (due to differential stretch when pulling tension on the anchor). The bands holding the Cap String to the tubing often break and fall downhole, and the Cap String can be an impediment to fishing and ball up in a birds nest if the tubing parts and an overshot is used. So for all these reasons, operators tend to avoid their use unless they are necessary. Despite their drawbacks, Cap Strings are the most effective way to treat flumping wells, so it might be necessary to install a Cap

String early on in the life of a well until the top of the fluid level pumps. Also note, Cap Strings pump chemical straight into the bottom of the tubing and so they do not treat the annulus fluids with chemical.

Another method of introducing chemical downhole on flumping wells is installing **solid, time-released chemical** at the very bottom of the tubing in chemical subs (Figure 4). The chemical subs can be tailor made for the well's needs (for example a 60' chemical sub with 60% corrosion inhibitor + 40% scale inhibitor mix) and this method of treating does not have the inherent risks associated with installing a Cap String along the outside of the tubing. The chemical is designed to be time released and the speed at which it is released into the annulus fluids can be controlled both chemically (based on the encapsulating properties of chemistry) and mechanically (how many perf subs are installed and where, to regulate how much fluid contact there is). Suppliers of this form of treatment say the chemical can be designed to last between 6-months to 2-years, but it must be properly designed for the given well's conditions and unforeseen circumstances can cause the chemical to dissolve/release faster than desired. The dissolution rate of the chemical into the produced fluids is often questionable, but residual tests of the produced fluids can measure what the current concentration rate of the chemical is. This treatment method can be an effective option for wells that like to flump for several months after a workover but then later calm back down as the bottomhole pressure drops—so the chem subs can provide some level of protection till regular treatment methods (Continuous or Truck) can be initiated. The chemical is released into the annulus, so both inside and outside of the tubing can be treated, but if the well is flowing hard up the annulus, much of the chemical might bypass the pump intake and go straight up the annulus to the flowline.

Lastly, **Chemical Squeezes** into the formation can used but this is a very infrequent, specialty form of introducing chemical. In this process, many barrels of chemical are pumped downhole (often done down the backside without a rig) and the chemical is chased with hundreds of barrels of produced water to try and push the chemical deep into the formation with the goal of having the chemical slowly release back into the produced fluids over time. Often this form of treatment might be performed if there is an issue with barium scale (not acid soluble) or if there are concerns of scaling on perfs that will cause formation damage and restrict inflow. If the job is done down the backside, it is not known what perfs take the chemical and how quickly the chemical will be produced back (will have to monitor residuals regularly to determine when the next chemical squeeze is appropriate). This is a specialty treatment and I won't discuss it any further in this paper.

FLUID LEVEL SHOTS, GRAVITY SEGREGATION, & OIL VS WATER BASED INHIBITORS

To a acquire a fluid level shot, the operator attaches a fluid level gun to the casing, shoots a pressure pulse down the annulus, and then a microphone on the bottom of the fluid level gun records the sound waves that are reflected back. Based on how long it takes for the pressure pulse to travel downhole, reflect off the top of the fluid level and back to the microphone, the distance to the top of the fluid level can be calculated. A Casing Pressure Build-Up Test will then be performed to approximate how much gas is flowing up the backside. An example acoustic fluid level report is shown in Figure 5.

The most basic information from a fluid level shot is the distance to the top of the fluid level and how much **GFLAP (Gas Free Liquid Above the Pump)** exists. If the well is not pumped off and it makes gas up the backside, then there exists some height of gassy fluid column above the pump. The calculated GFLAP tries to account for how much of that gassy liquid column is actual liquid. Both the distance to the top of the fluid level and the GFLAP are important in the analysis of chemical treatment methods: 1) if the top of the fluid level stays far from surface, you don't have to worry about flumping conditions pushing the chemical down the flowline; 2) if the well regularly holds a high GFLAP, the chemical might need additional help (extra flush fluid from a truck treater or extra slip fluid) to get downhole more effectively. Also, high GFLAP's might affect your decision on whether to use oil or water based corrosion inhibitors.

As seen in the example in Figure 5, the top of the fluid level is at 2344' (so flumping does not appear to be a concern) and the gassy liquid column above the pump is 6324' but only 1529' of that column is calculated to be liquid (i.e. the GFLAP). The GFLAP is high but not extraordinarily high, so likely any form of normal chemical treating practices should be sufficient.

What many people fail to realize is that if the well is running in steady-state and has produced long enough since an extended down-time (like a workover), then **all of the liquid above the pump is going to be *only oil*** (no water). This is illustrated in Figure 6. After a workover (or extended down-time), water and oil will reside above the pump in the well's normal oil/water ratio, but as the well pumps the fluid level will be pulled down, inflow from the reservoir will start and the oil pad will start to grow as oil slips by the pump intake and it migrates vertically to sit on top of the water due to natural gravity separation. Eventually the area in the annulus above the pump will be nothing but oil (and gas). Also, the area below the pump will be primarily water (or at least have a higher water concentration than the normal water cut) as gravity segregation is acting here as well.

This fact (only oil above the pump intake) is important in chemical treating as passionate discussions frequently occur as to whether oil or water soluble chemical should be used on a well in relation to the oil-water ratio of the produced fluids. Even if a well makes 95% water, eventually the only liquid above the pump will be oil and oil soluble chemicals should be able to easily mix in the oil pad (GFLAP) and make their way to the pump. I have heard many chemical company representatives talk about a well's high water cut and then assume a high water cut is sitting above the pump intake, so a water-soluble corrosion inhibitor needs to be employed to effectively mix with the fluid above the pump intake, but this is just not true. When producing in steady state, only oil exists above the pump.

Many old-school rules of thumb state if the water cut is greater than 60% or 70%, then water soluble inhibitors should be used, but that is not necessarily true. Personal discussions with a knowledgeable individual who runs a local chemical lab (who does quality control testing on various chemistries) has told me that oil soluble inhibitors have performed well in lab tests even in 100% water environments (and his experience with customers who apply oil based inhibitors in 98%+ water cut wells have shown good results/residuals). Oil-based corrosion inhibitors are hydro-carbon based and they have a stronger "film persistency" (they stick to the metal better to form a stronger barrier that keeps corrosive waters from contacting the metal). Oil based inhibitors are usually believed to provide better protection than water-based inhibitors for this reason, but since they are hydrocarbon based they are more expensive (maybe 1.3 - 2 times as expensive as water based, depending on the price of oil and the type of oil-based inhibitor).

Oil soluble inhibitors are usually considered better but they might not be ideal in situations where the well holds a high GFLAP as these inhibitors can get bound up in the oil pad (GFLAP) and have a hard time making their way down to the pump intake (or at least take a long time to migrate to the pump intake). If the GFLAP is high, a water based inhibitor will be able to fall down through the oil column more easily, so many chemical companies have rule of thumb that if the GFLAP is greater than 1000' or 1500', then water based inhibitors should be used. Water based inhibitors are heavier than oil based, which also helps them migrate down through the GFLAP.

HOW DATA FROM FLUID LEVEL SHOTS CAN BE APPLIED TO OPTIMIZE CHEMICAL TREATMENT

1. Slip-Stream Functioning

Slip-streams are of particular interest to me as a Well Tech who shoots fluid levels as I have to shut the slip-stream off before shooting the fluid level (to prevent background noise that can affect the clarity of the acoustic data), so I always check to see if the slip-stream is actually slipping before I close it off and take the shot. From my 8-years of experience I would approximate that **I only find about 10-20% of wells actually slipping any fluid!** Some operators have much better success with their slip-stream operation but only if they have good equipment designs and have made it a special point of emphasis in their company (and especially to their pumpers) to pay attention to the slip-stream.

The problem with slip-streams is that the control valve (usually a 1/4" needle valve that is pinched down to restrict the amount of fluid slipping) easily plugs off and requires regular/daily attention from pumpers who need to open it, flush out the solids that packed off on the stem/seat, and reset it—that is extra work that few pumpers do—and with few companies checking up on pumpers or emphasizing they need to do this, it rarely ever gets done. Many people think that if the valve is cracked open then fluid is slipping, but the valves need to be pinched down to ensure too much fluid does not slip back downhole, and when a valve is only slightly cracked open it is very easy for solids to quickly bridge off and plug the small opening, which then prevents fluids from slipping through.

Needle valves are good for regulating the flow of *clean* fluid, but iron, scale, sand, paraffin and other trash that comes up the tubing easily plugs them off due to their design (a stem sticks down into a seat), which provides a perfect ledge for solids to build up on (Figure 7). I recommend you NEVER use needle valves on slip-streams and only use ball valves, as they are more difficult to plug off due to their design (they are full opening with no stem for solids to bridge off on) and from my experience, they are much more likely to stay slipping. Also, they are much easier/faster to flush clean and reset (important if you want a pumper to do it regularly) and it is visually evident how open (or closed) they are based on the angle of the handle. You never know how open a needle valve is until you turn it fully closed, then count the turns as you open it. Never use needle valves on slip-streams!

No slip fluid can be a serious problem for continuous treatment, especially if the well is deep and/or holds a lot of fluid above the pump. If 2-quarts are being introduced a day, how long will it take to dribble down the casing/tubing walls (fighting gas flowing in the opposite direction) down to the pump intake? Remember, the purpose of filming corrosion inhibitors is to *cling* to metal surfaces to create a barrier between them and the corrosive fluids, so how many weeks/months of chemical could get bound up on the tubing/casing walls? Also, if the well holds a large pad of GFLAP, you need that chemical to be mixed with a larger volume of well fluids to help carry it down through the large pad of oil sitting above the pump so it can get to the pump intake.

Anytime a fluid level shot is taken, the operation of the slip-stream should be noted in the report (and ensure to open the slip-stream back up after finishing the fluid level shot). Due to my reporting of slip-stream issues to operators, I have seen field operations turn around with much better success rates of slip-stream operation. This often entails changing out 1/4" needle valves to ball valves, ensuring adequate pressure differential between the TP and CP (need a force to push the fluids), and emphasizing the importance to pumpers who ultimately are the ones who ensure their proper operation. There is very little oversight/ consequences for pumpers who pay no attention to the slip-stream, so the results I usually see might be predictable.

To get away from the plugging issues of the slip-stream control valve, I have seen operators use a 1" circulation loop with an automated valve that opens for several minutes periodically throughout a day. A full 1" opening valve will not have plugging issues, but valve/automation costs and maintenance will arise. I have also seen operators at wits end actually drill a tiny hole in 1/4" ball valves so when the valve is actually closed, there is still a tiny hole that allows fluid to slip. This seemed like a plausible solution, but it was hard to properly size the holes so they were not too big and slipped too much or too tight and the tiny hole pugged itself. Proper slip-stream functioning is a constant battle.

The best solution in my experience is a 1/4" ball valve and a pumper who gets feedback from managers when their slip-streams are too frequently not operating properly. Also, something completely underutilized are clear sight-glasses that can be installed on the slip-stream (Figure 8) to make it visible and obvious to pumpers if any fluid is slipping. Without these sight-glasses (which few operators use), to ascertain if a slip-stream is properly slipping, you have to usually put your ear to the slip-stream and closely listen to hear fluid moving through—which is not always easy if there is lots of noise from back-pressure valve chatter.

Occasionally, I find slip-streams slipping too much (or even wide open) which is also bad as too much fluid is being circulated back downhole, so the well's production will be reduced (if it doesn't pump off) or more run time is required to stay pumped off (so more electricity, rod/tubing wear, etc). If there is too much fluid circulating down the slip-stream it is often impossible to find the top of the fluid level when taking a fluid level shot as the pressure pulse bounces off all the scattered falling fluid so no fluid level "kick" can be seen: this is another reason to observe the performance of the slip-stream before shutting it off and taking the fluid level shot. In summary—watch your slip-streams and explain the purpose/function of it to your field personnel.

2. Treating Flumping Wells Without a Cap String or Solid Chemical Subs

If the top of the FL is staying well below surface with no risk of flumping, then either form of Continuous or Truck Treating should be adequate, and the operator can pick their preference as the chemical will stay downhole and eventually get to the pump intake. (Keep in mind, scale or paraffin inhibitors are usually only recommended with continuous injection). If the calculated GFLAP is very high, or there is some risk of flumping as the backside periodically kicks and unloads, then the operator might want to slightly increase either the flush volume on Truck Treatments (for example, increase it from their standard 3 bbls to 5 or 10-bbls) or it might be desired for the slip-stream to be more open and allow more slip fluid to circulate back downhole to tame down the backside.

However, if the top of the fluid level is at surface or right below surface, or if production tests indicate the well is making more than the pump's maximum displacement rate, the well is likely flumping. I have encountered many flumping wells that are on continuous treatment with zero chance of the chemical getting downhole as the well is heading liquids up the backside, so how could the chemical go anywhere except down the flowline? Chemically treating flumping wells can be difficult if the flumping condition was not taken into account the last time the tubing was ran into the well. As previously discussed, the best methods for chemically treating these wells are either using a Cap String or solid time-released chemical deployed in tubing subs down at the bottom of the tubing string, but of course, both of those must be installed during the last workover when the tubing was being run into the well.

So what do you do if you didn't install a Cap String or Chem Subs during the last pull and the well is flumping hard? How can you get chemical downhole to protect your rods/tubing?

One potential solution is to Truck Treat the well and circulate it for a specified amount of time after the treatment. This would entail shutting the casing valve to the flowline, pumping the chemical and flush water, and then opening the circulation loop (Figure 9) to push additional produced fluids to the backside to circulate the chemical down and into the tubing. This can be done multiple ways. The casing valve to the flowline can be fully closed or just pinched tight (but still cracked open) so that it holds some back-pressure but still allows some gas to escape to the flowline (so the well doesn't pressure up as much). Also, the tubing valve to the flowline can be fully close (to force all fluids to the backside), but it is probably better to leave this valve open and rely on the tubing back-pressure valve to create the pressure differential needed to force fluids to the backside (this way the stuffing box does not pressure up and make a big mess).

For example, if the TP = 300# and the CP = 100# before circulating, once you initiate circulation the TP will drop to 100#, but often the CP will eventually pressure up to 300# (unless the casing valve is cracked) and at this point TP = CP = 300# and all the fluid will start pumping through the backpressure valve and down the flowline. After the specified circulation time (usually, the next day when the pumper arrives), the pumper will shut off the circulation loop and crack the casing valve and return it to normal production till the next time it is circulated. The downside to this treatment method is losing a significant portion of the well's production (maybe a full day's worth) every circulation; also, solids from the rods/tubing/rod guides will be circulated back downhole and can cause pump wear/fouling that otherwise would not have occurred.

If the well is flumping and is set up for Continuous Treatment, additional casing pressure can be continuously held to depress the top of the fluid level below surface to stop the flumping and therefore insure the injected chemical stays downhole. For example, if the CP = Flowline Pressure = 65#, you could screw in the casing choke and maintain a CP of 150# to depress the top of the fluid level below surface. In Figure 5 (highlighted in yellow), the calculated percentage of liquid on the backside above the pump is 24% (the rest is gas). Based on this, the gradient of the fluid on the backside (40˚ API) = 0.433 x 0.83 x 0.24 = 0.086 psi/ft. Doing the math, the top of the FL should be depressed around 988' by adding that much back pressure [= (150-65)/0.086 = 988']. (Note: this calculation is slightly simplified. Also Note: the correlation that approximates the gas fraction in the Echometer software tends to dramatically over-estimate the gas fraction on wells that have a fluid level close to surface, which means the fluid level would not be depressed as far as calculated as the pressure gradient of the column on the backside is actually much higher than computed). Holding the additional CP would depress the top of the fluid down sufficiently to be confident the chemical is staying downhole, but the downside is that you are pinching off the additional production related to flumping (i.e. all the liquid production coming up the backside will cease). That may not be a problem if only 5% of the well's production is coming up the backside, but if it is 20% you might start getting questions from upper management. To ensure this procedure is working as desired, take a follow-up fluid level shot several days after increasing the CP to confirm the fluid level is sufficiently depressed.

It is commonly assumed that holding higher CP will increase the bottomhole pressure (**BHP**) and restrict the well's production, or higher CP will increase gas interference in the pump. Testing using bottomhole pressure gauges has proved higher CP does not increase the BHP. When the CP is increased, the BHP could increase for a short transient period but it will stabilize at the same level it was at. The Walker Depression Test (which increases the CP in stages, depresses the top of the fluid level and allows for an accurate computation of the pressure gradient of the gaseous liquid column in the annulus so an accurate Pump Intake Pressure, **PIP**, can be computed) is based on the principle that the PIP does not change (once stabilized) with the higher CP being held (Figure 10). The higher CP depresses the fluid level, so the component of the PIP due to the hydrostatic gradient of the gaseous fluid column is reduced due to its shorter height, but this is now offset by the higher CP being held at surface and the larger pressure gradient of the gas column, so in the end it all equals out and the PIP is unchanged.

The higher CP also does not increase the likelihood of gas interference either in the long-run assuming the CP is not so high it depresses the top of the fluid level to the pump, which should not be an issue for this discussion as we are discussing wells that flump. I have found casing valves accidentally left closed with 1500# CP, the fluid level depressed to the pump and the pump has 100% fillage every stroke. I would never advocate for holding additional CP anytime unless the goal is to depress the fluid level to prevent flumping with respect to chemical treatment programs. For wells that pump off or have a top of the fluid level close to the pump, holding additional CP can reduce production as the pumpable volume of liquid is being depressed lower, so the pump will not have access to as much of it.

3. Raise the Seating Nipple if it Carries a High Fluid Level

One other way to help the chemical get 'down-and-around' can be applied to wells that cannot pump down but which are maxed out on their production potential. Most operators want to stick the pump on bottom, which is usually a good idea as we want to pump the well off and obtain the lowest PIP to maximize production. But what if the SPM or Max Displacement is maxed out and you cannot pump the well down, or what if the well is a high failure rate well and you don't want to pump it as hard as possible to reduce the failure rate? If the well runs 100% of the day with 100% fillage and maintains 1500-3000'+ of GFLAP, the best solution would likely be to raise the seating nipple (**SN**) and set the pump higher.

This will offer several advantages. First, the pump doesn't need to be set so low anyways, so the production will not be adversely affected (as long as the SN is not raised too high to where it pumps off, or so high the reduced PIP adversely increases gas interference). Second, you are removing unnecessary rods/tubing from the well that can be points of failure. Third, the new higher SN depth will lighten the rod loads and ultimately you might be able to upsize the pump and actually increase the production. Fourth, it pulls the pump higher away from the perfs and potential solids issues. Fifth, and related to this conversation, there is less of a fluid column the chemical will have to work through to ultimately get to the pump intake so you can more effectively treat the well.

It sometimes seems like heresy to speak of raising the SN to clients but there are so many benefits related to it that it should be strongly considered: if you want to keep the SN low then you must justify its low placement by getting more production and pumping it down; and if the pump's capacity can't keep up with the inflow from the reservoir, then raise it up and pump it higher for all the above mentioned benefits.

4. Monitoring Critical Gas Velocity

If a well makes a lot of gas up the backside, the velocity of the gas can be greater than the Critical Gas Velocity, which means the producing gas can actually carry liquids out of the well to surface. So if a well is on continuous chemical treatment and a fluid level shot shows it making 500+ MCFPD, you should be concerned if the critical gas velocity is being exceeded which would prevent any of the chemical from being able to fall down the annulus. Do keep in mind, a fluid level shot can approximate the gas volume coming up the backside but you should not rely on this this number alone—confirm the well's gas production rate from a metered well test (as previously mentioned, current Echometer software overestimates the gas volume rate if the top of the fluid level is relatively close to surface). However, also keep in mind a well might produce a decent portion of the well's gas up the tubing (especially if downhole gas separation is not efficient), but we are only concerned with the gas flow rate up the annulus when trying to determine if the chemical will stay downhole. The gas production from a well test will tell you the total gas made by the well (up the tubing and casing).

All chemical companies should have a Critical Gas Velocity calculator that should be able to approximate when the gas flow rate for a particular well is of concern. There are many factors that go into the calculation but of most importance is the gas production rate (MCFPD), tubing and casing dimensions, and the surface casing pressure. Plugging in some representative numbers (your wells might be different) to calculate the critical gas velocity using the Coleman Model, two facts readily stand out (Table 1). First, the smaller the casing size (or smaller annulus clearance), the lower the gas production rate up the annulus needs to be to reach critical velocity, so high gas rate wells in 4.5" casing are of bigger concern. Second, and more importantly as this is something we can control, the surface casing pressure has a huge influence on the critical gas rate, so as CP is reduced the required gas flow rate to carry liquids out is greatly reduced. This is one reason why when a flowing gas well loads up, or if a plunger lift well is having a hard time surfacing a plunger, the well is often blown down to atmosphere (0# surface pressure) to get a slug of liquids or the plunger out.

As seen in Table 1, if a 2-7/8" by 5.5" well makes 700 MCFPD up the annulus, the critical gas rate will not be reached if the CP = 100#, but if the CP is a low 30#, that is a real problem and all liquids (and any chemical introduced from surface down the annulus) will be carried out by the gas and pushed down the flowline.

A technician who is shooting a fluid level can get an indication that critical rate is being exceeded and raise a flag for more investigation. However, in practice, a well that is flowing above critical rate will often look like a flumping well based on the acoustic trace from the fluid level shot (and it technically is a flumping well as the liquid is scattered/atomized in small droplets as it is carried out by the gas stream); when shooting these wells, no distinctive fluid level kick will show up on the acoustic trace because there is no true "fluid level". If the gas rate producing up the annulus is above critical rate, the CP should be increased sufficiently to keep the chemical downhole if no Cap String is already installed.

CONCLUSIONS

The data from fluid level shots can be very valuable for optimizing chemical treatment programs. The historical data from fluid level shots can be leaned on the next time a well has a failure to evaluate if the well regularly flows up the backside, then during the next pull a Cap String or Solid Chemical Subs can be installed on the tubing. If these were not installed and a well is flumping, there are methods to depress the fluid level and keep the chemical downhole while using regular Truck Treating or Continuous Treatment methods. Continuous treatment is very common, and proper operation of the slip-stream is vital to help chemical get downhole to the pump intake, so fluid level technicians should monitor their performance to observe patterns and help ensure pumpers are properly paying attention to them. Also, constantly high GFLAP's or very high gas rates producing up the annulus should raise a red flag to consider raising the pump setting depth or ensure the Critical Gas Rate is not being exceeded.

The ultimate feedback showing if the chemical treatment is working will come from testing for chemical residuals in the produced fluid and the condition of the downhole equipment when it is pulled out of hole. If residuals are poor, or downhole equipment is pulled out in heavily corroded/scaled conditions, you should look at the chemistries being use, the chemical treatment method utilized to introduce the chemicals, and look at the history of the fluid level reports. Then create a thesis as to why the poor performance exists and how to correct it. You might have the best chemical in the world, but if it does not effectively get to where it needs to be, it will be of little value.

Abbreviations

BHP - Bottom Hole Pressure, psi
CP - Casing Pressure, psi
GFLAP - Gas Free Liquid Above the Pump, ft
PIP - Pump Intake Pressure, psi
PPM - Parts Per Million
SN - Seating Nipple
TP - Tubing Pressure

Tbg/Csg	CP, psi	Critical Gas Vel. MCFPD
2-3/8" x 4.5"	30	400
"	50	510
"	100	730
"	200	1030
2-7/8" x 5.5"	30	600
"	50	770
"	100	1100
"	200	1550

Table 1 – approximate Critical Gas Velocities (in MCFPD) for gas producing up the annulus based on tubing/casing size and the surface casing pressure. As the CP increases, the gas flow rate must be much higher for the produced gas to carry liquid droplets out of the well.

Figure 1 – Truck Treater (for batch chemical treatment). Truck carries tanks of various chemicals (in the front compartments) and a water tank on back that is loaded with produced water to flush the chemicals downhole.

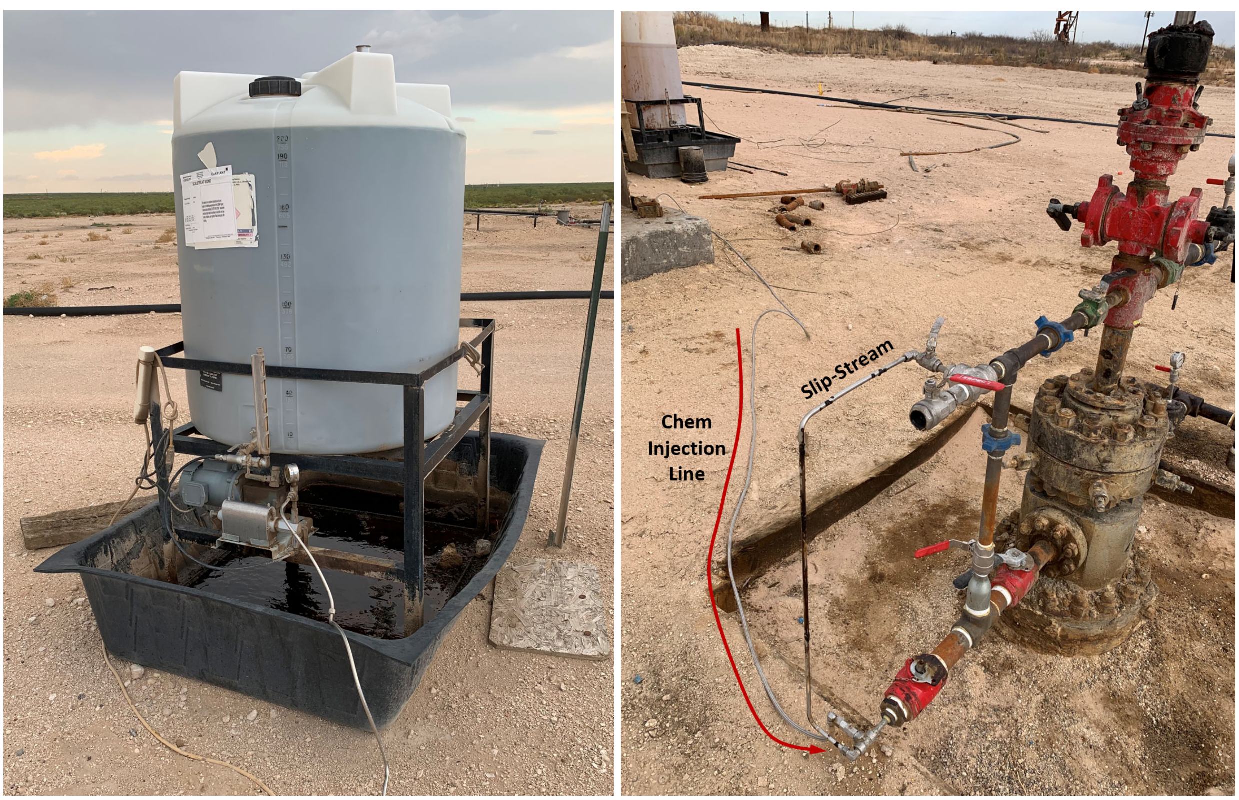

Figure 2 – Continuous Chemical Treatment. Chemical tank and chemical pump (left). The Slip-Stream takes some produced fluid from the tubing, mixes it with the injected chemical to help carry the chemical downhole to the pump intake.

Figure 3 – Capillary String. The Cap String runs from surface all the way to the pump intake downhole and is banded to the outside of the tubing to ensure the chemical can be injected directly into the pump intake.

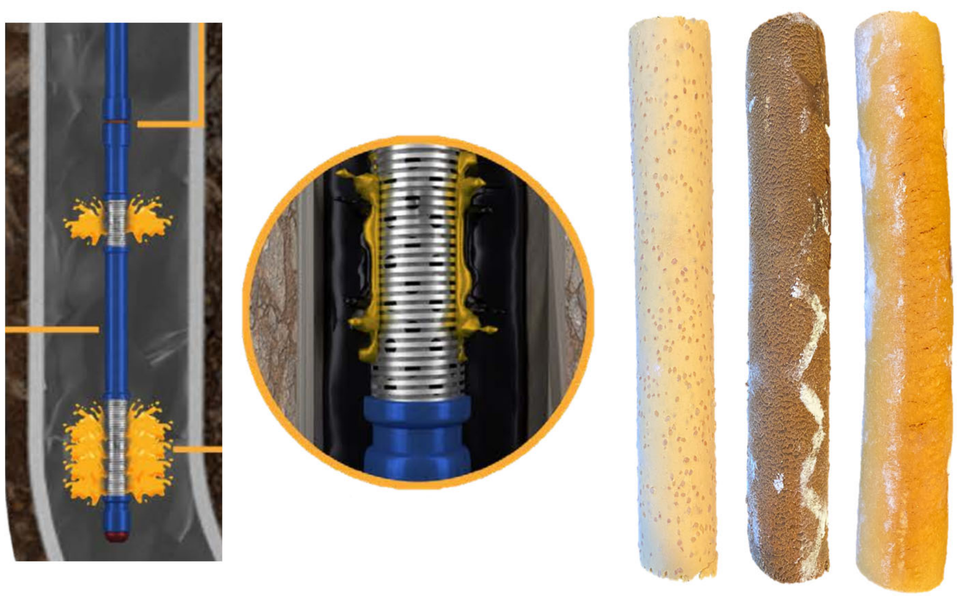

Figure 4 – Solid Time-Released Chemical Subs. The solid chemical sticks are inserted into chemical subs on bottom of the tubing string and they time-release into the produced fluids. Diagram images from Odessa Separators and images of solid chem sticks from Freedom Technologies (which are two providers of this technology). Chem sticks (from left to right): scale inhibitor, corrosion inhibitor, and paraffin inhibitor.

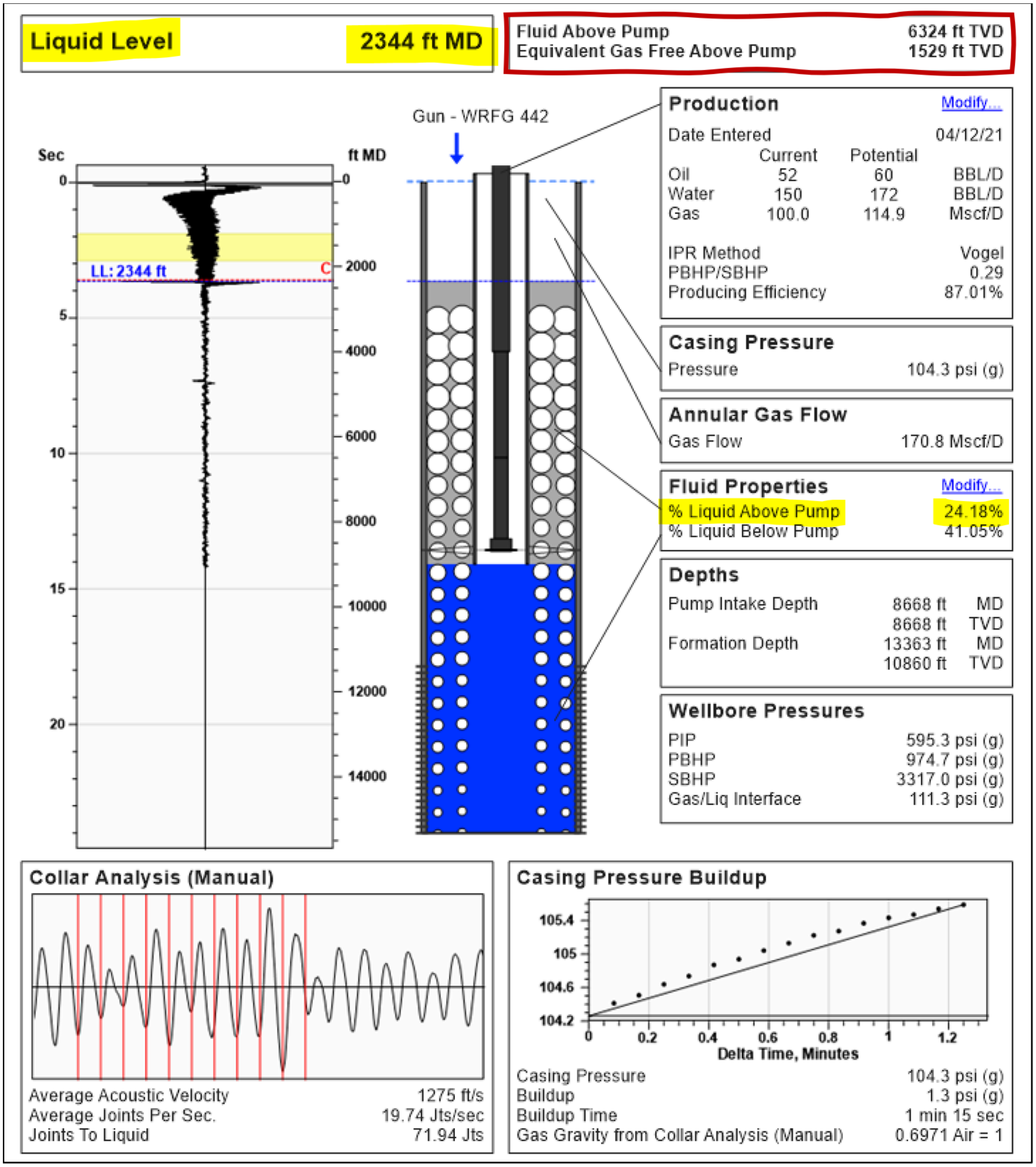

Figure 5 – Fluid Level Report. The top of the fluid level is at 2344' and there is 6324' of gaseous liquid above the pump with 1529' of that consisting of pure liquid. The calculated percentage of liquid in the gaseous fluid column is 24% (meaning the other 76% of the gaseous liquid column above the pump is comprised of gas).

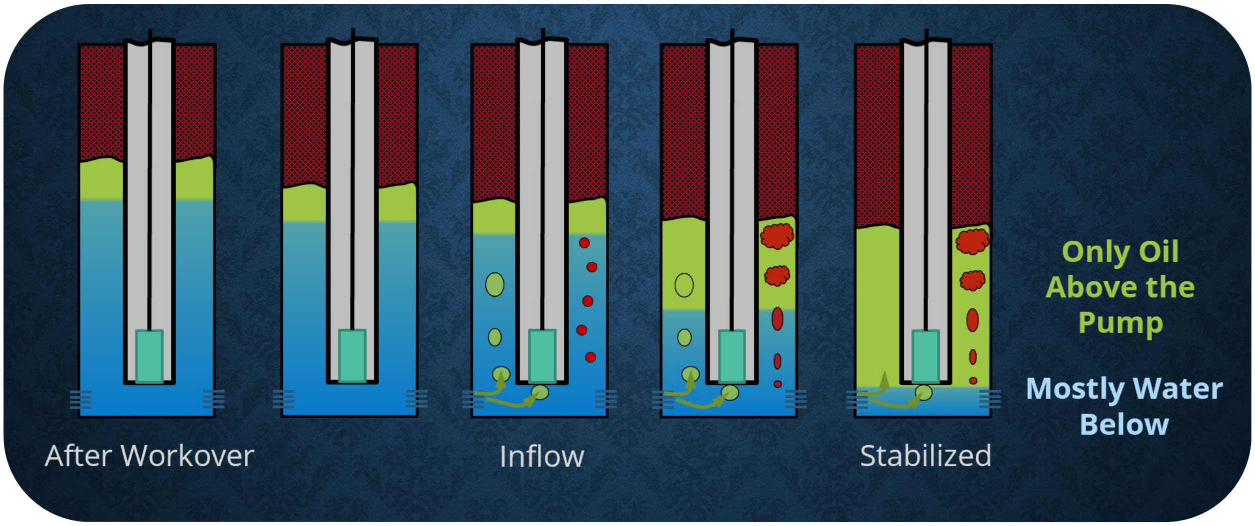

Figure 6 – After stabilized production, only oil (and gas) reside above the pump due to gravity separation.

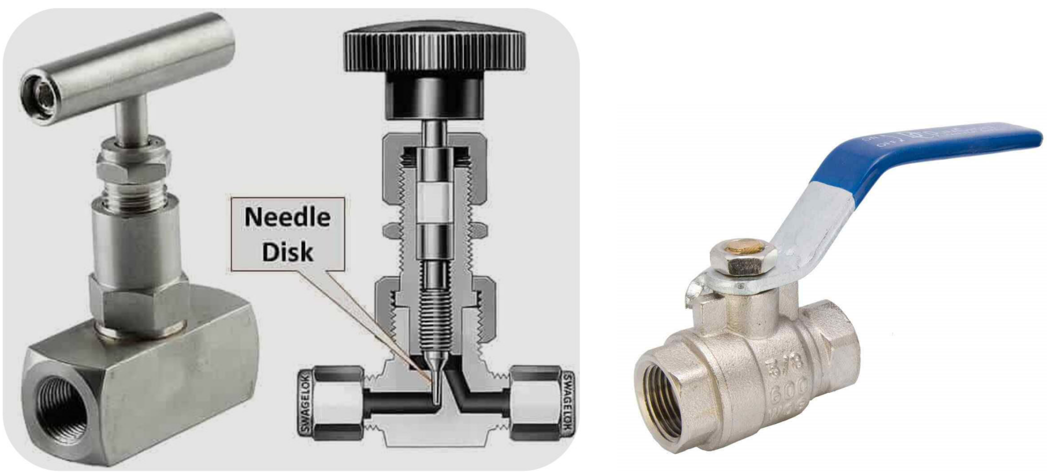

Figure 7 – Control valves for a slip-stream: needle valve (left) and a ball valve (right). Due to the design of the needle valve with the stem sticking down into the seat, they are much more likely to plug with small amounts of solids when pinched down. Ball valves have a different design with less plugging issues.

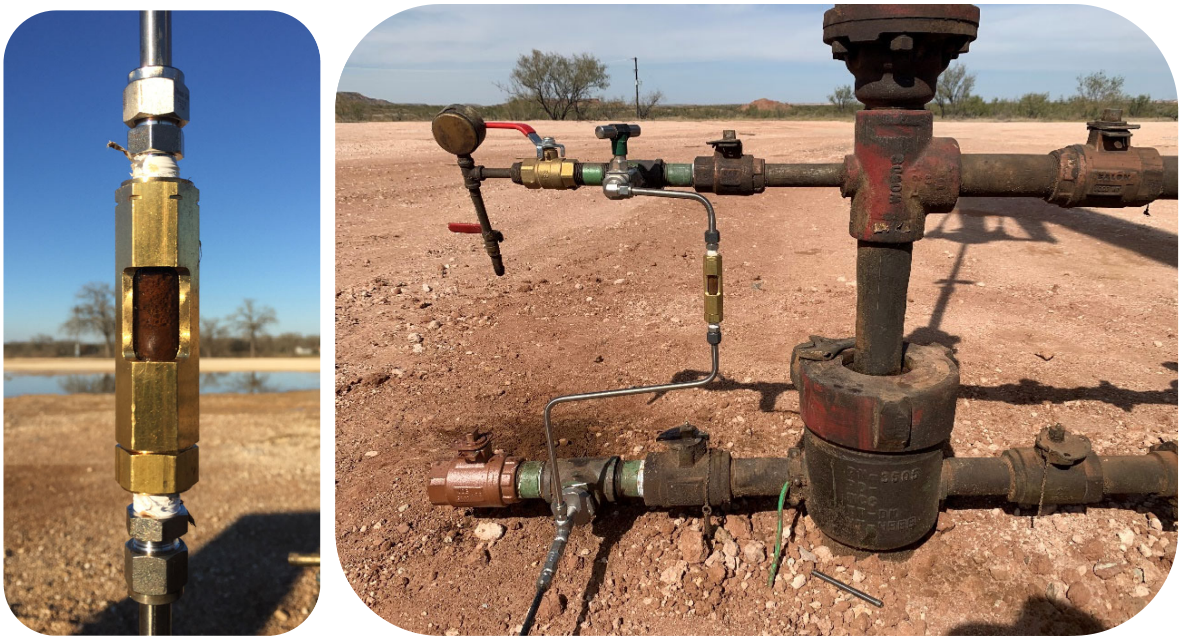

Figure 8 – Clear sight glass on slip-stream. These allow a pumper to visually see if the slip-stream is properly operating and approximate how much fluid is slipping back downhole.

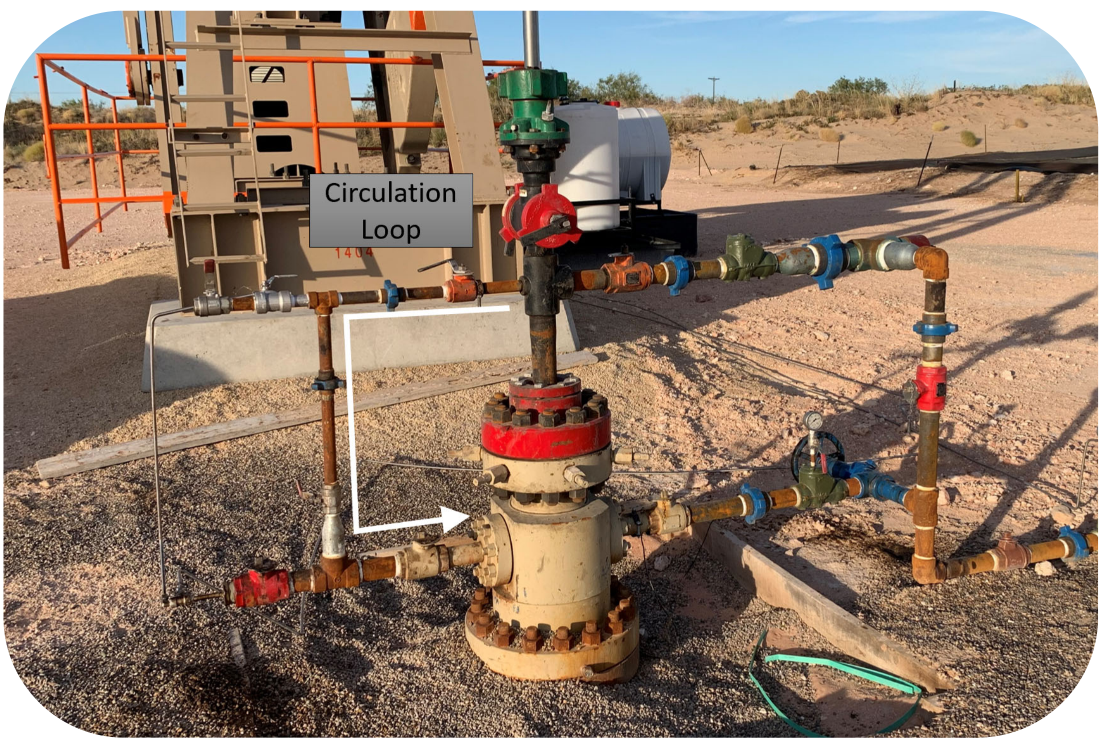

Figure 9 – Circulation Loop, which allows chemicals to be circulated in the well—fluid moves from the tubing to the annulus. These can be helpful in ensuring the chemical gets downhole on flumping wells.

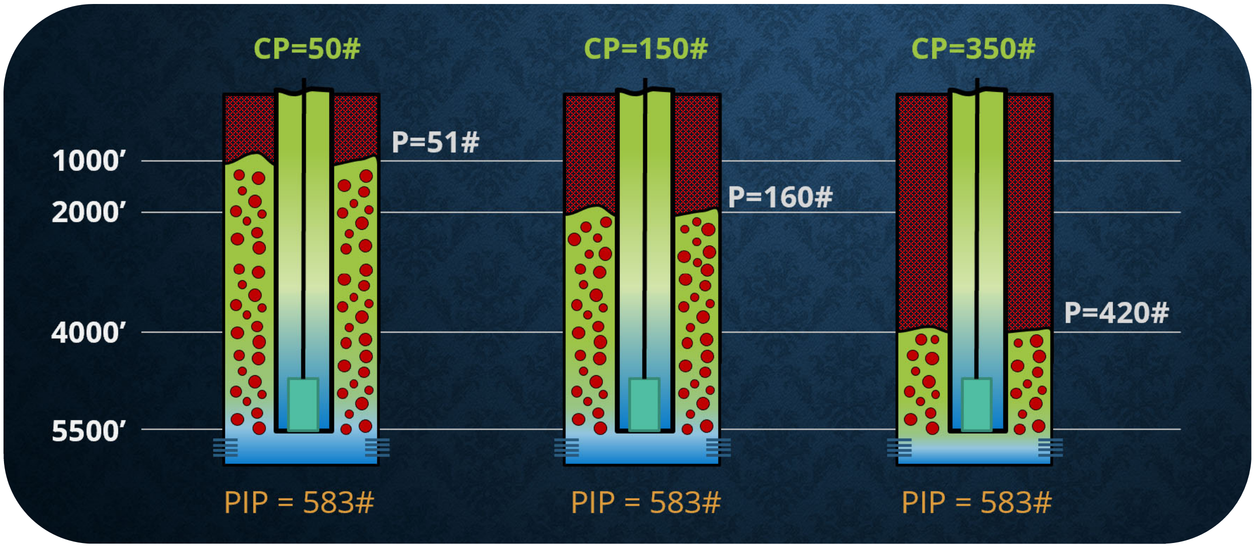

Figure 10 – Walker Depression Test. Holding additional casing back-pressure will depress the top of the fluid level but not increase the PIP after the well stabilizes, as shown in this example. The Walker Test increases the CP in increments, fluid level shots are taken after stabilization, then a plot of the depth vs the pressure at the top of the fluid level can be extrapolated to accurately calculate the PIP.