iWELLSITE AUTOMATION INC

# Using Fluid Shot Analysis and Foam Suppression (Depression) to Determine Accurate Production Well Inflow Pressure

In a previous article we talked about "IPR's" (Inflow Performance Relationship's) and the way that operators and Engineers typically take fluid shots to determine inflow pressures on producing oil wells. In this article we will focus on Fluid Shots and Foam Suppression.

First, we should describe what a "Fluid Shot" is. A Fluid Shot is done by shutting in the casing (Annulus between the tubing and casing) of the well in to the flow line. On the other side of the well we attach a "Fluid Shot Gun" to the Casing (annulus). A Fluid Shot Gun is a tool that creates a concussive force (sound wave) down the annulus by using a burst of pressure from an inert gas (usually nitrogen). Once this force is applied we have a sound recorder (that is part of the gun) which measures the sound waves created by the concussive force. The tubing in the well has collars that are of a wider diameter than the tubing itself. These collars connect the joints of tubing together the length of the well, and as a result every time the sound goes past one of these collars it creates a recordable wave. Once the sound hits fluid or foam the deflection of the sound wave is even greater. Thus we can count the smaller deflections recorded until we get to a larger deflection. Knowing the length of the tubing joints we can then calculate the distance to the fluid or foam from the surface of the well.

In order to create a proper accurate IPR we need accurate inflow pressures, and we need to take fluid shots in order to determine these inflow pressures. The problem most operators face taking these shots is "Foam".

Most if not all oil producing wells will always have some foam created in the annulus, this is a naturally occurring event. The issue with foam, is when you take a fluid shot on a well it appears as a deflection on your strip chart and in most cases determined to be fluid. So why is this the case?

It is interesting that in my years of experience how many times most operators will deny that they have any foam in their wells. I believe that this occurs for many reasons such as;

1. The time and resources needed to take more than one fluid shot.
2. Not knowing how to determine a fluid level vs a foam level.
3. Using automated (pre-programmed) fluid shot guns to determine whether you have foam or fluid.

I believe that item number one is the most common, but the result of not taking enough time to take more than one shot can be costly. The solution to this problem is educating the operators to ensure they know why it is important to get accurate fluid shot results and what these results will be used for. It is surprizing to me, how many operators do not really know what this information is for and how or why it is used.

I believe item number two is also very common, and even if they know how to determine fluid vs foam. There are some calculations involved, for which some are not comfortable doing.

Item number three is something that has become a problem in the more recent years, due to technology improvements and the creation of programmable fluid shot guns. The problem is the settings in these programmable devices, and if they are not set properly it can create errors in the output of the fluid level from these machines.

So, what is the solution to problem number two and three? To answer this question, we need to understand how it is we determine fluid vs foam;

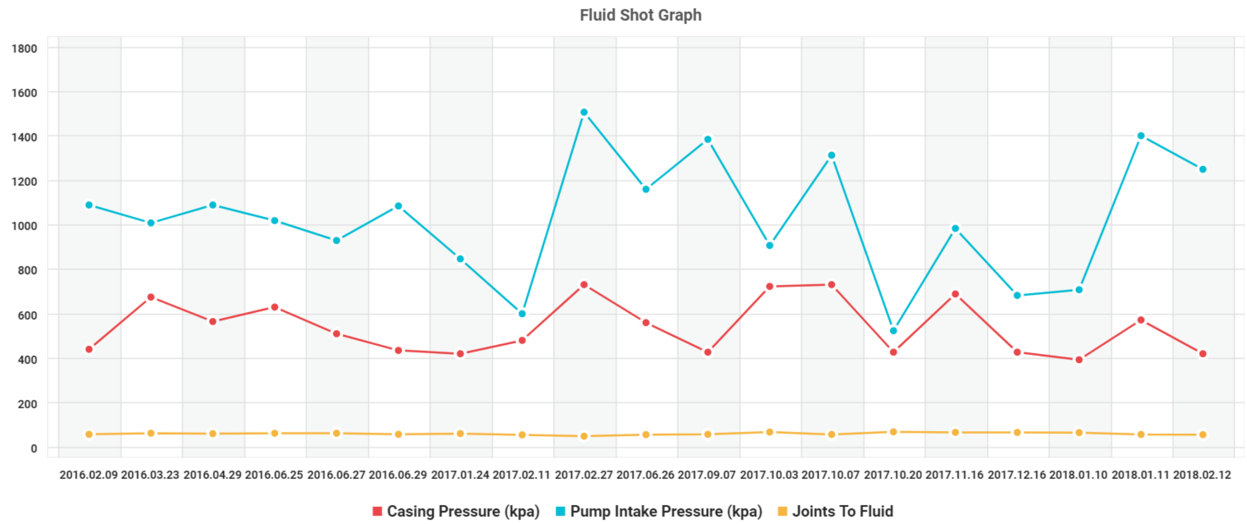
It is a simple calculation that requires at least 2 fluid shots. The difference between the two casing (annulus) pressures recorded while taking the shots, divided by the difference in the fluid levels determined from your fluid gun will give you the answer. By doing this we end up with a gradient in pressure per linear distance. Most light oil will have a gradient not less than 4.0 based on its specific gravity. Most wells that produce high volumes of water will have a gradient no greater than 9.0 for the same reason. So as a result of this knowledge, if you have a gradient of less than 4.0 after taking two fluid shots, you still have foam in your annulus. This means you need to take more fluid shots until a gradient between 4.0 and 9.0 is achieved. With new technology and software we can make these calculations easy and seamless. Please see some of the examples being used today.

| Fluid Shot Date | Fluid Shot Time | Casing Pressure | Joints to Fluid | Pump Intake Pressure | Average Joint Length | Number of Tubing Joints | Operator ID | Fluid Above Pump | Gradient |
|---|---|---|---|---|---|---|---|---|---|
| 2018.02.12 | 12:00 | 420 kPa,a | 55.66 | 1250 m | 9.34 m | 70 | SM | 133.94 m | - |
| 2018.02.12 | 13:00 | 427 kPa,a | 55.78 | 1250 m | 9.34 m | 70 | SM | 132.81 m | 6.2 |

The illustration above showing a snapshot of iWellsite Fluid Shot functionality detailing a gradient calculation based on two fluid shots.

| Fluid Shot Date | Fluid Shot Time | Casing Pressure | Joints to Fluid | Pump Intake Pressure | Average Joint Length | Number of Tubing Joints | Operator ID | Fluid Above Pump | Gradient |
|---|---|---|---|---|---|---|---|---|---|
| 2018.02.12 | 13:00 | 420 kPa,a | 55.78 | 1250 m | 9.34 m | 70 | SM | 132.81 m | 6.2 |
| 2018.01.11 | 13:00 | 572 kPa,a | 56.81 | 1402 m | 9.34 m | 70 | SM | 123.19 m | 6.35 |
| 2018.01.10 | 13:00 | 393 kPa,a | 65.27 | 709 m | 9.34 m | 70 | SM | 44.18 m | 6.75 |
| 2017.12.16 | 17:00 | 427 kPa,a | 66.03 | 683 m | 9.34 m | 70 | SM | 37.08 m | 6.52 |
| 2017.11.16 | 18:00 | 689 kPa,a | 66.17 | 984 m | 9.34 m | 70 | SM | 35.77 m | 6.32 |
| 2017.10.20 | 12:00 | 427 kPa,a | 68.58 | 524 m | 9.34 m | 70 | SM | 13.26 m | 5.17 |
| 2017.10.07 | 12:10 | 731 kPa,a | 57 | 1314 m | 9.34 m | 70 | SM | 121.42 m | 4.77 |
| 2017.10.03 | 12:00 | 723 kPa,a | 67.57 | 908 m | 9.34 m | 70 | SM | 22.7 m | 6.58 |
| 2017.09.07 | 11:00 | 427 kPa,a | 57.38 | 1385 m | 9.34 m | 70 | SM | 117.87 m | 7.89 |

The illustration above showing a snapshot of iWellsite Fluid Shot functionality detailing a fluid shot summary.




The illustration above showing a snapshot of iWellsite Fluid Shot functionality detailing a fluid shot analytical plot.

The above illustrations show snapshots of the "iWellsite" Fluid Shot functionality, based on real time analytics and historical data. If you would be interested in a demonstration of how this tool may help you to achieve your production targets. Please contact the iWellsite team for a free demonstration.

**Stay tuned for other articles dealing with everyday problems and potential solutions using new technology and the power of the internet. Our next article will feature "Real Time" data capture and the advantages of sorting wells by exception.**