WHITE PAPER

ORIFICE METER AND ULTRASONIC FLOW METER LIFE CYCLE COMPARISON

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ABSTRACT

This paper discusses the benefits and advantages of orifice plate flow metering from 2023 moving forward, showing that life cycle costs (LCC) of a properly designed orifice metering facility can far outweigh the LCC of a typical Ultrasonic Flow Meter (USM) station while having comparable measurement uncertainty.

The main contributors for this comparison are the primary element capital cost, multiple shipping costs to and from a natural gas calibration laboratory, and the calibration itself. This is required under American Gas Association Standards AGA-9 for custody metering of natural gas by ultrasonic meter, since all USM meter brands are different in design which requires a proof of performance operationally for the client/end user, versus the easy installation for the meter fitting or orifice plate support structure which does not require a flow calibration to manage its uncertainty.

The comparison concept is not new or novel as USM suppliers have used this technique to point to the prowess of this electronically based technology type.

Orifice plate systems can point to the use of Differential Pressure transmitter stacking, high differential pressure operating techniques for increased turn down, ease of maintenance, plus the latest Differential Pressure control-based monitoring techniques (diagnostics), that are available today without having to call a specialist to assist with the complexity associated with a purely electronic based flow meter.

The elimination of unnecessary orifice plate changes and long-term savings, by smaller meter run sizes giving fewer meter run changes at end of life, are all available when incorporating a high DP design at first gas, in conjunction with these new diagnostic (CBM) systems, helping the user have confidence in the meter run performance 100% in real time, for less cost than a laboratory calibration to determine an initial performance.

Recent changes to AGA-9 USM uncertainty levels contribute to the undeniable benefits of orifice metering. The specifications described in this paper fully comply with the latest edition of AGA-3 orifice meter standard and are based on a “no change” to the orifice plate meter beta ratio **.

*** Orifice plate changes increase the rangeability of the orifice measurement system up to 100:1, however comparisons herein are based on a “no orifice plate change scenario”.*

LATEST CONCEPTS AND OPERATIONAL ENHANCEMENTS (O.P.)

To accurately measure Merchantable Quality natural gas upstream of a gas plant, the connecting party generally can be limited within a partner agreement to using orifice plate technology because of pipeline rouge, condensate and retrograde condensate which can affect certain USM meter types. A table showing the effect of pipeline rouge on various USM types and Orifice Plate will be shown later in the paper, however since DP technologies measure mass flow (due to conservation of energy) and not radial velocity which is dependent on geometric distance between transducers, any pipeline rouge deposition has a smaller effect on a DP measurement.

The latest revolutionary development to enhance the orifice plate meter operationally are diagnostics systems for differential pressure devices, that are now being used to keep an orifice meter system on track with fewer maintenance visits.

These new pressure field monitoring systems can indicate in real time, orifice meter performance trends and perform or suggest a diagnosis via artificial intelligence, thus allowing maintenance to be performed before most meter problems occur.

Standardized volumetric flow rates (MMSCF) for both USM and orifice meters are calculated in compliance with AGA, ISO or OIML methodologies for performance comparison. The USM meter is a volumetric flow device as stated utilizing radial velocity techniques usually ignoring Reynolds number analysis.

The DP meter family uses mass flow techniques and the universally known conservation of mass principle using Bernoulli calculations.

Both device types require gas analysis from either sampling or gas chromatography to derive a true gas density for conversion from flowing conditions to standard conditions (mass flow or standard volumetric flow) with temperature and pressure correction, plus energy values used for CTM calculations.

Both Orifice meter and USM meter type performance benefits are discussed within this paper, with options being combined to provide net overall operational metrics or related Life Cycle Costs (LCC) with industry proven references under the next section “Technical Discussions”.

USM meters should be operated at sub-sonic velocities and multi-path units are widely used under pseudo-developed to fully developed flow and turbulence structure for optimum performance in pipeline quality gas applications, according to the latest standards and recommendations.

The effect of retrograde condensate and pipeline rouge may negatively affect certain types of ultrasound meters. Also, noise reduction techniques should be used, where pipeline borne noise is possible, usually by the addition of extra T’s, at each end of the meter run which are designed to change or dampen inherent noise in the ultrasound range, which can affect the meters signal to noise ratio.

These should be transported to the laboratory, where proof testing should be performed per AGA-9 recommendations.

High Differential Pressure (High Dp) Application Orifice Plate

Technical Reference #1

AGA Engineering Technical Note: Guidelines for Using High Differential Pressures for Measuring Natural Gas with Orifice Meters Catalog No. XQ9902, August 1999 States DP versus orifice plate thickness.

Table 1 – Maximum Allowable AGA-3 Differential Pressures

NPS (Nominal Pipe Size)	Orifice Thickness (inches)	DP - " WC (inches Water Column)
2	0.125	1000
3	0.125	1000
4	0.125	1000
6	0.1875	1000
8	0.3125	1000
10	0.375	1000
12	0.500	1000
16	0.500	1000
20	0.500	595
24	0.5625	570

Technical Reference #2

Determination of erosion-based maximum velocity limits in natural gas facilities *(Botros, Jensen and Foo, NOVA Centre for Applied Research, and Trans Canada Pipelines 2018)* discusses the industry accepted maximum pipeline flow rates range from 66 ft/s (20 m/s) to 200 ft/s (60 m/s), based on the number/amounts of solid contaminants in the gas.

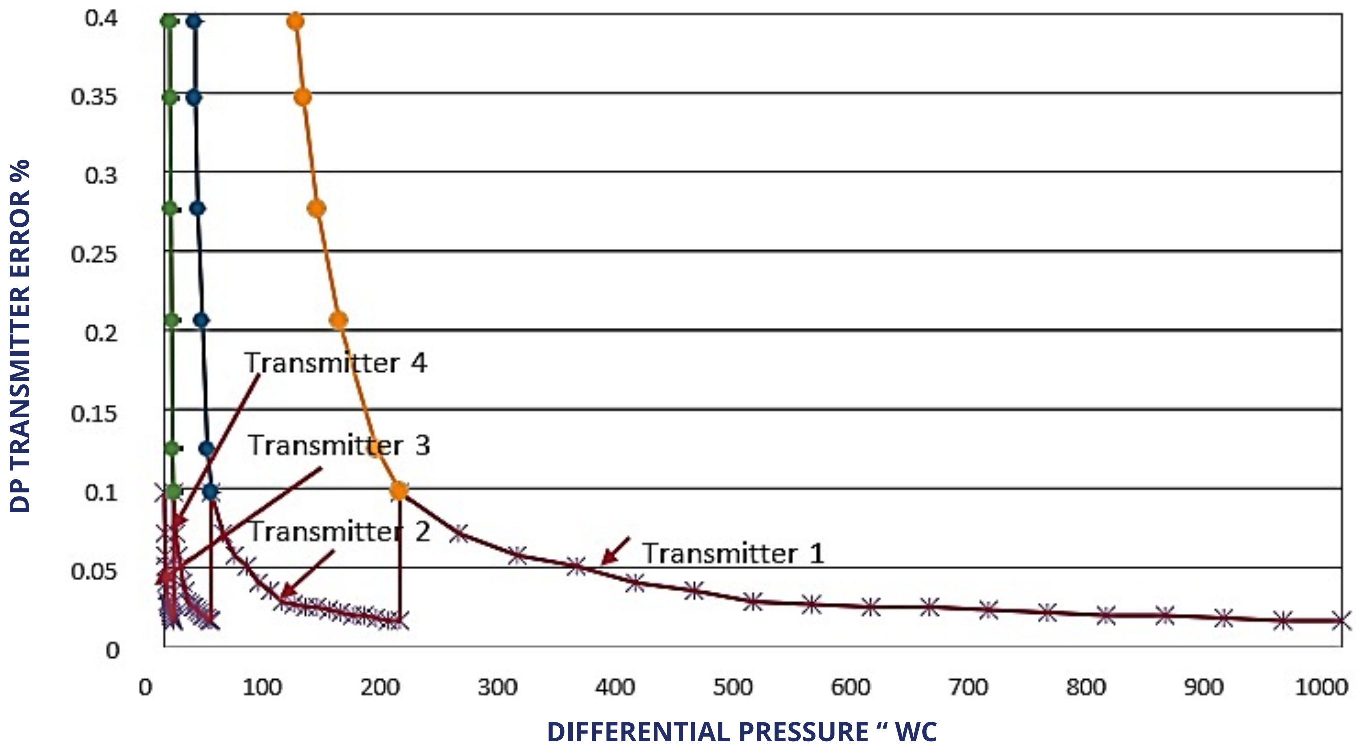
The paper postulates that the **maximum pipeline velocities** are driven from USM signal wash parameters which occur at approximately 38 to 42 ft/s. In the case of the orifice meter this can be determined at a maximum DP of 1000" w.c. as shown in ***Table 1: Maximum Allowable AGA-3 Differential Pressures***. **Note:** Complicated & tedious flow rate calculations are not required to determine this aspect, just a simple Bernoulli based calculation.

Differential Pressure Transmitter Stacking, using what is called in the industry "Stack DP Transmitters", means installing two or three or more differential pressure transmitters in series, each one calibrated at say, the lower 20% of the other higher range transmitter (See Figure 1).

This offers a good linearity over a large flow/uncertainty range. This industry recommended method is used to reduce the requirement to change-out orifice plates where large and variable flow rates are to be measured, thereby reducing many operational cost components often used in an Orifice Meter to USM comparison.

It is important to mention that DP orifice meter installs with, say a 10:1 rangeability, generally covers approximately 92.3% of an available operating range of 40:1 claimed by many USM meter suppliers. **Note:** Rangeability implies nothing about the maximum flow capacity of a meter.

Figure 1 – 1000" DP with 4 Stacked Transmitters (0-1000" shown)



Technical Reference #3

Differential Pressure Meters – A Cabinet of Curiosities (and Some Alternative Views on Accepted Meter Axioms), Steven, Britton, Kinney, 30th International North Sea Flow Measurement Workshop Oct 2012 discussed this effectively.

Statement: AGA-3 section 1.12.2 Part 1, General Equations and Uncertainty Guidelines: From a practical standpoint, the accuracy envelope for an orifice meter is usually estimated using the uncertainty assigned to the differential pressure sensing device.

This technique realistically estimates the uncertainty associated with the designer's flow range. An accuracy envelope incorporates the influence quantities associated with the ΔP sensing device.

The significant quantities include ambient temperature effects, static pressure effects, long-term drift, hysteresis, linearity, repeatability, and the calibration standard's uncertainty.

For some applications, parallel orifice meters are required to meet the user's desired uncertainty and rangeability. In addition, the designer may choose to install stacked ΔP devices calibrated for different ranges to minimize uncertainty while maximizing rangeability for a given orifice plate, as shown in ***Figure 1-3 of AGA-3 Part 1 page 25.***

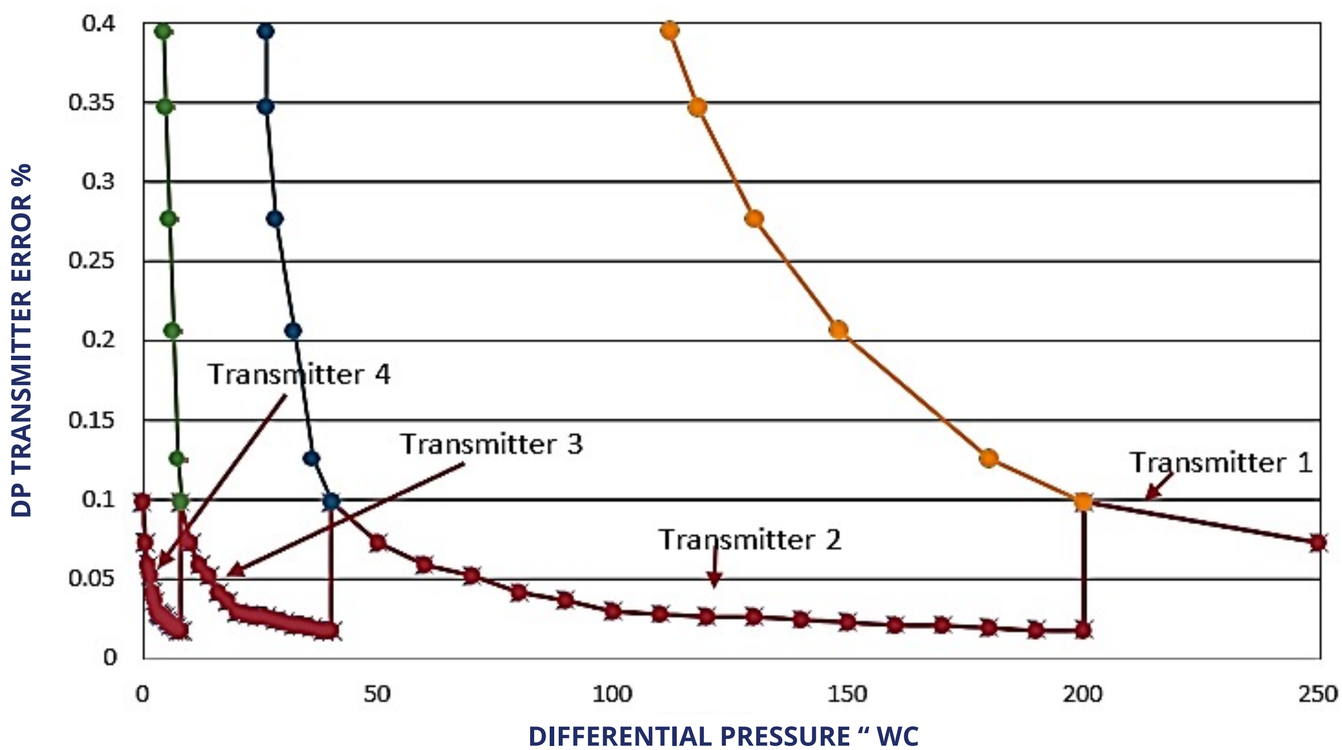
Technical Reference #4

"Low-Cost Solution Increases Orifice Meter Rangeability From 2:1 to 8:1" *(Canadian School of Hydrocarbon Measurement Conference 2005)* explains in detail how three transmitter stacking is employed to eliminate orifice plate changes for 2:1 to 8:1 rangeability. Rangeability is simply the maximum flow rate/minimum flow rate at a chosen uncertainty limit. *(In a differential producing device as an orifice meter, the square root of the DP reading equals the turn down of the overall flow rate Q max i.e., square root of 100" wc to 1 "wc DP = 10-1 turn down.)*

This stacked transmitter method can be carried out even further, by reviewing ***Table 1*** *(page 4)* and installing 4 Stacked Transmitters with the highest range now at 1000 inches water column, this extends the turn down ratio of the orifice meter to 1000:1 on the DP which is equal to a new turn down ratio of 32:1 (The square root of 1000") on flow rate. ***Figure 2*** magnifies how the minimum DP of 1" can be employed on a 1000" DP system.

To conclude this, the benefit of transmitter stacking is a reduction or elimination of plate change requirements thus giving equal operating comparison between the orifice meter and a USM.

Figure 2 – 1000" wc DP with 4 Stacked Transmitters (0-250" wc to clarify concept)



The rangeability of a USM is equal to its pipe mean velocity turn down because the USM is a Volumetric flow rate meter. Values then are in the 40:1 to 80:1 range depending on the minimum flow rate the USM can attain verses the maximum.

Minimum USM flow rates are determined by the point at which convective gas movement overcomes the mean of the meters pipe diameters (0.5 to 1 m/s), and the maximum flow rates (38 - 44 m/s) are determined by the flow rate at which the transmitted and received ultrasonic flow signals are washed outside the area of the receiving USM transducer.

Meter Accuracy (Uncertainty)

This is, of course, a subject which would easily fill a single topic research paper or a book(s). It has already been discussed in hundreds of papers since 1993. Most of the information provided to industry by the proponents of USM technology can be skewed to endorse this type of metering unit depending on the viewpoint.

The USM, as previously mentioned in the references, is an actual inferential velocity/volumetric flow rate measurement device and the flow path velocities are used to infer a volumetric flow rate related to pipe diameter and manufacturer proprietary algorithms.

Each meter is calibrated, usually in 2 stages: 1) At zero flow with nitrogen as a test medium, and 2) A dynamic calibration to prove the meter at a certified test laboratory as near as possible to the actual operating conditions. This is to provide dynamic and kinematic similarity since all USM meters are not identical.

The expansion/contraction of the meter housing due to pressure and temperature change are critical factors in the meters operation for custody transfer and needs to be managed by the purchaser or confirmed during the calibration process, since the dimensional stability of the USM transducers is critical in providing good uncertainty and accuracy and depending on the quality of the housing/ meter body. Expansion/contraction with temperature may not be linear unless a forging is used to align the grain structure of the material.

It is difficult to verify the expansion/contraction algorithm on gas ultrasonic meters unlike liquid USM's which can be tested on different viscosities using heated oil systems thus seeing the effect on the meter factor with Reynolds number change as the housing/body changes and the compensation algorithm answer in real time can be verified.

A USM meter accuracy is usually provided by comparison to "standard volumetric reference meters" usually turbine meters. To convert actual volumetric flow rate to reference flow rate, gas density is required. A volumetric flow rate conversion is required as shown in equation 1-AGA-7 entitled, "volumetric flow rate conversion". USM uncertainties are always stated in actual volumetric flow rate without using Reynolds number and without the uncertainty of the AGA-8 compressibility calculation to convert the gas volumetric flow to standard conditions extensively used for trade or custody transfer which the orifice uncertainty calculation includes ***(Equation 1)***.

Equation 1

$$\dot{V}_{std} = \dot{V}_{act}\left(\frac{P_{act}}{P_{std}}\right)\left(\frac{T_{std}}{T_{act}}\right)\left(\frac{Z_{std}}{Z_{act}}\right)$$

The largest contributor to USM uncertainty is the fact that it is calibrated in actual volumetric flow rate units and operated in actual volumetric flow rates. The pipe Reynolds number at calibration and in operation and the shift in error due to Reynolds number change is also ignored. ***Table 2*** below indicates the custody transfer volumetric flow rate conversion factor parameters indicated in a natural gas financial transactions by the flow computer, meter system or SCADA HMI's.

Table 2

AGA-7 VOLUMETRIC FLOW RATE CONVERSION TERMS	
V_{std}	Volumetric Flow rate at standard conditions
V_{act}	Volumetric Flow rate at flowing conditions*
P_{act}	Absolute Pressure at flowing conditions
P_{std}	Absolute Pressure at standard conditions
T_{std}	Absolute Temperature at standard conditions
T_{act}	Absolute Temperature at flowing conditions
Z_{std}	Compressibility at standard conditions
Z_{act}	Compressibility at flowing conditions

** Via AGA-8*

The uncertainty of the volumetric flow rate at flowing conditions (V_{act}) is a summation of many variables *(Note: There are many papers discussing this topic available to read),* the main dominating factors are the uncertainty of the meter itself and the uncertainty of the test facility summed together as the square root of the sum of the squares equation *(General uncertainty calculations used in flow measurement and available in the ISO Guide to uncertainty of measurement - GUM).*

For example: the uncertainties of the USM (U_{meter} @ 95% confidence) are shown in ***Table 3***, and a simplified summation of errors, "Square Root of the sum of the Squares error estimate" is shown below in ***Equation 2***.

The reader may have alternative values from experience for the uncertainties of each contributor for a total uncertainty and can recalculate the total uncertainty as shown in Equation 2.

Equation 2

$$U_{Meter} = \sqrt{U^2_{Vact} + U^2_{Pact} + U^2_{Pstd} + U^2_{Tact} + U^2_{n} \ldots}$$

Table 3 indicates a typical calculation % based on the calibration facility and USM flow meter.

Table 3

USM UNCERTAINTY TABULATION (EXAMPLE)		
V_{std}	±	0.45
V_{act}*	±	0.40
P_{act}	±	0.10
P_{std}	±	0.00
T_{std}	±	0.00
T_{act}	±	0.10
Z_{std}**	±	0.10
Z_{act}	±	0.10

** The Actual volumetric flow rate as indicated is the uncertainty sum of the calibration facility, and the repeatability of the meter*

*** Via AGA-8*

Note: For both AGA-9 and OIML R-137 reference flow meter class/type, it is recommended to carefully read both standards for further information on this subject.

A comment from AGA-9 Appendix C, (Normative) discusses Flow Metering Packages and Flow-Conditioner Performance **Verification Testing**. The last paragraph of that particular section is as follows:

"The metering package shall be subjected to the upstream disturbance tests specified in OIML R – 137 1 - 2, Edition 2012 (E), Gas meters, Annex B, Entitled "Flow Disturbance Tests". "The result of each tested flow rates of the calibrated test assembly shall be compared to the disturbed flow tests and shall not exceed a ±0.3% difference."

The defined ±0.3% limit in the paragraph ensures that the Ultrasonic Meter meets OIML R137 Class 1 Requirements – more precisely 0.3% x 3 = Class 0.9, but the OIML standard only has 3 Classes: 0.5, 1 and 1.5. In essence, by an arbitrary application of the industry developed standards, the oil and gas industry have inadvertently opened the acceptable uncertainty for an AGA-9 ±0.3% meter to be assigned at a 0.9% value with no statistical reason whatsoever.

Alternatively, the orifice meter (OM) is still held to long proven statistically and mathematically substantiated uncertainties based on data, a major fact commented on in the paper ***"Using Common Ultrasonic Meter Diagnostics to Estimate Changes"*** – *Canadian School of Hydrocarbon Measurement 2022.*

THE ORIFICE METER

The Orifice meter is a mass flow rate measurement device as discussed earlier. The standard flow rate ***Equation 3*** below, illustrates this *(there may be slight variations in other international standards)*. Fundamentally, this is the equation as referenced in AGA-3 pt1, and universally used in DP flow metering.

Equation 3

$$\dot{m} = C_d Y E_v \frac{\pi}{4} d^2 \sqrt{2\Delta P \rho}$$

Table 4

TERMS as used in AGA - 3	
$\dot{m}$	Mass flow
$\dot{v}$	Actual volumetric flow rate
Cd	Coefficient of discharge (=mass flow actual/mass flow indicated) Figures 1-4 X 1-5 AGA-3)
Y	Expansion factor (= Cd compressible/Cd noncompressible)
Ev	Velocity of approach Factor $(1/(1-B^4)^{1/2}$
d	Orifice bore diameter
ΔP	Differential Pressure
p	Density

Note: Dividing the orifice flow rate ($\dot{m}$) by the flowing density (p) will provide actual volumetric flow rate. Semantics really, however, to do a straight comparison it is required. We then can correctly equate the flow rate for the actual volumetric flow rate (V_{act}) as shown in ***Equation 4****, to enable direct comparison to the USM standard volumetric flow rate.*

Equation 4

$$\dot{V}_{act} = C_d Y E_v \frac{\pi}{4} d^2 \sqrt{\frac{2\Delta P}{\rho}}$$

To calculate the standardized volume (V_{std}) the following equation is used including compressibility:

Equation 5

$$\dot{V}_{std} = C_d Y E_v \frac{\pi}{4} d^2 \sqrt{\frac{2\Delta P}{\rho}} \left(\frac{P_{act}}{P_{std}}\right) \left(\frac{T_{std}}{T_{act}}\right) \left(\frac{Z_{std}}{Z_{act}}\right)$$

Density and compressibility (mentioned above) for both the USM and the OM must come from a different uncorrelated source, uncorrelated means the source of the density and compressibility is a completely independent of the USM and Orifice Meter process and equations.

The associated calculated values with each quantity are defined as:

Equation 6

$$Pv = znRT$$

Equation 7

$$\rho = \frac{P}{znRT}$$

Table 5

DENSITY & COMPRESSIBILITY TERMS	
p	Density (kg/m³)
v	Specific Volumen (1/p) (m³/kg)
z	Compressibility – AGA-8
n	Kg/mole
R	Universal Gas Constant (8.314 kgm²/S²mol K)
T	Temperature kelvin (K)
P	Pressure (pa, N/m², kg/S²m)

Uncertainty

The uncertainty for the orifice plate is described within the AGA-3 custody transfer standard ***Figures 1-4***, for U_{Cd95} (95% confidence) and a beta 0.75 = 0.75 (worst case), multiply by ***Figure 1-5*** at the flowing Reynolds Number in this case, we can say Re = 5,000,000, Re factor = 1.001. U_{Cd95} = 0.75. Also included is the AGA-3 option for determining the Cd at a Flow Lab exactly as is required for the USM meter verification, indicated as a Flow Lab Calibration. This information is indicated in the uncertainty summation ***Table 6***.

Uncertainty calculations (actual and standard) are shown next for information:

Equation 8

$$Uom_{actual95} = \sqrt{U_{Cd}^2 + U_Y^2 + (\frac{2}{1-\beta^4})U_d^2 + (\frac{2}{1-\beta^4})U_D^2 + \frac{1}{4}U_\rho^2 + \frac{1}{4}U_{\Delta P}^2}$$

Equation 9

$$Uom_{std95} = \sqrt{U_{\dot{V}act}^2 + U_{Pact}^2 + U_{Pstd}^2 + U_{Tact}^2 + U_n^2 \ldots}$$

Table 6

ORIFICE METER UNCERTAINTY SUMMATION (EXAMPLE)				
$\dot{V}std$	±	0.61 AGA-3 Cd		0.45 Flow Lab Cal
$\dot{V}act$**	±	0.59 AGA-3 Cd		0.40 Flow Lab Cal
$Pact$	±		0.1	
$Pstd$	±		0.0	
$Tstd$	±		0.0	
$Tact$	±		0.1	
$Zstd$	±		0.1	
$Zact$	±		0.1	
Cd*	±	0.575 AGA-3		0.40 Flow Lab Cal
Y	±		0	
Ev	±		0	
d	±		0.01	
ΔP	±		.1	
p**	±		.1	

Note: AGA-3 allows for the use of a lab calibration rather than the use of the Cd data base. This reduces the OM uncertainty but at a large financial cost, as per mandated USM calibrations at traceable laboratories. Uncertainty for density ρ, and super-compressibility (z) must also be calculated in accordance with AGA-8 "Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases". It is recommended to review the reference ***Figure 1 – AGA-8, Targeted Uncertainty for Natural Gas Compressibility Factors using the Detail Characterization Method*** *for further information on this subject.*

The reference table below shows typical uncertainty comparisons between USM, and OM tabulated with calibration and predictions based on the AGA standard. In this example the uncertainties of the two meters are indicated in ***Table 7***.

Table 7 – Uncertainty Comparison Table

UNCERTAINTY	TYPE
0.45%	USM – Flow Lab Calibration
0.61%	OM – AGA-3 Cd
0.45%	OM – Flow Lab Calibration

METER INSTALLATION DETAILS (OM)

The benefit and major advantage when using an Orifice Meter is the ability to accurately measure a fluid flow rate without a Flow Lab Calibration.

This however may have a small cost in Cd Uncertainty if higher beta ratios are used which also dictates the meter run length, and flow conditioning requirements. However, noise reduction T's, are not required for orifice meter systems which increase the cost of a USM meter installation.

Typical installation length parameters are shown in ***Figure 3*** below for the Orifice Meter Run uncertainties for this design are related to ***Table 8***.

The Orifice Meter System standardized run lengths shown below are also used when the option of a flow calibrated orifice meter is desired with the same calibration installation parameters as per USM. However, since the meter is a continuity of mass flow meter type, this is generally performed with Reynolds number values considered using a blow down system with laboratory grade Venturis per flow range point.

The function of the Flow Conditioner is to help provide isolation to the meter from upstream piping installation effects and to shorten the meter run.

Figure 3 – Orifice Meter Run Up/Down Stream Lengths

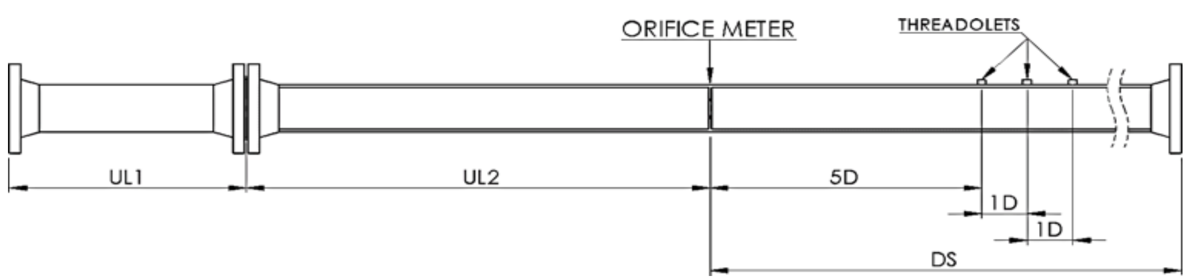


Table 8 – Orifice Meter Run Lengths based on AGA 3

TYPE	UL-1	UL-2	FLOW CONDITIONER	Cd/FLOW LAB
AGA-3 45D	37D	8D	CPA 50E	AGA-3 Cd or Flow Lab Calibration
AGA-3 29D	21D	8D	CPA 50E	AGA-3 Cd or Flow Lab Calibration
AGA-3 17D	9D	8D	CPA 50E	AGA-3 Cd or Flow Lab Calibration
AGA-3 13D	5D	8D	CPA 50E	AGA-3 Cd or Flow Lab Calibration
AGA-3 6D	3D	8D	CPA 55E	Flow Lab Calibration

ULTRASONIC METER INSTALLATIONS

The USM is a performance-based meter. Meter run lengths are therefore dictated by the performance of the metering package. AGA-9, Measurement of Natural Gas by Multipath Ultrasonic Meters ISO 17089 and OIML 137, and numerous papers written since 1993 on the subject are available for further study. The Meter Class as defined by OIML R-137, dictates that various meter run lengths and Flow Conditioners will be required to meet the various Custody Transfer Classes. AGA-9 provides performance specifications for various sizes of meters. In addition, there are now industry accepted methods of USM linearization which is not applied to the OM. ***Figure 4*** shows the AGA meter run requirement without noise reduction Ts indicated.

They are:

1. **FWME:** Flow Weighted Mean Error. The whole calibration curve is moved vertically up or down.
2. **Poly-Correction:** A polynomial correction is applied to the calibration curve.
3. **Point by Point:** Each calibration point is manually adjusted as required, on the day of calibration.

Figure 4 – Ultrasonic Meter Run Length

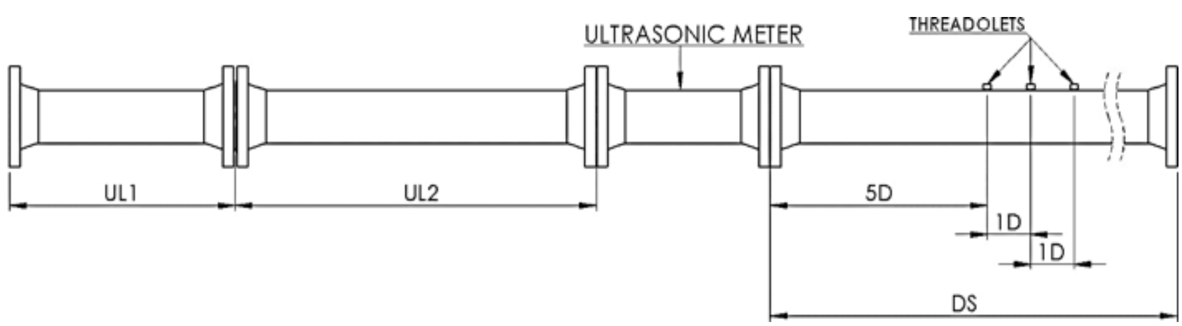


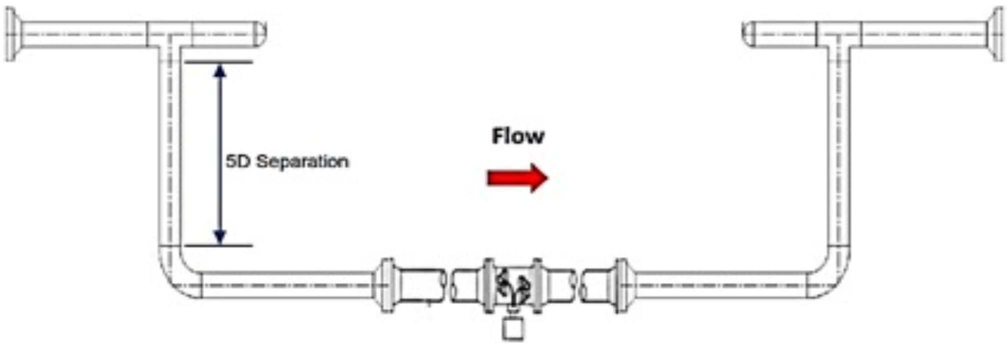
Table 8 – Orifice Meter Run Lengths based on AGA 3

TYPE	UL-1	UL-2	FLOW CONDITIONER	Cd/FLOW LAB
AGA-9, 3 - 13D	Overall Upstream = (Meter Run Length) – (UL2)	3D - 8D	CPA 50E CPA 55E CPA 65E	AGA-3 or Flow Lab Calibration

NOISE REDUCTION T'S

Typical USM flanged noise dampeners are shown in ***Figure 5,*** and usually should be included in the calibration test run, up and down stream of the custody meter run, they can be quite large to transport. *(* Laboratory Testing of Chordal Path Ultrasonic Gas Meters with New Noise Reduction Tee Designs, ISFFM International Conference Arlington. 2015)*

Figure 5 – Noise Reduction T's / Noise Dampening System



LIFE CYCLE COSTS

Life Cycle Cost (LCC) calculations are usually based on a "25-Year" life span for installation including Mean Time Before Failure (MTBF) – this is one aspect that must be considered.

The typical costs shown next include both capital and operational costs per 2023 in US dollars.

CAPITAL COSTS

The following Capital components are held common between the two-meter designs to allow a LCC comparison in the following ***Table 10*** and ***Table 11,*** and subsequent charts ***Figure 6*** and ***Figure 7***.

Table 10 – Capital Costs

ITEM	ORIFICE METER	ULTRASONIC METER
13D Meter run	X	X
6D Meter Run	X	X
High Performance Flow Conditioner	X	X
Meter	X	X
Pressure Transmitters	X	X
Temperature Transmitters	X	X
Differential Pressure Transmitters (x4)	X	
Manifold	X	X
Flow Computer	X	X

The following table of operational functions are held common between the two-meter designs to allow an LCC.

Table 11 – Operational Costs

ITEM	ORIFICE METER		ULTRASONIC METER
	AGA-3 Cd	Flow Cal	
Plate Changes			
Calibration (every 5 years)		X (once)*	X
Shipping return to calibration facility (every 5 years)		X (once)*	X
Meter Inspection (every year)	X	X	X
Pressure Transmitters Calibration (yearly)	X	X	X
Temperature Transmitters Calibration (yearly)	X	X	X
Differential Pressure Transmitters (x4) as required	X	X	

Note: The orifice meter will be calibrated once. There is no need to verify every 5 years as there is no physical changes to the meter, unlike the USM (Transducer upgrades, computer upgrades, transducer port cleaning etc.). When an OM system is used with DP diagnostics, hourly or sooner performance reporting can also be provided giving 100% measurement confidence in the meter without maintenance visits. Also, due to California's ROHAS requirement adopted from the EU where electronic computers etc. are subject to circuit board manufacture without a lead solder base, an inherent corrosion effect long term and subsequent dry-joints and what is called whisker growth between circuit paths are more common today than in the past on similar units manufactured under this regulation. This aspect is not included in the cost analysis, as it has larger impact on purely electronic based devices. Transmitter versus USM repair costs due to this regulation has an impact. *(Paper Number: NACE-10080 CORROSION 2010, San Antonio, Texas, March 2010)*

LIFE CYCLE COSTS

Figure 6 – Life Cycle Costs 25 years at 66ft/s Max Velocity

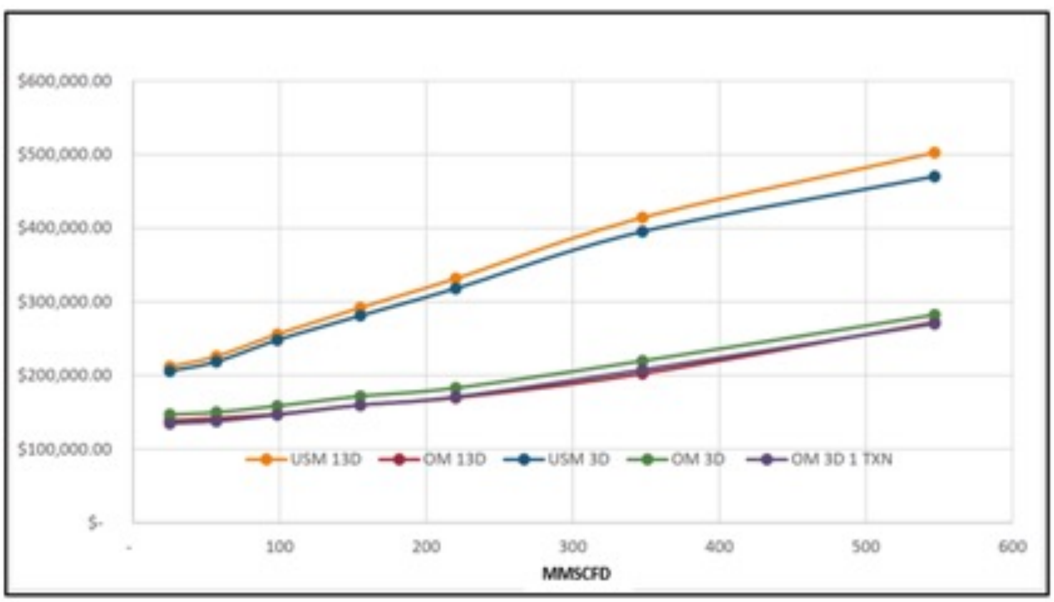
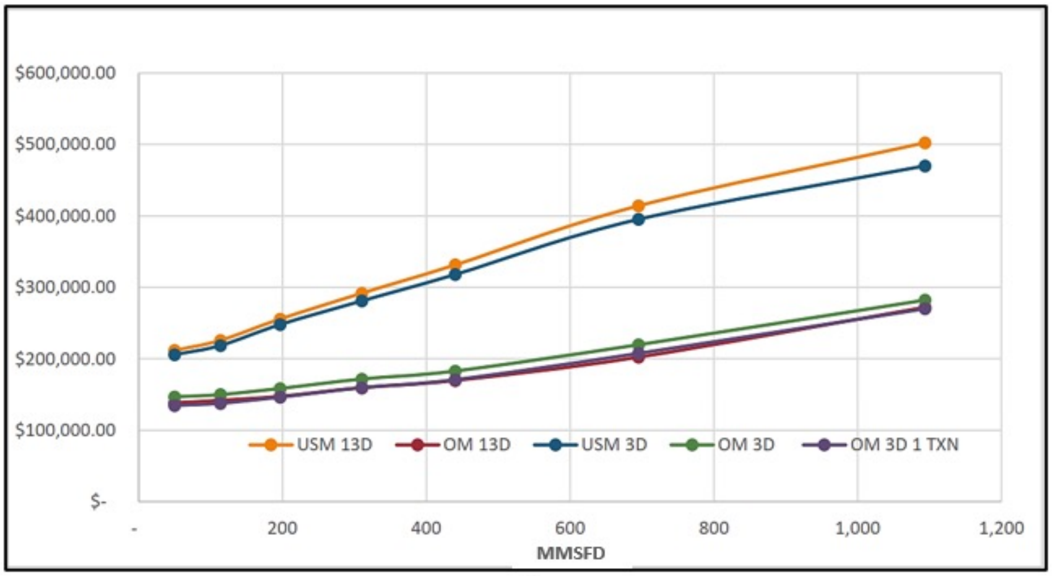


Figure 7 – Life Cycle Costs 25 years at 132 ft/s Max Velocity



DIFFERENTIAL PRESSURE DIAGNOSTICS (CONTROL BASED MAINTENANCE)

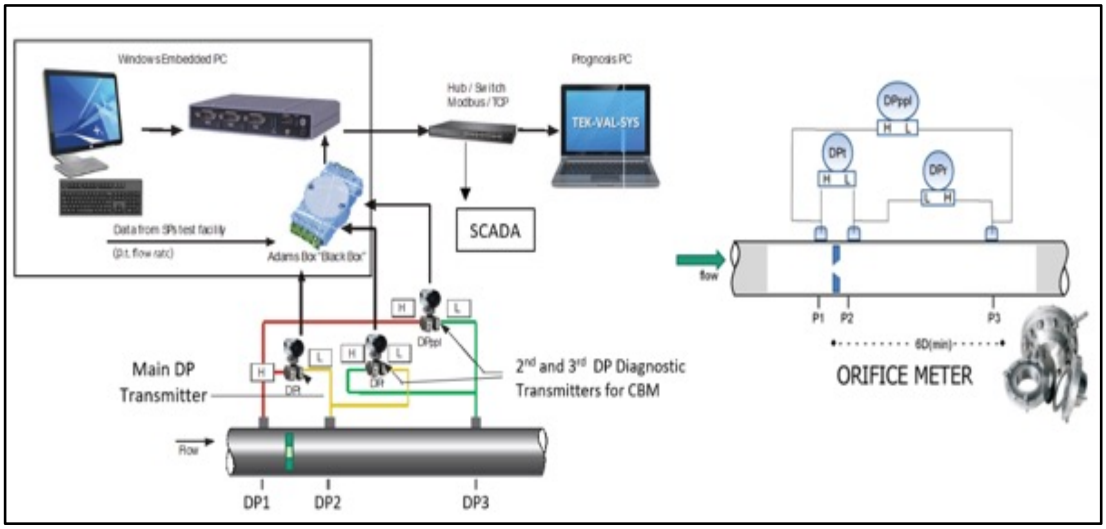
DP Flow Meter diagnostics using Ai (built in analysis) are desirable as they can verify a DP meter's performance, thereby reducing exposure to measurement error, and allow condition-based maintenance (CBM) instead of routine scheduled maintenance. They can also avoid unnecessary, risky routine or scheduled maintenance on HP systems, and high H2S – "if it isn't broke, don't try and fix it."

CBM can help technicians be more productive and efficient, reduce LCC, and can provide more real time data than USM based diagnostic systems such as wet gas liquid quantity and gas flow values when programmed to do so.

On offshore applications, this system can help to save lives in risky environments by reduced maintenance visits (helicopter crashes in poor weather, etc.). ***Figure 8*** and ***Figure 9*** indicate the topographical display of a typical system and system with DP/transmitter issue showing drift/integrity.

Figure 8 – Topographic View of Orifice Plate CBM Result

Figure 9 – Typical Differential Pressure Diagnostics CBM System with Communications



PARALLEL METER RUNS

The use of parallel meter runs is often used to facilitate redundancy and to increase flow capacity or capability where large pipe diameters are not possible alone.

There has been work done on this aspect regarding USM and OM systems. The following table indicates the slight differences in using this technique, when operating in the upstream area.

Below in ***Table 12*** are details regarding such installations, these usually involve upstream and downstream headers to facilitate two or more units in one system. There is no need for sound isolation techniques for OM systems as they have no possibility to interfere with each other from a noise frequency point of view. Comparison shown using a high-pressure application based in the Gulf of Mexico where the plant inlet pressure was 1385 PSIG and temperature was 100ºF.

Table 12 – Parallel Meter Run Combined Uncertainty Table

TYPE	PARALLEL METERS	U^{95} (%)
Orifice[1]	1	0.48
Orifice[1]	2	0.41
Orifice[1]	3	0.37
Orifice[1]	4	0.35
Ultrasonic[2]	1	0.76
Ultrasonic[2]	2	0.65
Ultrasonic[2]	3	0.60
Ultrasonic[3]	1	0.39
Ultrasonic[3]	2	0.35
Ultrasonic[3]	3	0.33

Note: The following assumptions are made about this table's calculations: GOM outlet of gas plant composition; P_f of 185 psig and $\partial P_f/P_f$ of ±1.3 psig, then $\partial\rho_{tp}/\rho_{tp}$ is ±0.11%; T_f of 100°F and $\partial T_f/T_f$ of ±0.2°F, then $\partial\rho_{tp}/\rho_{tp}$ is ±0.06%; and an online GC or flow-weighted sampling system, then $\partial\rho_{tp}/\rho_{tp}$ is ±0.25%.

[1]Assumes a dual-chamber orifice fitting $\partial C_d/C_d$ per A.G.A.3.

[2]Assumes a multipath ultrasonic ∂MF/MF of ±0.70% per A.G.A.9 without linearization.

[3]Assumes a multipath ultrasonic ∂MF/MF of ±0.25% per A.G.A.9 with linearization.

CONCLUSION

From the peer reviewed reference data provided in this paper, it can be confirmed that maximum orifice meter capabilities and flow rate capacities are very high when implemented using proper field measurement design considerations.

By using AGA "DP" standards recommendations, the use of high differential pressures will increase the capacity of the orifice meter beyond the maximum allowable pipeline velocities used in the past and can initiate direct comparison to the ultrasonic flow meter flow rate maximums with high confidence levels, particularly when used with the latest DP diagnostic systems, rivaling electronic based technologies used in the field today for control-based maintenance (CBM).

Using AGA recommended and compliant differential pressure transducer stacking (Stack Dps), will increase "DP" meter rangeability and reduce the uncertainty of the orifice meter system to ultrasonic meter system levels.

The total "Uncertainty" of orifice meter systems can be compared to better ultrasonic flow meter U95% values when using a flow lab calibration as is normally mandated for the ultrasonic flow meter in standards.

An external calibration of this type for the OM need only be done once, not every 5 or 6 years as is required for USM devices, due to the robust design of the orifice meter. This significantly reduces the LCC over 25 years and is 100% fully AGA compliant.

The use of very short meter runs for the orifice meter is 100% fully AGA compliant when a flow lab calibration is offered using the same geometric piping arrangements as per the field usage, which must be the case for an ultrasonic meter particularly where noise reduction Tee's are installed, but not needed for OM systems.

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