UPM 18020

Hydrocarbon Dew Point Effects on Gas Flow Measurement
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Abstract

In this paper we will discuss the effects of Hydro Carbon Dew Point (HCDP) on measurement accuracy. We will look at multiple factors that affect uncertainty such as proper meter operation, maintaining fluid in a gaseous state, gas sampling and handling of samples after they are obtained. All of these factors and more contribute to increased uncertainty when measuring gas close or in the critical area.

Introduction

There are numerous causes of gas being in a continually state of Natural Gas Liquid (NGL) drop out, they include excessive heavy components in the gas stream that are not removed due to lack of separation facilities or economic decisions. With the introduction of dense phase offshore gases, rich shale gases and formation storage gas HCDP values have risen to the point where they can easily reach their critical point and drop out causing numerous effects on metering accuracy. As well the price fluctuations in Natural gas and NGLs also dictates the level of separation as economical conditions may exist that make it more frugal to leave the NGLs in the gas to increase energy rates. When these conditions exist the measurement, sampling and analysis of the fluid can all be affected cause large uncertainties.

Definitions

Non-associated gas:	Gas which is in reservoirs that do not contain significant quantities of crude oil
Associated gas:	Gas found in association with crude oil in the reservoir
Tight Gas:	Gas produced from reservoirs with low permeability that require massive hydraulic fracturing
Shale Gas:	Gas Trapped in shale formations which has a high permeability than tight gas formations
Coal Bed Methane:	Natural gas extracted from coal beds and seams, it is adsorbed into the coal and released through shallow wells that produce both gas and water.
Cricondentherm:	The highest dew point temperature seen on a Liquid-vapor phase envelope curve
Cricondenbar:	The maximum pressure on the liquid-vapor phase envelope at which no gas can be formed regardless of the temperature.
HCDP Curve:	This is also called the liquid-vapor phase envelope as it shows the state of specified fluids in relation to pressure and temperature.

Gas Supplies

Shale gas in some regions are entrained with large amounts of NGLs, when prices for these liquids are high it makes economic sense to separate them from the natural gas. If the NGL prices are low and below the price of natural gas it makes sense to leave them in the gas stream raising the energy content. Some offshore gas also have high levels of NGLs as does gas stored in depleted formation that may leach heavier hydrocarbons from the original production. All of these applications must be analyzed and judged on the economic viability of installing separation and/or filtration equipment.
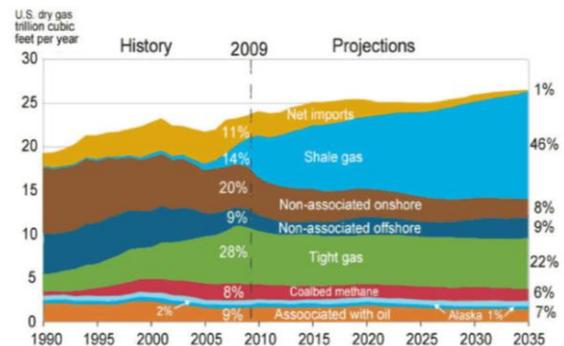

Figure 1

Figure 1 show the distribution of gas types in the US over a 45-year period, it shows the amount of associated and non-associated gas declining while Shale gas is increasing making up the difference and adding to the

overall supply. The addition of these new supplies will change the overall composition of the gases being processed and delivered to pipelines and eventually end users. During the processing and transportation cyclethere are a number of receipt and delivery measurement points, changes in the state of the fluid being moved can adversely affect the accuracy and certainty of the measurement. This will be particularly acute if the product is being sold on its energy content and not on volume.

Figure 2

Figure 2 shows a HCDP curve or Liquid-vapor dew point curve, these curves show where a fluid will change state, if for any reason the product does change state measurement uncertainty will increase leading to errors and increased lost and unaccounted for product. Figure 3 shows HCDP curves for various products with widely different compositions, the leaner gases have a much lower cricondentherm value than those with a larger proportion of heavy components. The compositional values for these 5 different gases are shown in appendix A.

Figure 3

In figure 4 & 5 HCDP curves for 4 wells in the Marcellus shale field show a significant difference in the cricondentherm values from well 1 to well 4. If the

gathering and transportation system were designed to handle well 1 gas than if any of the other well's gases are introduced the HCDP good be reached which would cause NGL fallout. If this fall out occurs the measurement and sampling of the gas can be compromised, we will look into these affects later in the paper.
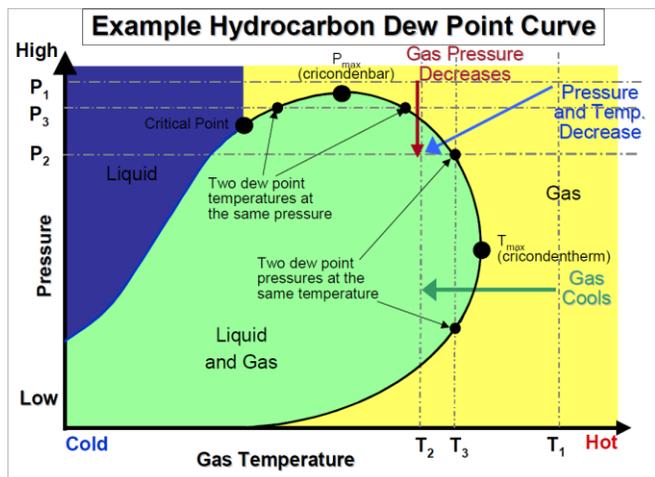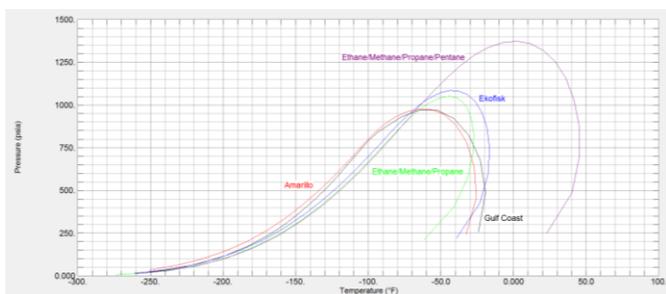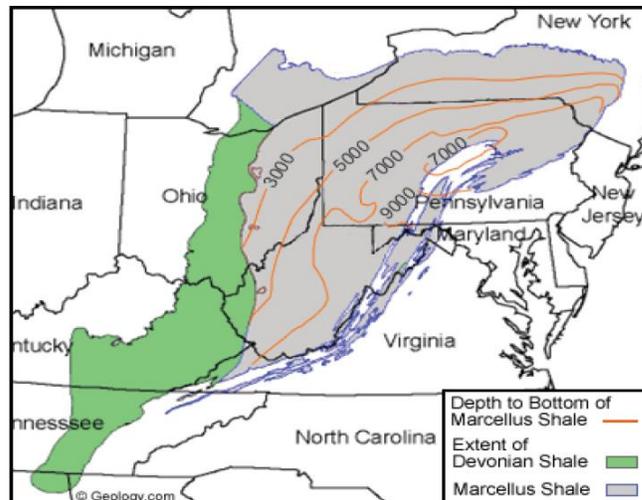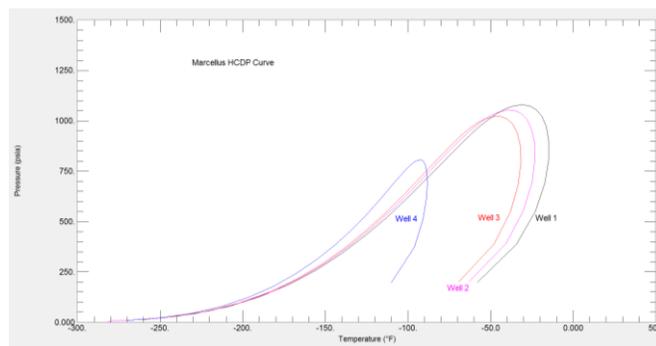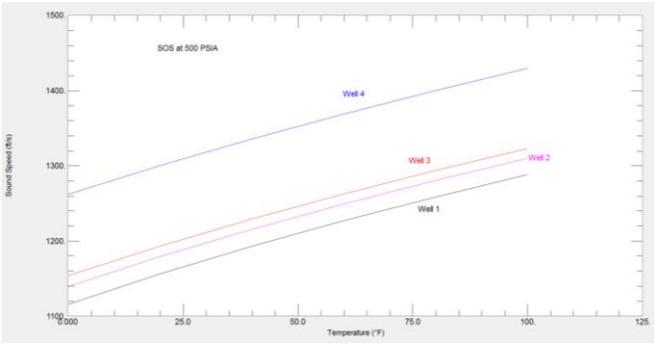

Well	C1	C2	C3	CO2	N2
1	79.4	16.1	4.0	0.1	0.4
2	82.1	14.0	3.5	0.1	0.3
3	83.8	12.0	3.0	0.9	0.3
4	95.5	3.0	1.0	0.3	0.2

Figure 4

Figure 5

Figure 6

In figure 6 the Speed of Sound (SOS) is plotted for the 4 wells, one of the less visible effects of these richer gases is that they are pushing the limits of the current accepted equations of state (EOS). AGA 10 is currently used to calculate a Theoretical SOS (TSOS) value to compare with the value being measured by an ultrasonic meter (MSOS). Rich and dense phase gases fall outside of the compositional limits set for these EOS, the inability to validate the TSOS with the MSOS is annoying since in some installations it is used as a meter validation point. The SOS mismatch points to a bigger and much more serious problem which is the inability of AGA 8 to calculate correct super compressibility values, as AGA 10 is derived from AGA 8, the Fpv value is a direct multiplier in the volume correction equation and as such any errors in this value will render the final result incorrect.

Measurement and Sampling

As discussed earlier when gases are close to their HCDP there can be numerous additional uncertainties added if heavy components start to drop out. The dropout can have numerous causes, gradual reduction in the products temperature, pressure reductions caused by piping components or regulators. This may sound counter intuitive as reductions in pressure should raise the HCDP temperature, but the Joule-Thompson (JT) effect states as a rule of thumb that for every 100 PSI decrease there will be a ≈7° F drop, this will change based on composition, see Figure 7
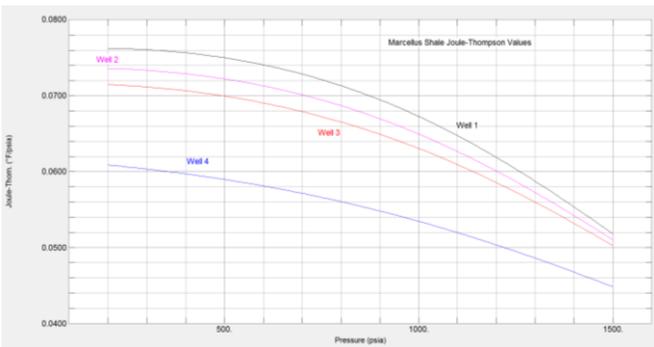

Figure 7

The J-T drop will also occur as gas moves down pipelines and through facilities even if there are no pressure cuts, the temperature can also be affected by ground and ambient temperature as well as cooling if there are any water crossings. These changes can all cause serious issues as the majority of pipelines were built prior to the discovery of these rich gases and don't have any way of either re-suspending these liquids in the gas or removing them prior to being measured and/or compressed. These free NGLs can cause serious safety issues as well, Hydrates can form, regulation and control valves sensing lines can be clogged or frozen off as well as possible internal damage from abrasion and cavitation.

Measurement Effects

Meters used on natural gas pipeline are designed to measure single phase product, the assumption is made that if you use an Orifice, Turbine or Ultrasonic meter that there is only gas flowing through the meter. This is very important as if any of the cross sectional area of the meter is taken up by liquids there will be large errors in the basic actual volume calculations. Research has shown that Liquid Volume Fractions (LVF) of as little as .01% will cause significant errors. To illustrate these affects we will look at test work done on Ultrasonic meters as their reaction to changes in cross sectional area is simplified by the fact that at low LVFs there should be little or no effect on the measurement elements and all shifts in accuracy will be directly caused by liquids occupying a section of the meter body. Figure 8 below shows two error curves for the same meter in the same installation, the only difference is that the first test was done at 200 psi and the second at 800 psi. The liquids and gases used were the same so the only affect is the difference in the gases density caused by the higher pressure. It is interesting to see that at higher pressures the effects of increased LVFs is lower than at 200 psi. The higher pressure increases the density of the gas by ≈ 4 times, this increase in density makes the gaseous fluid properties closer to that of the liquid which allows for more of the liquid to be suspended as it flows through the meter reducing the amount of cross sectional area change. In both cases as the velocity decreases the error increases which is expected as the energy from the higher velocity helps keep the liquid suspended.
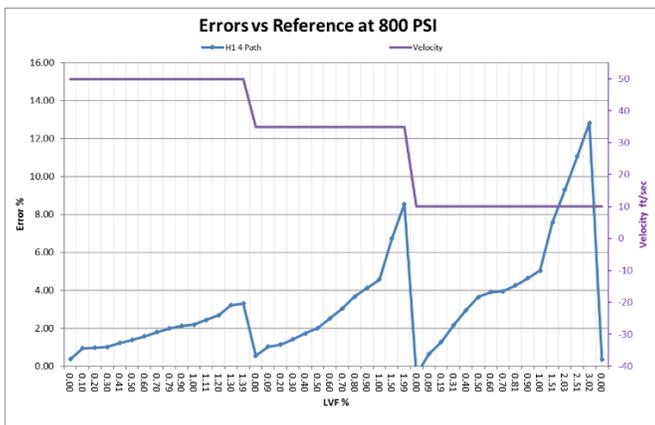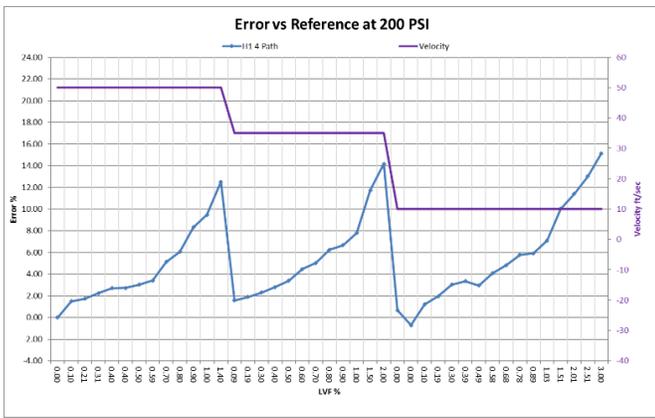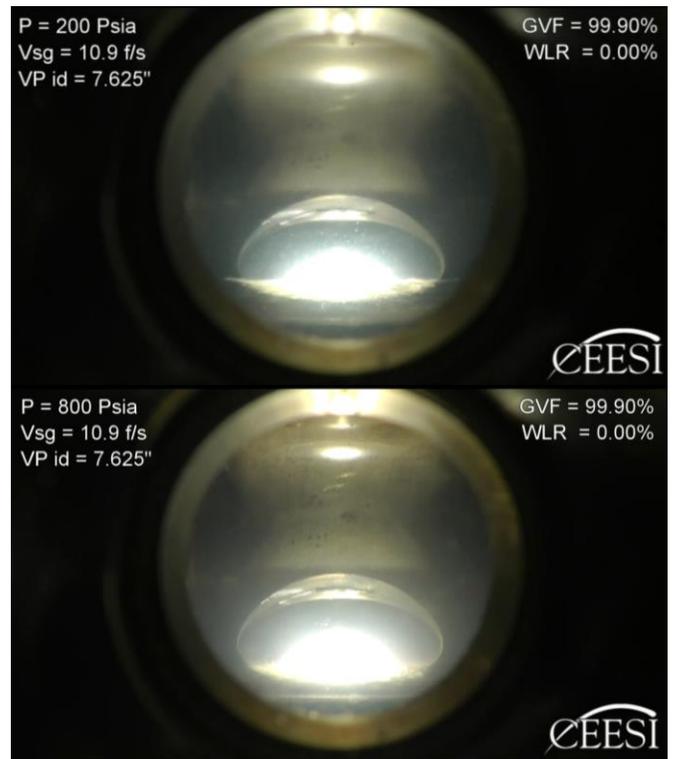
Figure 8

Figure 10

Figure 9 shows the effect of pressure on the fluid in the pipe, cloudier appearance of the right hand image shows that the liquids are being suspended at a higher rate than that on the left. Figure 10 shows that at lower velocities the suspension of the liquids is much less and there is a higher degree of cross sectional area reduction. These measurement errors will affect all of the remaining volumetric calculations as no matter how you try and adjust for the initial flowing errors the final results will be adversely affected. Even using correction factors derived from equations of state cannot correct for the initial mismeasurement. Figure 11 shows the difference in density for the four well from the Marcellus gas we've been using throughout. It should be noted that measurement of wet gas is a completely different and more complex topic and is not part of this discussion.
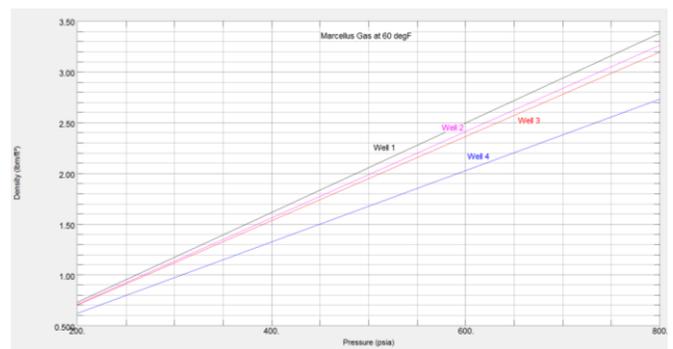
Figure 9

Figure 11

Sampling and Analysis

If we forget about the previous discussion and assume that the physical measurement of the fluid going through our meter is correct, we will still be faced with potential errors caused by not being able to extract and analyze a representative sample of the fluid flowing through the pipe. When gas is received into a pipeline it will normally be at its highest pressure and temperature while being measured at the custody transfer point. During its journey through the pipe it will be heated, cooled, compressed and de-compressed, all of these changes will have an effect on the HCDP of the gas. When the gas is initially measured it will most likely be in a complete gaseous state, therefore when a sample is taken for analysis it would be assumed that all of the components and their energy values will be part of the final equations to determine the amount of energy being transferred. As the gas moves through the pipeline it will affected by temperature and pressure changes, if any of these values drop into the critical range there could be drop out of heavy components and if these are not remixed prior to sampling the energy calculation will be adversely affected. The first components that will drop out will be the heavies, there may be small amounts of these in the gas but their contribution to the overall energy value is large.

Gas	Composition	Gross Heating value	Net Heating Value
Methane	C1H4	1011	910
Ethane	C2H6	1783	1530
Propane	C3H8	2572	2371
Butane	C4H10	3225	2977
Pentane	C5H12	3981	3679
Hexane	C6H14	4667	4315

Figure 12

Figure 12 shows a listing of common natural gas components and their heating value, these along with some diluents such as Nitrogen, CO2 and any other components that have no contribution to the gas heating value make up natural gases.
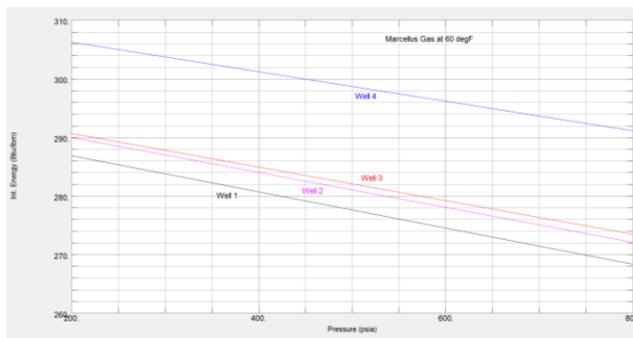

Figure 13

Not getting a representative sample can be caused by poor probe placement, uncontrolled dropping of pressure at the sample point which will cause drop out, incorrect sample line sizing, poor handling of samples either through the sample lines to the GC or to the sample cylinder. If any of these mistakes are made the results of the final energy calculation will differ from calculations done with a proper representative sample.

Conclusion

The constantly changing gas supplies have put added stress on facilities and pipelines that were not designed to handle these types of gases. Measurement errors can start from the basic volumetric measurements and be further affected by poor analysis information and a number of other factors that will all adversely affect the final results. Mismeasurement at any point will cause shifts in the unaccounted for gas in either direction depending on what state the product is in when it's received and delivered. Care should be taken to ensure that fluids are kept in the gaseous state and as far away as possible from the critical point where components can start to drop out and add uncertainty to measurement.