CONSIDERATIONS FOR LIQUID MEASUREMENT IN PRODUCTION APPLICATIONS

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Introduction

With the proliferation of horizontal drilling allowing access to tight oil formations, liquid production in the U.S. has significantly increased over recent years. Consequently, there is renewed interest in accurate measurements for both custody transfer and allocation purposes. Advances in measurement automation have yielded operators' savings in the millions of dollars annually.

Over the last several years, the increase of shale play drilling has created a problem within the industry. Most of the shale plays have been developed in primarily natural gas production areas, where a lack of liquids measurement knowledge may exist. While there certainly are knowledgeable people in these areas, measurement personnel can be spread thin due to the many active drill sites. Both allocation measurement and custody transfer measurement occur in these areas, so measurement personnel must be well versed on both. Typical questions that come up are: What is the right technology to use in each of the areas of measurement? Should I use turbine meters, Coriolis meters, or maybe just orifice meters? What data do I need to get back to my host system? Should I just count barrels or do I want to get some real insight into the process?

In years past, most people just wanted to know how many barrels they produced into their knockout pots. Sometimes they did not even care about that, as that was just a bi-product of what they really wanted to measure - GAS! With the shale plays producing hydrocarbon liquids that are very high in energy value (BTU content) yet very light, these liquids have become much more valuable, especially since the quantities have increased from 10-15 barrels per day up to 1,000-3,000 barrels per day. At its highest point, oil was selling at about $120 per barrel, so how important is it to measure that oil accurately? In my estimation, it is very critical not only to measure the product accurately, but also, to make sure the equipment used to measure the product is always working properly.

Design Considerations

So what do we do? Well, let us first look at a typical oil and gas production facility. The well stream produces into a knockout or separator to first separate the liquids from the gas. The separator can be either a two-phase separator or three-phase separator. Diagrams of these two types are shown below.

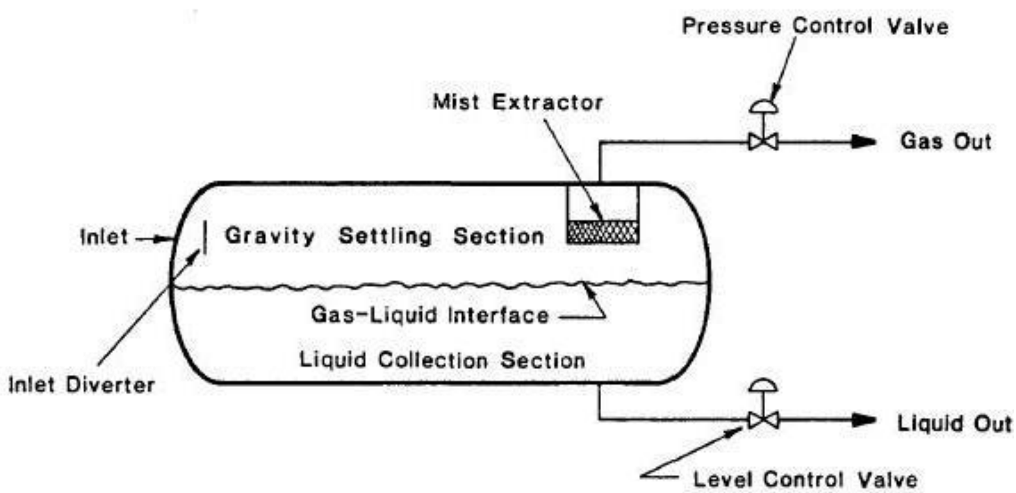

FIGURE 1. Two-Phase Separator

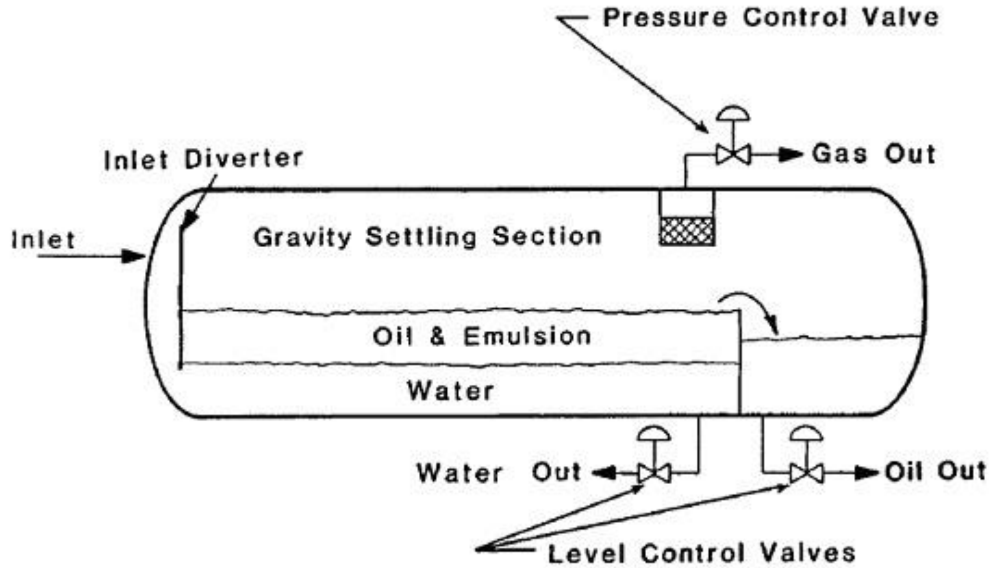

FIGURE 2. Three-Phase Separator

These separators will have level controls that can be controlled either mechanically or electronically. The two-phase separator uses just a total liquid level to control and maintain the level so it does not get so high that it could go out of the gas leg or so low that the separator does not empty. The three-phase separator has individual level measurement points for the emulsion layer and the water layer in the settling section. It also has an additional liquid level measurement in the oil box area, i.e., the far right area inside the separator shown in Figure 2.

These controls are important, as they are what keep either liquid from comingling or gas being carried with the liquid. The function of the valve they are attached to also affects the flow measurement system. It is equally important that the valves connected to these level controllers be properly designed. There should also be no restrictions in the piping before the flow measurement devices. The reason for this is to prevent a bubble point change on the oil. The water does not really have a bubble point, as it does not hold any gas molecules. In contrast, the oil is made up of an array of hydrocarbon molecules of various types, some of which can change from liquid to gaseous phase as the system pressure decreases. The state of equilibrium for each particular molecule is determined by the pressure of the separator. Once a system has reached the bubble point or equilibrium, you should not reduce the pressure further before the flow stream reaches the measurement point.

Since all flow meters today are single-phase measurement devices, it does not matter whether a turbine, Coriolis, positive displacement, differential pressure, magnetic, or ultrasonic flow meter is used. All of these are single-phase meters, meaning they can only measure single-phase liquid or single-phase gas streams accurately. If you inject gas into a liquid stream, the measurement accuracy will be compromised.

One flow meter type can determine if it has two-phase flow going through it. That is the Coriolis meter. The Coriolis meter can detect two-phase flow and alert you or sometimes even correct for it. However, there is a limit on the percentage of the two-phase mixture that can be corrected.

There are a few things you can do to prevent gas breakout (due to system depressurization) or two-phase flow. You can use full-port ball valves in the upstream piping, you can put the meter in the lowest part of the line with the control valve downstream at a higher point, or you can properly size the meter to have less than 2 PSI pressure drop across the flow meter when it is flowing at its peak rate. The peak rate is not always the number of barrels per day a well produces, but instead, the flow rate that occurs when the control valve opens to empty the separator. This can be several times higher than the maximum production rate. The peak flow rate also depends on the setup of your control valves. Are they snap-acting valves or throttling valves?

A lot of people like to use throttling valves as they provide a constant flow rate; however, since the well stream flow rates can be quite low, this sometimes causes problems with the accuracy of the flow meter. Most meters have minimum flow rate thresholds. This holds true for Coriolis flow meters, even though that meter type can have a minimum flow rate threshold that is lower than other metering technologies. The other issue with throttling valves is that you have to have a smaller flow meter in the line. These smaller meters can become clogged with things that come out of the well. Even if you have a filter upstream of the flow meter, some impurities can still collect in the meter. I always recommend at least a 1" diameter flow meter, but prefer a 2" diameter meter with a snap-acting dump valve. With the snap-acting valve, you get repeatable high flow rates, which is the flow range where all flow meters work best.

Still, you have to be aware of the pressure loss at higher flow rates. Remember the 2-PSI pressure drop maximum! With a 1" diameter valve and a 50-PSI pressure drop from the separator to the tank, you can achieve around 10,000-BPD flow rates, which will produce about a 10-PSI pressure drop across a 2" diameter flow meter. What happens when we have a large pressure drop? We get gas going through the meter and through whatever we have downstream of the valve. So, make sure you have a properly sized flow meter and the proper valves before and after the meter.

Meter Diagnostics

The diagnostics of the meter are important as well. Most people are happy using turbine meters, as they just measure whatever goes through the line. It could be gas, liquid, or sand – the meter does not care. Now, if you are trying to determine the amount of oil you are producing, you may want to know what is going through that line and if the meter still has all of its parts. With a turbine meter, if you flash gas or send sand through the meter, mechanical damage can occur causing an inaccurate measurement of the fluid flow you are trying to measure.

Here is where a Coriolis meter may be preferred over other meter types. The Coriolis meter is not typically damaged by gas slugs or sand flow through the meter, unless the sand loading is high and flow rate is high for extended periods. Regardless, we will see the presence of either gas or sand in a couple of ways. One way would be a change in the fluid density reading from the meter. Higher than normal density readings can alert us that we may have sand and lower density readings may indicate gas in the flow stream. It is even possible to determine if you have water in your oil stream or oil in your water stream. Monitoring the meter sensor drive gain may tell you that you have gas breaking out in the meter, causing a possible measurement issue. These diagnostics not only assist in identifying meter issues, but can also indicate if your system is having problems, like stuck dump valves or sand buildup in the separator. The diagnostics can also indicate if you have your valve/level indicators set properly. Coriolis flow meter performance can be assessed by looking at the drive gain, pickoff voltage, fluid density changes, and measured flow rates.

Conclusion

Many flow meter types can be used for liquid flow measurement in production applications. The diagnostic capabilities of Coriolis flow meters may provide operational advantages in the more challenging field applications, such as in instances where there are large amounts of contaminants in the flow stream or gas breakout is a likely possibility. Micro Motion was the inventor of Coriolis flow metering technology, but many other brands are now available with similar capabilities. When various meter brands offer comparable performance, final selection often comes down to aspects other than meter performance and accuracy, such as meter cost, meter reliability and durability, and/or vendor support and responsiveness.