DID YOU KNOW? - RULES OF THUMB IN GAS MEASUREMENT

Many shortcuts are available as tools to measurement personnel..

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A colleague approached me and asked what I used as a rule of thumb for the percent of error in gas measurement per degree off calibration. I used the same .1% per degree he did. Upon checking this out later, I found the F_t error was .192% per degree. On further research the total error was .234% per degree. The reason for the change? The additional effect of supercompressablility, F_{pv}.. Of course the effect of F_t was constant while the F_{pv} varied with the absolute pressure. The colleague brought it to my attention because the pipe line correction appeared to be double what he expected. Had the error been in the opposite direction, the total error would have been only .15%, since the effects of temperature on F_t and F_{pv} are inverse to each other when the error is negative. The general rule we used for temperature was off by a factor of 2 and was variable, depending on the absolute pressure.

The thought of a "rules of thumb" paper started from this experience.

This brings several questions to mind.

- What other rules of thumb are there?
- Are they correct?
- Are they always correct?

The lower the flowing DP, the greater the error with the same calibration adjustment.

This is always correct. R.W. Miller suggests taking a flow calculation and adjust each variable to see what magnitude each one has. Trying this with differential pressure with +1 inch calibration results in the following table.

Flowing DP	*Percent Error*
100 Inches	+0.01%
50 Inches	+0.96%
10 Inches	+5.15%

The lower the absolute pressure, the greater the error with the same calibration adjustment.

This is also always correct. With a +1 pound calibration, the table generated follows.

Absolute Pressure	*Percent Error*
900 PSIG	+0.06%
100 PSIG	+0.44%
5 PSIG	+2.39%

The percent error can be calculated in the field taking the square root of the found and left.

Again, the is always correct. This method is less known and needs clarified. For DP errors use the following equation.

$(\text{Found DP})^{1/2}$ X $(\text{Left DP})^{1/2}$ /$(\text{Found DP})^{1/2}$

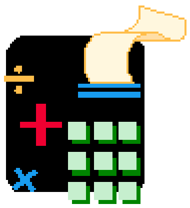
Comparing the volume using a volume calculation program with the square root method looks like this.

Found DP	Volume %	Sq. Rt. %
100 Inches	+0.01%	+0.01%
50 Inches	+0.96%	+1.00%
10 Inches	+5.15%	+5.13%

The absolute error requires you to add the barometric pressure to the PSIG to arrive at the answer. Also the AP must be put in a percent of scale form. For instance 840 PSIG with a 15 pound barometric pressure (855 PSIA) would be expressed as 85.5. The comparison table follows.

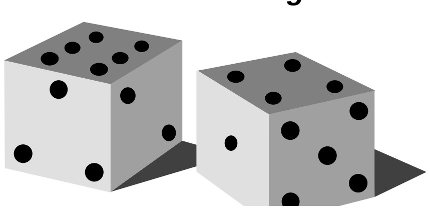
Found AP	Volume %	Sq. Rt. %
900 PSIG	+0.06%	+0.05%
100 PSIG	+0.44%	+0.50%
5 PSIG	+2.39%	+2.47%

The correct plate size can be field calculated using a common calculator.



Another "short cut" that works every time. Although the use of the fourth root is needed, it's not as hard as it sounds. If the calculator has a square root key, simply pressing it twice derives the fourth root. The formula is (Found DP)$^{1/4}$ / (Desired DP)$^{1/4}$ X Present Plate ID = Desired Plate ID. The value will be an odd number, which you can round up or down to the nearest 1/8 inch size (or available size!). For instance, a meter found with 5" DP with a plate ID of 1.000" and desiring a 40" DP derives a .595" plate, exactly the size a volume calibration program arrives at. If the present volume is expected to remain or drop, a .500" plate would be chosen, while a .625" plate would be chosen for a meter with the present volume to rise. If a square root chart is used, use the same procedure, but only calculate the square root of the found and desired DP, since the inches of water have been put in square root form already.

An EFM meter found with the DP or AP over scale will calculate volumes at the rated range.



This one may not be correct.

1) Certain brands of EFM use transducers that read values beyond the posted range, as much as 25% over-range. Such an EFM computer with a 250" DP can actually read 312.5". Since the transducer is usually not calibrated at this range, the accuracy may be off more than if "on scale".
2) At least one manufacturer (at the request of a customer) added software that can freeze the DP or AP at anywhere on the scale. If the DP or AP is on scale and moves suddenly off scale, the computer assumes this is an A to D error, not an actual DP or AP change. It then freezes the value at the last known "good" value until the value falls back on scale. Further, the unit does not record the actual value, nor record it in the events file. In this case, if a meter is flowing at 24" DP, then a compressor is started or a pigging operation occurs, or a duel run is shut in and the DP goes off scale, the unit will record 24" instead of +150" (the DP range). All three of these cases (with different DPs) occurred at sales points I have witnessed. I would submit that the likelihood of operation change forcing a DP or AP off scale is much more likely than an A to D error.

Zeroing the DP at line pressure eliminates the "Rose Effect" and Only Rosemount transducers have this problem.

By definition, these beliefs are never true. The "Rose Effect" is the effect line pressure has on the Wheatstone Bridge of transducers. It effects both the zero and span. All transducers using the Wheatstone bridge principle have this effect. In order to eliminate the total effect, there are several methods available. Rosemount did extensive research on its' model 1151DP/HP to quantify the effects. The methods suggested in Rosemount's Technical Data Sheet 3044 include the following:

- Use the correction table in 3044 to adjust the 20 mA after calibration.
- Use the corrections table to alter the high DP range while calibrating.
- Buy the transmitter pre-set to expected AP.
- Program the flow computer with the correction formulas.

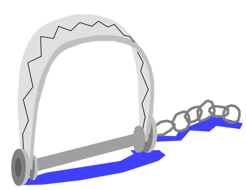
Do not assume the flow computer is making this correction! Those that do make the correction often have calibration procedures which must be followed to avoid adding errors.

Primary element errors cannot be quantified well enough to project an equitable adjustment.

Like many things in real life, this one depends. If a properly recording check meter with a separate meter tube exists, tube roughness, fluid in line, fouled straightening veins, plate not centered, plate not sharp, plate nicked, plate warped, leaks around plate, et. al. might be so quantified. There is a general table of these and more at the end of this paper. Those errors that can be corrected on-site in a short time span are easier to quantify, since the DP before and after can be compared with both meters. This, plus a variance sheet with before and after balances can quantify the error close enough to negotiate between the parties. Those requiring the line to be blown down complicate the process, since the rate when flow is resumed may not be the same. Only the variance sheet will be useful to determine error. If a flow control device not using the suspect meter is in use, this obstacle can be overcome. Simply resume flow at the same setting as before repairs.

For each 4 BTU adjustment, 1 BTU is lost due to volume change.

This rule is true, with one important exception. The exact loss may vary slightly, but the 25% change is close. This is true if the reason the BTU is changed is due to any or several hydrocarbon, oxygen, or nitrogen mol percentages were altered.



This is not true if the error was CO^2. CO^2 reduction also reduces the gravity, which causes even higher volumes, about .1% higher per 4 BTU. BTU adjustments caused by CO^2 errors then are each 4 BTU adds 4.4 BTU with the volume increase.

For the C^{6+} factors, use the average of 50% C^6 and 50% C^7 factors.

For those who aren't aware of this problem, the laboratory must "guess" as to what factors for gravity, heating content, GPM, etc. for the last hydrocarbon their lab can sense. Most labs stop at C^{6+} or C^{7+}, with some at higher carbon chains. The problem isn't that the lab doesn't know the individual factors for all hydrocarbons, but that it does not know what percentage of each is in your sample. An extended analysis will determine this, which costs fourth times the standard analysis or more. Is the extra expense worth the precision? For allocations, generally not. If an operator uses the same split for all wells, he is usually deemed a prudent operator for treating each well equally. Obviously, there are cases to the contrary, such as greatly varying reservoirs within a field. The sales point is an entirely different matter. Most operating companies with an in-house measurement staff will run extended analyses periodically to insure the pipe line is using a reasonable split for the field. While a well will change composition, especially when nearing draw-down, the main reason to retest a sales point is for new gas brought into the facility.

Most commercial labs use the 50/50 split mentioned or a 50/30/20 split of C^6, C^7, and C^8. Obviously, the higher the volume and richer the gas, the more reasons the run extended analyses, either periodically or monthly.

To check for air in a gas sample, compare the nitrogen mol percent to the prior sample.

This is an accepted method to check for air contamination.. Since 78% of air is made of nitrogen, a sample with higher nitrogen than normal could indicate air in the sample. A preferred method is to have a chromatograph column that senses oxygen

Of course there are exceptions.

- Nitrogen is used to purge flow lines requiring welding and other work performed.
- Some gas plants have a nitrogen rejection unit to either make the gas meet pipe line specifications or to use the nitrogen for enhanced oil recovery.

A nitrogen rejection unit being in use or not would have a dramatic effect on a sample. The prior example of nitrogen being used as a purge gas would have only a slight effect on a month's sample, but could have a huge effect on a spot sample. Both cases point to the need for continuous samplers at sales points.

EFFECT OF VARIOUS CONDITIONS IN PRIMARY ELEMENT ON ORIFICE METER MEASUREMENT TABLE FOLLOW

EFFECT OF VARIOUS CONDITIONS IN PRIMARY ELEMENT ON ORIFICE METER MEASUREMEN

Leaks Around Orifice Plate	
1. With one clean cut through sealing unit	
a. Cut on top side of fitting	(3.3%)
b, Cut next to tap holes	(6.1%)
2. With “V” notch cut through sealing unit 1/4” wide a top of “V”	
a. Notch up a top	1.5%
b. Notch down on bottom	(0.4%)
c. Notch on tap side	(0.9%)
d, Notch of opposite side from taps	(1.2%)
3. Orifice carrier up @ 3/8” from bottom. (Plate not centered)	(8.2%)
Dirty Plate	
1. Valve lubricant on upstream side of plate	
a. Three deposits	0.0%
b. Nine deposits	(0.6%)
c. Coated bottom 1/2 of plate 1/16” thick	(9.7%)
d. Coated full face of plate 1/16” thick	(15.8%)
2. Valve lubricant on downstream side of plate	
a. Three deposits	(3.3%)
b. Nine deposits	(2.6%)
c. Coasted bottom 1/2 of plate 1/16” thick	(0.8%)
d. Coated full face of plate 1/16” thick	1.7%
3. Valve lubricant on both sides of plate	
a. Plate coated 1/8” bottom 1/2 of both sides	(10.1%)
b. Plate coated 1/8” full face of both sides	(17.9%)
c. Plate coated 1/4” full face of both sides	(27.4%)
Nicked Plate	
1. .05” notch on tap hole side	(0.3%)
2. .05” notch opposite tap holes	(0.6%)
3. Two .02” notch 180° apart placed on opposite taps	1.0%
4. Two .05: notch 160° apart placed on and opposite taps	(0.1%)
Dull Edged Plate	
1. 1/4th circumference	(1.5%)
2. 1/2 of circumference	(8.1%)
3. 3/4th circumference	(9.4%)
4. Entire plate	(12.7%)
Beveled Side Upstream	(24.4%)
Warped Plate	
1. Warped toward gas flow 1/8” from flat	(2.8%)
2. Warped toward gas flow 1/4” from flat	(9.1%)
3. Warped away from gas flow 1/8” from flat	(0.6%)
4. Warped away from gas flow 1.4” from flat	(6.1%)
Turbulent Gas Stream	
1. Upstream valve partially closed - straightening vanes in	(0.7%)
2. Upstream valve partially closed - straightening vanes out	(6.7%)
3. Liquid in meter tube 1” deep in bottom of tube	(11.3%)
4. Grease and dirt deposits in meter tube	(11.1%)