AN EXAMINATION OF FLOWMETER TECHNOLOGY

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ABSTRACT

Flowmeters available to the petroleum industry fit into a wide range of operating principles and are diverse in the physical phenomena employed. Flow measurement may be made from (1) velocity, (2) mass transfer rate, (3) volumetric transfer, or (4) interference.

Our industry pumps fluids that range from (1) clean, homogenous newtonian to (2) heterogenous non-newtonian slurries. Application of flowmeter type to fluid type requires more than casual attention.

This paper presents a summary of flowmeter types currently available and gives advantages and disadvantages of each. Included in this technology survey are (1) flowmeter types, (2) operating principle, (3) range of accuracy, and (4) proper application of each.

The conclusion is reached that flowmeter choice is not as straightforward as users may have been led to believe, however, an informed user can select a meter that will give the best available service.

OBJECTIVE

The objective of this paper is to present a review of the array of flowmeters available for oil field service use. Each meter was evaluated as to the physical phenomena employed, the inherent performance characteristics, and any anomalies as to its applicability to the oil field industry.

INTRODUCTION

An explicit, all-around flowmeter that can meet all industry needs does not now exist; an explicit type of meter may more optimally meet the needs of an explicit situation. With prudence, a minimum number of types of meters may be chosen to fulfill a diverse array of metering requirements.

If one is attempting to pick a meter based upon vendor supplied publications, care should be taken, since each vendor is attempting to present his meter in the most optimistic manner. All meters under consideration should be evaluated in an equitable manner. Some of the typical factors to consider are:

1. Range of desired operation (turndown ratio)
2. Accuracy as per cent full scale over the desired range
3. Accuracy as per cent reading over the desired range
4. Ease of adjustment to zero and span

5. Ease and cost of installation
6. Ease and cost of maintenance
7. Material compatibility
8. Overall cost per service hour over the life of the meter

DISCUSSION

Before beginning a discussion of the metering devices, the variation in the types of fluids encountered in the oil field services industry should be briefly addressed. The spectrum of fluid types is wide and varied. For example, one of the easier fluids to handle is fresh water being pumped with a centrifugal type pump. This serves as an example of a homogeneous, newtonian, non-pulsating flow condition. On the other end of the spectrum one may find a foamed, sand-laden, gelled slurry, which may have highly corrosive chemical properties and may be under extreme temperature and pressure conditions, being pumped with a reciprocating positive displacement pump. This type of fluid illustrates a non-newtonian, pulsating flow condition which may quite easily become heterogeneous. It therefore becomes obvious that the interrelationship between temperature, pressure, molecular structure, and molecular behavior is complex. The complexity may be further aggravated by such items as variation in foam quality, geometric obstructions, and swirl, to name but a few. The one positive aspect may be that most of the more difficult fluids being pumped are normally well within the turbulent flow regime.

This paper is primarily concerned with the flow through circular cross sectional tubing. Therefore, the basic governing equations to keep in mind are:

$$Q = (A)(V_{avg})$$
$$M = (\rho)(Q)$$

where:

Q = volumeric flow rate
A = cross sectional area of the tube
V_{avg} = average velocity of the fluid
M = mass transfer rate
ρ = fluid density

Meters may be categorized in many ways, such as (1) pressure drop, (2) % full scale accuracy, (3) range, (4) turndown ratio, (5) chemical resistance, (6) price, and (7) ease of maintenance. In reference to the above equations, one of the more functional ways of categorization has been done by D. W. Spitzer. Spitzer[1] categorizes in the following manner:

Type A: Volumeric displacement rate measured
Type B: Velocity measured
Type C: Flow measured inferentially (flow determined empirically from some phenomenon resulting from flow)
Type D: Mass transfer rate measured

The list of meters chosen for discussion here is not exclusive; these meters were chosen with application to some specific needs of the oil field services industry. As each meter is discussed, some performance characteristics may be discussed.

Magnetic Flowmeters

This meter measures velocity of the fluid and is representative of a Type B mentioned above. The principle of operation is based on Faraday's Law of Electromagnetic Induction,[2] which states that a voltage is induced in a conductive media (in this case, the fluid) moving through a magnetic field (in this case at a right angle to the field). The magnitude of the induced voltage is proportional to the fluid velocity[2] by the following equation:

$$E = \text{Constant} \times B \times L \times V$$

E = Induced Voltage
B = Magnetic Flux Density
L = Distance Between Probes Across the Diameter
V = Fluid Velocity

Two types of electronics are commonly used in this measurement, those which excite the fluid with a continuous AC (alternating current) electromagnetic field, and those which use a pulsed DC (direct current) electromagnetic field. As one might suspect, "stray" voltages[1-3] do have adverse effects upon this meter's performance. Sources for some of the "stray" voltages are typically:

1. Triboelectric charge buildup (such as would be exhibited by flowing sand particles)
2. Electrochemical charges produced from electrolytic compatibility to the working fluid
3. Improper grounding of the meter
4. Inductive coupling of magnets within the flowmeter
5. Capacitive coupling

The DC electronic design allows for the signal voltage to be segregated from the noise background generated by these "stray" voltages. With pulsed DC, a reference or zero can be established between pulses, thus any electronic drift can also be compensated. One other major advantage of the DC design is that it provides for lower power consumption since it has a shorter duty cycle than the traditional AC circuit design.

The meter body is constructed of nonmagnetic material (such as stainless steel, titanium, inconel, etc.) and contains a liner of electrically insulating material such as teflon, aluminum oxide, polyethylene, and polyurethane. The electrodes are normally constructed of materials such as stainless steel, tantalum, titanium, platinum and other chemically resistant materials including some of the high nickel alloys.

A few of the more obvious advantages for this type meter are:

1. Not sensitive to viscosity
2. Insensitive to fluid density
3. No flow obstructions or moving parts, thus the pressure drop is negligible
4. Turndown ratio for this meter normally listed from 10:1 to as high as 40:1 (and may be higher)
5. Accuracies advertised to as low as 0.2% reading

This meter has operating constraints which must be considered; the most obvious is fluid electrical conductivity. Most magmeter manufacturers advertise that a minimum fluid conductivity of 1-5 microsiemens/cm is required for proper operation. Most pure hydrocarbons do not exhibit this minimum. One possible solution is to place additives in some of the more commonly used fluids to raise the minimum electrical conductivity, thus allowing the use of magnetic flowmeters in heretofore unusable circumstances. On this meter, two other constraints which may directly affect the oil producing business are pressure restrictions and flow rate limitations. Most of these meters are limited to flow velocities of 30-40 fps and pressure ratings of less than 1000 psig. The meter also must remain liquid full for proper measurement, thus plumbing could pose a problem (although a minimum number of diameters before and after the meter are not normally recommended by the manufacturer). Two other remaining considerations for the oil field user are fluid chemical compatibility to wetted parts and electrode coating (especially in the AC driven meters).

From an oil field user's point of view, this particular type of meter should not be quickly discounted during meter selection. Development of these meters within the last 10 years has given the meter the capability to work on less electrically conductive fluid, consume less power, measure more accurately, and to work in smaller physical packages. A substantial reduction in purchase price has also been observed for the last few years. Meters are also available with visual gage output at the meter, 4-20 mA output, frequency output, as well as RS-232 computer buss output.

Turbine Meter

The turbine meter is a velocity measuring device. Flow velocity is sensed by measuring the rotational velocity (displacement) of a bladed rotor; the rotational velocity is directly proportional to the fluid velocity. Major components of the meter are the (1) rotor, (2) rotor bearings, (3) housing, and (4) rotational sensing mechanism. The rotor is optimized for low rotational inertia to maximize response to rapid flow velocity changes. Bearings of various types are available; two of the more common types are tungsten carbide and jeweled bearings. Rotor speed is sensed in a variety of ways such as:

1. Non-contacting magnetic pickup
2. Mechanical gearing to a sealed output
3. RF - Proximity techniques

Chemical compatibility with materials used is a concern to the oil field user; also, self-lubricating capability of the working fluid is also a consideration with some meters.

Most turbine meters operate linearly in the turbulent flow regime with minimum Reynold's numbers varying from 4000 to 20,000. They do, however, perform best with axisymmetric flow, and a minimum number of pipe diameters is often prescribed for placement upstream and downstream of the meter, with straightening vanes normally recommended (a consideration in overall meter cost). Meters are available with proper sizing that can measure flows less than 1 gal/min and as high as 50,000 gal/min. The meter should not operate outside the recommended flow range, since excessive flow may damage the bearings. The turndown ratio is normally considered to be around 20:1, however under certain circumstances it may vary from 16:1 to as much as 100:1. Although normally used to measure a liquid product, these meters are also used in gas service.

Accuracy of the turbine meter is normally about ±0.5% of reading with accuracies as high as ±0.25% of reading under specific circumstances. Calibration of the meters for liquid service is normally done using water at room temperature.[4] The manufacturer should be contacted when the turbine meter is to be applied to other fluids and other environments.

Although the rotor velocity is a function of fluid velocity, there are other factors which must be considered that also may effect the rotor velocity. Some of these are:

1. Bearing friction - especially near the ends of the flow range
2. Viscous friction
3. Rotor blade geometry
4. Flow conditioning - or axisymmetric turbulent flow as mentioned earlier
5. Fluid density
6. Drag forces of the sensing device - such as a magnetic pickup

With proper installation and with the proper numerical technique applied to the data, most of these factors can be negated.[5] There are some use factors, however, which cannot be negated and for which precautions should be taken. Some of the more common are:

1. Deposits from the working fluid
2. Boundary layer thickness reducing the effective flow cross section
3. Cavitation of the rotor - normally resulting from a working fluid of high vapor pressure or excessive pressure drop across the meter
4. Debris
5. Temperature and pressure outside the recommended operating range
6. Erosion from the working fluid

Despite these disadvantages, the turbine meter, when properly applied, has a long history of high accuracy and dependability in the oil field. Comparable accuracy is often achievable only with much more expensive meters.

Differential Pressure Flowmeters

This type of meter has been in widespread use throughout the petroleum industry for many years.[6] Flow is empirically correlated to the pressure drop across some sort of line restriction such as an orifice plate, a venturi tube, or even something as simple as an elbow in the line. This type of meter can be classified as a Type C since neither mass, velocity, nor volume displacement is measured directly. The principle of operation is derived from an application of the Second Law of Thermodynamics[7] (more simplified as Bernouli's equation) across the restriction.

Many ingenious design techniques have been devised to optimize the performance over the years, for example (1) concentric square edged orifice, (2) conical entrance orifice, (3) eccentric orifice to eliminate entrapped gases or solids, (4) quadrant concentric orifice, and (5) standardized venturis to minimize pressure drop. Further performance optimization is found in such techniques as pressure tap placement, addition of straightening vanes, and proper number of diameters before and after the restriction.

The mechanical simplicity of these designs can be somewhat misleading when looking at the overall application from an economic point of view. The initial sizing procedure[8] can be somewhat involved and the fluid properties must be clearly defined. Reynold's number constraints are specified according to the type of restriction employed. Since the fluid properties are a function of parameters such as temperature, pressure, compressibility, density and expansion factors (especially with gas), these parameters must be known as accurately as possible.

The governing equations of operation dictate that the pressure drop is a function of the flow rate to the second power. Therefore, with the flow rate in the lower portion of the desired range, the error can increase dramatically. However, there are many situations in the petroleum industry where fluid properties can be well enough defined in a "steady-state" flow situation to allow the reliable use of this sort of device.

As with some other meters discussed in this paper, the total cost of this type of meter must include the addition of a specified number of pipe diameters upstream and downstream of the device since the performance is dependent upon an axisymmetric velocity profile. In addition, further cost may be incurred if it is determined that straightening vanes are necessary, nor can cost of the pressure sensing elements be eliminated from the design (inaccuracy of these devices will compound the inaccuracy of the overall meter system).

Other considerations in the employment of this type gage are installation techniques (such as the elimination of entrapped gases in the pressure sensing lines[1]) and maintenance cost. Corrosion and erosion properties of the working fluid cannot be ignored.

Although there are many variables to be considered with this type of meter, accuracies of ±2-4% can be achieved with the proper application; turndown ratios in the range of 4:1 are normal.

Positive Displacement Meter

Very similar to a pump in reverse, this meter measures the number of times a known quantity of fluid is entrapped and passed through the flowmeter. The meter normally generates a series of pulses as the entrapped fluid is passed through. Totalization is achieved by accumulating pulses, and flowrate is obtained by counting pulse rate. This meter represents the Type A category.

Precisioned mechanisms are normally associated with the entrapment process, thus, highly toleranced, machined parts are normally required. The driving force for operation of this device is provided by the pressure drop across the meter. Two of the more common types of mechanisms are the nutating disk and oscillating piston. As a result of the tolerance gaps necessary for the relative movement of these parts over the desired operating temperature range, some small amounts of fluid may pass through the meter without being part of the entrapped volume. This is commonly referred to as slippage. Although the device is not sensitive to Reynolds number, it is sensitive to the fluid viscosity. Because of slippage, higher viscosity fluids can often be measured more accurately than the less viscous liquids; however, as viscosity is increased so is the pressure drop for a fixed flowrate and meter size. Published accuracies of this device may be as low as 0.5% of rate; the user should also bear in mind that in the petro-chemical industry relatively large deviations in fluid viscosity may often occur over relatively small temperature ranges. The variance in viscosity could quite easily cause inaccuracy greater than that stated by the manufacturer.

As an example of slippage, Baker[9] has given the slippage varying from near zero for viscosities exceeding 20 cp to about 0.5% to 1% for gasoline (approximately 0.6 cp viscosity). Due to intrinsic mechanical design, wear, bearing friction, and other factors, slippage may vary from meter to meter.

In relation to the petro-chemical industry, further caution should be exercised in regard to the following:

1. Inaccuracy is induced by the presence of gas.
2. "Dirty" fluids can be very detrimental to the precisioned mechanism of the device.
3. Often to maintain a lower pressure drop, larger sized meters must be chosen making cost prohibitive.
4. Chemical compatibility to the meter materials must be observed.
5. Bearings of the device may require the metered fluid to have minimum lubricating properties.

In defense of this type meter, many of these devices have operated reliably, giving acceptable accuracy, with years as a mean time between failure. Primary use of this meter has been in the measurement of residential water usage where 80% of the usage is at flow rates of less than 4 gal/min. However, meters are produced in the 3-5 bbl/min range with pressure drops refined to a minimum. Since axisymmetric upstream flow is not a prerequisite, no upstream conditioning is necessary. The desired operating characteristics and environment should be closely evaluated before discounting the use of a positive displacement meter.

Vortices Shedding Meter

One meter which seems to be continually gaining more recognition is the vortex shedding flowmeter. This meter can be classified as Type C (flow inferentially determined). The physical phenomenon upon which the meter is based is quite intriguing. An obstructive object, most commonly a wedge, is placed at midstream of the flow. As the velocity is increased, vortices are shed alternately from side to side off the obstruction. A direct correlation can then be made between the frequency of vortex occurrence and flow rate. The geometric shape of the obstruction varies somewhat for each manufacturer.[10] In fact, each shape may be optimized explicitly for a desired application with emphasis on such parameters as abrasion, repeatability, linearity, and maintainability.

As intriguing as the phenomenon of the alternating vortices are the sensing systems used to detect the presence of these vortices. The alternating vortices create alternating pressure pulses and may be measured by (1) pressure transducers, (2) measurement of torque on the wedge as the vortex is shed, (3) acoustic sensors, and (4) thermal sensors that detect a change in temperature due to the vortex flow.

In order to allow the flow to be as axisymmetric as possible, a minimum number of upstream and downstream diameters may be recommended by the manufacturer (this may range to 30 diameters upstream). The plumbing restraints should require the line to also be full during operation. This meter is also Reynolds number sensitive. Reynolds numbers of 10,000 or more are normally required for linear operation. Some manufacturers advertise less if the meter is calibrated by them at their facilities. Indeed, as the fluid properties may change with temperature, the meter may be temperature sensitive.

Care should also be taken that all the fluid in each vortex remains at a pressure above the vapor pressure of the liquid to avoid cavitation. With these restraints in mind, this meter might well be applied in steady state known flow conditions.

These meters are typically designed for best operation around 7 ft/sec and have a minimum rate restraint of about 1 ft/sec. Thus the turndown ratio may be limited to less than 8:1 and can be much less. Typical advertised accuracies are ±0.5 - 1% of rate for liquids and 1-2% of rate for gases. Sizing of these meters is somewhat complex. As is most always a concern in the oil production business, pressure restraints and material compatibility must be considered.

Acoustic Meters

One of the more promising designs emerging within the last few years has been ultrasonic flow measurement. An acoustic transponder is used to determine flow in each of several different types of acoustic meters; however, the method of measuring acoustic response to flow differs among different types of ultrasonic flow meters. Some of the principles employed are (1) time of flight signal through the fluid, (2) doppler effect, (3) differential frequency, and (4) simply using acoustic reflections as a level measurement device. The main attribute of acoustic flow meters is that the number of wetted parts is kept to a minimum.

The time of flight device is composed of a transmitter and a downstream (opposite side) receiver. Fluid velocity is derived directly from the time distortion, as compared to the time of flight of the acoustic signal in a non-flowing filled stream. Any variations in sonic velocity (as would be seen with a change in temperature, pressure, or fluid composition) will degrade the performance of the meter. With this operating principle, the transmitter/receiver elements may be either strapped to the exterior of the pipe or exposed directly to the fluid. Obviously meters with these elements exposed to the working fluid will have less attenuation, since the acoustic signal does not have to transverse two pipe wall thicknesses, however, pressure seals and material compatibility must now be evaluated.

The differential frequency meter is physically constructed in a manner similar to the time of flight meter. In this device a frequency shift in the acoustic signal is observed between the transmitter and receiver; the magnitude of the shift is proportional to the flow rate. As before, any variation in the speed of sound in the working fluid will degrade the performance of the meter.

As the name indicates, the Doppler meter operates by comparing the frequency of an acoustic echo to the frequency of the input acoustic signal. Normally a "beat" frequency is derived by superposing the echo and input frequencies to increase the sensitivity of the instrument. This frequency differential is proportional to the velocity of the fluid. The reflections are actually from particles being transported by the fluid. For that reason most Doppler meters require that some entrained gas or particles be present. As one might predict, an excess of these particles, as would be encountered in a sand-laden slurry, could effectively block the acoustic signal and not give reflections from midstream as desired.

Some Reynolds number restrictions may also be applied to these types of meters. The differential frequency design may operate below 2000 (truly laminar region) and above 4000 (turbulent), but may not operate properly in the transition zone. Before selecting this type of meter, the manufacturer should be consulted for further Reynolds number restrictions. Other restrictions which may be applicable are a required minimum flow velocity and a maximum wall thickness with respect to diameter. Accuracies can be as shown in Reference 1; pressure restrictions and material compatibility must be considered.

Although they are not actually acoustic meters, acoustic transponder devices are used also in the measurement of open channel flow to determine the fluid surface level.

CONCLUSIONS

With the wide array of meters and claims on the market today, the choice of the "correct" meter can be baffling at best. One quickly concludes that to pick the optimum meter, one needs to apply some sort of systematic optimization technique. R. C. Johnson,[11] describes one such technique as applied to the design of mechanical elements. The same basic technique can be applied here. Minimum standards can be established by the user for such characteristics as cost, material compatibility, pressure rating, fluid flow mechanics restrictions (such as Reynold's numbers, minimum rate, etc.), maintainability, serviceability, mean-time between failure, and life expectancy (each user's list can be unique to his needs). Once this list is established, the "proper" meter can be chosen through a process of elimination. D. W. Spitzer[1] also gives a systematic method of categorizing and selecting available meters.

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Table 1
Flowmeter Selection Guide (Based on Ref. 12)

Flowmeter Element	Recommended Service	Range	Pressure Loss	Typical Accuracy, Percent	Required Upstream Pipe, Diameters	Viscosity Effect	Relative Cost
Orifice	Clean, dirty liquids; some slurries	4 to 1	Medium	±2 to ±4 of full scale	10 to 30	High	Low
Wedge	Slurries and viscous liquids	3 to 1	Low to medium	±0.5 to ±2 of full scale	10 to 30	Low	High
Venturi tube	Clean, dirty, and viscous liquids; some slurries	4 to 1	Low	±1 of full scale	5 to 20	High	Medium
Flow nozzle	Clean and dirty liquids	4 to 1	Medium	±1 to ±2 of full scale	10 to 30	High	Medium
Pitot tube	Clean liquids	3 to 1	Very Low	±3 to ±5 of full scale	20 to 30	Low	Low
Elbow meter	Clean, dirty liquids; some slurries	3 to 1	Very Low	±5 to ±10 of full scale	30	Low	Low
Target meter	Clean, dirty viscous liquids; some slurries	10 to 1	Medium	±1 to ±5 of full scale	10 to 30	Medium	Medium
Variable area	Clean, dirty, viscous liquids	10 to 1	Medium	±1 to ±10 of full scale	None	Medium	Low
Positive Displacement	Clean, viscous liquids	10 to 1	High	±0.5 of rate	None	High	Medium
Turbine	Clean, viscous liquids	20 to 1	High	±0.5 of rate	5 to 10	High	High
Vortex	Clean, dirty liquids	10 to 1	Medium	±1 of rate	10 to 20	Medium	High
Electro-magnetic	Clean, dirty viscous conductive liquids and slurries	40 to 1	None	±0.5 of rate	5	None	High
Ultrasonic (Doppler)	Dirty, viscous liquids and slurries	10 to 1	None	±0.5 of full scale	5 to 30	None	High
Ultrasonic (Time-of-travel)	Clean, viscous liquids	20 to 1	None	±1 to ±5 of full scale	5 to 30	None	High
Mass (Coriolis)	Clean, dirty, viscous liquids; some slurries	10 to 1	Low	±0.4 of rate	None	None	High
Mass (Thermal)	Clean, dirty, viscous liquids; some slurries	10 to 1	Low	±1 of full scale	None	None	High
Weir (V-notch)	Clean, dirty liquids	100 to 1	Very Low	±2 to ±5 of full scale	None	Very Low	Medium
Flume (Parshall)	Clean, dirty liquids	50 to 1	Very Low	±2 to ±5 of full scale	None	Very Low	Medium

APPENDIX

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