Advances in Flowmeter Proving for Shale Fields

In the past, calibrating flowmeters in remote shale fields required removing the meters and sending them to a calibration lab or using local provers. Now, mass and density calibration has come to the field.

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Figure 1: Calibrating flowmeters in the remote locations like the Permian Basin shale oil field can be a problem, but solutions are available in the form of local instead of remote calibration.

The oil and gas production renaissance in the U.S. has resulted in a large number of allocation and custody transfer meter installations. These installations are driving an increased need for "proving" or calibrating flow measurement points used for transactional purposes. Meeting these calibration requirements in oil and gas fields (Figure 1) is particularly difficult because shale plays are often in remote and isolated locations, far from proper maintenance facilities.

For example, estimates are that more than 5,000 wells will be drilled in the Permian Basin over the next 20 years. Each of these wells will have one or more flowmeters that must be calibrated and proven.

Flowmeter proving must be conducted on a regular basis due to regulations, legal contracts and validating accurate internal transfer of product. EPA regulations on reclaimed water used in fracking also require frequent flowmeter testing.

This increased demand, coupled with a shortage of staff and systems, has created a "calibration crisis" in many shale fields. The solution to this problem lies with better methods for calibration.

Rather than removing flowmeters for shipment to calibration labs, recent developments—now being deployed in the Permian Basin—bring flowmeter calibration to the shale fields.

Calibration Requirements

Flowmeters in a shale field have to be calibrated, typically based on the contract between the operator and its customers, usually every three months. The Bureau of Land Management (BLM) has new regulations specifying calibration frequency based on production well characteristics. BLM specifies calibration frequency, and monthly or quarterly proving intervals are typical. Custody transfer allocation locations are the most critical, while loading rack or regulated meters are often calibrated annually, sometimes quarterly.

Flowmeters are proven to determine if there is a significant shift in meter factors, resulting in greater measurement uncertainty. When a

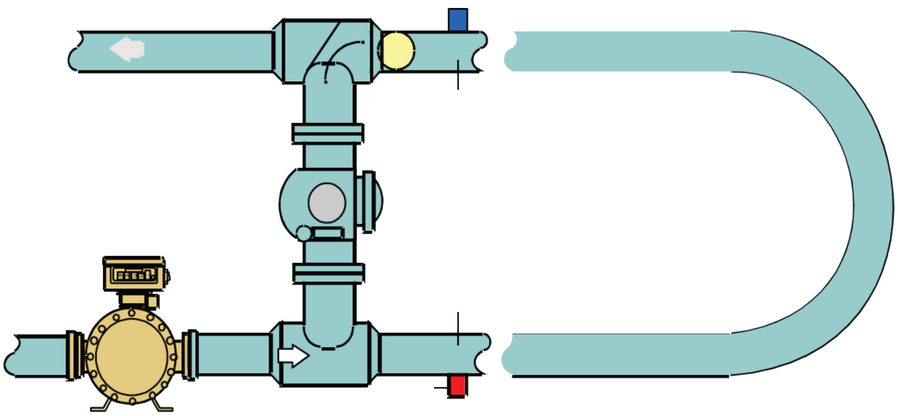

Figure 2: A ball prover works by passing a known volume of gas or oil through a meter while monitoring the meter's output. The yellow ball (top) is a sphere containing the known volume.

shift occurs, a root cause analysis is usually conducted. Changes can be due to paraffin buildup, mechanical damage to the fiscal meter, or upsetting operating conditions such as gas carry under in liquid lines.

Typically, calibrations are done on a regular, scheduled basis, unless there is a dispute or reconciliation problem. Unless removal of the flowmeters requires shutting down a well site or facility, meters are proven during operations.

When a flowmeter has to be sent to a calibration lab, the meter has to be removed, cleaned, packed up, shipped off to the lab, returned and re-installed. This process can take a week or more for each flowmeter, at a cost of about $500 per meter just for calibration—with additional costs for shipping, time and labor. In some cases, the well site or facility has to be shut down pending return of the calibrated meter.

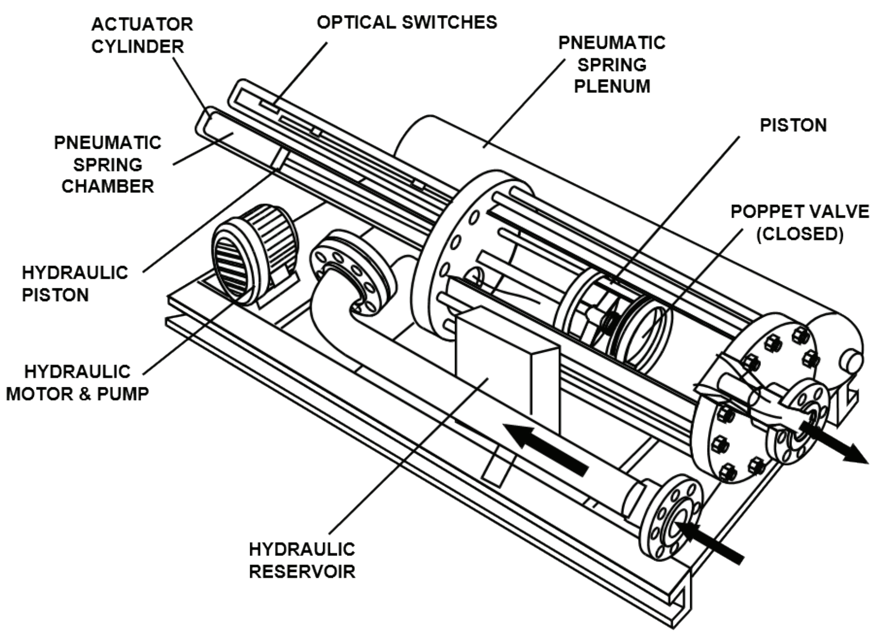

Figure 3: Like a ball prover, a piston prover provides a known volume of oil or gas for calibrating a flowmeter.

More often, critical meters are calibrated or proven "in-situ" without being removed from service. Most installations have proving taps to facilitate this process by allowing quick connection to a field prover, while others do not and require removal of the meter from the process.

Field Calibrations

Field proving and calibration are typically done through third-party service providers. These companies travel to the well sites to conduct the calibrations.

Large end users may have a prover integrated into their metering systems. Alternatively, field references such as ball provers (Figure 2), small volume provers and master meters can be used.

Field provers are based on the principle of comparing a known volume against the meter output. The ratio between the prover reference volume and the meter reading is the meter factor, which is used to correct the meter reading. Provers can be uni- or bi-directional, and use a sphere (ball provers) or a piston (piston provers, Figure 3). A flowmeter can also be put in series with a master meter, with their readings compared.

Field references used for proving typically have a higher level of uncertainty when compared to stationary calibration facilities or provers, are prone to site constraints, and don't work well in less than ideal operating conditions. Conventional ball provers and compact provers have many mechanical components—such as a four-way valve, piston seals, motors, pumps, etc.—that must be maintained and are subject to mechanical wear.

Master meter proving normally has the highest total uncertainty of all meter proving methods. The technique used to prove the master meter and the process to prove the line meter introduce various levels of uncertainty into the petroleum measurement hierarchy. Some of the factors that can contribute to a higher uncertainty include the following:

- Installation conditions where the master meter is not proven in-situ.
- Differences between the viscosity and density of the liquid used to prove the master meter and the liquid used during proving.
- Differences between the temperature, pressure, flow conditions and flow rates used to prove the master meter and those present during line meter proving.
- The reproducibility of the interval between proving, severity of service, meter damage, transportation and storage, use, corrosion, etc.
- Flow rate changes during proving of the master meter that result in poor repeatability and/or bias errors due to delay in response time of the master meter pulse output. Larger prover volumes may reduce the effect because it increases the proving time.

Bringing Provers to the Shale Field

Instead of relying on ball provers, piston provers or master meters, recent developments make it possible to bring a “calibration lab” to the shale field. For example, Endress+Hauser is working with a third party to deploy their HP80 (US patent pending 15/605,562) Field Reference Meter Standard (Figure 4) for mass, density and volume determination under existing operating conditions. This solution is also being adopted for calibration of tanks and level instruments.

This type of field reference meter standard system provides field metrologists and calibration specialists with the metrics, tools and information needed to measure and manage all primary measurements in the upstream, midstream and downstream segments of the oil and gas market, including shale fields.

In addition to measuring the accuracy of the mass flow, operating density and volume flow, linearity and repeatability

Figure 4: The Endress+Hauser HP80 Field Reference Meter Standard mounted on a trailer brings the capabilities of a calibration lab to the shale field.

of a EUT, a field reference meter standard can also capture and report field conditions including information on the process temperature, pressure, Reynolds number and viscosity.

These systems are designed to provide in-situ verification and calibration of all types of flowmeters including ultrasonic, positive displacement, turbine and Coriolis flowmeters.

For example, the HP80 system can calibrate 1.5-inch to 4-inch nominal size flowmeters over a range of 35 to >750 gallons/minute. The system uses three 2-inch Endress+Hauser Promass Q Coriolis flowmeters as field reference standards. The system has control valves, allowing the user to configure one, two or three meters for the test set up (Figure 5).

To conduct a flow verification, the team positions the field reference meter standard system as close as possible to the piping containing the EUTs. A field technician connects hoses using swivel joints to the EUT’s prover taps, opens the control valves, and adjusts the flow to accommodate calibration of the EUT. Hydrocarbons flow through the EUT, and then through the Coriolis field reference meter(s). A flow computer accumulates the totals from the reference meters in the system and compares the EUT output to that of reference standard. A meter factor and repeatability calculation are applied to complete a successful prove. The new meter factor is compared to the previous meter factor to assess any trends. A successful prove is dependent on obtaining three to five consecutive meter factors within 0.05%.

The calibration records are managed using a flow computer, with process data recorded and managed via the Endress+Hauser RSG45 Advanced Data Manager, or similar software. The system is self-contained including a 24 VDC power supply for all field and reference devices. Solar panels are used to maintain a charge within the battery assembly. Calibration profiles and results are captured and reported and can be archived locally on secured media, communicated to a local network for storage, or sent to cloud storage as part of an Industry 4.0 solution.

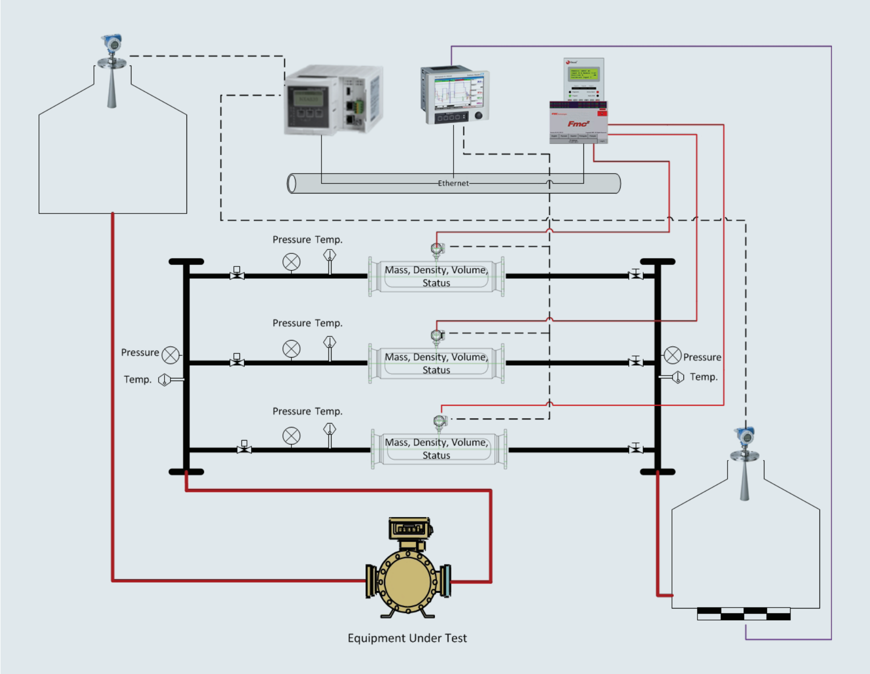

Figure 5: Hydrocarbons passing through the EUT flowmeter (at the bottom) is routed to field reference Coriolis flowmeters (center) for verification.

A typical calibration takes 30-45 minutes per meter including connection, test report generation and disconnection time. Field trials have shown these types of field reference meter standard systems can calibrate two to four times faster than a conventional ball prover or piston prover, with much greater accuracy on a mass basis. Full-stream density measurement is used to ensure product quality and to facilitate volumetric calibration using operating conditions or API tables.

Summary

Expansion of shale oil and gas fields in the U.S. have increased the need for regular calibration of flowmeters and level devices. Conventional calibration methods are expensive, time-consuming with high levels of uncertainty. Recent developments now bring laboratory quality calibrations to the shale fields with field reference meter standards systems deployed through third party service providers.

About the Author

Brian Hoover is the Business Development Manager for Strategic Alliances at Endress+Hauser, where he is active in developing solutions for managing gas, oil and water. He has been with Endress+Hauser since 1995, and has more than 30 years of experience with Coriolis flowmeters.

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