Wellhead Liquids Measurement, What's an Industry To Do?

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Liquids measurement in the oil patch is suddenly getting a lot of attention. Some are dismayed at the low level of technology used to measure liquids. Today, custody transfer of 80 to 85% of onshore crude and condensate production is still documented by a hauler climbing to the top of the tank and strapping it. "That would be a fair estimate," concurs Mark Davis Staff Engineer Shell Exploration and Production. The hauler straps the tank before loading his truck and again when he finishes. The producer is paid on whatever that hauler writes on the ticket.

"I did not realize it was that immature," remarked Grant Farris, Vice President Producer Services, CIMA Energy.

So, why it is that immature? Simple, really. The United States is experiencing the highest level of active liquids exploration and production in 40 years. Five years ago finding an oil play at NAPE was almost impossible. While the industry was diligently automating gas measurement to the digital world via electronic flow measurement, oil at $30/bbl and 15bbls/day was not given the same level of attention nor effort. These dynamics have changed.

The characteristics of produced fluid at the wellhead are just the first hurdle to accurate liquids measurement. Full well stream production is a very complex combination of oil, gas, condensate and/or water. Measuring any one of these components accurately is difficult. In combination, they make liquids measurement a real challenge. Furthermore, the produced fluid may undergo 2 or 3 phase separation or no separation at all. These facility design decisions dictate the measurement solutions available and the degree of accuracy to anticipate.

A typical production scenario has the produced fluid brought to the surface then processed through a 2 or 3 phase separator. The result is gas goes to sales or gas-lift, water and oil goes to their respective tankage. If a 2-phase separator is used, the gas goes to sales and the oil and water combination goes to tankage for gravity separation.

To develop effective solutions, producers need to help solution providers by answering questions such as: where in the production process should the liquids be measured? Since the custody transfer point for 80 to 85% of oil and condensate is by strapping the tank, does this mean tank level monitoring is more important? Will the industry entertain changing the custody transfer measurement point? Is the industry just interested in automation of the custody transfer point or does industry want more of a production monitoring tool or combination thereof? With today's remote monitoring and automation technology what production information does industry want to gather? What decisions does industry want to make with this information? Solution providers need these answers to deliver cost effective automated liquid measurement solutions.

No one defends the accuracy of the tank strap method of liquid measurement. So, how do industry suppliers develop consistent cost effective solutions? First, where in the production cycle do producers want to measure? Let's explore some of the key aspects to consider when determining the optimum wellhead liquid measurement point then delineate a state of the technology to accomplish it.

At the separator:

Depending upon the separation equipment installed, coming off the separator dump provides a good measurement on produced fluid for the hydrocarbon and/or water. This information can be quite helpful for reservoir analysis and management of production activity. However, coming out of the separator through the dump valve creates an issue of turbulence and flow characteristics that can affect measurement accuracy. In addition, even the most efficient separator cannot pull enough of the entrained gas out of suspension to avoid measurement. This gas will go through the metering equipment and be measured as a liquid component only to flash off as it sits in the tanks awaiting transport. With so many variables in play, from fluid characteristics to the type of facilities deployed, a host of tests are needed to insure accurate and repeatable measurement.

At the tank battery:

Tanks continue to be the custody transfer measurement point. Automated measurement of production here has distinct advantages. One is the ability to know the entire above ground inventory. While across the field, any one tank may not have a complete load to take to market. With the ability to see all the tanks in the field a number of tanks can be aggregated and hauled to market. Armed with this knowledge, critical decisions based on need for cash flow, commodity price advantages and many other factors can be used to more strategically monetize production. More sophisticated measurement and software analytics can provide more precise liquid production, but solution providers need the producer's feedback to develop this in cost effective packages. This information in turn can help production engineers monitor and optimize well performance. Tank level monitoring has the added advantage in that the fluid will be brought closer to atmospheric condition. Its measurement will then coincide more with the hauler's; reducing discrepancies and the resulting reconciliation issues.

At the loadline or pullout:

Measurement at the load line is more a function of the producer community rethinking how liquids are exchanged than it is for the solution providers to deliver the requisite measurement equipment. However, identifying exactly how much fluid was loaded in the hauling vessel could be the ultimate liquid measurement data point that can satisfy the needs of both production and accounting. Test separators would still be required to establish baseline production per well but actual sales could tie nicely for most other reporting requirements. Such a solution could save time for the hauling companies as well. Filling up a tank truck could be as automated as your neighborhood gasoline dispenser. Capturing all the relevant custody transfer information on who, when, where and how much. Measuring at this point in the process alleviates many of the reconciliation issues between production and sales and aids tremendously with the reporting requirements of partners, royalty interests and regulatory.

A variety of tools and techniques are available to measure at these points of production. From here is a brief presentation of the most common equipment, its advantages and disadvantages. All these solutions need more input from producers to perfect them.

Fluid measurement off the separator:

Liquid flow measurement technology abounds, but flow turbulence and fluid phases off the separator eliminate many of them. Keep in mind most flow measurement apparatus is based on a process of continual flow in a more controlled environment. Almost none of these conditions exists at the wellhead.
Practical solutions available: Turbine Meter, Coriolis Meter, Positive Displacement Meter.

Turbine Meters due to their moving parts are not as accepted as they once were. The fluid passing through the meter rotates a turbine that has magnetic pick-ups which due to the hall-effect produce an electro-magnetic pulse. These pulses are counted and accumulated to produce a rate and a total produced fluid measurement. Advantages: easy to understand, install, calibrate and inexpensive. Disadvantages: moving parts make them somewhat of a maintenance issue, inaccuracy due to entrained gas still in the fluid. Flow conditioning is needed to address fluid turbulence off the dump valve through the meter.

Coriolis Meters are taking the market space left by the decreased popularity for turbine meters. The property of operation is the behavior of mass on a rotating structure which responds to the Coriolis force. The rotation is provided with a vibrating tube through which the fluid flows. The fluids effect on the tangential plane of the vibrating tubes can be measured and a flow rate computed. Advantages: very accurate, no moving parts. Disadvantages: difficult to install and maintain, while accurate, susceptible to the same issues of measuring entrained gas and the rigors of wellhead operations, expensive.

Positive Displacement Meters

Here too is a device well known in the industry typically installed at high volume custody transfer points. The measurement concept is the fluid is passed into precise volumetric increments and those increments are then counted usually mechanically but can be digitized utilizing the hall-effect similar to a turbine meter. PD meters have the advantage of approvals by a number of regulatory bodies. However, the PD meter is more typically associated as a component in a larger LACT unit device which is precise and takes into accounts basic sediment and water, and temperature. Even so, LACT units are typically proved for each liquid transaction.

Tank Level:

The tank level is the primary location for custody transfer of most liquids at the wellhead. Tank level solutions are very diverse and many, if not all, have been applied in the field. Some have proven more robust and up to the rigors than others. The focus here is on tank level measurement with outputs that can be digitized for SCADA monitoring and reporting of the actual fluid in the tank not just fluid level alarm solutions for overfill or spillage avoidance.

Measurement solutions considered here are ultrasonic, guided wave radar, float systems and hydrostatic pressure.

Ultrasonic devices rely on a time interval of a transmitted signal to the surface of the fluid and its return to the sensor. While this has potential; foams, surface agitation and other factors have rendered it more as just a sophisticated high level alarm solution.
Ultrasonic measurement only measures to fluid surface level. It cannot measure the fluid cut level of oil and water.

Hydrostatic Pressure measures the fluid level based on the fluid column pressure on a transducer at or near the bottom of the tank. While accuracy can be achieved under the low level of pressures involved, there is no way to distinguish the cut level between oil and water. The appeal of the device is ease of installation, maintenance, especially submersible models, and low cost. As the industry still relies on tank strappings to capture custody transfer, this solution can be a very cost effective manner to track fluid production and movement.

Float systems are also a fairly straightforward solution. A float usually with a magnetic pickup traverses a rod embedded with wiring or sensors that detects the magnetic field to locate the device that equates to the corresponding fluid level. Floats can be weighted to the specific gravity of oil or water to simultaneously track oil and water levels. Float systems are very accurate and can provide a distinct measurement of oil and water simultaneously. Installation is somewhat difficult and buildup on the rod within the fluid can cause the floats to get stuck hindering performance. Devices are somewhat expensive.

Guided Wave Radar is an advancement on radar detected tank level by adding a probe or cable with which to guide the radar signal. While the insertion of a probe is required there are no moving parts within the medium measured and guided wave radar can measure the fluid cut level for oil and water. Issues are again installation within the tank and the device can be expensive compared to alternatives.

Measurement at the pullout or load line

This is a somewhat radical change and would require a big shift in the industry's thinking on fluid measurement and transfer. However, many of the aspects of the fluid that make it difficult to measure earlier in the production process are eliminated as the hydrocarbon becomes more atmospheric thus more consistently quantifiable. Higher cost devices such as coriolis meters or PD meters can make more economic sense as they can become the custody transfer point with an electronic record of when the load was taken, by whom and how much. This data can be conveyed wirelessly to all parties to the transaction. The difficulty in this scenario isn't the measurement solution; it is the rethink the industry must make to its operations, contractual terms and reporting.

In conclusion, as liquid production takes on a more significant portion of the oil and gas window, more sophisticated and updated measurement technology is needed. While a wide variety of devices and solutions to measure and collect production data are available, solution providers need input from producers, to develop and refine these tools to improve their accuracy and achieve economies of scale.

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