MASS MEASUREMENT

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INTRODUCTION

The petroleum industry most commonly measures fluids in volume units. When volume is used as the measurement unit, a specific set of conditions of temperature and pressure are designated to be the standard or base conditions for the custody transfer of the fluid. Thus the measurement of volume requires that the gross volume metered be adjusted to an equivalent net volume at these base conditions. This correction requires knowledge of the relative density or specific gravity of the fluid in addition to the temperature and pressure at which the gross volume was determined.

Tables and equations are available for certain fluids that will provide the user with the correction to net volume when the temperature, pressure, and relative density are known. This empirical data predicts the change in density of the fluid with temperature and pressure. Crude oil, refined products, and pure compounds are predictable fluids that can be measured in volume units by this method with very little uncertainty.

The physical behavior of mixtures of hydrocarbons is not very predictable. Different compositions can cause the density to vary differently with temperature and pressure. Another characteristic of mixed streams is known as volume shrinkage. The mixed stream has more volume due to its molecular structure than if all the components were measured by volume separately. However, a pound of one component added to a pound of another component always produces two pounds of the mixture. Custody transfer contracts for mixed streams are still written in volume units, however, the fluid is metered on a mass basis and then converted to volume by a ratio of weight per unit volume for each individual component in the stream.

There are some fluids with rapidly changing density at the temperature and pressure at which they are being measured. This region of rapidly changing density is known as the critical region. Such fluids as ethylene and carbon dioxide are often measured at conditions in this region, making it difficult to determine the net volume of these fluids. Contracts for custody transfer of these fluids are often written in mass units.

Mass measurement is utilized in the two instances above to solve the problems related to determining the net volume. There are certain other applications for which mass measurement is a logical alternative to volume determination such as inventory balance, as in underground storage, plant balance, and loading facilities. It can be argued that mass units are more logical units for custody transfer than volume units, since mass measurement does not require the measurement of temperature, pressure, and the use of empirical data to convert to a quantity that can be utilized for custody transfer. Mass units are a fundamental unit of measurement.

However, the metering technology for continuous mass measurement has only been available in the last thirty or so years, way after the petroleum industry had adopted standards for volume measurement. It has never been practical to weigh large quantities of fluid especially in a dynamic mode, though the weighing of tank trucks is often utilized for measurement of smaller quantities. Mass measurement also requires the use of electronics that again were not available in the earlier years.

This paper will now address the two methods of mass measurement. It will also identify areas where there are potential sources of error for mass measurement and will identify areas where this method has advantages over traditional volume measurement.

INFERRED MASS MEASUREMENT

Inferred mass measurement is the utilization of a volumetric measuring device in conjunction with a densitometer and flow computer. This method utilizes the following flow equation:

$$M = V_L D_L$$

Where M = mass flow
V_L = volume flow at line conditions
D_L = density at line conditions

The volume meter can be any one of several types, the choice being mainly dependent on the properties of the fluid to be measured and the flow rates. Turbine meters as well as orifice meters are common. The volume meter's recommended installation for volume metering does not differ for inferred mass measurement and these guidelines can be found in the MPMS Chapter 5 for turbine meters and Chapter 14.3 for orifice meters published by the American Petroleum Institute.

Vibrating element technology is the most prevalent technology for density measurement in the petroleum industry. It has no moving parts, thus requires little or no maintenance, and meets the accuracy requirement for custody transfer. The MPMS Chapter 14.6 published by the American Petroleum Institute contains the guidelines recommended for the densitometer when used for inferred mass measurement.

The most common problem in obtaining an accurate mass measurement by the inferred method is associated with the necessity to determine the volumetric flow and the density at exactly the same temperature and pressure. The most accurate densitometers require installation in a by-pass or slipstream as they cannot typically handle the flow rate of the main pipeline. Thus this densitometer flow loop must be engineered such that the fluid in the loop is maintained at the same, or as near as possible to the temperature and pressure of the main line. It is always necessary to insulate the loop. Pressure differential is minimized by locating the densitometer as close as possible to the volume meter with as little as possible pressure drop between the two measurements.

Another important consideration is that the densitometer should see a representative sample of the fluid that is flowing in the main line. This makes it critical to consider the flow rate in the densitometer loop when determining the sampling method. It may also require consideration of where the sample is taken if the fluid does not stay adequately mixed in the flowing stream.

For inferred mass measurement it is necessary to prove both the volume meter and the densitometer. The volume meter is proven utilizing the same technology as in any other metering application. The MPMS Chapter 4 published by the American Petroleum Institute should be followed. For light hydrocarbons, a pycnometer is required to prove the densitometer. The method for proving a densitometer with a pycnometer is covered in the MPMS Chapter 14.6 published by the American Petroleum Institute. A hydrometer is the acceptable method for proving a densitometer in crude oil service. The method for proving a densitometer with a hydrometer is covered in the MPMS Chapter 9 published by the American Petroleum Institute.

The proving of the density measurement is the second most common problem associated with inferred mass measurement. Proving any device under field conditions requires time and care. The problem is similar to the one noted above regarding the requirement for temperature and pressure equalization between the volume meter and the densitometer. The pycnometer must be filled with the fluid at the same conditions of temperature and pressure as the densitometer is seeing. Once this is accomplished the pycnometer is weighed so that the density of the fluid can be determined. The knowledge of the correct tare weight of the pycnometer and the accuracy of the scale contribute to the accuracy of the proving technique. A correction factor for the densitometer is determined, much like the meter factor for the volume meter.

A flow computer handles the calculations for inferred mass measurement. Signals are processed from the volume meter for gross volume, from the densitometer for density and with the meter factor and density correction factor, the mass is calculated. For contracts written in mass units, this is the final calculation for custody transfer. To determine the net volume for each component of a mixed stream, a chromatograph is utilized to analyze the weight fraction of each component. The weight per volume of these components at standard temperature is a known value. The flow computer can then use the total weight of the stream, the percentage of each component in the stream, and the known weight of these components at standard conditions to calculate the net volume of each component for custody transfer. This procedure is covered in the MPMS Chapter 14.7 published by the American Petroleum Institute.

DIRECT MASS MEASUREMENT

Coriolis flow meters are based on a principle of operation that relates the meter's output directly to the mass flow rate of the fluid. The Coriolis meter utilizes vibrating element technology much like a densitometer. The vibrating tube(s) twist with flow. The amount of twist is proportional to the mass flow rate of the fluid.

This metering technology, though relatively new to the petroleum industry, has revolutionized flow measurement across all industries. Their most distinct advantage over traditional metering devices is that they have no moving parts. This eliminates measurement errors due to wear on parts that create slippage and meter factor shifts over time, and eliminates costly repairs.

For those applications where mass measurement is the preferred method over volume measurement, the determination of mass can be done with a single device. This not only reduces the cost of the metering equipment, but also reduces the overall cost of the piping and the installation by eliminating the sample loop. The errors associated with temperature and pressure differences between the volume meter and the densitometer are eliminated.

An obvious limitation for Coriolis meters is their limited flow rate. Currently the maximum size available for Coriolis meters limits flow rate through a single meter to about 5000 BPH or 25000 lbs/min.

Another issue for the custody transfer of fluids on a mass basis utilizing a Coriolis meter is the technology for field proving on a mass basis. One approach is to install a densitometer on the volumetric prover, thus converting the volume of the prover to mass units. With this method, the result of the proving creates a meter factor with the same technology and potential error as proving an inferred mass measurement installation.

Since the petroleum industry most often requires volume measurement, the Coriolis meter offers the unique advantage of being either a mass or a volume meter. Vibrating element technology is used to determine the mass flow rate and the density of the fluid. With both measurements the volume of the fluid is determined by using the same equation for inferred mass measurement, only rearranged

$$V_L = M / D_L$$

Where M = mass flow
V_L = volume flow at line conditions
D_L = density at line conditions

CONCLUSION

Flow measurement technology is always evolving. The petroleum industry is continually searching for better and more accurate means of measurement. Being “better” is not only related to accuracy, but should be evaluated on a cost of ownership basis. Often better measurement technology can offer a higher degree of safety, reliability and/or benefits related to efficiency, thus contributing to the overall profit of the industry.