

# GUIDE TO **FLOW** MEASUREMENT



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IPP&T's Flow Measurement Handbook offers engineers and plant managers the latest insights on flow measuring techniques and instruments.

This handy collection of articles provides a wealth of practical advice on the design, operation, and performance of a broad range of flowmeters.

In the pages of the handbook, you'll find expert advice and applications that work best for a number of real-life situations, and tips on how to choose the best system for your flow challenges.

Included in the handbook are articles on:

- The challenge of measuring wet gas, including those with combustible gases that represent a safety hazard;
- A real-life situation of how the problem of turbine flowmeters being plugged by wax and sand was solved;
- Examining the differences between two flow measurement technologies, and how you can make the right choice; and
- A deep dive into the need for dedicated multiphase metering devices, which has been steadily increasing on pace with improved oil and gas reservoir management.

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•	•	?	•	?	•



## GUIDE TO FLOW MEASUREMENT

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# OVERCOMING FLOW MEASUREMENT CHALLENGES IN WET GAS AND OPEN STACK, RAIN-DOWN INSTALLATIONS

## Fluid Components International (FCI)

Wet gas is a challenge to measure in a number of industries, including those with combustible gases that represent a safety hazard. In the laboratory, today's air/gas flow sensors and measurement technologies operate at their highest accuracy and greatest reliability in air or gas free of moisture, droplets, particulates, etc. The real industrial world, however, is a much different environment where moisture can be entrapped in one form or another in air or gas flow streams with variable gas compositions and flow rates.

There is no single definition of what constitutes wet gas (Figure 1). It is instead a variable condition that ranges from mild humidity in the pipe to gas that presents itself as a multi-phase flow with for example a 90 percent volume of gas and 10 percent volume of other fluid in various forms. At the other end of the spectrum, pollution monitoring systems that measure air/gas flow in large vertical stacks must at times contend with the natural phenomenon of frequent rain in the pipe.

No matter the industry, the application or the pipe size, process engineers need to be able to measure wet gas flow accurately and consistently independent of the fluid composition in the pipe or the weather conditions. Failing to achieve accurate air/gas flow measurement creates inefficiencies in processes, reduces product volume throughput, causes maintenance issues, etc. The result of inaccurate measurement is higher costs and competitive weakness.

## Wet Gas Solutions

For entrained moisture, eliminating the



Fig 1. Wet Gas Flow in the Pipe

moisture from the gas stream is always the preferred, best practice. Common methods for this include the installation of a gas dryer or the installation of a knockout drum or knockout pot upstream from the flow meter's point of installation. Another option is to insulate or heat wrap the pipe to prevent condensation.

While these wet gas mitigation options are often effective and completely solve the problem, there are instances where either the gas composition or the variables in process, installed equipment or piping layout can frustrate the best efforts. If none of these moisture elimination practices are feasible or adequate to solve the problem, then there are several more solutions to consider at the instrument level.

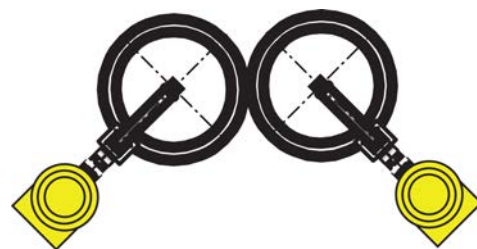
**Option 1.** Install a standard thermal flow meter using constant power (CP) technology and optimize the installation itself to minimize or prevent condensation from contacting the sensor. During the flow meter's installation, be sure the meter is angle-mounted in the pipe (Figure 2) so that gravity moves the moisture away from the sensor. If a knockout pot is already employed, the installation of the flow meter as

shown Figure 1 is also the recommended best practice.

Another alternative choice is to install a  $\Delta T$  (CT) method meter that is extremely heated, to 572°F (300°C) to “flash off” any moisture. There is an issue with inserting such a high heat source into the flow stream. This could create an unsafe condition, consumes much more energy to operate and can result in a shortened operating life-cycle, accelerate aging

and susceptibility to drift and/or premature failure of the sensors.

**Option 2.** Install a special purpose “wet gas” thermal flow meter, such as FCI's new “wet gas” sensor head (Figure 3). Its innovative design shunts the condensate away and never allows it to reach the sensors. As a mechanical design solution, all safety approvals remain in place, there is no increase in energy consumption to power the instrument and there is no impact on the sensors' service life. Furthermore, there is no de-rating of the instrument's T-rating and the sensor is safe to touch. The recommended installation is side-mounted in either the 90° or 270° position.



Angled at 45° from Horizontal

Fig 2. Angle-Mounted Standard Thermal Flow Meter



Fig 3. New Wet Gas MASter Flow Sensor

### The Wet Gas Sensor

The most effective of these approaches is the previously mentioned Wet Gas MASter™ sensor for the ST80 Series Flow Meter. This innovative mechanical design shunts moisture, condensation and water droplets away from the thermal sensor, thus maintaining an accurate gas flow measurement while minimizing errors that occur from a cooling effect on the sensor that could cause a spike or false high reading.

The Wet Gas MASter can be used in applications that have either moisture entrained in the gas (annular mist) or for protection against rain in larger, vertical stacks. Why is it needed? This new wet gas sensor is designed specifically for use in applications that have a high level of moisture or condensation present in the gas flow stream that cannot otherwise be removed using traditional solutions.

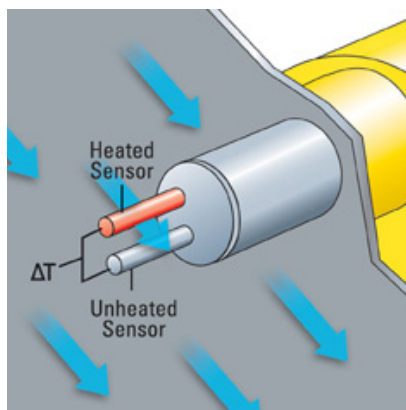


Fig 4. Thermal Dispersion Principle of Operation

The measuring principle of thermal mass flow meters involves heat transfer caused by gas flow. Any moisture or condensate in the gas stream that contacts the heated sensor can cause a sudden, momentary change in the heat transfer that can result in a spiked or fluctuating output reading, creating inaccurate or unstable flow measurement. Thermal flow meters using the constant  $\Delta T$  (CT) method are particularly reactive to moisture droplets, while constant power (CP) method meters, because their slightly heated sensor elevates the dew point, are less so (Figure 4).

Common moist gas applications with condensation droplets are found in biogas recovery systems (wastewater treatment digesters, landfill biogas production systems and reactors). Rain droplets found in open vertical stacks and flues are common in power plants, oil and gas operations, chemical plants and refineries.

The Wet Gas MASter Sensor option for the ST80 meter (Figure 5) is suitable for pipe diameters from 1 to 99 inches (25 to 2500 mm) and air/gas temperatures up to 850°F (454°C). These meters are accurate to  $\pm 1\%$  of reading,  $\pm 0.5\%$  of full scale, with repeatability of  $\pm 0.5\%$  of reading for flow rates up to 1000 SFPS (305 NMPS) and 100:1 turndown.

These meters are available with an extensive choice of outputs and user interfaces to ensure interfacing with virtually any control system and/or set-up or configuration devices. Standard outputs include dual 4-20 mA, NAMUR NE43 compliant analog outputs, HART (version 7), Modbus 485 and a USB port. Foundation Fieldbus or PROFIBUS PA can be optionally added.

An intuitive, easy-to-read backlit LCD display provides digital and bar graph readouts of the meter's flow rate and temperature, totalized flow, alarms, diagnostics feedback and a user defined label field is also available. Technicians can easily spot check flow data in person for reliability.

The meter's transmitter enclosure is NEMA 4X/IP67 rated, selectable for NPT or metric conduit port threading and is available in both aluminum and stainless

steel and maybe remotely located up to 1000 feet (305 m) apart from the flow element. In addition to SIL rating, the instrument with the wet gas sensor also carries full global instrument Div.1/Zone 1 Ex hazardous location approvals of FM, FMc, ATEX, and IECEx.

### Conclusions

While wet gas is unavoidable in many industries and processes, solving wet gas measurement challenges can be easier than you think. There are multiple options to eliminate the moisture or to mitigate any interference with flow measurement sensors.

Where possible, choosing the point of measurement and installation of the flow meter downstream from dryers, knock-out pots or knock-out drums is the traditional and best possible solution. If that doesn't work, then angle-mounting the meter in the pipe helps isolate the flow sensor from the fluid in the pipe.

The newest option is the wet gas sensor designed for the ST80 thermal meter, which mechanically shunts moisture away from the sensor head to ensure accurate, repeatable measurement. Its unique construction eliminates affects from both moisture in the pipe and is suitable for use in large open stacks where rain fall is an issue.

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Fig 5. ST80 Flow Meter



Wherever  
gases flow,  
that's where  
we go.



More thermal flow meters  
for more applications in  
more industries.



For more than five decades, FCI has been precisely where you need us. In pipe sizes from 1/4-inch to the largest of stacks, and everything in-between. Measuring more than 200 gases, pure or mixed. Operating over flow rates from 0.2 to 1000 fps, with turndowns from 100:1 to 1000:1. In temperatures up to 850°F. Generating analog outputs and digital bus I/O to go with your DCS, PLC, or SCADA. For the definitive choice in gas flow measuring solutions—for any industry, anywhere—there's only one way to go.

For specs, sales and expertise, go to [FluidComponents.com](http://FluidComponents.com)

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# NON-CONTACTING SOLUTION FOR PLUGGED OFF FLOW METERS IN THE OIL PATCH



Petrobakken Crude Oil Battery

## **“When something works, it works” Terry Willoughby Petrobakken Energy Ltd.**

For years Petrobakken Energy Ltd. used inline turbine flow meters to track the flow rate of oil recycled to treaters. But with a high concentration of wax and sand in the oil, the turbine meters were quickly plugging off. The line had to be shut down at least once a day and the turbine flowmeters disassembled for cleaning. This was troublesome and expensive. Petrobakken knew there had to be a better way.

Crude oil is delivered by tanker truck to the Petrobakken battery site in Drayton Valley, Alberta and offloaded to emulsion tanks and then pumped to treaters for processing where gravity, heat and chemical additives break down the oil-water emulsions.

To maintain production without shut downs Petrobakken contacted Seidlitz

Engineering of Cochrane, Alberta to help find a solution to their wax off problem. Seidlitz specified clamp-on ultrasonic meters because they work from outside the pipe without obstructing flow. They contacted Carbon Controls Ltd. in Calgary for DFM 5.0 Doppler Flow Meters manufactured by Greyline Instruments. Three meters were originally installed. Petrobakken’s lead operator, Terry Willoughby found that the Greyline DFM 5.0 meters measured flow reliably and were unaffected by wax and sand in the oil. Because they work from the outside of the pipe the Doppler ultrasonic flowmeters did not cause plugging off or pressure drop. With more than six months continuous operation with the new Greyline flowmeters there has been no shut downs for cleaning. Terry commented “when something works, it works”.

Seidlitz Engineering redesigned the pipe configuration for 1.5m straight runs

for good optimum flow conditions. Each flowmeter’s 4-20mA output is connected to Petrobakken’s PLC for pump speed control. Flow rate and totalizer are displayed on the instrument’s backlit LCD display. After three months of successful testing, Petrobakken installed three more Greyline DFM 5.0 flowmeters. All units are mounted on 3” steel pipes. The ultrasonic sensors do not require maintenance or cleaning and do not obstruct flow. Doppler works by injecting high frequency ultrasound through the pipe wall and into the flowing oil. It requires solids or gas bubbles in the fluid to reflect its signal so dirty crude oil is an ideal application for this technology.

The Greyline DFM 5.0 Doppler Flow Meter uses a single-head ultrasonic sensor mounted on the outside of a metal or plastic pipe. The clamp-on sensor works on ½” diameter or larger pipes and is rated for Div 2 locations, or it can be Div 1



Tanker Truck Offloading at Petrobakken Crude Oil Battery



Left: Sand, Wax and Solids Removed in Crude Oil Treater.  
Below: Clamp-on Ultrasonic Transducer Monitoring Crude Oil Flow in 3" Steel Pipe



with optional intrinsic safety barriers. It displays, totalizes and controls with settings entered through a simple keypad menu system.

Time is money in the oil business. Petrobakken's battery site is automated and runs 24 hours a day, 7 days a week. They produce 350m<sup>3</sup> of oil per day and are equipped to handle up to 1000m<sup>3</sup> per day. By switching to non-contacting Greyline DFM 5.0 Doppler Flow Meters Petrobakken can now keep production going without shut downs for flowmeter maintenance.

*\*Petrobakken is now Ridgeback Resources*

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# TWO TECHNOLOGIES FOR FLOW MEASUREMENT FROM OUTSIDE A PIPE

**D**oppler and Transit Time are two very popular types of flow meter for non-invasive measurement of flow in full pipes. We tend to confuse these technologies because they are both ultrasonic and both measure flow by using sensors clamped onto the outside of a pipe. In the real world, they actually work best in opposite applications. Success in your installation depends on understanding the differences and making the right choice.

Ultrasonics are a mature technology and widely used in medical and industrial applications. The clamp-on transducer design is popular because the flowmeters can be installed without cutting the pipe or shutting down flow. There is no pressure drop and the non-contacting transducers immune to chemicals, abrasives and pressure. They work on non-conductive fluids including oils and are not affected by electromagnetic fields or radiation. They have a wide temperature operating range plus excellent properties of repeatability and reliable operation

Ultrasound is sound generated above the human hearing range - above 20 kHz. Both Doppler and Transit Time flowmeter technologies are called “ultrasonic” because they operate far above the frequencies or sound range that we can hear.

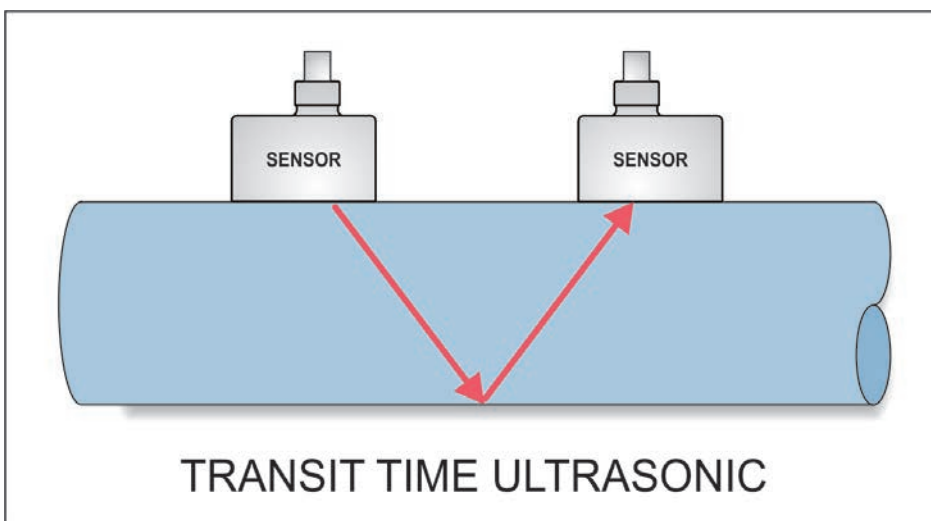
At the heart of each ultrasonic transducer is a piezo-electric crystal. They are glass disks about the size of a coin. These crystals are polarized and expand or pulse a minute amount when electrical energy is applied to the surface electrodes. As it pulses the transducer emits an ultrasonic beam approximately 5° wide at an angle designed to efficiently pass through a pipe wall. The returning echo (pressure pulse) impacts a second passive crystal and creates electrical energy. This is the received signal in a Doppler or Transit Time transducer.

The piezo-electric crystal was discovered in 1820 by French physicist Pierre Curie. But it was not until the mid 1900’s that the technology was applied in industrial sensing applications. To make an ultrasonic flow transducer, piezo-electric



crystals are embedded in rugged metal or plastic housings with specially-selected materials that conduct sound efficiently through the face of the transducer.

So far both these piezo-electric ultrasonic technologies seem much the same. No wonder the choice can be confusing. But now let’s look at the differences. Transit Time flowmeters must have a pair of transducers. One transducer transmits sound while the other acts as a receiver. As the name suggests, Transit Time flowmeters measure the time it takes for an ultrasonic signal transmitted from one sensor, to cross a pipe and be received by a second sensor. Upstream and downstream time measurements are compared. With no flow the transit time would be equal in both directions. With flow sound will travel faster in the direction of flow and slower against the flow. Because the ultrasonic signal must cross the pipe to a receiving transducer, the fluid must not contain a significant concentration of bubbles or solids. Otherwise the high frequency sound will be attenuated and too weak to traverse the pipe.

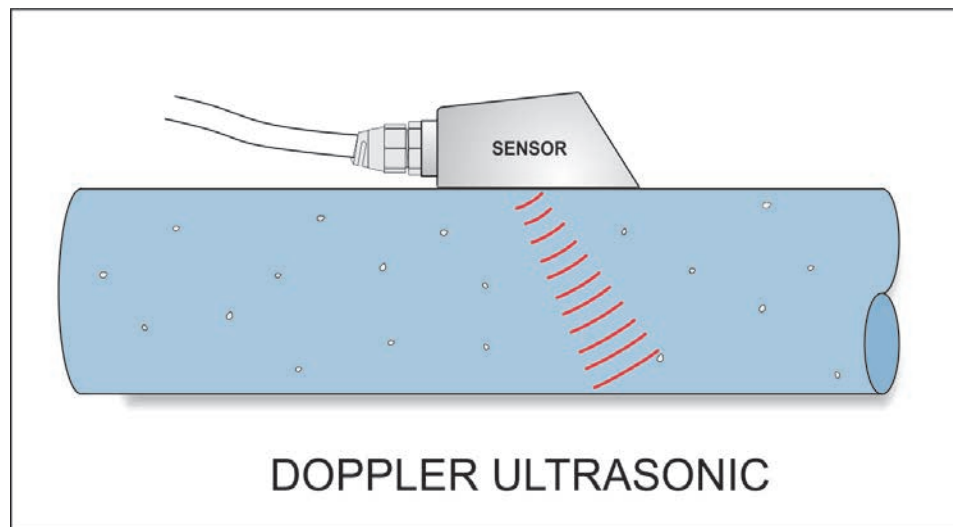




Transit Time transducers typically operate in the 1-2 MHz frequencies. Higher frequency designs are normally used in smaller pipes and lower frequencies for large pipes up to several meters in diameter. So operators must select transducer models/frequencies according to the application.

Transducers can be installed on opposite sides of the pipe so that the ultrasonic signal travels once diagonally across the pipe. This method is called 'Z' mounting and typically is used in large pipes or weak signal applications. The most common mounting configuration is 'V' mode where transducers are installed on the same side of the pipe with the sound bouncing off the opposite pipe wall so that it crosses the pipe twice. 'W' mode mounting is often used in very small diameter pipes where the signal crosses the pipe four times. The flow meter's software will normally specify the recommended mounting method and transducer separation distance as calibration parameters are entered into the calibration menu.

The Doppler effect was first documented in 1842 by Christian Doppler, an Austrian physicist. We all hear daily examples of the Doppler effect. It is the distinct tone change from a passing train whistle or the exhaust from a race car. We hear this tone change, or Doppler effect, only because we are stationary and the sound transmitter - the train or the race car - is in motion. Doppler flow meters use the principal that sound waves will be returned to a transmitter at an altered frequency if reflectors in the liquid are in motion. This frequency shift is in direct



proportion to the velocity of the liquid. It is precisely measured by the instrument to calculate the flow rate. So the liquid must contain gas bubbles or solids for the Doppler measurement to work.

Doppler transducers usually operate at 640 kHz to 1 MHz frequencies and work on a wide range of pipe diameters. Doppler flowmeters manufactured by Greyline Instruments use a single-head sensor design allowing fast, simple mounting on the outside of pipes. The single-head transducer includes both transmit and receive piezo-electric crystals in the same housing.

Dual-head Doppler flowmeters are available from some manufacturers although they are somewhat more difficult to install. They are often confused with Transit Time meters because dual-head Doppler meters also use separate transmit and receive transducers. Although they look very similar to Transit Time,

dual-head Doppler instruments are still measuring only the frequency shift of the transmitted signal from one transducer to the received signal by another. Whether single-head or dual-head design, Doppler instruments always work by measuring the frequency shift of signals reflected from moving particles or bubbles in the fluid.

### Two technologies, one decision:

Doppler flowmeters work best in dirty or aerated liquids like wastewater and slurries. Transit Time flowmeters work with clean liquids like water, oils and chemicals. Select the right ultrasonic technology for your application and enjoy the benefits of non-contacting flow measurement including easy, low-cost installation and highly repeatable readings. Contact Greyline for advice and information on selecting and applying these technologies successfully in your application.

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# KEY FACTORS IN PICKING THE OPTIMAL FLOW METER

**Summary** – Making assumptions about a flow meter going into an oil or gas application can lead to an expensive mistake. While a variety of factors impact meter performance, the most common culprits are flawed sizing and failing to choose the most appropriate technology. By more closely accounting for these and other variables, operators can ensure their future flow meter acquisitions are better suited for the job.

**F**low meters play a pivotal role in many applications, but some may underperform if they're not the best match for a process.

Making assumptions about a flow meter going into an oil or gas application can lead to an expensive mistake, especially in high-pressure situations. While a variety of factors impact meter performance, the most common culprits are flawed sizing and failing to choose the most appropriate technology.

By more closely accounting for these and other variables — and not going into the evaluation fixed on a specific meter technology — operators can ensure their future flow meter acquisitions are better suited for the job.

## **Pay Close Attention to Sizing**

Sizing is an issue because meters tend to be designed to potential maximum flows instead of actual operating flow rates. Is a meter the proper size for the flow rate, pressure, and temperature at which it will typically be operating? Because gas is compressible, for example, sizing a meter for maximum design pressure will provide a flow rate in standardized volumes that appears much different than it would be at normal operating pressure. In that case, selecting a flow meter to handle 2,000 psi based on the pipeline design,

even though it will really operate at 500 psi, will result in a meter that is substantially oversized for the application.

To mitigate these types of sizing issues, ask the vendor for a sizing report or for software to perform the sizing. Plug all the flow variables — fluid type, flow rate, pressure, temperature, viscosity, compressibility, and density — into the software. It will provide recommended technologies as well as an estimate of the devices' performance to help select the most suitable meter.

Sizing software can only go so far, as another common issue is not selecting the technology that's the optimal fit for an application.

For example, if there are corrosion inhibitors in a fluid, it would be inappropriate to use an electromagnetic meter since the additive may be inadvertently coating the sensor electrodes and thereby affecting the sensitivity of the device to flow changes. Account for any special considerations, such as the potential explosiveness or corrosiveness of what's being measured. Additionally, are there any electrical or hazardous materials approvals required for the technology to fit in an installation? Asking these types of questions will help you to determine material compatibility and narrow down the most appropriate options.

The table below may provide general guidance on technologies suited for certain applications.

## **Other Variables To Watch**


While proper sizing and choice of meter based on materials is critical, there are other fundamentals to consider when evaluating flow meters. These include:

- Be clear on what is required when it comes to accuracy, repeatability and pressure drops at nominal operating conditions. A greater pressure drop might be acceptable in some settings, but not in others. Most manufacturers' sizing software will provide several meter options that span a range of accuracy and pressure drops;

- Have a clear understanding of what's being measured and its overall state. While this seems straightforward, there can be confusion in some instances (i.e., might a liquid flash or a gas condense?). This may impact where and how you choose to install the meter, so consult the manufacturer if these types of conditions apply;

- Mechanically, what kind of flanges or end connections will be needed to mount the instrument? If the new flow meter is replacing an existing meter, understand the dimensions of what's being replaced. For example, what will be required to



	Electro-magnetic flowmeters	Variable area flowmeters	Ultrasonic flowmeters	Coriolis Mass flowmeters	Vortex flowmeters	dP flow measurement
<b>Liquids</b>						
Liquids (e.g. water)	•	•	•	•	•	•
Low flow rates	•	•	x	•	x	?
High flow rates	•	x	•	•	x	•
Non-conductive liquids	x	•	•	•	•	•
Viscous media	•	•	?	•	?	•
<b>Gases</b>						
Industrial gases	x	•	•	•	•	•
Low flow rates	x	•	?	•	x	•
High flow rates	x	?	•	•	•	•
Steam	x	?	•	?	•	•
<b>Special applications</b>						
Slurry, media with solids	•	x	x	•	x	?
Emulsions (oil/water)	?	•	?	•	?	•
Corrosive liquids (acids, alkalis)	•	•	•	•	?	•
Corrosive gas flows	x	?	•	?	?	•
Bi-directional measurements	•	x	•	•	x	•
<b>Type</b>						
2-wire	?	•	x	x	•	•
4-wire	•	x	•	•	x	x

• suitable      ? check conditions      x = not suitable

Figure 1. One step in selecting the proper flow meter is knowing which technologies should be in consideration for a particular use. (GRAPHIC COURTESY OF KROHNE).

adapt a new meter selected as a replacement for a mechanical device with a narrow facing;

- Determine if there are other requirements for a flow meter to operate within specifications in your setting, such as minimum upstream and downstream straight-pipe runs. Will space limitations impact flow meter performance? If so, is there a way around it? In some cases, additional hardware such as flow straighteners, or perhaps special factory calibration setups can be considered to account

for these constraints; and

- Have a clear understanding of the power requirements, environmental conditions and how the meter will connect to other devices. A meter tied into a control system might elicit a different set of recommendations from a vendor than one that will be operating independently or remotely connected to a SCADA system.

Finding an optimal flow meter solution depends on knowing as much as possible about the application. By asking the right questions and taking these variables into consideration you are more likely to find the best device for the application.

For more information visit KROHNE's website at <http://us.krohne.com> or email [info@krohne.com](mailto:info@krohne.com).

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# MULTIPHASE METERS – GAS LIQUID INTELLIGENT METERING SYSTEM – GLIMS INTRODUCTION

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Ross Waters, Chairman, CGIS  
Visit [www.cgis.ca](http://www.cgis.ca) to learn more.

The need for dedicated multiphase metering devices has been steadily increasing as improved oil and gas reservoir management continues around the globe. A two-inch GLIMS prototype, mainly dedicated to smaller production facilities, is undergoing laboratory testing using the CGIS Flow Loop Facility. GLIMS is one of the newest entrants and it could potentially offer comparable accuracy with other providers of multiphase flow meters (MPFMs) today at significantly reduced CAPEX and OPEX.

## Multiphase flow

For the purposes of this article and to better understand GLIMS' operating principle, "multiphase flow" refers to mixtures of liquids and gases co-currently flowing through same wellbores. Furthermore, the GLIMS operating principle applies mainly to mixtures of liquids and gas differentiated by two significantly different densities at the metering section.

The liquid "phase" could be a mixture of

liquid oil components and formation water, as usually obtained from any oil reservoir, and the gas phase mixtures comprising reservoir gas mixed with gas released from liquids as the pressure of gas-liquid mixture is reduced from the reservoir deep location to the measuring point. For any metering purposes the composition of gas and liquids is known and frequently measured through sampling and subsequent gas chromatography. For the given sample, thermodynamic equilibrium models (such as Peng-Robinson and others) are currently used to indicate the composition and amount of organic and inorganic components expected to be in the liquid and in the gaseous phases for known pressures and temperatures in the multiphase sensor metering zone.

The above statement is correct as long as the flow of gases and liquids are at thermodynamic equilibrium which, for some metering designs, is not sufficiently considered to be an important source of errors.

GLIMS has been considering this aspect

in its detailed design and therefore adopted a unique streamlined meter profile. In this way, local release of gaseous phase is almost eliminated, even for extreme operation conditions.

While GLIMS is fully able to indicate the ratio of gas – liquid as GVF and the total flow rate of gas and liquid it will indicate the amount of reservoir water in the liquid mixture, by using an additional, commercially available, "water cut meter."

## The need for multiphase flow meters

Multiphase Flow Meters (MPFM) are a relatively new technology family of flow meters that offers improved management of oil and gas production.

Prior to the 1980s, the Oil and Gas industry used conventional metering (turbine, orifice, venturi, coriolis, etc.) calibrated for gas or liquid streams only and positioned on the exit gas or liquid pipes from the test separation tank, located in the gathering station of the oil or gas field.

Expensive and cumbersome test separators are a common element in oil and gas facilities where each individual well is measured one at a time using field personnel in order to connect one well at a time.

As an example, for seven wells coming from an oil lease field, the tank separator method is not conducive to continuous metering and monitoring more than a single well, individual well metering occurs only one day a week.

Furthermore, the tank separator method is not able to continuously record production for all seven individual wells and assist in improving the overall reservoir performances; even more challenging is custodial transfer for "allocation" distribution



GLIMS flow computer.





GLIMS test flow loop instrument.

when a lease has many owners. As the well ages and the reservoir's pressures change, flow rates and phase fractions change, confounding the accuracies needed to manage the production. The health of individual wells cannot be determined unless their production is continuously observed and compared to all other producing wells in the reservoir.

Between 1980 and 2010 a significant effort was made to develop suitable technologies offering real time or momentary data on the amount of oil and gas being produced by each well.

After more than 40 years of effort a small number of technologies are presently available and installed. A 2006 study estimated that nearly 3,000 applications including field allocation, production optimization and mobile well testing are using MPFMs.

## Multiphase Flowmeter Technologies

Direct evaluation of the gas-liquid distribution is presently performed with the aid of a focused gamma-ray metering (fluid density significantly influences the absorption of gamma rays), high-speed cross-correlation of fluid(s) velocities and overall metering of electrical impedance appears to be among the most promising and tested metering principles used in various combination today<sup>1</sup> (see Table 1).

Table 1 shows a selected group of MPFM technologies with GLIMS, appended as a new candidate, in order to offer quick comparison criteria. This is not an exhaustive list; various customers may have different opinions how a certain technology

Manufacturer	Emerson (Roxar)	Halliburton	Schlumberger	Weatherford	ABB	KROHNE	GLIMS
Radioactive Source	Optional	None	Yes	Yes	None	None	None
Technology	EICC(a)	VFM(b)	Gamma Density	VFM, Gamma, Sonar	VFM(b) Orifice plate	Magnetic Resonance	Dispers. Phase Statistics
Range (GVF)	85-100%	0-100%	0-100%	0-100%	0-100%	0-98%	0-100%
Advantages	No Radiation	No Radiation	No Calibration Full GVF Range	Full GVF Range	No Rad., Simple	No Radiation	Discussed In paper
Disadvantages	Reduced GVF Range		Radioactive Source	Radioactive Source	Extended Initial Calibration	Reduced GVF Range	Not Field Ready

(a) Electrical Impedance Cross Correlations (EICC)  
 (b) Virtual Flow Metering (VFM)

Table 1. Summary of some industrial multiphase meters and GLIMS for quick comparison (ref 1)

is used in a particular location and flow conditions.

GLIMS essentially relies on a relatively simple sensing technology having the ability to count and produce a time-limited statistical interpretation of the strength and duration of electrical impulses that are mainly related to velocity and size of a great number of flowing discrete, dispersed phases (as bubbles carried by the liquid, or droplets carried by gases). For example, using a certain acceleration sensor, conveniently placed in the GLIMS metering area, a number of two million impulses could be obtained and stored during less than a minute of measuring time. The intensity of each impulse depends strongly on the size and velocity of the discrete element. It is essential to realize that the size of a discrete fluid element depends (through the known Kolmogorov-Hinze-Taitel-Barnea model<sup>2</sup>) on the turbulent dissipated energy of the gas-liquid multiphase stream entering the GLIMS apparatus.

Direct comparison of the GLIMS Acceleration Sensor response with an experimentally obtained "standard" sensor map, adjusted with the aid of the "Physical Model," produced a viable tool for assessing GLIMS response to broad ranges of pressure-temperature-gas-liquid conditions (such as flow conditions, viscosities, Reynolds number and interfacial tensions), a tool capable to tune GLIMS for specific

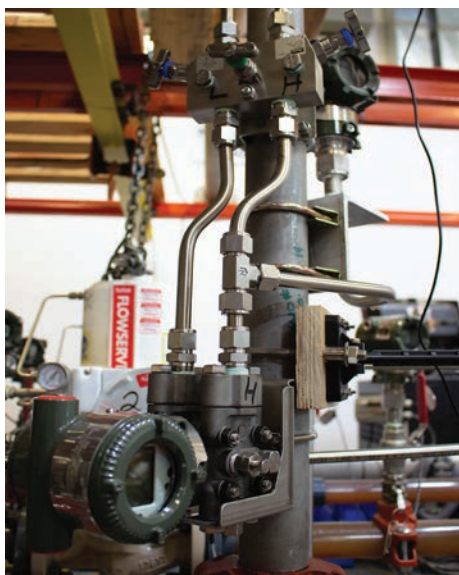
flow conditions in the metering zone. This considerably reduces or eliminates operating costs related to calibration (see Table 1).

In this way, GLIMS significantly departed from two-phase metering technologies relying on complicated scanning of the gas-liquid flow metering section (e.g. using gamma ray densitometry principle) and, instead, is using an accepted and verified mechanistic model relating transport velocity of gas and liquid and gas concentration (as GVF) in the metering area to the size-distribution of dispersed phase.

How do we know this two-phase flow physical aspect is valid and could be accurately used by GLIMS technology?

The answer to this question has been found by 2000-2001 during intense testing of acceleration sensors completed with the aid of a state-of-the-art multiphase loop (ARC/ATIF, Edmonton), testing described in an Oil and Gas Magazine<sup>3</sup> article. Approximately 500 independent tests have been conducted and a certain type of an acceleration sensor has been exposed to a broad range of liquid and gas concentrations (GVF) and to gas-liquid transport velocities from 0-4 m/s (in a one-inch tube!).

Sensor response data have been further analyzed and compared, all using a consistent statistical analysis of the signal received from the acceleration sensor. A very small deviation (less than one per cent)



GLIMS control piping.

was found for repeatability and a 3D characteristic of the sensor response was developed as:

$$PDF \text{ (probability density function)} = F \text{ (GVF, Transport velocity of gas and liquid)}$$

From this rigorous testing stage to GLIMS design, the team spent several years to consider and address most of the problems found with other technologies such as:

1. Extrapolation of empirical equations beyond initial testing limits of the metering device where the meter accuracy significantly decreases when the initial calibration map limit is not respected;
2. Complex distribution of gas and liquid in the body of the meter;
3. Phase density differences (gravity);
4. Gas phase being released from the liquid phase and possibly accumulated, (outgassing or “exolution”) taking place under relatively small, local pressure variations in the meter body; while the Liquid-Gas perfect equilibrium conditions are difficult to be achieved; a streamlined design including a fixed cage and a rigorously, axially-displaced plug indicated as “flow conditioning system” are adapting the GLIMS metering to a broad range of inflow conditions.

As can be seen from the equation, the acceleration sensor output (as “PDF”) pro-

vides one piece of information as a function of two unknowns (GVF and the transport velocity of gas and liquid).

This problem has been overcome by executing a pair metering operation at two independent yet close positions of the movable conical-shaped plug – where the metering section is slightly adjusted by a known value, without altering the incoming gas-liquid flowrate and concentration; the modification of velocity, however small, being significant enough to be picked up by the acceleration sensor and counted by PDF 1,2 thereby producing meaningful inputs to the GLIMS data processing algorithms.

### The GLIMS advantage

A general problem, for most of the successful multiphase metering technology today is the high CAPEX cost of the meter; cost that would restrict equipping wells producing less than 1000- 2000 BBD, in addition, (and particularly for wells under 1000 BBD), significant flowrate fluctuations may reduce the instrument accuracy under acceptable levels from an economic standpoint. In short:

- GLIMS is offering a metering system using the minute pressure fluctuations generated by the (intrinsic) transport of the flow-entrained dispersed phase and carried in a metering zone which is adjusted for relatively broad ranges of flowrates.
- GLIMS, with the aid of an acceleration sensor, records and analyses approximately two million impulses during a metering time interval of less than one minute. The strength and number of the recorded signals (in volts) being directly related to the size and “population” of the dispersed bubble indicated as “fluid particle” and to the transport velocity of the gas- liquid flowing stream.
- GLIMS is designed to perform a pair of metering procedures, under a known, yet small, variation of metering area, variation totally insignificant for any change of the input flowrate and GVF, yet fully recorded and statistically analyzed.
- GLIMS specific “fingerprint” is pro-

duced for each specific gas and liquid flow-rate combination; the “fingerprint” being decoded with the aid of a detailed (3D) map of the acceleration sensor and with the aid of a theoretical physical model describing the expected “size-velocity” distribution as a function of gas-liquid transport velocity for the physical properties of any (non- miscible) liquid-gas mixtures.

### The next steps

The development of GLIMS began several years ago and is now on a final track. The methodology was patented in April of 2019 (U.S. Patent No.10,274,354), while the apparatus itself just recently received its own patent in May of 2020 (U.S. Patent No.10,634,537 B2).

The GLIMS apparatus is currently being tested at CG Industrial Specialties Ltd (CGIS) in their Control and Instrument Demonstrator (CID) in Vancouver, B.C. Future efforts to finalize GLIMS development will be to take the apparatus to an industry accepted testing and simulation facility (such as NEL in the U.K.), install it in the field, manufacture a base unit and develop further diversified models.

### Summary

MPFMs are an increasingly valuable method of improving the management of oil and gas production facilities and are becoming available for a wider range of production rates. GLIMS is a promising game-changer due to its unique abilities to capture the real-time, accurate gas-liquid flow information, at reduced capital expenditure and operating costs.

1 Reference: Multi-Phase Flow Metering in Offshore Oil and Gas Transportation Pipelines: Trends and Perspectives by: Skov Hansen, Simon Pedersen and Petar Durdevic in : Sensors 2019, 19(9), 2184; <https://doi.org/10.3390/s19092184>

2 Barnea, D, Shoham, O, Taitel, Y., and Dukler, A.E.: “Gas-Liquid Flow in Inclined Tubes: Flow Pattern Transitions for Upward Flow” Chem. Eng. Sci., 1985, 40, 131 – see also “Mechanistic Modelling of Two Phase Flow by O. Shoham, U of Tulsa, SPE, 2006

3 New Concept for rapid transfer of novel technologies from laboratory to field, by P.Toma et al, in Pipeline and Gas J. July 2000.



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