Smith Meter Inc.
An FMC Corporation subsidiary

Improving Petroleum Custody Transfer Measurement Accuracy

Technical Paper 111

Issue/Rev. 0.0 (3/83)

Bulletin TP01001

Philip D. Baker

Abstract

Petroleum custody transfer measurement errors of 0.1 to 0.25 percent are typical today. Sources of these errors, and techniques for reducing them, are described. The factors affecting the choice and accuracy of P.D. meters and turbine meters are specifically addressed. Also discussed are factors affecting temperature compensation and air elimination.

Introduction

During the past decade the value of petroleum has increased ten fold. This has fostered great concern over its accurate measurement.

The two most common methods for measuring the volume of petroleum liquids are: (1) Metering and (2) Tank Gauging. A detailed discussion of the relative merits of these two techniques is found in Reference 1. Suffice it to say here that metering is normally much more accurate (and convenient) than tank gauging for measuring the volume of petroleum liquid **transferred** from one vessel to another **over a period of time**. However, tank gauging is best for verifying the volume (inventory) **contained** in a tank **at a specific moment in time** (e.g., month end).

The justification for improving petroleum measurement accuracy can be illustrated by a simple example. A moderately busy ten (10) meter position petroleum tank truck loading terminal (load rack) may load about 10 million gallons per month (120 million gallons per year) - worth about $100 million per year at today's prices. The potential annual loss due to the indicated volume measurement error would thus be:

Error	Potential Total Loss	Avg. Loss/ Load Position
1.00%	$1,000,000	$100,000
0.25%	250,000	25,000
0.10%	100,000	10,000

Volume measurement errors of 0.1 to 0.25 percent are typical at today's load racks, as well as in many other petroleum custody transfer installations.

Some of the causes of these costly measurement errors will be discussed in this paper. Included will be a discussion of errors caused by inadequate:

1. Correction for the effects of varying operating conditions (temperature, pressure, flow rate, and viscosity) on meter performance.
2. Correction for liquid density changes due to varying temperature (i.e., temperature compensation).
3. Meter calibration procedures.
4. Air (vapor) elimination.

Measurement Accuracy Terminology

The terms "volume measurement accuracy" and "meter accuracy" are not the same. "Volume measurement accuracy" is the **absolute** accuracy of the volume measured; whereas "meter accuracy" is simply the accuracy of a meter **relative** to its prover, usually for a constant set of operating conditions.

The terms "repeatability" and "linearity" are usually used to define "meter accuracy." Referring to Figure 1, **repeatability** is the variation in meter performance over several (e.g., five) consecutive proving runs at constant operating conditions (e.g., constant flow rate, viscosity, temperature, etc.). **Linearity** is the variation in meter performance over a range of flow, or **"turndown ratio,"** for otherwise constant operating conditions (e.g., constant temperature, viscosity, etc.).

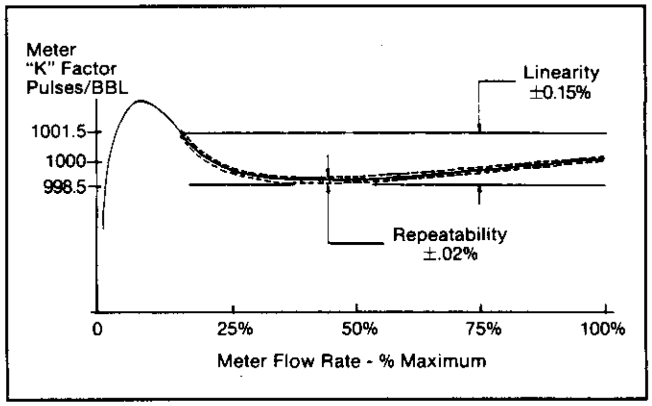

Figure 1 — Meter Accuracy Terminology

Absolute volume measurement accuracy is thus determined by the following factors:

1. Meter repeatability.
2. Prover calibration (e.g., waterdraw) accuracy.
3. Meter proving procedure.
4. Variations in operating conditions from those during meter proving, and their effect on meter performance.
5. Adequacy of air (vapor) elimination.
6. Accuracy of correction(s) for liquid density changes due to varying temperature (and pressure).

Meter Selection

Custody transfer metering of petroleum liquids is normally done with high performance versions of either positive displacement (P.D.) meters or turbine meters. There are many situations where one or the other is definitely preferred, and other situations where either type meter could be satisfactorily used. A key thing to remember, though, is that in custody transfer metering, it almost never pays to sacrifice measurement accuracy to save on meter cost. Normally, the payback from the increased measurement accuracy will quickly offset any initial extra cost.

Liquid viscosity is the major factor affecting whether a P.D. meter or a turbine meter will provide the best overall accuracy for a particular custody transfer application. Figure 2 provides a guideline for P.D. and turbine meter selection as a function of viscosity and flow rate.

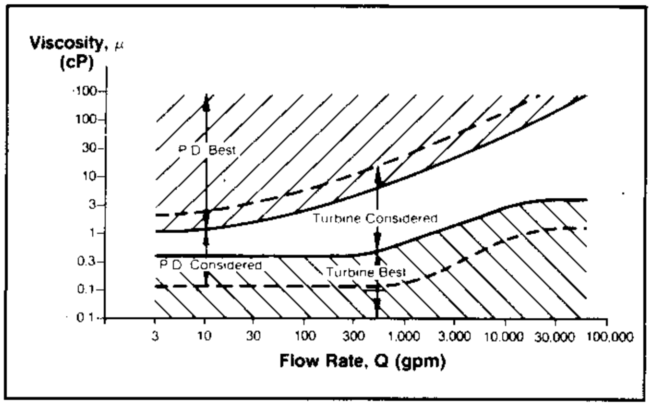

Figure 2 — P.D. and Turbine Meter Selection Guide

P.D. Meter Performance

The factors affecting the performance of P.D. meters can be described in terms of their effect on:

1. Volume of liquid displaced per rotor revolution.
2. Slippage through meter clearances.
3. External devices such as mechanical calibrators and pulse transmission lines.

Volume Displaced

The volume of liquid displaced per rotor revolution can be affected by: (1) Temperature, (2) Pressure, (3) Viscosity, (4) Wear, and (5) Deposits. For example, increasing **temperature** causes the measuring chamber volume to expand per the cubical expansion coefficient of its metal parts. When dissimilar metals are used (e.g., aluminum blades in a cast iron measuring element), the clearance between the dissimilar metal parts (e.g., blade tip clearance) changes with temperature, affecting displacement volume. The effect of temperature on liquid volume displaced is typically about 0.02 percent for a 10°F fluid temperature change, or about 0.10 percent for a 50°F change.

A substantial change in operating **pressure** will affect displacement volume in a single case meter, but not in a double case meter (where the pressure differential across the walls of the measuring chamber is nil). This effect varies with meter design. However, as a guideline, where operating pressure changes of over 20 psi are expected, the use of either a double case meter or a pressure adjusted meter factor should be considered.

With low **viscosity** fluids, as the relative velocity between adjacent surfaces increases, the liquid boundary layer on the moving surface (e.g., blade tip) becomes thinner, reducing the effective displacement volume. At higher viscosities and lower velocities, this boundary layer thickness remains constant.

Wear on bearing surfaces can cause measuring chamber boundaries to shift, usually causing an increase in displacement volume, as well as a decrease in meter repeatability.

Deposits such as paraffin on measuring chamber surfaces will reduce the volume displaced up to the point where clearances become nil. Then meter performance should remain very constant as long as the deposit remains in place.

Slippage

The "slippage" of fluid through the clearances between the stationary and moving parts of the measuring element, bypassing the measuring chamber, can be defined by the following relationship:

$$q = \frac{1}{12} \frac{Xc^3}{\mu Lc} \Delta P$$

Where (see Figure 3):

q = Bypass or slippage flow rate.
Xc = Clearance width.
LC = Clearance length.
ΔP = Differential pressure across clearance.
μ = Absolute viscosity, cP.

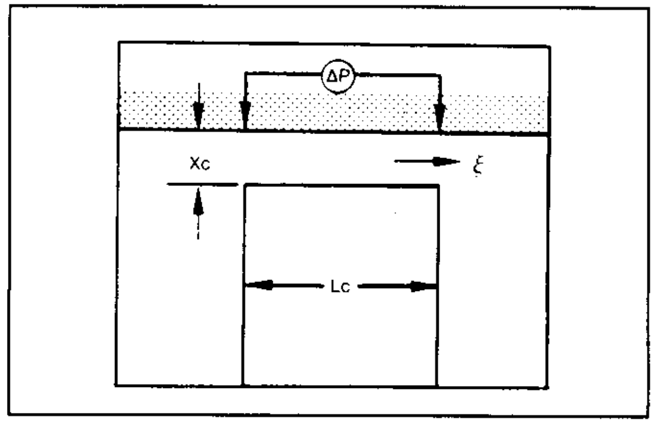

Figure 3 — Typical P.D. Meter Clearance

The slippage through the clearances of a typical high performance P.D. meter at normal flow rates will vary from near zero for viscosities exceeding aabout 20 cP to about 0.5% to 1% on gasoline (about 0.6 cP viscosity). Figure 4 shows a typical variation of meter performance with viscosity. The viscosity of petroleum products decreases with increasing API gravity and increasing temperature (see Figure 5). Thus, for lower viscosity fluids, it is important to prove a P.D. meter at its normal operating temperature, viscosity, and flow rate. How-

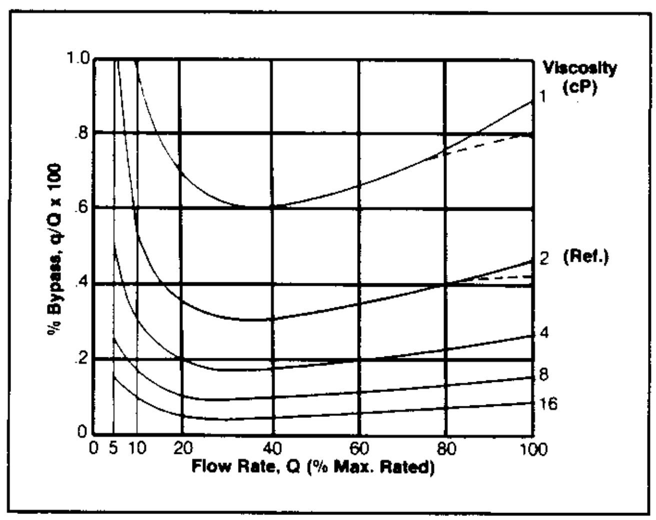

Figure 4 — Slippage vs. Flow Rate and Viscosity

ever, for higher viscosity fluids where zero slippage is approached, P.D. meters can normally be proved at viscosities and/or flow rates substantially different than their normal operating conditions without creating significant error.

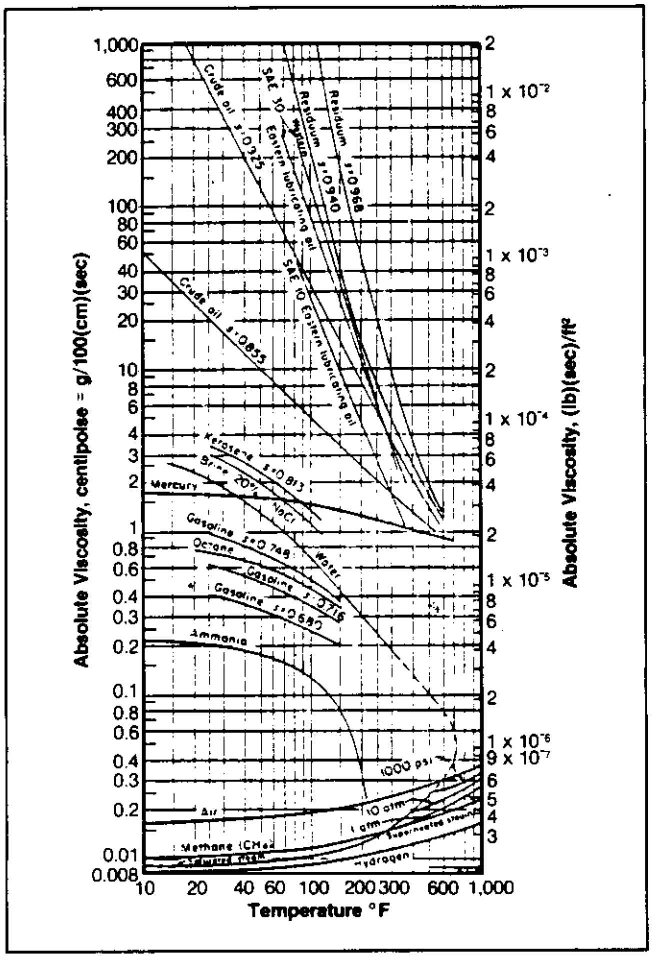

Figure 5 — Viscosity vs. Temperature for Petroleum Liquids

The factors mentioned in the previous section affecting meter clearances — namely temperature (when dissimilar metals are used in the measuring element), pressure (in single case meters), wear, and deposits — also affect slippage to the 3rd power of the resultant clearance change. For example, if a clearance width (Xc) doubled, the slippage through it would increase by a factor of eight (i.e., 2^3 equals 8).

External Devices

Devices outside the P.D. meter, but directly involved in the registration of volume throughput, can be adversely affected by environmental conditions or wear to cause significant errors in meter registration. For example, some mechanical calibrators will slip at high torque loads, or drift with temperature and wear. Remote counters may misregister due to induced noise on signal transmission lines.

Turbine Meter Performance

The factors affecting the performance of turbine meters can be described in terms of their effect on:

1. Flow area (through the rotor), and
2. Rotor velocity.

Flow Area

A turbine meter, being an inferential type of volumetric flow meter, is actually sensing flow velocity by measuring the rotational velocity (diplacement) of a bladed rotor. The volumetric flow rate (Q) is assumed to be proportional to this measured flow velocity (V) by assuming a constant flow area (A). This is described mathematically by the classical continuity equation.

$$Q = (V)\,(A)$$

$$(ft^3/sec) = (ft/sec)\,(ft^2)$$

Some of the factors that can affect this constant flow area assumption are:

1. Deposits (e.g., paraffin).
2. Boundary layer thickness.
3. Cavitation.
4. Debris.
5. Operating conditions (e.g., pressure and temperature).

A very thin **coating** on all internal surfaces of a turbine meter can change the flow area through it very significantly. For example, a one mil (0.001 inch) coating on all internal surfaces of a 4-inch turbine meter will reduce its flow area, and thus its meter factor, by about 0.5%. This effect is proportional to the square (2nd power) of meter size. Thus, for a 2-inch meter, a one mil coating will affect meter performance by about 2%.

One of the reasons turbine meters are not recommended for high viscosity liquids is the substantial increase in **boundary layer thickness**, and thus reduction in flow area, that occurs as laminar flow is approached.

When the following dimensionless relationship, called Reynold's Number, drops below about 6,000, the boundary layer thickness begins to increase rapidly:

$$Re = \frac{Vd}{\nu}$$

Where: Re = Reynold's Number
V = Velocity
d = Pipe Diameter
ν (nu) = Kinematic Viscosity (e.g., centistokes)

Thus, this laminar flow (boundary layer thickness) problem occurs at lower viscosities as meter size decreases. The recommended viscosity range for turbine meters, shown in Figure 2, reflects this fact.

A liquid will vaporize when subjected to pressures below its vapor pressure. At the high velocities through a turbine meter rotor, the local static pressure at the rotor can drop below the fluid's vapor pressure, resulting in the phenomena called **cavitation** (formation of vapor bubbles), even though the static pressure in the pipeline is above the vapor pressure. These vapor bubbles occupy much more flow area than would the equivalent fluid in liquid form, resulting in a significant rotor velocity increase (see Figure 6), and thus a significant metering error. To eliminate cavitation, the back pressure on the meter must be increased. API (Reference 2) recommends that the minimum back pressure on a turbine meter be 1.25 times absolute vapor pressure, plus two times the pressure drop through the meter. For example, a turbine meter on gasoline having a vapor pressure of 10 psia, flowing at a rate resulting in 3 psi drop across the meter, should be operated above a minimum downstream line pressure of 18.5 psig (i.e., 1.25 x 10 psi + 2 x 3 psi = 12.5 + 6 = 18.5).

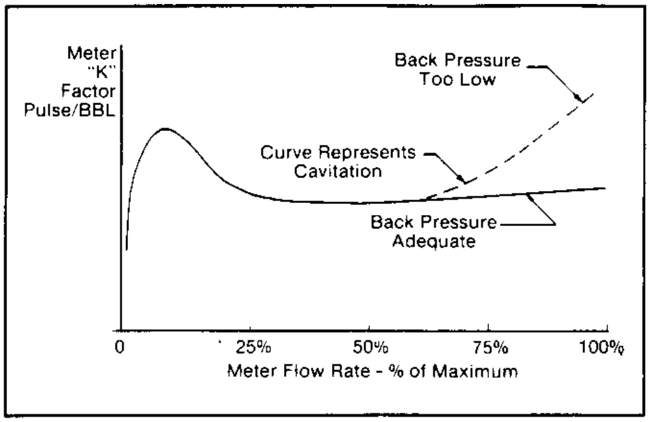

Figure 6 — TM Performance with Cavitation

Reference 3 describes the effect of pipeline **debris** on turbine meter performance. Obviously, any debris which blocks off part of the flow area through the rotor will drastically affect meter performance.

Turbine meters will undergo changes in flow area with significant changes in **operating pressure and temperature**. The flow area through a typical turbine meter will increase only an insignificant 0.002% for a 100 psi increase in operating pressure; but, a significant 0.02% for a 10°F increase in temperature.

Rotor Velocity

The assumption that the measured rotor velocity is directly proportional to the axial velocity through the turbine meter can be affected by the following factors.

1. Bearing friction.
2. Viscous friction.
3. Rotor blade configuration.
4. Flow conditioning.

One of the distinguishing characteristics of a high performance petroleum pipeline turbine meter is extremely low **bearing friction**. Also, because of their typical high speed continuous duty operation, pipeline turbine meter rotor bearings must be very wear resistant. Thus, a very precise, highly polished tungsten carbide journal bearing is normally used. The clearance between the moving rotor bearing and stationary platform bearing must be very precise to assure rotation on a thin film of liquid (i.e., like hydroplaning) to further minimize friction.

High performance pipeline turbine meters usually have a floating rotor, which has little or no thrust bearing friction over the meter's rated operating range. Figure 7 illustrates the floating rotor principle used in the Smith Sentry Series Pipeline Turbine Meters.

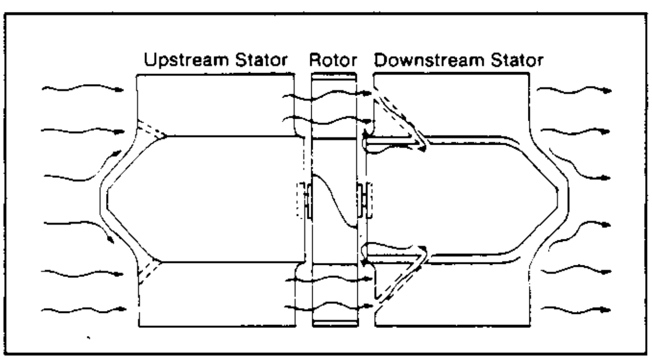

Figure 7 — Floating Rotor - Sentry TM

The frictional drag on a turbine meter rotor is nearly constant at all rotational speeds. However, rotor driving torque is proportional to the fluid density (ρ) and the flow velocity squared (V^2). Thus, at high flow rates, the low frictional drag is insignificant compared to the high driving torque. But, as flow rate decreases, the rotor driving torque decreases rapidly, while the rotor frictional drag remains the same. For example, at 10% of maximum flow rate, the rotor driving torque (ρV^2) is only 1% of its value at maximum flow rate. Now, frictional drag starts to become significant. As flow rate decreases further, the rotor/fluid velocity relationship becomes more non-linear (see Figure 8). Eventually, the rotor stops turning.

Figure 8 also illustrates the effect of **viscous drag** on the rotor/fluid velocity relationship. The flow rate at which rotor velocity begins to become disproportionate to fluid velocity increases as viscosity increases.

Should the effective angle of attack of just one **rotor blade** be changed slightly due to being struck by debris in the flowing stream, the rotor/fluid velocity relationship will be changed significantly. Also, any significant change in the edge geometry of the rotor blades due to erosion, corrosion, or debris adherence, will alter the rotor/fluid velocity relationship, and thus meter performance.

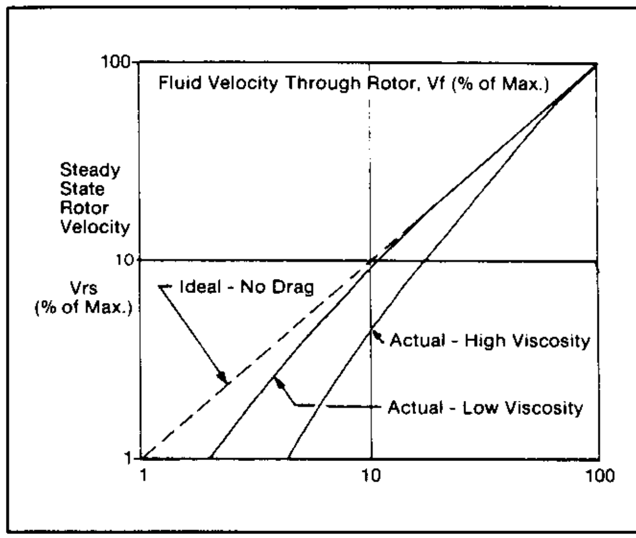

Figure 8 — Rotor/Fluid Velocity

As with other inferential (velocity sensing) types of flow meters, turbine meters require **flow stream conditioning** immediately upstream and downstream of the meter. API's detailed recommendations for turbine meter flow conditioning are found in Reference 4. Typical flow conditioning (see Figure 9) consists of an upstream straightening section ten (10) pipe diameters long, the same diameter as the meter, with a tube bundle located therein 5 to 8 pipe diameters ahead of the meter, and a downstream straightening section five (5) pipe diameters long. If the tube bundle is omitted, the length of the upstream straightening section should be increased to 20 to 30 pipe diameters.

The purpose of the tube bundle is to eliminate any "swirl" in the flow stream before it reaches the meter. Swirl will add to, or subtract from, the rotor's normal angular velocity. An extra long run of straight pipe will also help dampen out any angular velocity component in the flow stream.

Velocity profile distortion, caused by elbows, valves, strainers, etc., (see Figure 10) should also be eliminated by the straightening section. A distorted velocity profile is unstable. Any change in fluid velocity and/or viscosity will alter its shape and affect turbine meter performance. A symmetrical velocity profile is needed to obtain good turbine meter performance over a range of operating conditions.

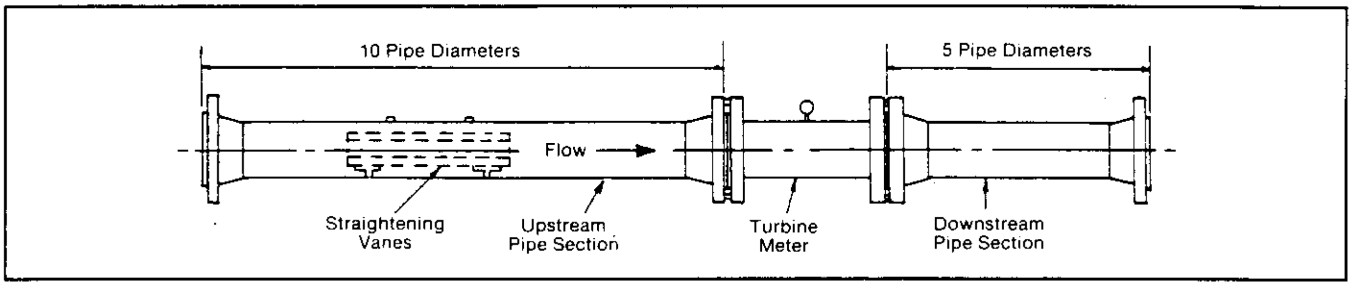

Figure 9 — Typical Flow Run

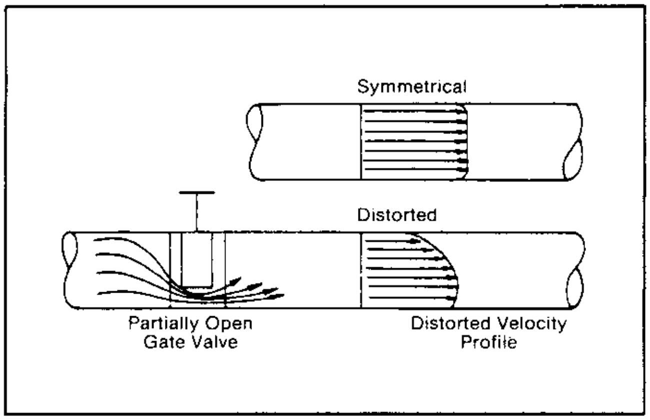

Figure 10 — Velocity Profile Distortion After Gate Valve

Meter Proving

The best meter in the world is worthless unless it is properly calibrated. The most common devices for calibrating meters are as follows:

1. Volumetric prover can.
2. Mechanical displacement prover.
3. Weigh tank.
4. Master meter.

A detailed discussion of meter provers and proving techniques is beyond the scope of this paper. Suffice it to say here that any of the above meter proving devices, when properly calibrated (e.g., waterdrawn), and operated with good proving techniques, can be satisfactorily used to calibrate high performance custody transfer petroleum meters.

Temperature Compensation

A characteristic of all liquids is that as temperature increases, density decreases. For example, a unit volume (e.g., 1.000 gallon) of 60 degree API gasoline at 60°F occupies 0.68% more volume at 70°F, and 0.68% less volume at 50°F (see Figure 11).

The Coefficient of Expansion (C of E) of a liquid is defined as the change in volume (ΔV) per unit volume (V) per change in temperature (ΔT):

$$\text{C of E} = \frac{\Delta V/V}{\Delta T}$$

Thus, the slope of the volume - temperature curve in Figure 11 gives the C of E for 60 degrees API gasoline (i.e., 0.00068/° F or 0.068%/° F).

The worth of a specific petroleum liquid is proportional to its energy content, mass, or equivalent (net) volume at a reference temperature (e.g., 60°F); not to its gross volume at whatever temperature it may happen to be when measured. Thus, accurate temperature compensation of gross measured volume is crucial to accurate custody transfer petroleum measurement.

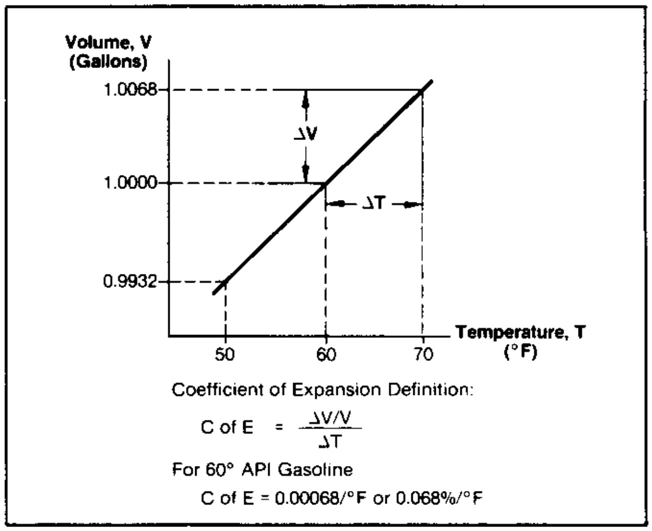

Figure 11 — Volume Versus Temperature for 60° API Gasoline at 60°F

The key to accurate temperature compensation is accurate temperature measurement, applied to the correct C of E for the liquid being metered. In September 1980, new, more precise values for the C of E of petroleum liquids were published (Reference 5). The tables of Reference 5 give Volume Correction Factors (VCF) directly as a function of temperature and API gravity. The VCF is the factor by which the gross volume is multiplied to obtain the correct net (temperature compensated) volume. For example, using the gross volume values from Figure 11, Table 1 shows the VCF values (same as found in Reference 5) needed to yield the 1.000 gallon net volume at 60°F used in Figure 11.

Temp. Degrees F	Gross Volume	X	VCF	=	Net Volume @ 60°F
70	1.0068	X	0.9932	=	1.0000
60	1.0000	X	1.0000	=	1.0000
50	0.9932	X	1.0068	=	1.0000

Table 1 — Volume Correction Factors for 60° API Gasoline

Table 2 is a listing of the approximate C of E values for several common petroleum liquids at 60° F. Note that as API gravity increases, the C of E value increases.

Liquid	Typical API Gravity	C of E (%/Degree F)
No. 6 Oil	10	0.037
No. 4 Oil	25	0.043
No. 2 Oil	37	0.047
Kerosene	42	0.050
Gasoline	60	0.068
Butane	100	0.10
Propane	150	0.18

Table 2 — Coefficient of Expansion of Various Petroleum Liquids (At 60° F)

Accurate temperature measurement is important as even a one degree F error results in a substantial (e.g., 0.37% to 0.18%) net volume measurement error. One major advantage of metering versus tank gauging is the potential for much better temperature compensation accuracy, since all of the liquid transferred passes by the temperature probe at the meter. Temperature measurement errors of several degrees F are typical when using tank temperatures for temperature compensation of delivered volume (see Reference 1).

At installations (e.g., load racks and LACT units) delivering relatively small batches with relatively long time periods between some batches, response time of the temperature probe becomes important. Some temperature probes take several minutes to fully respond to a step change in temperature.

In locations where wide ambient temprature fluctuations occur, the initial probe temperature can be substantially different that the temperature of the bulk of the product to be delivered from the storage tank. Thus, for a small batch, the probe may never reach the temperature of the bulk of the fluid delivered. However, there are highly responsive electronic temperature probes which will respond to a sudden temperature change in 10 to 15 seconds. These probes should be used in situations where slow probe response creates a substantial temperature measurement error.

Where computers are used in electronic temperature measurement systems, their temperature sampling rate must be considered. For example, in a typical terminal automation system with temperature compensation, the temperature is usually measured every 100 or 200 gallons. In extreme winter weather, such an infrequent temperature sampling rate can result in over registration errors of up to one or two gallons per batch (which could be several gallons per truck load). Dedicated microprocessor-based units, such as the Smith AccuLoad, overcome this problem of sampling temperature every half to one second.

Most automatic temperature compensating devices assume a constant C of E for a given product at all temperatures. If a wide range of product temperatures is encountered, particularly for gasoline and lighter petroleum liquids, a substantial error can result. For example, 60 degree API gasoline has a C of E at 0° F, 60° F, and 100° F of 0.067, 0.068, and 0.069%/° F rather than 0.067%/° F at 0° F, creates a net volume over registration error of 0.06%. The error becomes worse for lighter products (e.g., butane, propane, etc.). This problem is overcome in some microprocessor-based temperature compensation devices (e.g., Smith AccuLoad) by including a second order term in the temperature correction equation.

Performance independent of ambient temperature is an important factor for an automatic temperature compensator (ATC). A mechanical ATC usually has some sort of ambient temperature compensating device (e.g., ambient bellows assembly) to compensate for the effects of ambient temperature change. However, they are not 100% perfect and some error due to ambient temperature variation does occur. For example, a net volume measurement error of 0.1% or more due to a 50° F ambient temperature change would not be unusual for a mechanical ATC.

The performance of an electronic temperature compensator, on the other hand, is virtually unaffected by ambient temperature change. Thus, for best accuracy, electronic temperature compensation should be used.

Air (Vapor) Elimination

Any air or vapor passing through a P.D. or turbine meter will be registered (in error) as additional liquid. Thus, it is essential for liquid metering systems, where air or vapor can be present in lines ahead of the meter, that appropriate steps be taken to assure its elimination prior to metering.

Sources of air or vapor in liquid metering systems include:

1. Completely emptying the supply tank, or at least emptying it close to its outlet level, allowing air to be sucked into the delivery line.
2. A dry hose or line on start-up.
3. Lines being blown down with air after the previous delivery.
4. Product shrinkage between two closed valves, due to temperature drop after the valves are closed (e.g., overnight), leaving vapor to fill the void.
5. Sucking in air through leaks in the suction line.
6. Flashing light end (i.e., high vapor pressure) constituents due to high pressure drop, and resultant high velocity (causing cavitation), through throttled valves or clogged strainers.
7. Dissolved gas (in gas saturated liquids) coming out of solution as pressure is reduced.

An air eliminator must perform three (3) basic functions: First, it must **separate** the air from the liquid; second, it must **sense** the air level; and third, it must **discharge** the air.

Sensing and discharging the air is relatively simple, but separating the air efficiently can be difficult, especially for higher viscosity liquids such as fuel oils and crude oils. Air separation efficiency is a function of the time available, and the time needed, for air bubbles to rise to the top of the vessel. Bubble rise time increases with increasing viscosity and/or decreasing bubble size.

The time available for air separation is essentially the liquid stay-time in the air eliminator vessel, which is determined by vessel capacity and liquid flow rate. Thus, to provide sufficient stay-time for complete air separation in systems encountering substantial quantities of air, either the air eliminator tank must be large, or the flow rate must be reduced or stopped when air is sensed. Usually the latter approach is most cost effective.

The basic Smith Petro-gard System, shown in Figure 12, is an example of this latter approach. When air is first sensed and starts to exhaust to atmosphere through the air release head (valve), it also pressurizes and shifts the 3-way pilot causing the main line valve to close. Flow remains stopped while the air is being discharged, allowing time for air to separate (bubbles to rise) in the relatively small tank.

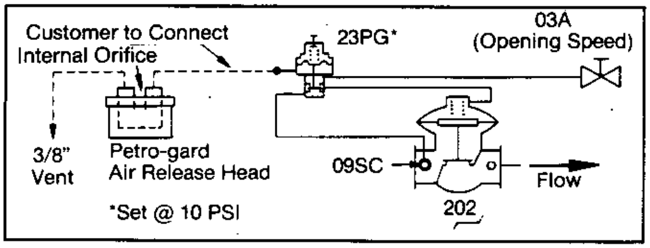

Figure 12 — Petro-gard System for Efficient Air Elimination

Conclusions

Efforts to improve petroleum volume measurement accuracy, particularly in custody transfer applications, is certainly justified at today's prices for petroleum liquids. Attention particularly should be given to improving meter accuracy by correcting meter performance for changes in operating conditions such as fluid temperature, viscosity, flow rate, and (at times) pressure. The accuracy of automatic temperature compensation can be improved significantly by using dedicated microprocessor-based electronic temperature compensating devices. Good meter proving equipment and procedures must be used. Effective air (vapor) elimination is essential when air (vapor) is present.

References

1. Swanson, P. E., "Accuracy of Metering versus Tank Gauging of Vessel Delivered Petroleum Liquids," *Technical Paper 107*, (Smith Meter Inc., Erie, PA, 1980).
2. "Chapter 5 - Metering, Section 3 - Turbine Meters," *Manual of Petroleum Measurement Standards*, (American Petroleum Institute, July 1978), Page 4.
3. Kolb, R. H., and Lilley, G. C., "Shell Expands Turbine Meter Use in Crude Measurement," *Pipeline Industry*, (October 1976), Page 57.
4. "Chapter 5 - Metering, Section 3 - Turbine Meters," *Manual of Petroleum Measurement Standards*, (American Petroleum Institute, July 1976), Page 14.
5. "Chapter 11.1 - Volume Correction Factors," *Manual of Petroleum Measurement Standards*, (September 1980).

Acknowledgements

This paper was originally presented by the author at The Fifth Petroleum Measurement Seminar, American Petroleum Institute, Tulsa, Oklahoma, March 10, 1983.

The specifications contained herein are subject to change without notice and any user of said specifications should verify from the manufacturer that the specifications are currently in effect. Otherwise, the manufacturer assumes no responsibility for the use of specifications which may have been changed and are no longer in effect.

Headquarters	1602 Wagner Ave., P.O. Box 10428, Erie, PA 16514-0428, Phone: 814/898-5000, Fax: 814/899-8927, Telex: 19-9902,
Smith Systems Oper.	737 North Padre Island Dr., P.O. Box 4658, Corpus Christi, TX 78469, Phone: 512/289-3400, Fax: 512/289-1115, Telex: 650/601-2865
E. Hemisphere Oper.	Smith Meter GmbH, Regentstrasse, P.O. Box 1164, 25470 Ellerbek, Germany, Phone: (49) 4101-3040, Fax: (49) 4101-304255, Telex: 17410134
Sales Offices:	
Houston	6677 North Gessner, Suite 315, Houston, TX 77040, Phone: 713/510-6970, Fax: 713/510-6972, Telex: 6975810
Los Angeles	19802 Terri Drive, Canyon Country, CA 91351, Phone: 805/250-1033, Fax: 805/298-3112
London	Ambassador House, 181 Farnham Road, Slough SL1 4XP, Berkshire, England, Phone: (441) 753-571515, Fax: (441) 753-529966, Telex: 846765
Barcelona	Via Augusta, 125 Desp. 1-7a, E-08006 Barcelona, Spain, Phone: (34) 93 201-0989, Fax: (34) 93 201-0576
Singapore	FMC Southeast Asia Pte Ltd., 149 Gul Circle, Singapore 629605, Box 236, Jurong Town Post Office, Singapore 916108, Phone: (65) 869-0605, Fax: (65) 861-2401
Moscow	Smith Meter International Ltd., 3rd Samotechny Per., 11, 103473 Moscow, Russia, Phone: 7 (502) 225-8705, Fax: 7 (502) 221-4066
Beijing	604 CITIC Bldg., 19, Jianguo Men Wai DaJie, Beijing 100004, P.R.C., Phone: 011/86-10/6500-2251, 6501-8005 (Dir), Fax: 011/86-10/6512-6857

Smith Meter Inc...Quality...From Concept, to Product, to You.