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Chapter 4—Proving Systems

Section 2—Conventional Pipe Provers

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FOREWORD

Chapter 4 of the *Manual of Petroleum Measurement Standards* was prepared as a guide for the design, installation, calibration, and operation of meter proving systems commonly used by the majority of petroleum operators. The devices and practices covered in this chapter may not be applicable to all liquid hydrocarbons under all operating conditions. Other types of proving devices that are not covered in this chapter may be appropriate for use if agreed upon by the parties involved.

The information contained in this edition of Chapter 4 supersedes the information contained in the previous edition (First Edition, May 1978), which is no longer in print. It also supersedes the information on proving systems contained in API Standard 1101, *Measurement of Petroleum Liquid Hydrocarbons by Positive Displacement Meter* (First Edition, 1960); API Standard 2531, *Mechanical Displacement Meter Provers;* API Standard 2533, *Metering Viscous Hydrocarbons;* and API Standard 2534, *Measurement of Liquid Hydrocarbons by Turbine-Meter Systems*, which are no longer in print.

This publication is primarily intended for use in the United States and is related to the standards, specifications and procedures of the National Bureau of Standards (NBS). When the information provided herein is used in other countries, the specifications and procedures of the appropriate national standards organizations may apply. Where appropriate, other test codes and procedures for checking pressure and electrical equipment may be used.

For the purposes of business transactions, limits on error or measurement tolerance are usually set by law, regulation, or mutual agreement between contracting parties. This publication is not intended to set tolerances for such purposes; it is intended only to describe methods by which acceptable approaches to any desired accuracy can be achieved.

Chapter 4 now contains the following sections:

Section 1, "Introduction"
Section 2, "Conventional Pipe Provers"
Section 3, "Small Volume Provers"
Section 4, "Tank Provers"
Section 5, "Master-Meter Provers"
Section 6, "Pulse Interpolation"
Section 7, "Field-Standard Test Measures"

Suggested revisions are invited and should be submitted to the director of the Measurement Coordination Department, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

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Chapter 4—Proving Systems

SECTION 2—CONVENTIONAL PIPE PROVERS

4.2.1 Introduction

Conventional pipe provers are used as volume standards for proving liquid meters that generate at least 10,000 unaltered pulses during a prover pass. Pipe provers may be straight or folded in the form of a loop. Both mobile and stationary provers may be constructed in accordance with the principles described in this chapter. Pipe provers are also used for pipelines in which a calibrated portion of the pipeline (either straight, U-shaped, or folded) serves as the reference volume. Some provers are arranged so that liquid can be displaced in either direction.

A pipe prover's main advantage over a tank prover is that its flow of liquid is not interrupted during proving. This uninterrupted flow permits the meter to be proved under specific operating conditions and at a uniform rate of flow without having to start and stop.

The reference volume (the volume needed between detectors) required of a pipe prover depends on such factors as the discrimination of the proving register, the repeatability of the detectors, and the repeatability required of the proving system as a whole. The relationship between the flow range of the meter and the reference volume must also be taken into account. Provers that have a smaller volume than was once considered necessary can now be used as a result of pulse-interpolation techniques and precision displacer detectors (see Chapter 4.3).

4.2.1.1 SCOPE

This chapter outlines the essential elements of unidirectional and bidirectional conventional pipe provers and provides design, installation, and calibration details for the types of pipe provers that are currently in use. The pipe provers discussed in this chapter are designed for the running start-and-stop procedures described in Chapter 4.1. These provers consist of a pipe section through which a displacer travels and activates detection devices before stopping at the end of the run as the stream is diverted or bypassed.

4.2.1.2 DEFINITION OF TERMS

Terms used in this chapter are defined in 4.2.1.2.1 through 4.2.1.2.4.

4.2.1.2.1 A *prover pass* is one movement of the displacer between the detectors in a prover.

4.2.1.2.2 A *prover round trip* refers to the forward and reverse passes in a bidirectional prover.

4.2.1.2.3 *Meter proof* refers to the multiple passes or round trips of the displacer in a prover for purposes of determining a meter factor.

4.2.1.2.4 A *meter prover* is an open or closed vessel of known volume utilized as a volumetric reference standard for the calibration of meters in liquid petroleum service. Such provers are designed, fabricated, and operated within the recommendations of Chapter 4.

4.2.1.3 REFERENCED PUBLICATIONS

The current editions of the following standards, codes, and specifications are cited in this chapter:

API
Manual of Petroleum Measurement Standards
Chapter 4, "Proving Systems," Section 1, "Introduction," Section 3, "Small Volume Provers," Section 5, "Master-Meter Provers," Section 6, "Pulse Interpolation," and Section 7, "Field-Standard Test Measures"
Chapter 5.4, "Accessory Equipment for Liquid Meters"
Chapter 7.2, "Dynamic Temperature Determination"
Chapter 11, "Physical Properties Data"
Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"

DOT[1]
49 *Code of Federal Regulations* Parts 171–177 (Subchapter C, "Hazardous Materials Regulations") and 390–397 (Subchapter B, "Federal Motor Carrier Safety Regulations")

4.2.2 Pipe Prover Systems

All types of pipe prover systems operate on the common principle of the repeatable displacement of a known volume of liquid from a calibrated section of pipe be-

[1] U.S. Department of Transportation. The *Code of Federal Regulations* is available from the U.S. Government Printing Office, Washington, D.C. 20402.

tween two signalling detectors. Displacement is achieved by means of a slightly oversized sphere or piston that is driven along the pipe by the liquid stream being metered. The corresponding metered volume is simultaneously determined.

A meter that is being proved on a continuous-flow basis must be connected at the time of proof to a counter that can be instantly started or stopped by the signalling detectors. The counter is usually an electronic pulse counter. The counter is started and stopped when the displacing device actuates the two detectors at the ends of the calibrated section.

The two types of continuous-flow pipe provers are unidirectional and bidirectional. The unidirectional prover allows the displacer to travel in only one direction through the proving section and has an arrangement for returning the displacer to its starting position. The bidirectional prover allows the displacer to travel first in one direction and then in the other and incorporates a means of reversing the flow through the pipe prover.

Both unidirectional and bidirectional provers must be constructed so that the full flow of the stream through a meter being proved will pass through the prover. Pipe provers may be manually or automatically operated.

4.2.2.1 UNIDIRECTIONAL PROVERS

Unidirectional provers may be subdivided into the following two categories depending on the manner in which the displacer is handled:

a. The *manual-return unidirectional prover*, sometimes referred to as the measured distance, is an elementary form of an in-line prover that uses a section of pipeline as the prover section. Detectors that define the calibrated volume of the prover section are placed at selected points. A displacer launching device is placed upstream from the prover section, and receiving facilities are installed at some point downstream from the prover section. Conventional launching and receiving scraper traps are usually used for this purpose. To make a proving run, a displacer (a sphere or specially designed piston) is launched and allowed to displace the reference volume before being received downstream and manually transported back to the launching site.

b. The *circulating-return unidirectional prover* (see Figure 1), often referred to as the endless loop, has evolved from the prover described in Item a. In the endless loop, the piping is arranged so that the downstream end of the loop crosses over and above the upstream end of the looped section. The interchange is the means by which the displacer is transferred from the downstream to the upstream end of the loop without being removed from the prover. The displacer detectors are located inside the looped portion at a suitable distance from the interchange. Continuous or endless prover loops may be automated or manually operated.

The base volume of a unidirectional prover is the calibrated volume between detectors corrected to standard temperature and pressure conditions.

4.2.2.2 BIDIRECTIONAL PROVERS

Bidirectional provers (see Figures 2 and 3) have a length of pipe through which the displacer travels back and forth, actuating a detector at each end of the calibrated section and stopping at the end of each prover pass when the displacer enters a region where the flow can bypass it or when valve action diverts the flow. Suitable supplementary pipework and a reversing valve or valve assembly that is either manually or automatically operated make possible the reversal of the flow through the prover. The main body of the prover is often a straight piece of pipe, but it may be contoured or folded to fit in a limited space or to make it more readily mobile. A sphere is used as the displacer in the folded or contoured type; a piston or sphere may be used in the straight-pipe type. The base volume in a bidirectional prover is expressed as the sum of the calibrated volumes between detectors in two consecutive one-way passes in opposite directions, each corrected to standard temperature and pressure conditions.

4.2.3 Performance Requirements

4.2.3.1 CALIBRATION REPEATABILITY FOR PROVER VOLUME

When the prover volume is calibrated, the results, after correction, of two or more consecutive runs as agreed upon by the interested parties shall lie within 0.02 percent (± 0.01 percent of the average) to determine the prover volume (see 4.2.11).

4.2.3.2 VALVE SEATING

The sphere interchange in a unidirectional prover or the flow-diverter valve or valves in a bidirectional prover shall be fully seated and sealed before the displacer actuates the first detector. These and any other valves whose leakage can affect the accuracy of proving shall be provided with some means of demonstrating during the proving run that they are leak free.

4.2.3.3 FREEDOM FROM SHOCK

When the prover is operating at its maximum design flow rate, the displacer shall decelerate and come to rest safely at the end of its travel without shock or damage

(*text continued on page 6*)

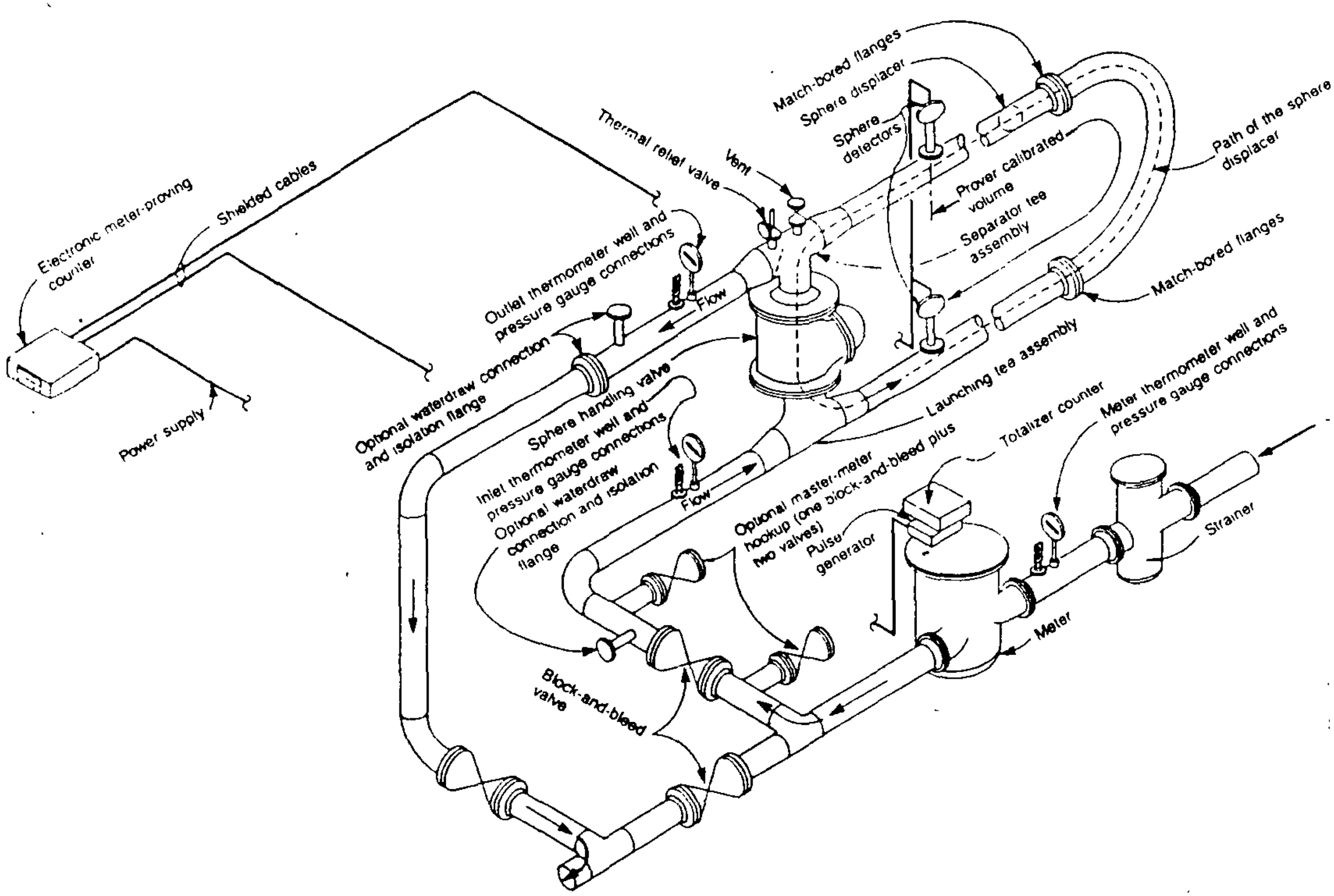

Figure 1—Typical Unidirectional Return-Type Prover System

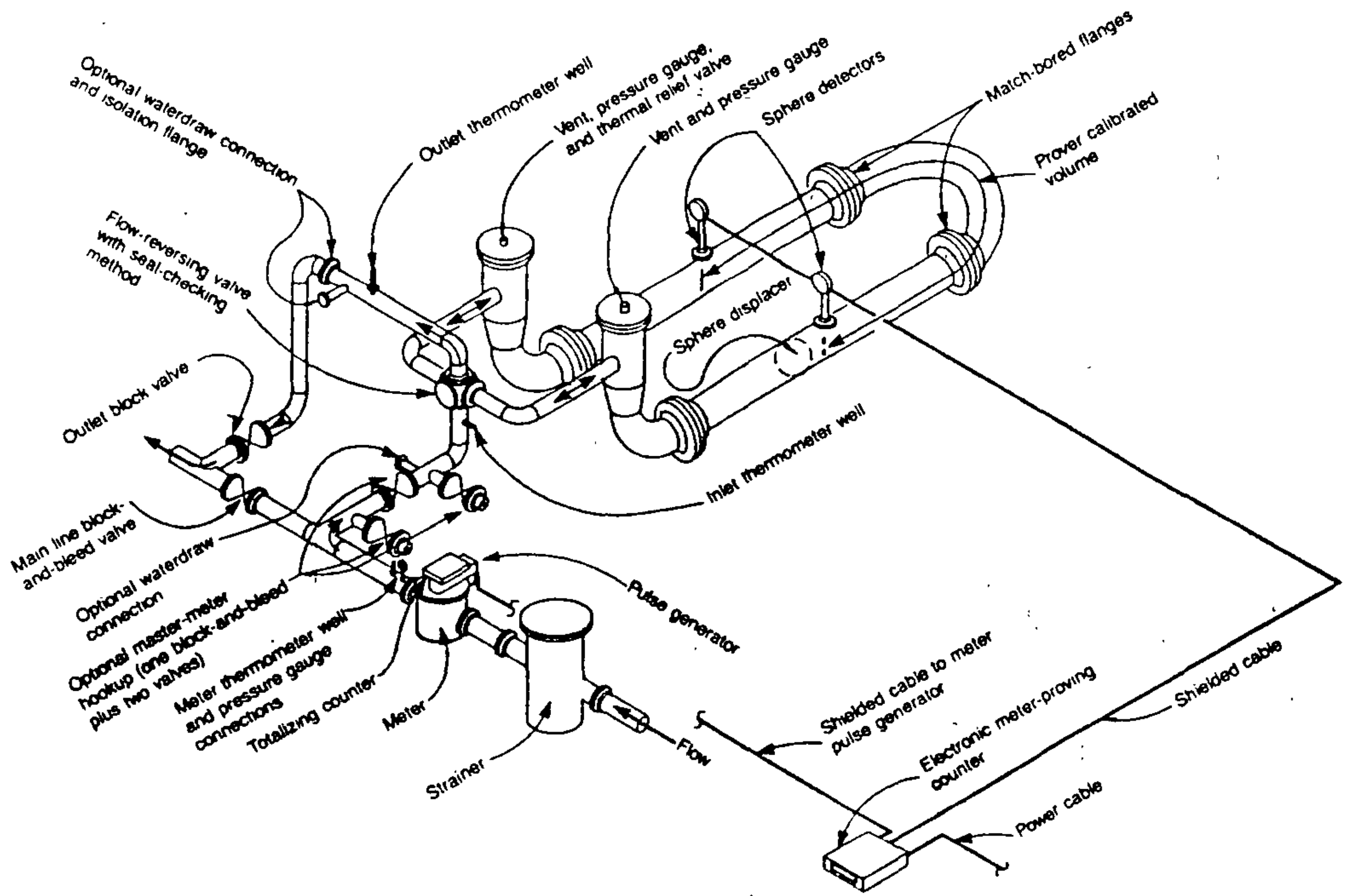

Figure 2—Typical Bidirectional U-Type Sphere Prover System

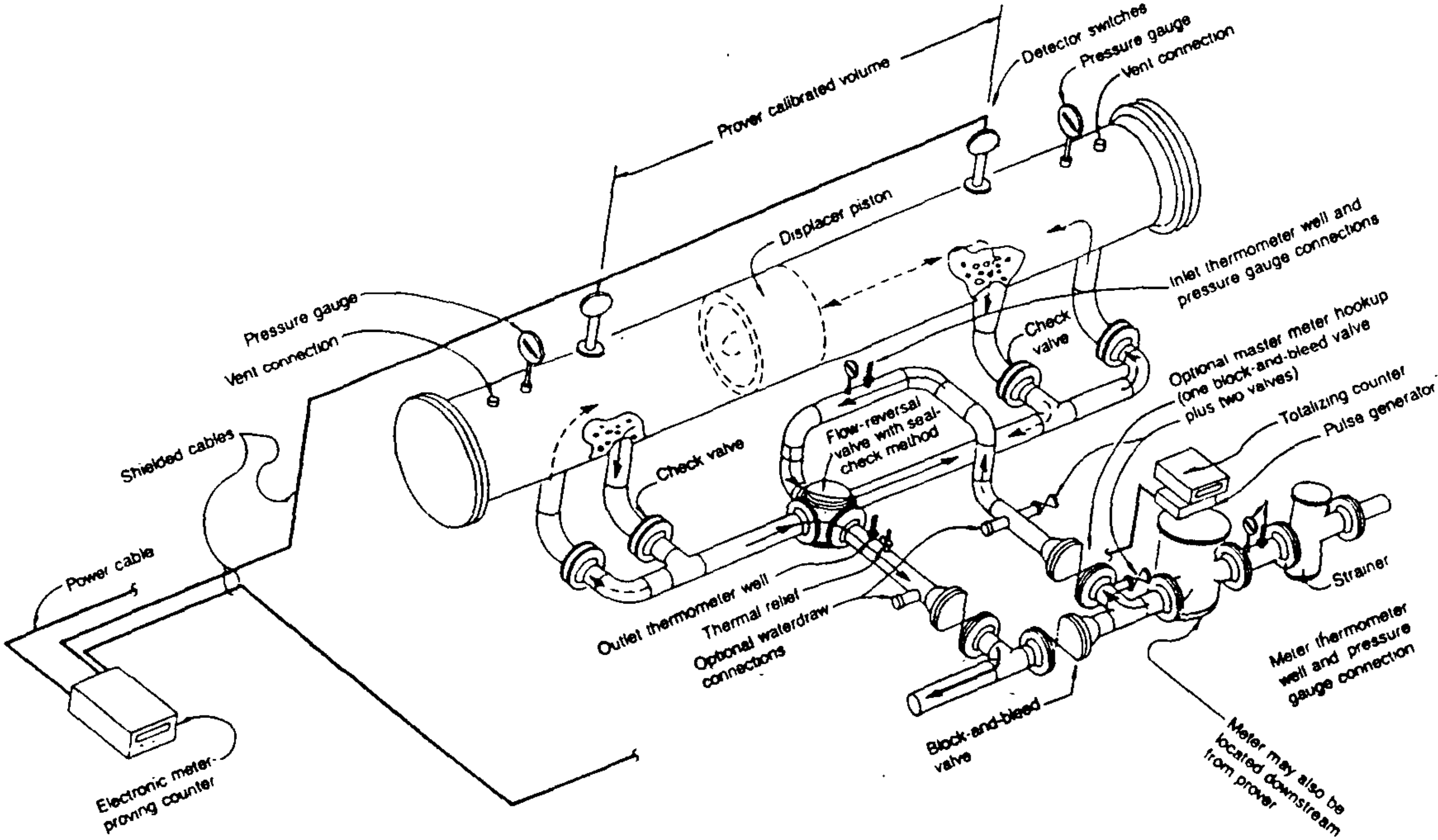

Figure 3—Typical Bidirectional Straight-Type Piston Prover System

4.2.4 Equipment

4.2.4.1 MATERIALS AND FABRICATION

The materials selected for a prover shall conform to applicable codes, pressure and temperature ratings, corrosion resistance, and area classifications. Pipe, fittings, and bends should be selected for roundness and smoothness to ensure consistent sealing of the displacer during a prover pass.

The calibrated section of the prover between the displacer position sensors must be designed to exclude any appurtenances such as vents or drains.

Flanges or other provisions should be provided for access to the inside surfaces of the calibrated and prerun sections. Care shall be exercised to ensure and maintain proper alignment and concentricity of pipe joints. Flanges in the calibrated volume shall be match bored and uniquely doweled or otherwise designed to maintain the match-bored position of the flanges. Gaskets used in the calibrated section shall be designed to seal on a flange-face metal-to-metal makeup, with the sealing being obtained from an O-ring-type seal. All internal welds and metal surfaces shall be ground smooth to preclude damage to and leakage around the displacer.

Internally coating the prover section with a coating material that will provide a hard, smooth, long-lasting finish will reduce corrosion and prolong the life of the displacer and the prover. Experience has shown that internal coatings are particularly useful when the prover is used with liquids that have poor lubricating properties, such as gasoline or liquefied petroleum gas; however, in certain cases, satisfactory results and displacer longevity may be achieved when uncoated pipe is used.

4.2.4.2 TEMPERATURE STABILITY

Temperature stability is necessary to achieve acceptable proving results. Temperature stabilization is normally accomplished by continuously circulating liquid through the prover section with or without insulation. When provers are installed aboveground, the application of thermal insulation will contribute to better temperature stabilization.

4.2.4.3 TEMPERATURE MEASUREMENT

Temperature-measurement sensors shall be of suitable range and accuracy and shall be installed at the inlet and outlet of the prover (see Chapter 7.2 for detail requirements). Caution must be exercised to ensure that the temperature sensors are located where they will not be shut off from the liquid path.

4.2.4.4 PRESSURE MEASUREMENT

Pressure-measurement devices of suitable range and accuracy are used at appropriate locations to measure pressure at the meter and the prover. The pressure devices should reflect the pressures within the meter and the calibrated section of the prover. See Chapter 12.2 for further information.

4.2.4.5 DISPLACING DEVICES

One type of displacing device commonly used in pipe provers is the elastomer sphere hydrostatically filled with liquid under pressure. The displacer is expanded to provide a seal without excessive friction to a diameter greater (normally 2–4 percent) than that of the inside diameter of the prover pipe. In general, the larger the sphere, the greater the percentage of inflation required. Insufficient expansion of the sphere can lead to leakage past the sphere and consequently to measurement error. Excessive expansion of the sphere may not improve sealing ability and will generally cause it to wear more rapidly and move erratically. Care must be exercised to ensure that no air remains inside the sphere. The displacer shall be as impervious as possible to the operating liquids. The liquid used to fill the sphere shall have a freezing point below any expected temperatures. Water or water-glycol mixtures are commonly used. Another commonly used displacer is the cylindrical piston with suitable seals.

4.2.4.6 VALVES

All valves used in pipe prover systems that can provide or contribute to a bypass of liquid around the prover or meter or to leakage between the prover and meter shall be of the block-and-bleed type or an equivalent with a provision for seal verification.

Full positioning of the flow-reversing valve or valves in a bidirectional prover or the interchange valve in a unidirectional prover must be accomplished before the displacer is allowed to actuate the first detector. This design ensures that no liquid is allowed to bypass the prover during the displacer's travel through the calibrated volume. The distance before the first detector, commonly called prerun, depends on valve operation time and the velocity of the displacer. Methods used to shorten this prerun, such as faster operation of the valve or delay of the displacer launching, require that caution be exercised in the design so that hydraulic shock or additional undesired pressure drop is not introduced. If more than one flow-directing valve is used, all valves should be arranged by linkage or another means to prevent shock caused by an incorrect sequence of operations

4.2.4.7 CONNECTIONS

Connections shall be provided on the prover or connecting piping to allow for calibration, venting, and draining.

4.2.4.8 DETECTORS

Detection devices must indicate the position of the displacer within close tolerance Various types of detectors are currently used. The most common is the mechanically actuated electrical switch. Other types include the electronic proximity switch and the induction pickup; these types may be used if they provide satisfactory repeatability. The repeatability with which the detector in a prover can signal the position of the displacer, which is one of the governing factors in determining the length of the prover section, must be ascertained as accurately as possible. Openings through the pipe wall for detectors must be smaller than the longitudinal sealing area of the displacer.

4.2.4.9 PERIPHERAL EQUIPMENT

A meter pulse generator shall be provided for transmission of flow data and must provide electrical pulses with satisfactory characteristics for the type of proving counter used. The device should generate a sufficient number of pulses per unit volume to provide the required discrimination (see Chapter 5.4)

4.2.4.10 PROVING COUNTER

An electronic pulse counter is usually used in meter proving because of the ease and accuracy with which it can count high-frequency pulses and its ability to transmit this count to remote locations. The pulse-counting devices are equipped with an electronic start/stop switching circuit that is actuated by the pipe prover's detectors (see Chapter 5.4).

4.2.5 Equipment for Automatic-Return Unidirectional Pipe Provers

4.2.5.1 SPHERE INTERCHANGE

The sphere interchange provides a means for transferring the sphere from the downstream end of the proving section to the upstream end. Sphere interchange may be accomplished with several different combinations of valves or other devices to minimize bypass flow through the interchange during the sphere-transfer process. A verifiable leaktight valve seal is essential before the sphere reaches the first detector switch of the proving section

4.2.5.2 SEPARATOR TEES

Separator tees are at least one pipe size larger than the nominal size of the sphere or loop. Sizing is best determined by experience. The design of the separator tee shall ensure dependable separation of the sphere from the stream for all rates within the flow range of the prover. For practical purposes, the mean liquid velocity through the tee should not exceed 5 feet (1.5 meters) per second; a considerably lower liquid velocity is often desirable. The tee must sometimes be sized several sizes larger. Smooth-flow transition fittings on both ends of the tee are important. A means of directing the sphere into the interchange shall be provided at the downstream end. Care should be taken in designing this device to prevent damage to a sphere.

4.2.5.3 LAUNCHING TEES

Launching tees are generally only one pipe size larger than the sphere displacer They shall have smooth transition fittings leading into the prover. The launching tee should have a slight inclination downwards toward the prover section, or another means should be provided to ensure that the sphere moves into the prover during periods of low flow, which might occur during calibration by the waterdraw method.

4.2.6 Equipment for Bidirectional Pipe Provers

4.2.6.1 OUTLETS AND INLETS

The outlets and inlets on the pipe prover end chambers of bidirectional provers are designed to pass liquids and restrain the displacer. The openings shall be deburred and shall have an area sufficient to avoid excessive pressure loss.

4.2.6.2 FLOW REVERSAL

A single multiport valve is commonly used for reversing the direction of the displacer. Other means of flow reversal may also be used. All valves must be leak free and allow continuous flow through the meter during proving. A method of checking for seal leakage during a proving pass shall be provided for all valves. The valve size and actuator shall be selected to minimize hydraulic shock.

4.2.7 Design of Pipe Provers

4.2.7.1 INITIAL CONSIDERATIONS

Before a pipe prover is designed or selected, it is necessary to establish the type of prover required for the application and the manner in which it will be connected with the meter piping. From a study of the application, intended use, and space limitations, the following should be established:

a. Whether the prover is to be stationary or mobile.
 1. If the prover is stationary, whether it will be dedicated (on line) or used as part of a central system.
 2. If the prover is stationary and dedicated, whether it will be kept in service continuously or isolated from the metered stream when it is not being used to prove a meter.
 3. If the prover is stationary, what portions, if any, are desired below ground.

b. The ranges of temperature and pressure that will be encountered.
c. The maximum and minimum flow rates expected and the flow-rate stability.
d. The maximum pressure drop allowable across the prover.
e. The physical properties of the fluids to be handled.
f. The degree of automation to be incorporated in the proving operation
g. Available utilities.

4.2.7.2 PRESSURE DROP ACROSS THE PROVER

In determining the size of the piping and openings to be used in the manifolding and the prover, the pressure loss through the pipe prover system should be compatible with the pressure loss considered tolerable in the metering installation.

4.2.7.3 VOLUME

In determining the volume of a prover between detectors, the designer must consider the following items:

a. The overall repeatability required of the proving system.
b. The repeatability of the detectors.
c. The accumulation of 10,000 unaltered pulses or the use of pulse interpolation (see Chapter 4.6).
d. The resolution of the meter pulse generator (that is, the number of pulses per unit volume).
e. The maximum and minimum flow rates of the system.

4.2.7.4 DISPLACER VELOCITY

The velocity of the displacer can be determined by the internal diameter of the prover pipe and the maximum and minimum flow rates of the meters to be proved Some practical limit to the maximum velocity of a displacer must be established to prevent damage to the displacer and the detectors Nevertheless, the developing state of the art advises against setting a firm limit to displacer velocity as a criterion for design. Demonstrated results are better to use as a criterion. The results are manifested in the repeatability, accuracy, and reproducibility of meter factors using the prover in question.

Most operators and designers agree that 10 feet (3 meters) per second is a typical design specification for unidirectional provers, whereas velocities up to 5 feet (1.5 meters) per second are typical in bidirectional provers. Higher velocities may be possible if the design incorporates a means of reducing surges and displacer velocity before the prover completes its pass. Minimum displacer velocity must also be considered, especially for proving meters in a liquid that has little or no lubricating ability, such as gasoline that contains high proportions of aromatics or liquefied petroleum gas. When lubricating ability is poor or nonexistent and the displacer is operating at low velocities, the displacer may move, hesitate, and move again. *Velocities*, as the term is used in this publication, refers to uniform velocities between detectors.

This standard is not intended to limit the velocity of displacers. Provided that acceptable performance can be assured, no arbitrary limit is imposed on velocity.

4.2.7.5 REPEATABILITY AND ACCURACY

4.2.7.5.1 General Considerations

The ultimate requirement for a prover is that it prove meters accurately; however, accuracy cannot be established directly because it depends on the repeatability of the meters, the accuracy of the instrumentation, and the uncertainty of the prover's base volume. The repeatability of any prover/meter combination can be determined by carrying out a series of repeated measurements under carefully controlled conditions and analyzing the results statistically. Repeatability is usually adopted as the primary criterion for a prover's acceptability. Whereas poor repeatability is an immediate indication that a prover is not performing satisfactorily, good repeatability does not necessarily indicate good accuracy because of the possibility of unknown systematic errors. Operators must always guard against such errors.

The minimum distance between detector switches depends on the detector's ability to repeatedly locate the displacer. The total error of the displacer during a proving pass shall be limited to 0.02 percent of the volume between the detectors.

4.2.7.5.2 Replacing the Detectors

When the worn or damaged parts of a detector are replaced, care must be taken to ensure that neither the detector's actuating depth nor its electrical switch components are altered to the extent that the prover volume is changed. This is especially true for unidirectional provers because changes in detector actuation are not compensated for round trip sphere travel as they are in bidirectional provers. Recalibration of unidirectional provers is in order as soon as practical.

4.2.7.5.3 Counter Resolution

The resolution of a digital counter is unity; that is, a counter can indicate only a whole number of pulses. The indicated pulse count therefore has a ±1 pulse uncertainty for a pass between detectors. For example, to limit the pulse uncertainty to 1 pulse during a prover pass without using pulse interpolation (see Chapter 4.6), at least 10,000 pulses would have to be collected during a single pass. This degree of uncertainty is represented mathematically as follows:

$$U = \frac{\pm 1 \text{ pulse}}{N}$$

Where:

U = degree of uncertainty of the recorded pulse count during a prover pass, commonly called the resolution.
N = minimum number of pulses to be collected during a prover pass.

4.2.7.5.4 Pulse Generation

The preceding considerations suggest that prover volumes can be reduced by increasing the pulse-generation rate of the meters to be proved. Caution must be exercised when gear-driven pulse generators are used on displacement meters to obtain very high pulse-generation rates, since mechanical problems such as backlash, drive-shaft torsion, and cyclic variations can cause irregular pulse generation. An electronic means of pulse interpolation can also be used to increase the resolution for both small volume and conventional volume provers (see Chapter 4.6).

4.2.8 Dimensions of Provers

The dimensions selected for provers have to be based on a compromise. Decreasing the diameter of the prover pipe increases the length between detectors for a given volume and reduces the sensitivity to detector resolution. Decreasing the pipe diameter also increases displacer velocity; this increase may become a limiting factor. Increasing the diameter of the prover pipe has the opposite effect: the velocity of the displacer is reduced, but the resulting decrease in length increases the sensitivity to detector resolution and thus may become a limiting factor.

4.2.9 Sample Calculations for the Design of a Pipe Prover

A typical approach to the design of unidirectional or bidirectional pipe provers is described in 4.2.9.1 through 4.2.9.5. The examples given are for a 6-inch (150-millimeter) meter operating at 1200 barrels per hour and generating a nominal 2000 pulses per barrel.

4.2.9.1 BASIS OF CALCULATION

The repeatability obtained during calibration runs must be within the range stated in 4.2.3.1. For the purpose of this example, the following conditions are assumed:

a. The acceptable counter resolution error, U (see 4.2.7.5.3), is ±1 pulse during a prover pass.
b. The meter to be proved generates 2000 pulses per barrel.
c. The repeatability for each of the detectors to the sphere is assumed to be ±0.030 inch.
d. The maximum displacer velocity is provisionally set at 10 feet (3 meters) per second.

4.2.9.2 MINIMUM-VOLUME CALCULATION

After the degree of uncertainty during a prover pass (see 4.2.7.5.3) is established, the minimum volume during a pass is determined using Equation 1 as follows

$$V = \frac{\pm 1 \text{ pulse}}{UK} = \frac{N}{K} \tag{1}$$

Where:

V = minimum volume between prover detectors
$= \frac{\pm 1}{UK}$
$= \frac{\pm 1}{(1/10{,}000)(2000)}$
= 5 barrels.
U = degree of uncertainty of the recorded pulse count during a prover pass.
K = minimum number of counts per consistent unit volume of any meter that will be proved.
N = minimum number of pulses to be collected during a prover pass

4.2.9.3 MINIMUM-LENGTH CALCULATION

The minimum length between detector switches depends on the accuracy with which the detector switch can repeatedly determine the position of the displacer and the desired discrimination of the prover system during calibration. Item b in 4.2.9.1 indicates that the desired discrimination of the prover system during calibration is

0.02 percent (±0.01 percent of the average). Item c in 4.2.9.1 states that the repeatability of response to the sphere for each of the detector switches is ±0.030 inch (±0.75 millimeters). If L represents the nominal indicated length of the prover, one pass could displace a maximum volume represented by L plus 0.060 inch (1.5 millimeters); another pass could displace a minimum volume represented by L minus 0.060 inch (1.5 millimeters). When the minimum is subtracted from the maximum, the difference in the indicated length cannot exceed 0.12 inch (±3 millimeters). The calculation for the minimum length would then be 0.12 inch (±3 millimeters) divided by 0.02 percent (0.0002), which results in a 50-foot (15-meter) minimum length. If the repeatability of response for each of the detector switches is better than ±0.030 inch (±0.75 millimeters), the lengths between the detector switches can be decreased.

4.2.9.4 PROVER DIAMETER

Item d in 4.2.9.1 sets a provisional maximum displacer velocity of 10 feet (3 meters) per second for use in this example. The smallest applicable prover diameter would therefore be 6 inches (150 millimeters); however, the length necessary to obtain the 5-barrel (0.795-cubic meter) volume would have to be in excess of the 50 feet (15 meters) previously calculated.

4.2.9.5 SUMMARY OF CALCULATIONS

Based on the stated assumption of a 6-inch (150-millimeter) meter operating at 1200 barrels per hour, the calculations indicate that a prover with a minimum length of 50 feet (15 meters) between detectors that would displace a minimum volume of 5 barrels (0.795 cubic meter) and has a minimum diameter of 6 inches (150 millimeters) is required.

4.2.10 Installation

4.2.10.1 GENERAL CONSIDERATIONS

All components of the prover installation, including electrical piping, valves, and manifolds, shall be in accordance with applicable codes. Once the prover is onstream, it becomes a part of the pressure system.

The proving section and related components shall have suitable hangers and supports prescribed by applicable codes and sound engineering principles. When proving systems are designed and installed, precautions should be taken to cope with expansion, contraction, vibration, pressure surges, and other conditions that may affect piping and related equipment

Consideration should be given to the installation of suitable valving to isolate the prover unit from line pressure when it is not onstream (for example, during maintenance or removal of the displacer).

All units shall be equipped with vent and drain connections. Vent valves should be installed on the topmost portion of the pipe and should be located where all air is vented from dead spaces that are not swept by the displacer. Provisions should be made for the disposal of liquids or vapors that are drained or vented from the prover. This may be accomplished by pumping liquids or vapors back into the system or by diverting them to a collecting point.

Temperature sensors in accordance with Chapter 7.2 and pressure gauges shall be installed in suitable locations near the meter and the prover to determine the temperature and pressure of each. Blind flange or valve connections should be provided on either side of a leak-free block valve in the piping system to serve as a connection for proving portable meters or as a means for calibrating the prover by the master-meter method. Connections at the inlet and outlet should be provided for calibration by the waterdraw method. Examples of suitable connections are shown in Figures 1–3.

Pressure relief valves with discharge piping and leak-detection facilities are usually installed to control thermal expansion of the liquid in the prover while it is isolated from the mainstream. Where practical, pressure relief valves should not be installed in piping between the meters and the prover. Power and remote controls should be suitably protected with lockout switches, circuits, or both between remote and adjacent panel locations to prevent accidental remote operation while a unit is being controlled locally. Suitable safety devices and locks should be installed to prevent inadvertent operation of or unauthorized tampering with equipment.

Provers should be protected by straining or filtering equipment.

All wiring and controls shall conform to applicable codes. Components shall conform to the class and group appropriate to the location and operation. All electrical controls and components should be placed in a location convenient for operation and maintenance. Manufacturers' instructions should be strictly followed during the installation and grounding of electronic counters, controls, power units, and signal cables.

4.2.10.2 PROVER LOCATION

Pipe provers may be either mobile (portable) or stationary.

4.2.10.2.1 Mobile Prover

A mobile prover is normally mounted on a road vehicle or trailer so that it can be taken to various sites for on-site proving of meters in their installed positions while they are in normal operation. Mobile provers are occasionally housed in containers or mounted on self-contained skids so that they may be transported by road, rail, or sea. Mobile provers are always provided with a means of safely and conveniently connecting them to the metering system. Mobile provers are designed to operate in the meter's environment. Provisions must be made to electrically ground the prover.

Portable meter provers mounted on a truck or trailer fall within the purview of the DOT *Code of Federal Regulations* for the transportation of hazardous materials. The code is applicable when portable meter provers are moved on public roads and contain flammable or combustible liquids or are empty but not gas free. The most recent edition of 49 *Code of Federal Regulations* Parts 171–177 (Subchapter C, "Hazardous Materials Regulations") and 390–397 (Subchapter B, "Federal Motor Carrier Safety Regulations") should be consulted. (See specifically Sections 172.500, 172.503, 172.504, 172.506, 172.507, 173, 177.817, 177.823, 391.11(a)(7), 391 41.49, and 393.86.) The DOT provides an exemption from 173.119, 173.304, and 173.315 for portable meter provers.

4.2.10.2.2 Stationary Prover

A stationary prover is connected by a system of pipes and valves to a meter or battery of meters. Its sole function is to prove the meters one at a time at intervals, as required.

4.2.10.2.3 Central Prover

A central prover is permanently installed at a location where pumping facilities and a supply of liquid are available. It is used to prove meters that are periodically brought to the prover and temporarily connected (see Chapter 4.1). After a meter is proved centrally, caution must be exercised to ensure that the meter is not mishandled in a way that could destroy its reliability before the meter is reinstalled in the line.

4.2.11 Calibrating Pipe Provers

Calibrating a pipe prover involves determining the base volume displaced between the detectors

The two methods of calibrating a pipe prover are the waterdraw method and the master-meter method

A pipe prover must be calibrated before it is placed in service to determine its base volume at standard conditions [usually atmospheric pressure and 60°F (15°C)] Periodic recalibration of the prover is also required. See Chapter 12 2 for details about calculating all the correction factors and the base volume

The base volume shall be documented on a calibration certificate. See Chapter 12.2 for volume corrections and calculations that lead to base-volume determinations.

The base volume of a unidirectional prover is the calibrated volume corrected to standard temperature and pressure conditions and displaced between detectors for a single pass. The base volume of a bidirectional prover is the sum of the volumes displaced between detectors for a round trip of the displacer corrected to standard temperature and pressure conditions.

Complete records of calibration should be prepared and maintained.

4.2.11.1 CALIBRATING PIPE PROVERS BY THE WATERDRAW METHOD

Calibrating pipe provers by the waterdraw method requires using National Bureau of Standards (NBS) traceable/certified volumetric field-standard test measures (see Chapter 4.7) against which the volume of the prover may be determined. The largest available field standards should be used. The method may be expedited by placing the prover, field standards, and test water in a constant-temperature enclosure shaded from direct sunshine to allow the equipment and water to reach an equilibrium temperature.

Because of the effect of viscosity and surface tension on the drain time of a field-standard test measure, water is the only medium that can be used for the draw method into standards that have been certified to deliver a given quantity of water Water was selected because it has well-defined properties and is readily available. Clean, fresh, deaerated water is required (see Chapter 4 7) The prover should be clean, and the displacer should be moved through the prover enough times to flush and eliminate air that may have been caught in parts of the prover system and to allow both the metal and liquid of the prover system to reach a common and steady temperature. At least one trial calibration run should be made to determine the approximate volume of the prover between its detectors so that the appropriate number and sizes of reference standards can be selected. The temperature and pressure at the discharge of the prover should then be observed and recorded as the temperature and pressure in the prover at the start of calibration

The prover may be calibrated using small-diameter water lines and temporary valves, as shown in Figures 4 and 5, or by using the valves and piping that are part of the field installation. Solenoid valves actuated by the detector switches are normally used to start and stop the calibration run.

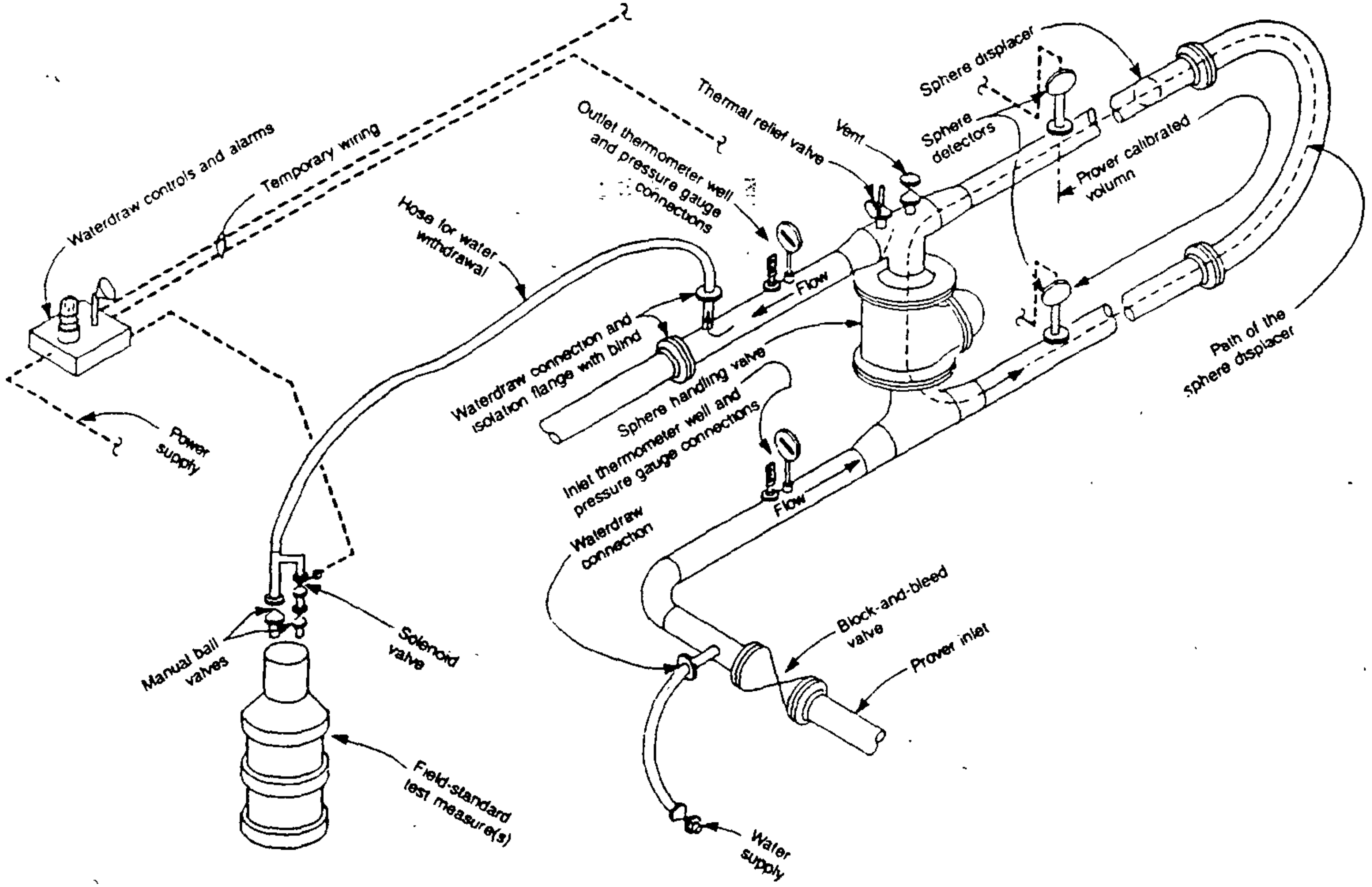

Figure 4—Waterdraw Calibration of Unidirectional Provers

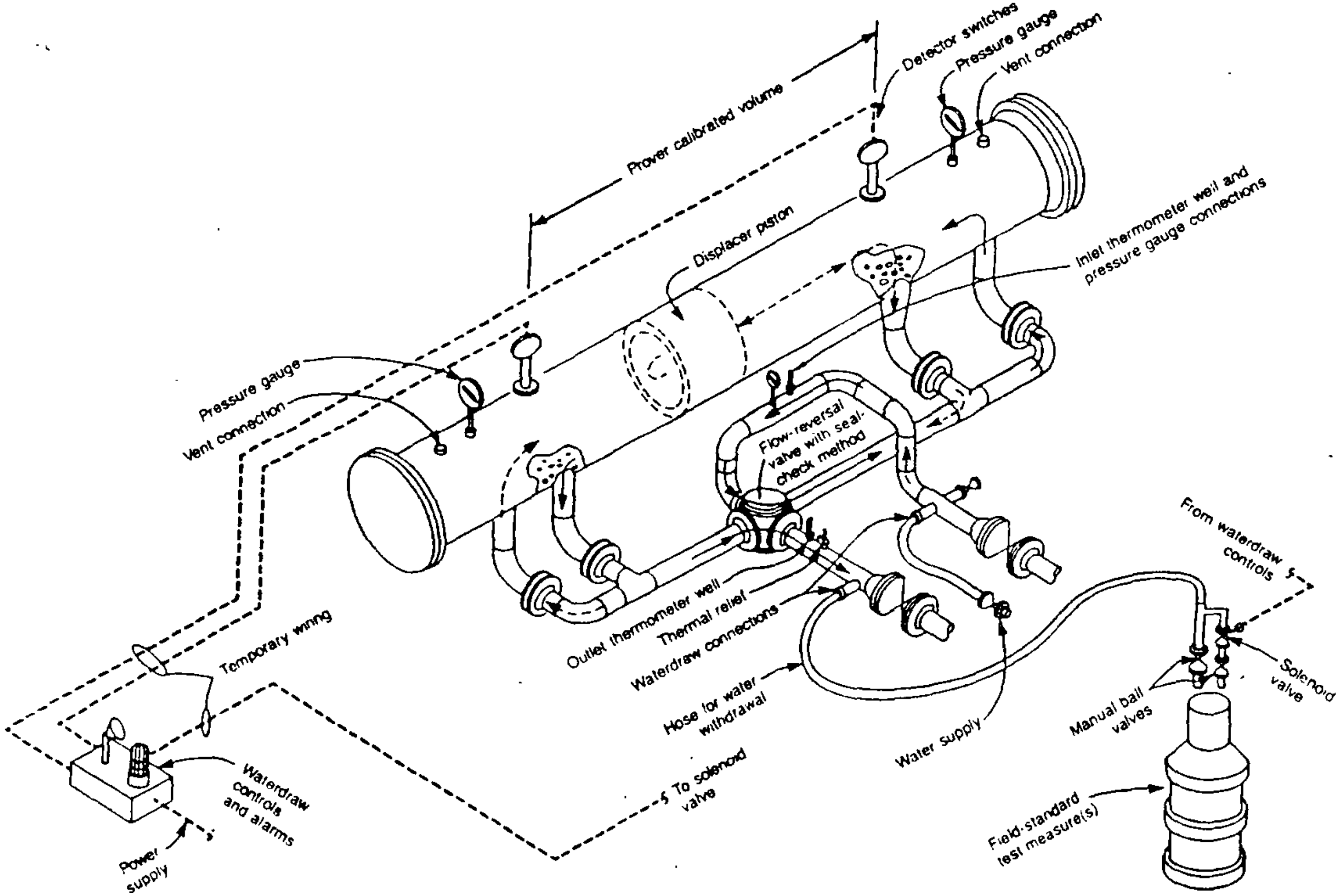

Figure 5—Waterdraw Calibration of Bidirectional Provers

The volume observed in the field standards for each trip of the displacer must be subjected to corrections to determine the base volume of the prover as follows:

a. The individual field-standard test measures must be corrected for any difference in water temperature between the starting temperature of the prover and the water temperature in the field standard when its volume is read and recorded. The purpose of the correction is to adjust the volume of water measured in the field standard to the volume it occupied at the prover starting temperature.

b. The temperature-corrected field-standard volume must then be corrected for the effect of temperature on both the prover and the field-standard materials. The temperatures of the pipe prover and the field standard's shell are assumed to be the same as the temperature of the liquid that they contain. See Chapter 12.2 for the application of corrections.

c. The water volume obtained in Item b shall then be corrected for the compressibility of the water in the prover at the start of the calibration. See Chapter 12.2 for complete details.

d. The volume shall be corrected for the effect of pressure on the prover steel at the start of the calibration.

The calibrated volume of a field standard is its volume at a temperature specified by the calibrating agency [commonly 60°F (15°C)]. By correcting the observed volume in the field standard to its actual volume at 60°F (15°C), the field standard can then be used to determine a prover volume at 60°F (15°C).

The observed volume for each prover pass shall be corrected individually to obtain the base volume, which implies standard conditions. Two or more consecutive runs, after correction, shall fall within 0.02 percent (±0.01 percent) of the average.

Repeatability is only one component of accuracy. By filling the same field standards with the test runs made at an equal rate, an operator can complete a series of erroneous calibrations as the result of a consistent leak. The absence of a consistent leak should be verified by making an additional run at a rate change of 25 percent or greater. With the changed flow rate, a volume after correction that is beyond 0.02 percent (±0.01 percent of the average) of the initial runs, after correction, indicates the possibility of a leak in the proving circuit that must be corrected before calibration can be achieved. This is true for both unidirectional and bidirectional provers.

After a prover calibration is completed, the data sheets shall be signed by all parties who witnessed the calibration and used to prepare a certificate of calibration. The certificate shall state the method used, the base volume of the prover, and the reference temperature and pressure.

4.2.11.2 CALIBRATING BIDIRECTIONAL PROVERS BY THE WATERDRAW METHOD

This section refers to provers that operate on a round trip basis.

After preparatory steps are taken as described in 4.2.11, the calibration runs are started. The displacer is driven past one of the switches into the space just outside the calibrated volume at either end of the prover. The valves should be reversed so that the displacer travels toward the section to be calibrated while it wastes the effluent water. The water should be wasted slowly through a slow-rate bleed or, if the adjustment is sufficiently sensitive, through the hose nozzle. The waste should be stopped at the instant the switch indication shows *ON*. This should be done automatically by a solenoid valve controlled by the detector switch. All additional effluent water should then be directed into the selected field standards. The withdrawals should continue until the last field standard is being filled. The withdrawal should be reduced to a controllable slow-bleed rate until the *ON* switch indication is observed at the second detector; withdrawal should be stopped at the instant the detector shows *ON*. The total of the field-standard volumes indicates the observed displaced volume between detectors in that direction of travel under conditions of pressure and temperature that existed in the prover at the start of calibration. The pressure conditions, drain-hose fill, and other withdrawal equipment shall be the same at the end of the withdrawal as they were at the start.

A similar displacer trip should now be made in the opposite direction, repeating the procedure. These two trips do not necessarily have to agree in observed displaced volume because the action of the detector switches may be different for each direction of travel. The volume observed in a given direction after correction must agree within 0.02 percent (±0.01 percent of the average).

The calibrating procedure should be repeated until satisfactory repeatability is achieved. If the prover, displacer, and detectors are in good working order, an experienced operator can expect the first two determinations, after correction, to agree within 0.02 percent (±0.01 of the average). The average of two or more consecutive round trip corrected volumes is considered the round trip based volume. The corrected volume for two or more consecutive trips in any given direction shall also agree within 0.02 percent (±0.01 percent of the average). This standard does not restrict the determination of the base volume to only two consecutive runs. More runs may be used if agreed upon by the parties involved.

Failure to repeat may be caused by leaking valves, air in the system, varying temperature or pressure, improper condition of the displacers, or poor calibration technique.

Once a suitable set of runs has been made, the average then becomes the base volume of the prover.

All subsequent use of the bidirectional prover for proving a meter requires a full round trip of the displacer for each proof run of the meter.

4.2.11.3 CALIBRATING UNIDIRECTIONAL PROVERS BY THE WATERDRAW METHOD

The procedure for calibrating a unidirectional prover by the waterdraw method is substantially the same as the procedure described for a single one-way trip of the displacer in a bidirectional prover. Every calibration run must be made by passing the displacer through the prover in the direction in which it will subsequently travel during actual meter proving. When an automatic-return or endless-loop prover is calibrated, the entire loop and interchange must be filled with water, bringing water through an outlet connection. The interchange valves may be used to transport the displacer through the pipe and the interchange to the start of the prover section. When a manual-return or in-line unidirectional prover is calibrated, the entire prover and associated piping must be filled with water, and the displacer must be launched in the normal manner in the proper direction and returned for relaunching for subsequent calibration runs. Care must be exercised to ensure stable temperature and pressure conditions and the elimination of all air.

The calibrated volume of a unidirectional prover is the volume displaced in passing the displacer from one detector switch to another. The described one-way procedure should be repeated until satisfactory repeatability is achieved. The average value of two or more consecutive one-way corrected calibrated volumes is considered the base volume of the prover at standard conditions. The corrected volume for two or more consecutive trips should agree within 0.02 percent (± 0.01 percent of the average).

4.2.11.4 CALIBRATING PIPE PROVERS BY THE MASTER-METER METHOD

4.2.11.4.1 Principle and Apparatus

In the master-meter method of proving, the function of the master meter is to serve as an intermediate link between the prover and the volumetric standard. This method is an additional step away from NBS traceability. A meter used in this manner is commonly called a master meter. The volumetric standard may be either a pipe prover or tank prover and is hereafter identified as the master prover. The master prover is used to prove the master meter; the master meter is then immediately used to determine the volume of the pipe prover in need of calibration.

The master-meter method can be used for any installation, but in situations like those found in the arctic, the desert, or on an offshore platform, the master-meter method may be the only practical one to use. The requirements for master-meter proving include an ample supply of a stable liquid, a selected master meter, and the accessory equipment necessary for proving the master meter against the master prover.

The three main pieces of apparatus—the prover to be calibrated, the master prover, and the master meter—must be connected in series so that the total flow through each is the same. The sequence in which the three pieces are arranged can be modified to suit local conditions.

The master-prover base volume shall be determined by the waterdraw method and shall be a size that is sufficient to ensure that the master meter can be accurately proved.

A master meter may be either a pulse-generating displacement meter or a turbine meter; if it is a turbine meter, it shall be connected to its normal conditioning section (straightening vanes or a sufficient length of straight pipe). The master meter shall be of high quality and known to have an excellent short-term repeatability.

A single meter is recommended for use as a master meter. Each master meter shall conform to Chapter 4.5.

The master meter shall have the same connected accessories when it is being proved as when it is being used to calibrate the prover. The meter shall not be fitted with any device, such as a calibrator or a temperature compensator, that enables the operator to change in any way the ratio between the indicated output of the meter and the number of revolutions it has turned.

The master meter shall be in good mechanical condition and shall have a history of consistent performance. Its meter factor should vary little with the flow rate over its operating range.

The master meter shall generate at least 10,000 pulses during any one pass of the master prover or one emptying or filling of a tank prover.

Attention must be given to the equipment requirements discussed in 4.2.4, especially as they apply to temperature and pressure measurements, valves, flow-reversing valves, displacers, pulse generators, and counters. In addition, vents must be available at high points in the assembly to allow for the removal of air before calibration begins. Also, a strainer should be placed upstream of the master-meter/master-prover unit.

When hydrocarbons are used in the master-meter method, accurate thermometry becomes even more important than when water is used. Hydrocarbon liquids typically have low heat capacities and high coefficients of thermal expansion. Temperatures must be obtained to the accuracies required in Chapters 7.2 and 12.2.

If a liquid with a high vapor pressure is used, care must be taken during the calibration to ensure that the pressure does not fall below a level where gas bubbles may be formed.

4.2.11.4.2 Preparation

The master-meter calibration procedure consists of the following three operations in immediate succession:

a. Proving the master meter against the master prover.
b. Calibrating the stipulated prover.
c. Reproving the master meter against the master prover.

The liquid should be slowly introduced into the three principal pieces of apparatus (the master prover, master meter, and prover to be calibrated), venting the air or gas carefully as the fill proceeds.

The flow should be started through the system, and the remaining air or gas should be vented from each piece of equipment. While the prover to be calibrated (and the master prover if it is the pipe-prover type) is being vented, the displacer should be launched as often as required to flush air or gas towards the vents. The required calibration repeatability will not be obtained unless the system is rendered completely free from air or gas.

Flow should be continued until the temperature of the system stabilizes. While this is being done, the master meter should be proved against the master prover a number of times on a trial basis to see whether consistent results are being obtained. During the first few trial provings, the calculation of meter factors may be unnecessary if the successive pulse counts differ by so much that the repeatability is obviously inadequate. When a point is reached at which two or more consecutive master-meter factors agree within 0.02 percent (±0.01 percent of the average), the master meter and the master prover may be considered to be performing acceptably.

Next, a similar check should be made to ensure that the prover to be calibrated is functioning correctly. Repeated precalibration runs of the master meter against the prover should be made until two or more consecutive results agree within 0.02 percent (±0.01 percent of the average).

Should it prove impossible to obtain the above repeatabilities, the malfunction must be identified and corrected. When the required repeatability is obtained, the calibration of the prover may begin, using the procedure outlined in 4.2.11.4.3.

4.2.11.4.3 Procedure

The procedure described in this section is for use with either a turbine meter or a displacement meter that has an electrical pulse generator. This standard does not preclude the use of a displacement meter that has only a mechanical register for this method of prover calibration, provided that the meter register has a discrimination smaller than 0.01 percent of the volume of the master prover and preferably smaller than 0.005 percent. Appropriate modifications to the procedure given here are necessary if such a meter is used.

First, the flow rate should be set to the desired value. The flow rate shall be maintained constantly within 5 percent or better throughout the entire procedure and shall fall within the linear range of the meter.

To prove the master meter, a series of two or more meter proofs must be made. The results of these proofs shall agree within 0.02 percent (±0.01 percent of the average) or better, or the results shall be regarded as invalid. The average of the meter proofs shall be recorded as the initial master-meter factor.

Next, a series of two or more calibration runs of the master meter against the prover to be calibrated must be made. The results of these runs shall be regarded as valid only if they agree within 0.02 percent (±0.01 percent of the average). The master-meter volume shall be regarded as a known quantity; the base volume of the prover is the quantity to be determined.

Finally, the master meter should again be proved against the master prover to check that its meter factor has not changed significantly during the operation. Two or more meter proofs are required, and the results are valid only if they agree within 0.02 percent (±0.01 percent of the average). The average of these results is adopted as the final master-meter factor. In addition, the final master-meter factor must lie within 0.02 percent of the initial master-meter factor. The average of the initial and final meter-factor values shall be used in the calculation to determine the base volume of the prover being calibrated

Prover calibration runs completed at one flow rate may incorporate an undetected constant leak. This possibility can be eliminated by repeating the full calibration procedure at a rate change of 25 percent or greater. With the changed flow rate, a volume after correction that is not within 0.02 percent (±0.01 percent of the average) of two initial runs, after correction, indicates the possibility of a leak in the proving system that must be corrected before calibration can be achieved. This is true for both unidirectional and bidirectional provers.

If the calibration fluid is a hydrocarbon covered in Chapter 11, the tables in Chapter 11 can be used to determine the necessary temperature corrections. If the calibration fluid is a hydrocarbon of unknown pressure, volume, or temperature properties, samples must be taken to determine these properties.

Full records of all the provings of the master meter shall be kept, since a detailed history of performance is a valuable guide to its reliability.

Manual of Petroleum Measurement Standards Chapter 4–Proving Systems

Section 3—Small Volume Provers

Measurement Coordination Department

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Chapter 4—Proving Systems

SECTION 3—SMALL VOLUME PROVERS

4.3.1 Introduction

The use of small volume provers has been made possible by the availability of high-precision displacer-position detectors used in conjunction with pulse-interpolation techniques (see Chapter 4.6). The small volume prover normally has a smaller base volume than that of conventional pipe provers (see Chapter 4.2) and is usually capable of fast proving passes over a wide range of flow rates.

Small volume provers have a volume between detectors that does not permit a minimum accumulation of 10,000 direct (unaltered) pulses from the meter. Small volume provers require meter pulse discrimination using a pulse-interpolation counter or another technique that increases the resolution (see Chapter 4.6). This may include using provers with both large and small base volumes, depending on the pulse rates of the meters to be proved.

The small volume prover may be used in many applications in which pipe provers or tank provers are commonly used. Small volume provers may be stationary or portable.

The volume required of a small volume prover can be less than that of a conventional pipe prover when high-precision detectors are used in conjunction with pulse-interpolation techniques Pulse-interpolation methods of counting a series of pulses to fractional parts of a pulse are used to achieve high resolution without counting 10,000 whole meter pulses for a single pass of the displacer between detectors (see Chapter 4.6.)

To achieve the required proving accuracy and repeatability, the minimum volume between detector switches depends on the discrimination of a combination of pulse-interpolation electronics, detectors, and uniform meter pulses, as well as flow rate, pressure, temperature, and meter characteristics.

4.3.1.1 SCOPE

This chapter outlines the essential elements of a small volume prover and provides descriptions of and operating details for the various types of small volume provers that meet acceptable standards of repeatability and accuracy.

4.3.1.2 DEFINITION OF TERMS

Terms used in this chapter are defined in 4.3.1.2.1 through 4.3.1.2.6.

4.3.1.2.1 *Interpulse spacing* refers to variations in the meter pulse width or space, normally expressed in percent.

4.3.1.2.2 *Meter proof* refers to the multiple passes or round trips of the displacer in a prover for purposes of determining a meter factor.

4.3.1.2.3 A *meter prover* is an open or closed vessel of known volume utilized as a volumetric reference standard for the calibration of meters in liquid petroleum service. Such provers are designed, fabricated, and operated within the recommendations of Chapter 4.

4.3.1.2.4 A *prover pass* is one movement of the displacer between the detectors in a prover.

4.3.1.2.5 A *prover round trip* is the result of the forward and reverse passes in a bidirectional prover.

4.3.1.2.6 A *proving timer/counter* is a high-speed counter used in double chronometry to measure time with a pulsed signal of known frequency.

4.3.1.3 REFERENCED PUBLICATIONS

The current editions of the following standards, codes, and specifications are cited in this chapter:

API

Manual of Petroleum Measurement Standards

Chapter 4, "Proving Systems," Section 2, "Conventional Pipe Provers," Section 6, "Pulse Interpolation," and Section 7, "Field-Standard Test Measures"

Chapter 5, "Metering," Section 2, "Measurement of Liquid Hydrocarbons by Displacement Meters," Section 3, "Measurement of Liquid Hydrocarbons by Turbine Meters," and Section 4, "Accessory Equipment for Liquid Meters"

Chapter 7.2, "Dynamic Temperature Determination"

Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"

NFPA[1]

70 *National Electrical Code*

[1]National Fire Protection Association, Batterymarch Park, Quincy, Massachusetts 02269.

4.3.2 Small Volume Prover Systems

The small volume prover is available in several different configurations that allow a continuous and uniform rate of flow. All types operate on the common principle of the repeatable displacement of a known volume of liquid in the calibrated section of a pipe or tube. A displacer travels through a calibrated section with its limits defined by one or more highly repeatable detectors. The corresponding metered volume simultaneously passes through the meter, and the whole number of pulses is counted. Precise calculations are made using a pulse-interpolation technique (see Chapter 4.6).

The two types of continuous-flow small volume provers are unidirectional and bidirectional. The unidirectional prover allows the displacer to travel and measure in only one direction through the proving section and has a means of returning the displacer to its starting position. The bidirectional prover allows the displacer to travel and measure first in one direction and then in the other and is capable of reversing the flow through the prover section.

Both unidirectional and bidirectional small volume provers must be constructed so that the full flow of the stream passing through the meter being proved will pass through the prover.

4.3.3 Equipment

The small volume prover must be suitable for the intended fluids, pressures, temperatures, and type of installation. The materials used must be compatible with the fluid stream and the location where the prover will be installed.

A small volume prover will normally consist of the following elements:

a. A precision cylinder.
b. A displacer piston, spheroid, or other fluid-separation device.
c. A means of positioning and launching the displacer upstream of the calibrated section.
d. A displacer detector or detectors.
e. A valve arrangement that allows fluid flow while the displacer is traveling from one position to the opposite position.
f. Pressure-measurement devices.
g. Temperature-measurement devices.
h. Instrumentation with timers, counters, and pulse-interpolation capability.

4.3.3.1 MATERIALS AND FABRICATION

The materials selected for a prover shall conform to applicable codes, pressure ratings, corrosion resistance, and area classifications.

The calibrated volume-measurement section of the prover, located between the displacer-position sensors, must be designed to exclude any appurtenances such as vents or drains.

Flanges or other provisions should be included for access to the inside surfaces of the calibrated and prerun sections. Care should be exercised to ensure and maintain proper alignment and concentricity of pipe joints.

Internally coating the prover section with a coating or plating material that will provide a hard, smooth, long-lasting finish will reduce corrosion and prolong the life of the displacer or displacer seals and the prover.

4.3.3.2 TEMPERATURE STABILITY

Temperature stability is necessary to achieve acceptable proving results. Temperature stabilization is normally achieved by continuously circulating liquid through the prover section, with or without insulation. When provers are installed aboveground, the application of thermal insulation will contribute to better temperature stabilization.

4.3.3.3 TEMPERATURE MEASUREMENT

Temperature-measurement sensors should be of suitable range and accuracy and should be graduated by temperature discrimination in fractional degrees to at least 0.5°F (0.25°C). See Chapters 7.2 and 12.2. Temperature-measurement devices shall be installed at appropriate locations to measure temperature at the meter and the prover. Caution must be exercised to ensure that the temperature sensors are located in a position in which they will not be shut off from the liquid path.

4.3.3.4 PRESSURE MEASUREMENT

Pressure-measurement devices of suitable range and accuracy, calibrated to an accuracy of 2 percent full scale or better, shall be installed at appropriate locations to measure pressure at the meter and the prover. (See Figures 1–4 and Chapter 12.2 for further information).

4.3.3.5 DISPLACING DEVICES

One type of displacer is a piston, with seals, connected to a central shaft. A second type of displacer is a free piston that uses seals between the precision cylinder and the piston. A third type is the elastomer sphere filled with liquid under pressure. To provide a seal without excessive friction, the sphere is expanded to a diameter greater than the prover pipe's inside diameter, which is normally 2–4 percent. Insufficient expansion of the sphere can lead to leakage past the sphere and

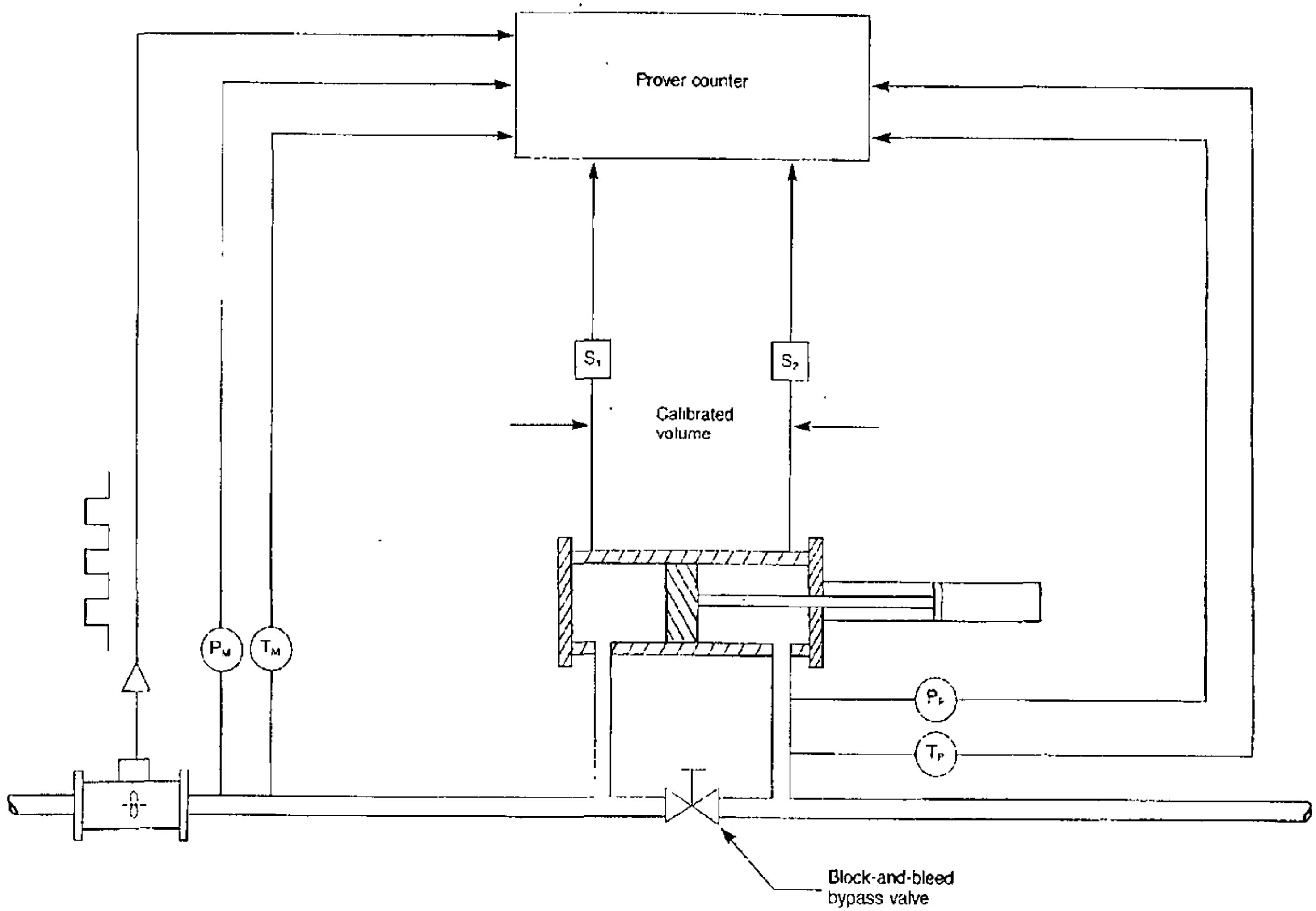

Figure 1—Generalized System Overview

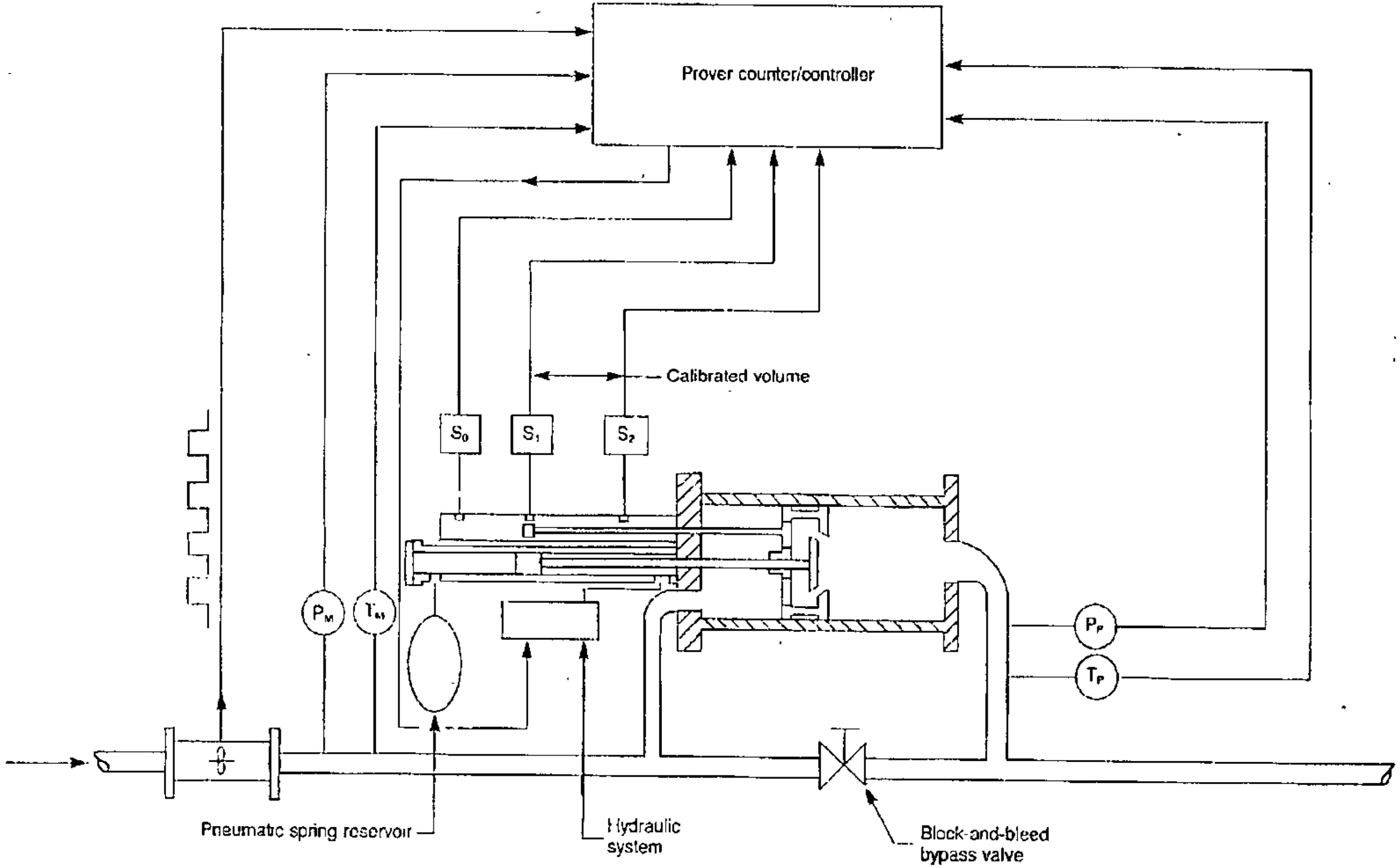

Figure 2—System Overview of Internal Valve

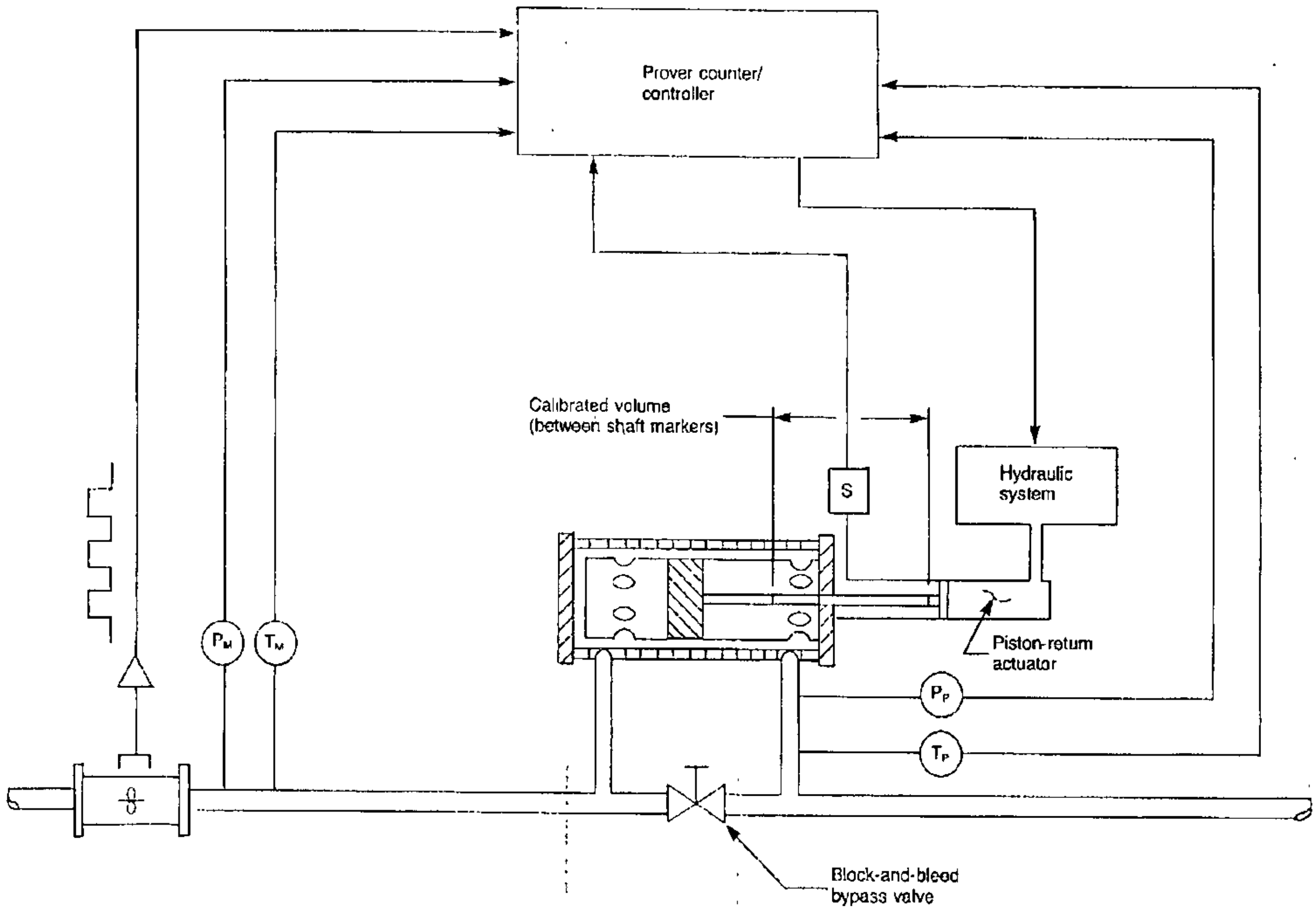

Figure 3—System Overview of Internal Bypass Porting With External Valve

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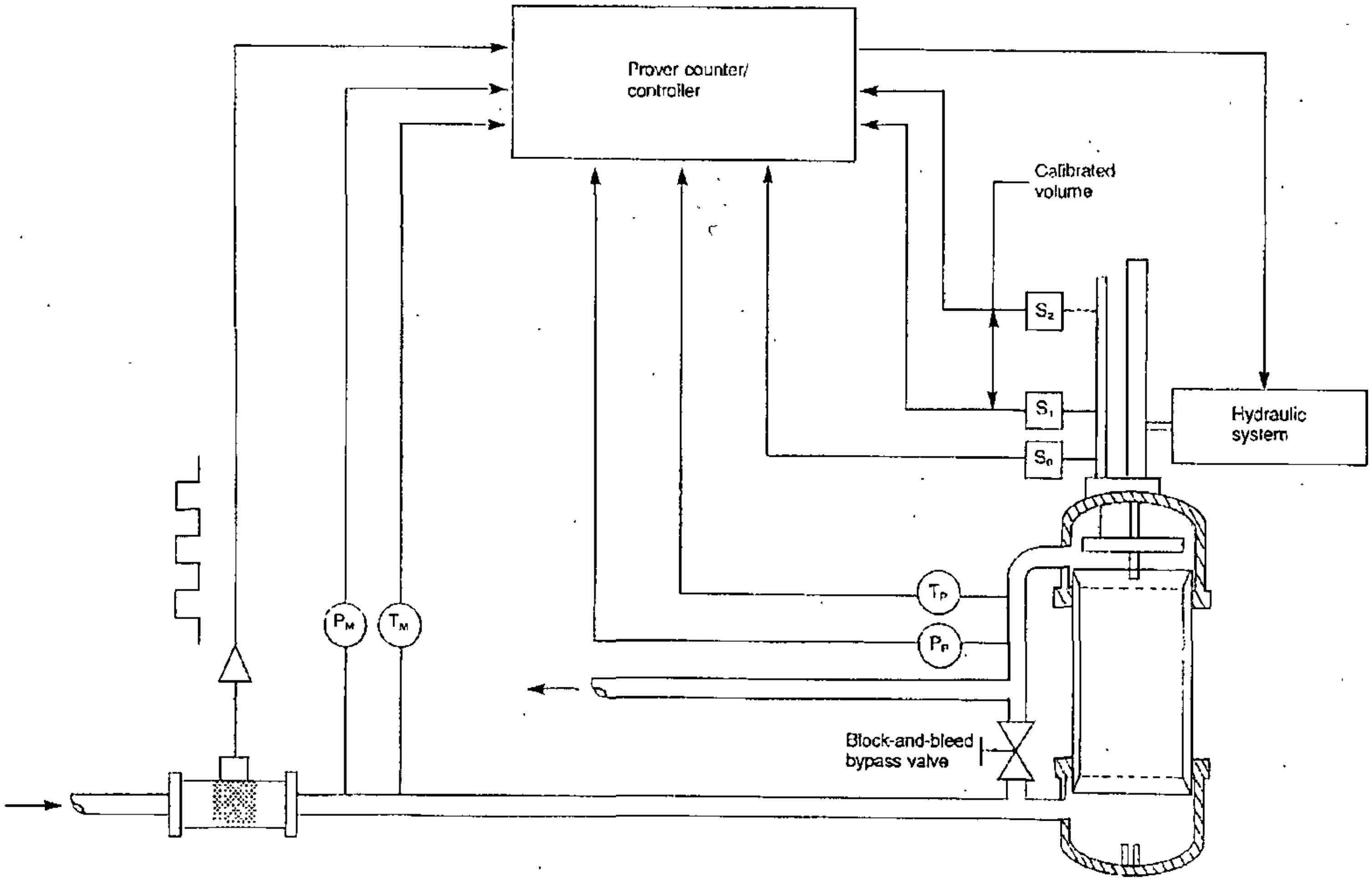

Figure 4—System Overview of Pass-Through Displacer With External Valve

consequently to measurement error. Excessive expansion of the sphere may not improve sealing ability and will generally cause the sphere to wear more rapidly and move erratically. Care must be exercised to ensure that no air remains inside the sphere. The elastomer should be impervious to the operating liquids.

A means for inspecting or monitoring displacer-seal integrity must be included in the design and operation of all small volume provers. Displacer-seal integrity may be either statically or dynamically verified under conditions of low-pressure differential that are consistent with normal operations.

Other types of displacers will be acceptable if they provide accuracy and repeatability that is equal to or better than the three types described above.

4.3.3.6 VALVES

All valves used in small volume prover systems that can provide or contribute to a bypass of liquid around the prover or meter or to leakage between the prover and meter shall be of the block-and-bleed type.

Full positioning of the flow-reversing valve or valves in a bidirectional prover or the interchange valve in a unidirectional prover must be established before the displacer is allowed to actuate the first detector. This design ensures that no liquid is allowed to bypass the prover during the displacer's travel through the calibrated volume. The distance before the first detector, commonly called prerun, depends on valve operation time and the velocity of the displacer. Methods used to shorten this prerun, such as faster operation of the valve or delay of the displacer launching, require that caution be exercised in the design so that hydraulic shock or additional undesired pressure drop is not introduced.

4.3.3.7 CONNECTIONS

Vent and drain lines shall be provided on the prover or the connecting piping and must have a means of checking for leaks. Provisions should be made to allow field waterdraw calibration of the small volume prover.

4.3.3.8 DETECTORS

Detectors must indicate the position of the displacer within ±0.01 percent. The repeatability with which a prover's detector can signal the position of the displacer (which is one of the governing factors in determining the length of the calibrated prover section) must be ascertained as accurately as possible. Care must be taken to correct detector positions that are subject to temperature changes throughout the proving operation.

4.3.3.9 METER PULSE GENERATOR

A meter pulse generator shall be provided for transmitting flow data. The generator must provide electrical pulses that have satisfactory characteristics for the type of electronic instrumentation employed.

4.3.3.10 PULSE-INTERPOLATION SYSTEM

The prover timer/counter for small volume provers is an electronic device that utilizes pulse interpolation and double chronometry (see Chapter 4.6).

4.3.3.11 CONTROLLER

The controller is used to process all signals both to and from the prover. It receives the start/stop signals from the detector or detectors that gate the timers, receives the pulses generated by the test meter, performs the calculations, and displays all data. The proving controller may be equipped to provide remote operation, alarms, printing, logic sequences, and other desired functions.

4.3.4 Design of Small Volume Provers

4.3.4.1 INITIAL CONSIDERATIONS

Before a small volume prover is designed or selected, it is necessary to establish the type of prover required for the application and the manner in which it will be connected to the meter piping. The following items should be established from a study of the application, intended use, and space limitations of the prover:

a. Whether the prover will be stationary or mobile.
   1. Whether a stationary prover will be dedicated (on line) or used as part of a central system.
   2. Whether a stationary and dedicated prover will be kept in service continuously or isolated from the metered stream when it is not being used to prove a meter.

b. The temperature and pressure ranges that will be encountered.
c. The expected maximum and minimum flow rates and the flow-rate stability.
d. The maximum pressure drop allowable across the prover.
e. The physical properties of the fluids to be handled.
f. The degree of automation to be incorporated into the proving operation.
g. The availability of electric power and other utilities.
h. The size and types of meters to be proved.
i. The applicable codes.

4.3.4.2 PRESSURE DROP ACROSS THE PROVER

In determining the size of the piping and the openings to be used in the manifolding and the prover, the pressure loss through the prover system should be compatible with the pressure loss considered tolerable in the metering installation. Flow rate should not vary significantly during movement of the displacer.

4.3.4.3 DISPLACER VELOCITY

The velocity of the displacer can be determined by the diameter of the prover cylinder and the maximum and minimum flow rates of the meters to be proved. A practical limit to the maximum velocity of a displacer must be established to prevent damage to the displacer and the detectors.

Typical maximum displacer velocities are close to but not limited to 5 feet per second (1.5 meters per second). The developing state of the art advises against setting a firm limit on displacer velocity as a criterion for design. Demonstrated results are better to use as a criterion. The results are manifested in repeatability, accuracy, and reproducibility of meter factors using the prover in question.

Establishing guidelines for minimum velocities is difficult because of the many factors that must be considered, such as the following:

a. The smoothness of the cylinder's internal surface.
b. The type of displacer used.
c. The displacer's launching capability.
d. The lubricity of the liquid being measured.

Piston-type displacers can generally operate at lower velocities than can sphere types.

The intention of this standard is not to limit the velocity of the displacer. Provided that acceptable performance is guaranteed, there is no arbitrary limit imposed on velocity.

4.3.4.4 VOLUME

In determining the volume of a prover between detectors, the designer must consider the following items:

a. The overall repeatability required of the proving system.
b. The repeatability of the detectors.
c. The ability of the electronic counter to indicate whole pulses, unless pulse interpolation is employed.
d. The resolution of the meter pulse generator (the number of pulses per unit volume).
e. The maximum and minimum flow rates of the system.
f. The uniformity of the meter signal, or pulse, relative to time (interpulse spacing).
g. The meter's displaced volume per revolution.

4.3.4.5 CRITICAL PARTS

When a detector's worn or damaged parts are replaced, care must be taken to ensure that neither the detector's actuating depth nor its electrical switch components are altered to the extent that the prover volume is changed. This is especially important in the case of unidirectional provers because changes in detector actuation are not compensated for by round trip sphere travel, as they are in bidirectional provers. When unidirectional provers are used, recalibration is needed as soon as practical.

4.3.4.6 COUNTERS

The small volume prover requires using a meter pulse-interpolation-type system (see Chapter 4.6) to provide a resolution of at least one part in 10,000 of the indicated meter volume for each pass of the displacer between the detectors.

4.3.4.7 METER PROVING GUIDELINES

Different types of meters produce pulse trains that have different characteristics.

At a steady flow, the rotation of a turbine meter and its pulse train is uniform. Under comparable flow, the rotation of some displacement-meter elements is also uniform; however, mechanical gears, couplings, adjustors, counters, temperature-correction devices, and other accessories reduce the uniformity of the displacement-meter pulses.

Demonstrations have shown that the closer the pulse generator is to the meter rotor, the more uniform the pulse train will be. The further the pulse is moved from the meter rotor, the more erratic the pulse train becomes (see Appendix A).

For example, a displacement meter that has a close-coupled pulser will require only a minimal number of prover passes performed by a relatively-low-volume prover to establish a meter factor. (See Figure A-2 for pulse train characteristics.) A displacement meter with a full assortment of accessories will usually require more passes or the use of a larger prover to establish a meter factor. (See Figure A-3 for pulse train characteristics.)

4.3.5 Sample Calculations for the Design of Small Volume Provers

A typical approach to the design and application of small volume provers is provided in 4.3.5.1 and 4.3.5.2.

Note: Test-run observation indicates that the calculation method used in 4.3.5.1 and 4.3.5.2 should provide a minimum volume for proving a meter with a uniform pulse train (for example, a turbine meter or a displacement meter that has a uniform pulse output). A proving method that consists of five prover passes, or round trips, with a repeatability range of 0.05 percent is achievable. Proving methods for use on nonuniform pulse output meters are discussed in Appendix B. The examples used in this section are not intended to imply that the meter and prover data will be appropriate for all equipment or that other methods of prover design analysis are inappropriate.

4.3.5.1 PROBLEM

The maximum flow rate of the meter to be proved is 1715 barrels per hour (1200 gallons per minute, 272.66 cubic meters per hour). The minimum flow rate is 343 barrels per hour (240 gallons per minute, 54.49 cubic meters per hour).

The meter is a 6-inch displacement meter with a pulse rate of 8400 pulses per barrel (52,834.4 pulses per cubic meter). The maximum interpulse spacing is equal to ±10 percent of the average. The meter pulse output is approximately uniform with the rotation of the meter element.

The pulse interpolation is performed by the double-chronometry method using one clock with a frequency of 100,000 hertz.

The prover displacer-position detectors have a repeatability range of 0.001 inch (0.0254 millimeter) and a position stability range of 0.001 inch (0.0254 millimeter).

The meter output resolution at the start and end of one prover pass is ±0.01 percent (±0.0001 percent of the average) The prover displacer-position error at the start and end of a prover pass has an uncertainty of ±0.01 percent. The maximum displacer velocity is 3.5 feet per second (1.067 meters per second). The minimum displacer velocity is 1.2 inches per second (3.048 centimeters per second).

The required design data is the minimum volume, minimum diameter, and minimum length of the prover.

4.3.5.2 SOLUTION

The potential error due to the resolution of double-chronometry timers during a prover pass can be calculated as follows:

$$U_t = \pm 2 / N_c \qquad (1)$$

Where:

U_t = potential error in time accumulated by two timers (one that times meter pulse output and one that times prover displacement), expressed as a plus/minus fraction of a pulse.
2 = number of timers.
N_c = number of clock pulses accumulated during a prover pass.

The number of clock pulses accumulated during a prover pass is calculated as follows:

$$N_c = T_2 F_c \qquad (2)$$

Where:

T_2 = clock operating time during a prover pass, in seconds.
F_c = clock frequency, in hertz.

The clock operating time during a prover pass is calculated as follows:

$$T_2 = N_m / F_m \qquad (3)$$

Where:

N_m = number of meter pulses during a prover pass, in pulses.
F_m = meter pulse frequency, in hertz.

Equations 1, 2, and 3 can be combined to express the error of the timers in terms of meter output and timer frequency:

$$U_t = \pm 2F_m / N_m F_c \qquad (4)$$

The meter pulse frequency is calculated as follows:

$$F_m = Q_m P_r / 3600$$

Where:

Q_m = meter flow rate, in barrels per hour (cubic meters per hour).
P_r = meter pulse rate, in pulses per barrel (pulses per cubic meter).
3600 = number of seconds per hour.

In this example the maximum pulse frequency is calculated as follows:

$$F_{m(max)} = (1715)(8400) / 3600 = 4002 \text{ hertz}$$

In SI units,

$$F_{m(max)} = (272.66)(56,834.4) / 3600 = 4002 \text{ hertz}$$

The potential error of the double-chronometry time can be calculated from Equation 4 as follows:

$$U_t = (\pm 2)(4002) / (N_m)(100,000) = \pm 0.080 / N_m$$

The error due to nonuniform meter interpulse spacing at the start and end of a prover pass is calculated as follows:

$$U_m = (2)(\pm P_i) / N_m \qquad (5)$$

Where:

U_m = potential error due to nonuniform meter interpulse spacing during a prover pass, expressed as a plus/minus fraction.

2 = number of displacer detections during a prover pass.

P_s = meter interpulse spacing expressed as a plus/minus fraction of a pulse.

In this example the error due to nonuniform meter interpulse spacing is as follows:

$$U_m = 2(\pm 0.10)/N_m$$
$$= \pm 0.20/N_m$$

The combined meter output error at the start and end of a prover pass can be estimated by combining Equations 4 and 5 as follows:

$$U_t + U_m = \pm 2F_m/N_mF_t + (2)(\pm P_s)/N_m \qquad (6)$$

Note: Equation 6 sums the errors U_t and U_m instead of taking the root mean square, the usual method of calculation. This approach results in a slightly larger prover than might otherwise be calculated.

In this example the combined meter pulse uncertainty during a prover pass is as follows:

$$U_t + U_m = (\pm 0.080 + \pm 0.20)/N_m$$
$$= \pm 0.280/N_m$$

The maximum meter output error at the start and end of a prover pass is limited to the following:

$$U_t + U_m = \pm 0.0001(\pm 0.01 \text{ percent})$$

In this example the minimum number of meter pulses that limits meter error to ± 0.0001 is as follows:

$$\pm 0.280/N_m = \pm 0.0001$$

Therefore,

$$N_m = 2800 \text{ meter pulses}$$

The minimum prover volume is calculated as follows:

$$V_{P(min)} = N_m/P_t$$
$$= 2800/8400$$
$$= 0.33333 \text{ barrel } (0.05299 \text{ cubic meter})$$
$$= 14.000 \text{ gallons } (52.996 \text{ liters})$$
$$= 3234.0 \text{ cubic inches } (52.996 \text{ cubic centimeters})$$

The minimum diameter of a prover's calibrated chamber at the maximum flow rate is calculated as follows:

$$D_p = [Q_m/(0.7854V_d)]^{0.5}$$

In SI units,

$$D_p = [Q_m/(0.7854V_d)]^{0.5}$$

Where:

D_p = internal diameter of the prover's calibrated chamber, in inches (centimeters).

Q_m = meter flow rate, in cubic inches per second (cubic centimeters per second).

V_d = displacer velocity, in inches per second (centimeters per second).

In this example the minimum prover diameter for the velocity limit is calculated as follows:

$$D_{p(min)} = \{4620/[(0.7854)(42)]\}^{0.5}$$
$$= 11.83 \text{ inches}$$

In SI units,

$$D_{p(min)} = \{75,708.2/[(0.7854)(106.68)]\}^{0.5}$$
$$= 30.06 \text{ centimeters}$$

The velocity of the displacer at the minimum flow rate, with the inside diameter given above, is calculated as follows:

$$V_{d(min)} = Q_m/[0.7854(D_p^2)]$$
$$= 924/[(0.7854)(11.83^2)]$$
$$= 8.4 \text{ inches per second}$$
$$= 0.7 \text{ foot per second}$$

In SI units,

$$V_{d(min)} = Q_m/[(30.05)(D_p^2)]$$
$$= 15,141.6/[(0.7854)(30.05^2)]$$
$$= 21.35 \text{ centimeters per second}$$
$$= 0.213 \text{ meter per second}$$

Since the minimum calculated displacer velocity of 0.7 foot per second (0.213 meter per second) is more than the design limit of 0.1 foot per second (0.03 meter per second), the diameter of 11.83 inches (30.05 centimeters) is satisfactory.

The prover's calibrated section is calculated as follows:

$$L_p = V_p/[0.7854(D_p^2)]$$

In this example the minimum prover length, based on the minimum volume and diameter of the prover section, is as follows:

$$L_{p(min)} = 3234/[(0.7854)(11.83^2)]$$
$$= 29.42 \text{ inches}$$

In SI units,

$$L_{p(min)} = 52,996/[(0.7854)(30.05^2)]$$
$$= 74.72 \text{ centimeters}$$

The error in the displacer's position during a prover pass can be estimated as follows:

$$U_d = [2(r_d + s_d)]/L_p$$

Where:

U_d = range of error in the displacer's position during a prover pass, expressed as a fraction.

2 = number of displacer positions during a prover pass.

r_d = range of repeatability of the displacer detector or detectors, in inches (centimeters).

s_d = range of stability in the mounting position of the displacer detector or detectors, in inches (centimeters).

In this example the minimum length of the prover's calibrated section for a maximum error range of 0.0002 (0.02 percent) in displacer positions during a prover pass would be as follows:

$$\begin{aligned} L_{P(min)} &= 2(r_d + s_d) / U_d \\ &= [2(0.001 + 0.001)] / 0.0002 \\ &= 20 \text{ inches} \end{aligned}$$

In SI units,

$$\begin{aligned} L_{P(min)} &= 2(r_d + s_d) / U_d \\ &= [2(0.00254 + 0.00254)] / 0.0002 \\ &= 50.8 \text{ centimeters} \end{aligned}$$

Since the minimum prover length corresponding to the minimum diameter [29.42 inches (74.72 centimeters)] is longer than the minimum prover length based on displacer detector error [20 inches (50.8 centimeters)], the former prover length is satisfactory.

4.3.5.3 SUMMARY OF PROVER DESIGN CALCULATIONS

The minimum volume equals 14.000 gallons (52.996 liters). The minimum diameter equals 11.83 inches (30.05 centimeters). The minimum length equals 29.42 inches (74.72 centimeters).

4.3.5.4 OTHER CONSIDERATIONS

When operating at its maximum design flow rate, the small volume prover shall allow the displacer to come to rest safely without shock at the end of its travel.

When the prover is operating at its maximum flow rate with liquids for which it was designed, there shall be no sign of cavitation in the prover, the valves, or any other apparatus within the specified temperature and pressure ranges.

4.3.6 Installation

All installation components of the small volume prover, including connecting piping, valves, manifolds, and so forth, shall be in accordance with the applicable piping codes. Once the prover is onstream, it becomes a part of the pressure system.

If the proving section and related components are installed aboveground, they shall have suitable hangers and supports prescribed by the applicable codes and in accordance with sound engineering principles. Adequate provisions should be made for expansion and contraction, vibration, reaction to pressure surges, and other conditions.

Suitable valves shall be installed to isolate the prover unit from line pressure during maintenance, removal of the displacer, replacement of seals, cleaning, and recalibration. Likewise, connections on the prover or in the lines should be considered for subsequent recalibrations.

All units shall be equipped with vent and drain connections, and provision should be made for the disposal of liquids or vapors that are drained or vented from the small volume prover section. This may be accomplished by pumping liquids or vapors back into the system or by diverting them to a collecting point.

Temperature and pressure devices shall be installed in suitable locations near the meter and the prover so that they can be used to determine the temperature and pressure of each.

Blinded valves or valve connections should probably be provided on either side of a bubbletight block valve in the carrier stream to serve as a permanent connection for proving portable meters.

Installations in hazardous locations must be recognized as such, and all wiring and controls in these locations shall conform to the requirements of NFPA 70 and any other applicable electrical standards. Provisions shall be made for proper grounding and electrical installation of portable small volume provers.

Components shall come from the class and group that are most appropriate for the location and operation. All electrical controls and components should be placed in a location that is convenient for operation and maintenance. Manufacturers' instructions should be strictly followed during the installation and grounding of such items as electronic counters, pulse-interpolation equipment, and signal cables (see Chapter 5.4).

Pressure relief valves and leak-detection facilities shall be installed with discharge piping to control thermal expansion of the liquid in the small volume prover while it is isolated from the main stream.

Power controls and remote controls should be suitably protected with lockout switches between remote and adjacent panel locations to prevent accidental remote operation while a unit is being controlled locally. Suitable safety devices and locks should be installed to prevent inadvertent operation of or unauthorized tampering with equipment.

Automated or power-operated meter proving systems may be equipped with emergency manual operators for use during a power failure.

Small volume provers may require straining or filtering equipment.

4.3.7 Calibration

4.3.7.1 GENERAL CONSIDERATIONS

A small volume prover must be calibrated before it is placed in service to determine its base volume (the calibrated volume corrected to standard conditions). Periodic recalibration of the prover is also required. Chapter 12.2 gives details for determining all the correction factors and calculating the base volume. Some of the differences in calculating the base volume of a small volume prover are discussed in the following paragraphs.

The accuracy of the base volume (documented on a calibration certificate), as determined, cannot be better than the accuracy of the field standard used in determining it (see Chapter 12.2).

It should be clearly understood that the base volume of a unidirectional prover is the calibrated volume corrected to standard conditions and displaced between detectors for a single pass. The base volume of a bidirectional prover is the sum of the volumes displaced between detectors for a round trip of the displacer and corrected to standard conditions.

Some unidirectional small volume provers have one or more shafts attached to the displacer. The shaft may be continuous or may be on only one side of the displacer. If the shaft is continuous and uniform, the effective upstream volume may be equal to the effective downstream volume; however, if the shaft is on only one side of the displacer, the effective upstream volume will differ from the effective downstream volume. For further clarification, if the shaft is on the upstream side of the displacer, the effective volume when a meter is proved upstream of the prover will be less than the effective volume when a meter is proved downstream of the prover. Conversely, if the shaft is on the downstream side of the displacer, the effective volume when a meter is proved upstream of the prover will be greater than the effective volume when a meter is proved downstream of the prover. The difference in volumes is equivalent to the volume displaced by the shaft. Both volumes shall therefore be stated on the calibration certificate. If only one volume is determined, the certificate shall clearly state and identify the side of the prover that is calibrated to ensure that it is the side used to prove a meter.

The methods of calibrating a small volume prover include the waterdraw method, the gravimetric method, and the master-meter method. The waterdraw method, described in 4.3.7.2, is by far the most common.

4.3.7.2 WATERDRAW METHOD

The calibration of small volume provers by the waterdraw method may be simplified where possible by placing the prover, field standards, and test liquid in a stable temperature environment shaded from direct sunshine to allow the equipment and liquid to reach an equilibrium temperature.

Water is the ideal calibrating medium because of its high heat capacity, low compressibility, and low coefficient of thermal expansion compared to petroleum liquids. The use of any other medium in these measures changes the surface tension; consequently, the measure is no longer calibrated. To prevent contamination of the water, the prover and fill lines must be void of foreign materials.

The displacers should be moved through the small volume prover enough times to flush the prover and eliminate air that may have been caught in parts of the small volume prover system and to allow both the metal and liquid of the prover system to reach a common and steady temperature. Uninsulated small volume provers that are calibrated outdoors under hot or cold conditions should be temporarily insulated and sheltered to reduce variations in temperature. In addition to stabilizing the prover, it is necessary to verify that the valves, seals, and displacer are secure and that there is no leakage from or around the prover.

The temperature and pressure of the water at the prover, between the displacer and the standard measures, shall then be observed and recorded as the temperature and pressure in the prover at the start of calibration.

Test measures for the calibration of small volume provers shall comply with the requirements given in Chapter 4.7. High-sensitivity field standards with a resolution of 0.02 percent or better are recommended for use in calibrating small volume provers. Only a single field standard or as few field standards as possible should be used during a waterdraw calibration of a small volume prover.

The prover may be calibrated using small-diameter water lines and temporary valves. Automated fast-responding valves actuated by the detector switches, commonly called solenoid valves, shall be used. (See Figure 5.) Provisions shall be made to ensure that no water bypasses the field standard. The data recording sheets should be checked and signed by all parties that witness the calibration.

4.3.7.3 CALIBRATING BIDIRECTIONAL PROVERS

After completion of the preparatory steps for flushing air out of the prover and stabilizing the temperature, at least one trial calibration run should be made to determine the approximate volume of the small volume prover between its detectors so that the appropriate number and sizes of field standards can be estimated. A

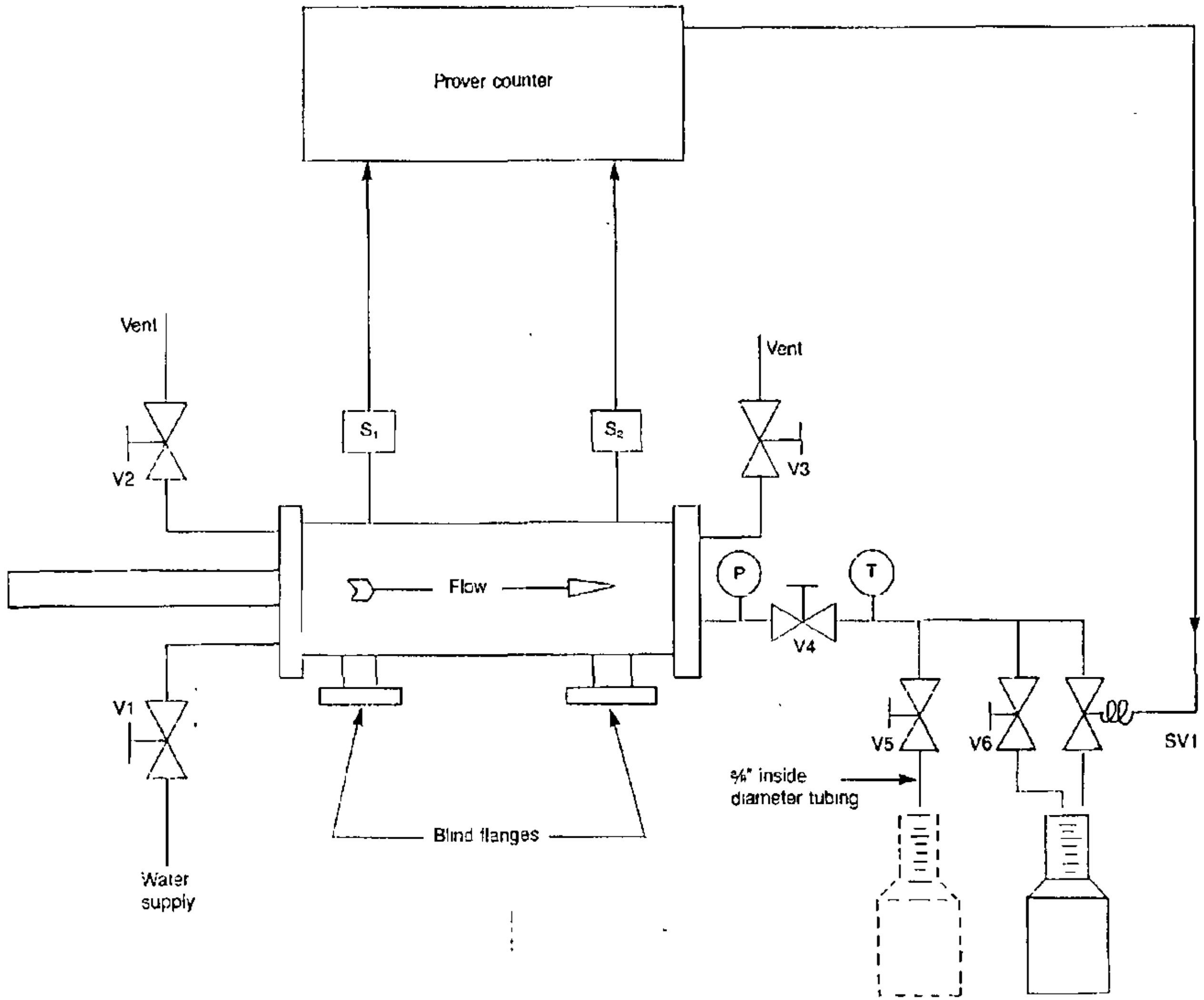

Figure 5—Generalized System Overview of Waterdraw Method

minimum number of field standards should be used (see Chapter 4.7).

Bidirectional calibration runs should now be started. The displacer should be driven past one of the switches into the space just outside the calibrated volume at either end of the small volume prover. The valves should be reversed so that the displacer travels toward the section to be calibrated while wasting the effluent water. Before reaching the detector, the water should be wasted slowly through a fast-acting automated valve. The waste should be stopped by using the fast-acting automated valve at the instant the switch indication shows "ON." The temperature and pressure of the water in the prover should be recorded. Next, all additional effluent water should be directed into the selected field standards. The withdrawals should be continued until the last field standard is being filled. The withdrawal should be reduced to a controllable slow-bleed rate through the fast-acting automated valve until the "ON" switch indication is observed at the second detector point; the withdrawal should be stopped at the instant the switch shows "ON." The total of the field-standard volumes indicates the observed displaced volume between detectors in that direction of travel under conditions of pressure and temperature that exist at the start of calibration. The fill condition of the drain hose and other withdrawal equipment shall be the same at the end of the withdrawal as it was at the start.

A similar displacer trip should now be made in the opposite direction, repeating the procedure. These two trips do not necessarily have to agree in observed displaced volume because the action of the detectors may be different for each direction of travel.

The calibrating procedure should be repeated until satisfactory repeatability is achieved. The average of at least two consecutive round trip corrected volumes within 0.02 percent (±0.01 percent of the average) is required. The corrected volume for the consecutive trips in any given direction shall also agree within 0.02 percent (±0.01 percent of the average).

The base volume is the average of two or more consecutive round trips of the displacer within the tolerances after correcting to the standard temperature and pressure.

Failure to repeat may be caused by leaking valves, air in the system, varying pressure, improper condition of the displacer or detectors, or poor calibration technique.

4.3.7.4 CALIBRATING UNIDIRECTIONAL PROVERS

The base volume of a unidirectional prover is the volume that is displaced as the displacer moves from one detector switch point to a second detector switch point. The described one-way trip procedure should be repeated until satisfactory repeatability is achieved. The average value for a minimum of two such one-way corrected volumes is considered the base volume for the prover at standard conditions.

This publication does not restrict the determination of the base volume to two consecutive runs. More runs may be used if agreed to by the parties involved.

The procedure for calibrating a unidirectional prover by the waterdraw method is substantially the same as the procedure described for a single one-way trip of the displacer in a bidirectional prover. The results of two or more consecutive runs (as agreed upon by the interested parties) shall agree within 0.02 percent (±0.01 percent of the average) or better to determine the base volume. For waterdraw calibration of the upstream section with the displacer moving in the opposite direction, the procedures are exactly the same except that care must be taken to use the same edge of the detector trigger that is used in calibrating the downstream section, and the displacer and valve seals must be confirmed in this direction. In effect, the difference between upstream and downstream volumes is equivalent to the area of the shaft or shafts times the length between detector trigger points.

4.3.7.5 REPEATABILITY

Repeatability is only one component of calibration accuracy. By filling the same field standards with the test runs made at an equal rate, an operator can complete a series of erroneous calibrations as the result of a consistent leak. This hazard can be reduced or eliminated by making an additional run at a rate change of at least 25 percent. With a changed flow rate, a different volume (after correction) that is outside 0.02 percent (±0.01 percent of the average) of the initial runs (after correction) indicates the possibility of a leak in the proving circuit, which must be corrected before calibration can be achieved. All corrected volumes at both flow rates shall fall within 0.02 percent (±0.01 percent of the average). This is true of both unidirectional and bidirectional provers.

4.3.7.6 CERTIFICATE OF CALIBRATION

After a small volume prover is calibrated, the data sheets shall be used to prepare a certification of calibration. The certificate shall state the calibration method used, the base volume or volumes, the reference conditions, the serial numbers, and the date.

For unidirectional small volume provers that have a shaft attached to the piston, the certificate shall clearly state and identify the side of the prover that is calibrated to ensure that it is the side used to prove a meter.

4.3.8 Operation

Proving with small volume provers requires the same good practices commonly associated with pipe provers.

All valves in the flow path between the meter and the small volume prover must be positioned so that fluid cannot be diverted from or added to the stream. All valves associated with the proving system must include a method for detecting leaks and must be free from leaks.

The proving system shall include at least one temperature indicator in the flow line adjacent to the meter and at least one indicator adjacent to the prover (see 4.3.5.3).

Pressure indicators shall be installed at appropriate locations to measure pressure at the meter and the prover (see 4.3.5.4).

Venting should be performed on the small volume prover and at other appropriate locations to ensure that air or gas is not trapped in the flow system before proving.

Steady flow should be established in the system to ensure stable temperature and pressure before proving.

The need for maintaining back pressure on the meter/prover system depends on various factors such as fluid velocity, fluid vapor pressure, and operating pressure and temperature. (See Chapters 5.2 and 5.3 for recommendations.)

Meter pulse output should be checked to ensure pulse integrity. Mechanical or electrical meter register tests should be conducted before proving.

The displacer seals of small volume provers should be checked for sealing integrity in accordance with the manufacturer's recommended procedure.

Pulse-interpolation or other types of counters used in conjunction with small volume provers shall be verified for correct operation before proof runs are conducted. (See Chapter 4.6 for descriptions of calibration tests and functional checks.)

Automated small volume provers that incorporate microprocessor computer sequence control, pulse interpolation, data acquisition, and data reduction shall be tested for functional operation before meter proofs are conducted. Such systems should contain self-test features to verify the operation of computer software and hardware. Manufacturers' procedures and recommendations should be followed in accordance with the appropriate sections of the *Manual of Petroleum Measurement Standards*.

In unidirectional small volume provers, a proving run consists of one trip of the displacer through the calibrated section.

Note: Care must be exercised during the use of displacers that incorporate a rod or rods, since the volumes upstream and downstream of the displacer will be different.

In bidirectional small volume provers, a proving run consists of a round trip of the displacer (that is, the sum of two consecutive trips in opposite directions through the calibrated section)

4.3.9 Nonuniform Pulses

Caution is recommended when gear-driven pulse generators are used on displacement meters to ensure that backlash, drive-shaft torsion, and cyclic effects do not cause irregular pulse generation. If these problems occur, an evaluation of the gearing and pulse-generation systems should be made to ensure that proper equipment is selected to provide optimum performance. Problems should be referred to the manufacturer of the meter and the small volume prover.

APPENDIX A—EVALUATION OF DISPLACEMENT METER PULSE VARIATIONS

A.1 General

During the development of Chapter 4.3, a question was raised about the magnitude of the pulse variations in conventional displacement meter systems. No experience or data were known, and two manufacturers volunteered to test several meters to define the range of pulse variations that could reasonably be expected.

Some of the terms used to describe pulse variations include interpulse linearity and pulse interspace variations. In fact, the concern is with pulse frequency variations within one cycle or rotation of a meter-measuring element or the gear train that provides the output motion for the proving pickup or counter. Gear systems, universal joints, and clutch-type adjustment devices are known to impart accelerations within a single revolution of a meter. The same variations may occur in gear-driven turbine-meter outputs and turbine-meter rotors where the magnetic plugs are not uniformly spaced on the perimeter of the rotor. These are probably minor variations compared with those that would be expected from displacement meters. No tests were performed on turbine meters.

Forty-four tests consisting of 10–25 provings with a small volume prover and 11 tests consisting of five pass provings with a 54-barrel unidirectional displacement prover were completed and recorded. The results are summarized in A.2 through A.4.

A.2 Equipment

A.2.1 METERS AND PROVERS

The displacement meters were connected in series in flowing-liquid test loops with nominal 15-gallon small volume provers for the tests. A conventional 54-barrel displacement prover was in the loop in one series of tests.

The meters were new production units available at the manufacturer's test facility. Each had limited pretest operation.

The pulses were generated in the conventional manner from commercial displacement meters. Two 3-inch meters, two 4-inch meters, and one 6-inch meter were used. In addition, a 3-inch and a 6-inch meter were equipped with special close-coupled pickup arrangements to monitor the performance of the measuring element only, without the influence of gears and shafts.

A.2.2 RECORDER

A precision high-frequency recording system was used for the tests at both locations. The 8-pen recorder with a chart speed of 50 millimeters per second was used to display the pulse trains generated by the meters.

A.3 Analysis of Results

The chart records of the test were analyzed manually to quantify the pulse variations. The following method was used:

a. Pulses generated by several rotations of the meter system were recorded.
b. The number of pulses representing 0.25 gallon of liquid passing through the meter was counted and marked. This resulted in 25- and 50-pulse segments for the meter outputs that were tested.
c. The length of chart represented by the pulses from 0.25 gallon was measured and recorded.
d. The series of chart lengths was plotted in bar-graph style.
e. The maximum chart length (that is, the lowest frequency segment) and the minimum chart length (that is, the highest frequency segment) within a meter rotation were identified.
g. The pulse variation was calculated as follows:

$$\text{Percent pulse range} = \frac{(\text{maximum chart length} - \text{minimum chart length}) \times 100}{2 \times \text{mean chart length}}$$

A.4 Results

A.4.1 GENERAL

Figures A-1, A-2, and A-3 illustrate the typical bar-graph analysis and results. The plots represent typical results obtained for the three meter sizes and the accessory equipment noted on the respective figures. The graphs are typical and cannot be considered specific for any given manufacturer's equipment. The charts do, however, illustrate the quality of the pulse output for various accessory arrangements and indicate the trend in pulse quality that may be expected from more or less equipment on a meter stack.

A.4.2 EXPLANATION OF BAR CHART

A displacement meter equipped with a pulse generator produces a series of electrical pulses separated by spaces. For simplification, a pulse should be considered to have a length of ¼ inch, which is then followed by a space of ¼ inch. This is termed a 50-percent-on/50-percent-off pulse train. This is predicated on the meter operating at a constant flow rate.

Even though the meter may be running at a constant flow rate, irregularities in the meter's drive mechanism may cause the pulse train to be alternately compressed and expanded.

Each of the bar charts has a horizontal and vertical axis. The horizontal axis represents the total number of pulses accumulated over a given period of time, and the numbers shown represent pulses counted on a linear chart. The vertical axis represents the number of inches between the pulses counted on the horizontal axis. Thus, on Figure A-1 the first six pulses/spaces account for 15.9 inches, whereas the second six pulses and accompanying spaces account for 16.0 inches, and so forth. The shortest and the longest lengths in the bar-chart group are 15.85 and 16.1 inches, respectively. Thus, 16.1 minus 15.85 divided by the mean length of 16 inches is equal to 1.5 percent interspace variation.

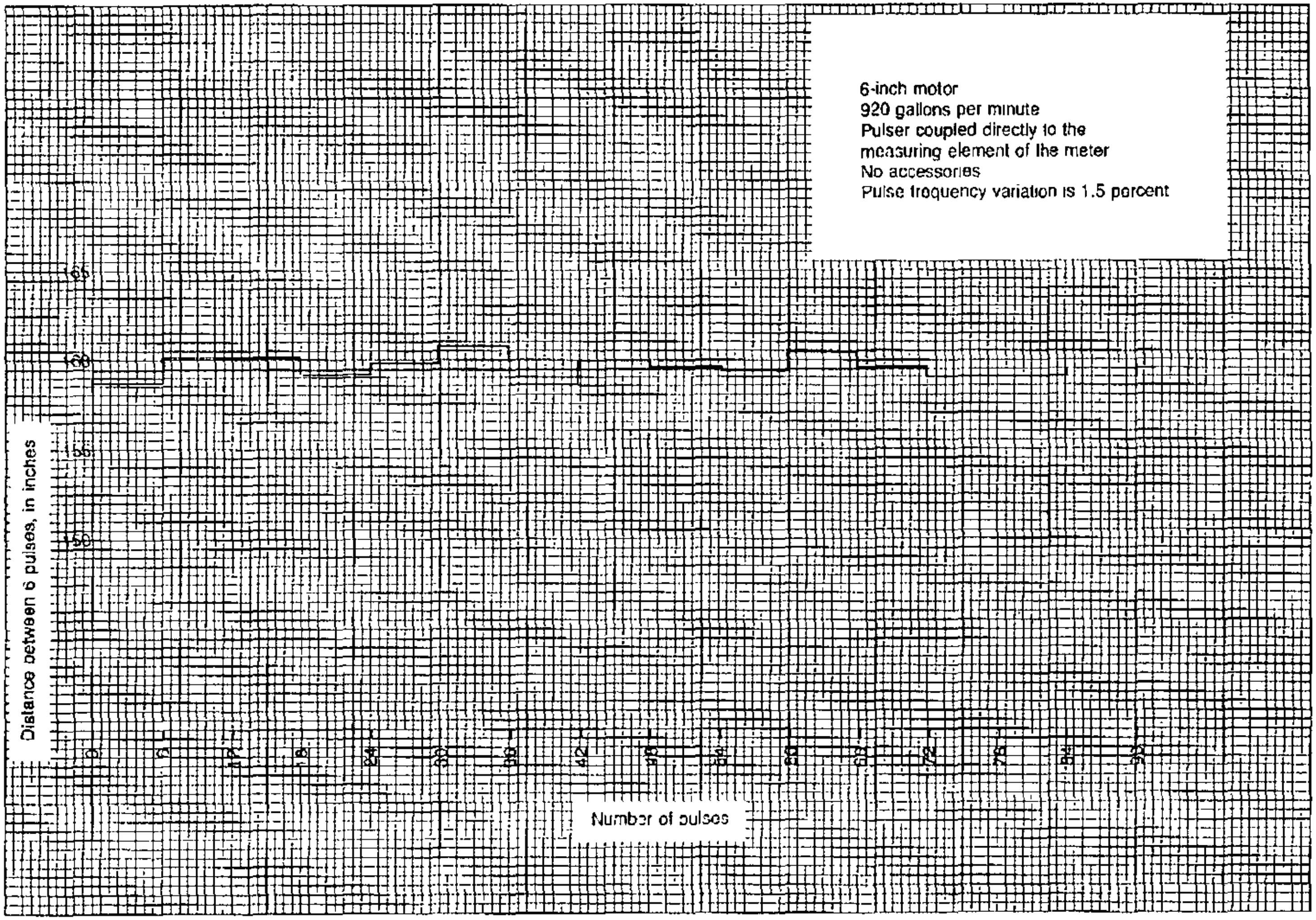

Figure A-1—Pulse Variation Graph/Direct

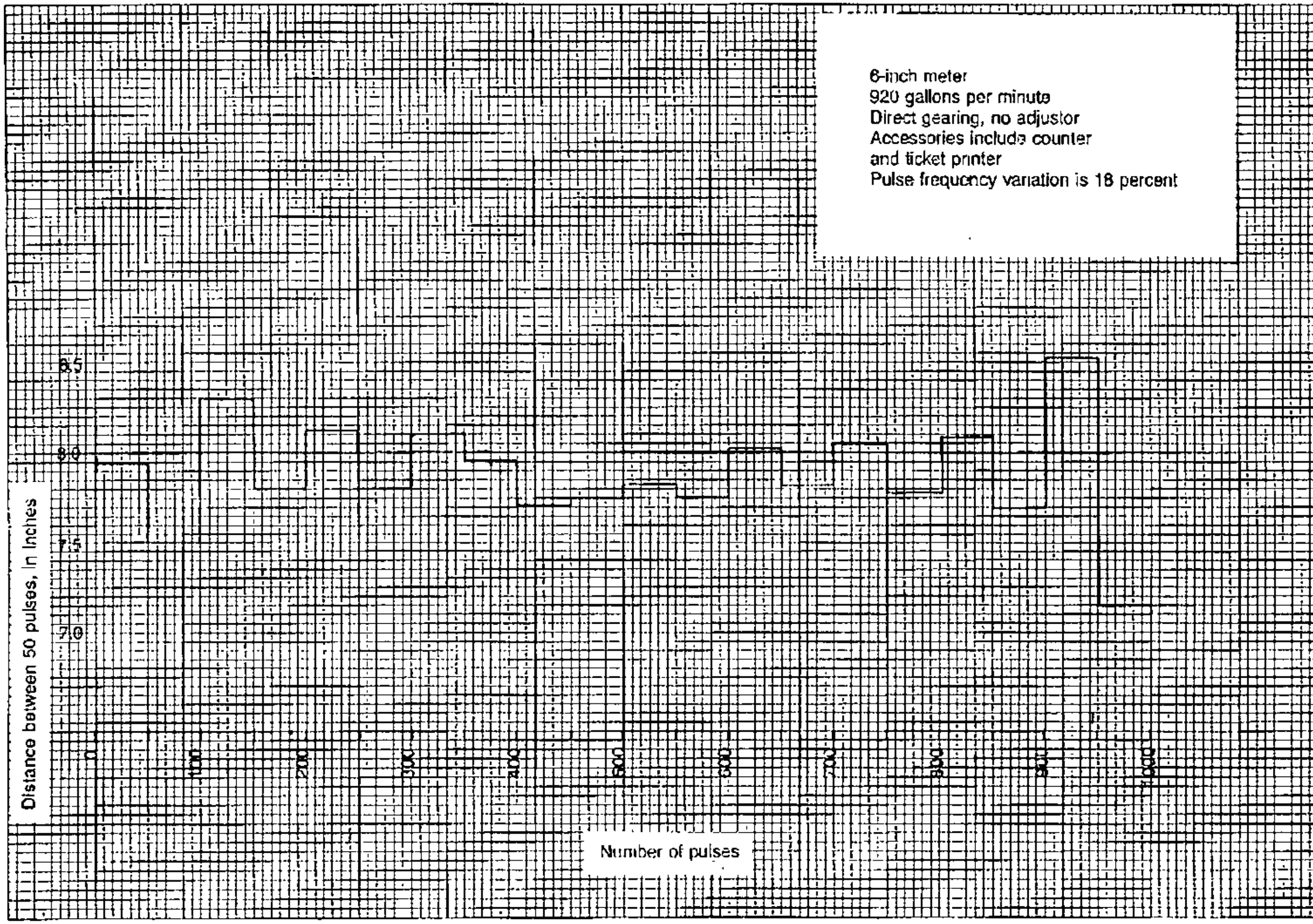

Figure A-2—Pulse Variation Graph/Geared

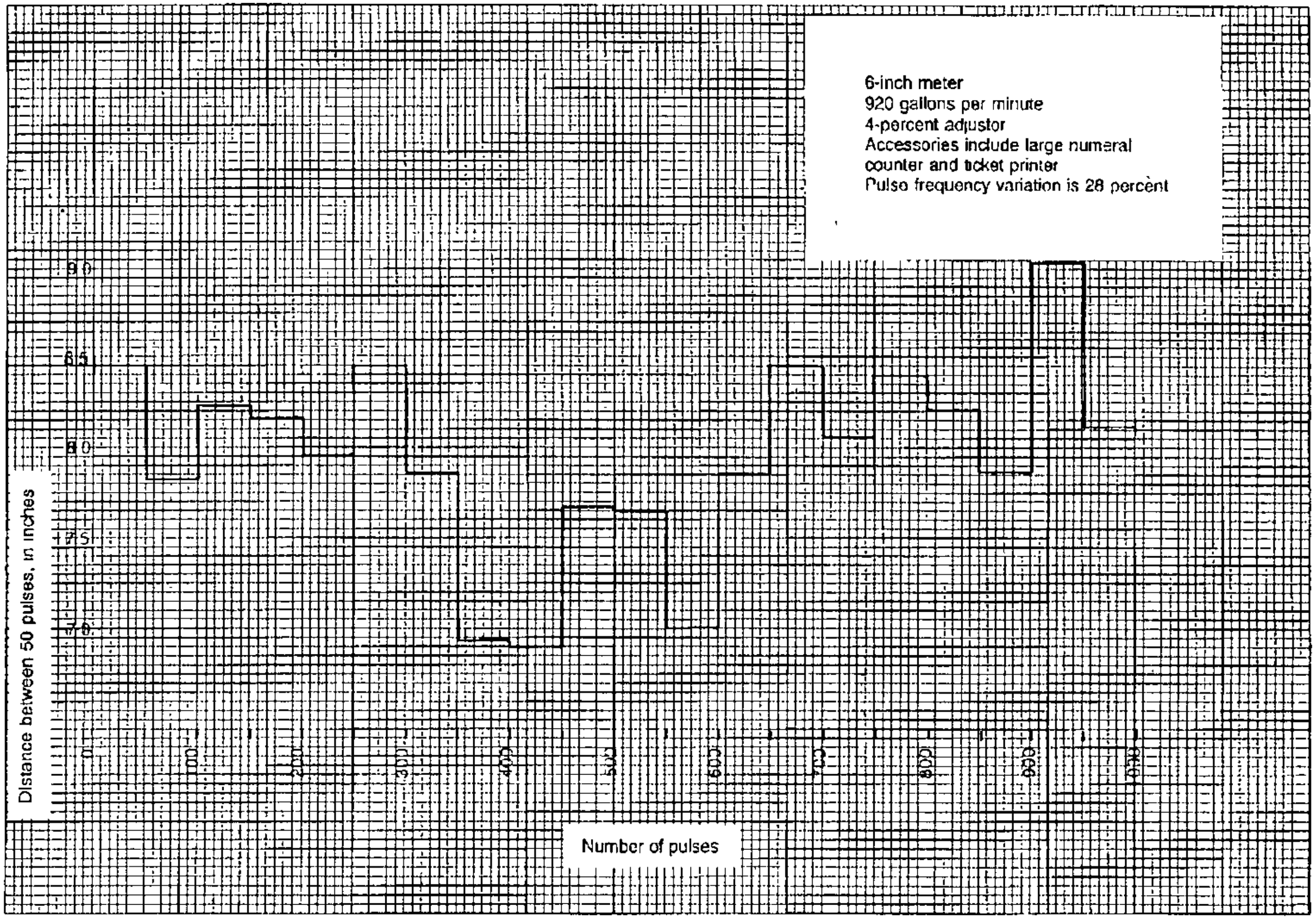

Figure A-3—Pulse Variation Graph/4-Percent Adjustment

APPENDIX B—METER FACTOR DETERMINATION WITH SMALL VOLUME PROVERS

B.1 General

The contributors to the initial Chapter 4.3 perceived a need to provide guidance for the development of acceptable meter factors with small volume provers. The methods described in the following paragraphs have been demonstrated to yield meter factors either comparable to those obtained from conventional displacement provers or considered to be accurate within usual tolerances by virtue of the repeatability of individual passes or prover round trips or groups of passes or prover round trips from properly operated systems. Calculation details shall be in accordance with the usual practices and as documented in Chapter 12.2.

The meter factors obtained from two separate provers for a specific meter and operating condition will rarely agree exactly because of the differences in the equipment, base-volume calibration tolerances, meter repeatability, and other factors. Agreement within 0.04 percent (±0.02 percent of the average) is generally considered acceptable for normal industry practice if no other agreement has been defined.

The following methods, based on observations and experience, were compiled by the working group before 1986. The methods are for guidance only; they are not a final recommendation, nor are they all-inclusive. Other methods, some of which were arrived at by various statistical techniques, exist but have not been sufficiently demonstrated to be listed here. The methods will ultimately be replaced by mature techniques to be documented in a future section of Chapter 4 that will address operational aspects of proving and will supersede this appendix.

B.2 Method 1

Turbine meters and displacement meters whose pulse generation is directly from, or very close to, the measuring elements can be proved with the same methods used for conventional displacement provers. This normally consists of five consecutive passes or round trips that repeat within 0.05 percent (±0.025 percent of the average). The average of the results from these passes or prover round trips then becomes the meter factor to be used in subsequent operations.

B.3 Method 2

Meters that have a nonuniform pulse output (that is, turbine and displacement meters with gear trains, shaft couplings, and shaft-driven accessories) may be proved by increasing the number of passes or prover round trips or by increasing the repeatability tolerance. For example,

> 10 passes or prover round trips that repeat within 0.10 percent (±0.05 percent of the average).
>
> The average of the prover-pass results becomes the meter factor to be used in subsequent operations.

Additional passes or prover round trips may be added as required to accommodate meters that repeat beyond 0.10 percent (±0.05 percent of the average) because of the nonuniform pulse characteristics. For example, 15 prover passes or prover round trips that repeat within 0.15 percent (±0.075 percent of the average) would be the next level of consideration.

The rationale for this procedure is that as the number of passes or prover round trips is increased, the repeatability performance of the meter usually increases and at the same time the quality of the average improves.

B.4 Method 3

A meter that has more severe nonuniform pulse output or a prover that is minimal in size may necessitate using the following method. The concept is to accumulate individual prover passes or prover round trips to form groups and then to average each group. The ranges of these groups should fall within tolerances that are consistent with the first and second methods. The average of the group averages then becomes the meter factor to be used in subsequent operations.

Increasing the number of passes or prover round trips in each group will improve the quality of the intergroup repeatability. Twenty passes or prover round trips per group is considered a practical limit; more will not improve the quality. If an acceptable repeatability is not obtained in 20 or fewer passes or prover round trips, the meter manufacturer should be consulted.

Manual of Petroleum Measurement Standards Chapter 4—Proving Systems

Section 6—Pulse Interpolation

Upstream Segment

SECOND EDITION, MAY 1999

American Petroleum Institute

Helping You Get The Job Done Right.℠

FOREWORD

Chapter 4 of the *Manual of Petroleum Measurement Standards* was prepared as a guide for the design, installation, calibration, and operation of meter proving systems commonly used by the majority of petroleum operators. The devices and practices covered in this chapter may not be applicable to all liquid hydrocarbons under all operating conditions. Other types of proving devices that are not covered in this chapter may be appropriate for use if agreed upon by the parties involved.

The information contained in this edition of Chapter 4 supersedes the information contained in the previous edition (First Edition, May 1978), which is no longer in print. It also supersedes the information on proving systems contained in API Standard 1101, *Measurement of Petroleum Liquid Hydrocarbons by Positive Displacement Meter* (First Edition, 1960); API Standard 2531, *Mechanical Displacement Meter Provers;* API Standard 2533, *Metering Viscous Hydrocarbons;* and API Standard 2534, *Measurement of Liquid Hydrocarbons by Turbine-Meter Systems,* which are no longer in print.

This publication is primarily intended for use in the United States and is related to the standards, specifications, and procedures of the National Bureau of Standards and Technology (NIST). When the information provided herein is used in other countries, the specifications and procedures of the appropriate national standards organizations may apply. Where appropriate, other test codes and procedures for checking pressure and electrical equipment may be used.

For the purposes of business transactions, limits on error or measurement tolerance are usually set by law, regulation, or mutual agreement between contracting parties. This publication is not intended to set tolerances for such purposes; it is intended only to describe methods by which acceptable approaches to any desired accuracy can be achieved.

MPMS Chapter 4 now contains the following sections:

Section 1, "Introduction"
Section 2, "Conventional Pipe Provers"
Section 3, "Small Volume Provers"
Section 4, "Tank Provers"
Section 5, "Master-Meter Provers"
Section 6, "Pulse Interpolation"
Section 7, "Field-Standard Test Measures"
Section 8, "Operation of Proving Systems"
Section 9, "Calibration of Provers"

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Suggested revisions are invited and should be submitted to the general manager of the Upstream Segment, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

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Chapter 4—Proving Systems
Section 6—Pulse Interpolation

0 Introduction

To prove meters that have pulsed outputs, a minimum number of pulses must be collected during the proving period. The prover volume or the number of pulses that a flowmeter can produce per unit volume of throughput is often limited by design considerations. Under these conditions it is necessary to increase the readout discrimination of the flowmeter pulses to achieve an uncertainty of 0.01%.

The electronic signal from a flowmeter can be treated so that interpolation between adjacent pulses can occur. The technique of improving the discrimination of a flowmeter's output is known as pulse interpolation. Although pulse-interpolation techniques were originally intended for use with small volume provers, they can also be applied to other proving devices.

The pulse-interpolation method known as double-chronometry, described in this chapter, is an established technique used in proving flowmeters. As other methods of pulse interpolation become accepted industry practice, they should receive equal consideration, provided that they can meet the established verification tests and specifications described in this publication.

1 Scope

This chapter describes how the double-chronometry method of pulse interpolation, including system operating requirements and equipment testing, is applied to meter proving.

2 Definitions

2.1 detector signal: A contact closure change or other signal that starts or stops a prover counter or timer and defines the calibrated volume of the prover.

2.2 double-chronometry: A pulse interpolation technique used to increase the readout discrimination level of flowmeter pulses detected between prover detector signals. This is accomplished by resolving these pulses into a whole number of pulses plus a fractional part of a pulse using two high speed timers and associated gating logic, controlled by the detector signals and the flowmeter pulses.

2.3 flowmeter discrimination: A measure of the smallest increment of change in the pulses per unit volume of the volume being measured.

2.4 frequency: The number of repetitions, or cycles, of a periodic signal (for example, pulses, alternating voltage, or current) occurring in a 1-second time period. The number of repetitions, or cycles, that occur in a 1-second period is expressed in hertz.

2.5 meter pulse continuity: The deviation of the inter-pulse period of a flowmeter expressed as a percentage of a full pulse period.

2.6 nonrotating meter: Any metering device for which the meter pulse output is not derived from mechanical rotation as driven by the flowing stream. For example, vortex shedding, venturi tubes, orifice plates, sonic nozzles, and ultrasonic and electromagnetic flowmeters are metering devices for which the output is derived from some characteristic other than rotation that is proportional to flow rate.

2.7 pulse period: The reciprocal of pulse frequency, i.e., a pulse frequency of 2 hertz, is equal to a pulse period of $1/2$ seconds.

2.8 pulse generator: An electronic device that can be programmed to output voltage pulses of a precise frequency or time period.

2.9 pulse interpolation: Any of the various techniques by which the whole number of meter pulses is counted between two events (such as detector switch closures); any remaining fraction of a pulse between the two events is calculated.

2.10 rotating meter: Any metering device for which the meter pulse output is derived from mechanical rotation as driven by the flowing stream. For example, turbine and positive displacement meters are those *metering* devices for which the output is derived from the continuous angular displacement of a flow-driven member.

2.11 signal-to-noise ratio: The ratio of the magnitude of the electrical signal to that of the electrical noise.

3 References

The current editions of the following standards are cited in this chapter:

API

MPMS Chapter 4, Proving Systems Section 3, "Small Volume Provers"

Chapter 5, Metering Section 4, "Instrumentation and Auxiliary Equipment for Liquid Hydrocarbon Metering Systems", Section 5, "Security and Fidelity of Pulse Data"

4 Double-Chronometry Pulse Interpolation

Double-chronometry pulse interpolation requires counting the total integer (whole) number of flowmeter pulses, N_m, generated during the proving run and measuring the time intervals, T_1 and T_2. T_1 is the time interval between the first flowmeter pulse after the first detector signal and the first flowmeter pulse after the last detector signal. T_2 is the time interval between the first and last detector signals.

The pulse counters, or timers, are started and stopped by the signals from the prover detector or detectors. The time intervals T_1, corresponding to N_m pulses, and T_2, corresponding to the interpolated number of pulses (N_I), are measured by an accurate clock. The interpolated pulse count is given as follows:

$$N_I = N_m (T_2/T_1)$$

The use of double-chronometry in meter proving requires that the discrimination of the time intervals T_1 and T_2 be better than ± 0.01%. The time periods T_1 and T_2 shall therefore be at least 20,000 times greater than the reference period T_c of the clock that is used to measure the time intervals. The clock frequency F_c must be high enough to ensure that both the T_1 and T_2 timers accumulate at least 20,000 clock pulses during the prove operation. This is not difficult to achieve, as current electronics technology used for pulse interpolation typically uses clock frequencies in the megahertz range.

4.1 CONDITIONS OF USE

The conditions described in 4.6.2.1.1 through 4.6.2.1.3 apply to double-chronometry pulse interpolation as described in this chapter.

4.1.1 The interpolated number of pulses, N_1, will not be a whole number. N_1 is therefore rounded off as described in section 3.12 of *MPMS* Chapter 12.2, Part 3.

4.1.2 Pulse-interpolation methods are based on the assumptions that actual flow rate does not change substantially during the period between successive meter pulses, and each pulse represents the same volume. To maintain the validity of this assumption, the short period fluctuations in the flow rate during the proving operation shall be minimized.

4.1.3 Because pulse interpolation equipment contains high speed counters and timers, it is important that equipment be installed in accordance with the manufacturer's installation instructions, thereby minimizing the risk of counting spurious pulses caused by electrical interference occurring during the proving operation. The signal-to-noise ratio of the total system shall be adequately high to ensure that typical levels of electrical interference are rejected. Refer to Chapter 5.4, Chapter 5.5, and other sections of Chapter 4 for more details.

4.2 FLOWMETER OPERATING REQUIREMENTS

The flowmeter that is being proved and is providing the pulses for the pulse-interpolation system shall meet the following requirements:

a. If the pulse repetition rate at constant flow rate cannot be maintained within the limits given in *MPMS* Chapter 4.3, then the flowmeter can be used with a pulse-interpolation system only at a lower overall accuracy level. In this case, a revised calibration accuracy evaluated or multiple runs with averaging techniques.

b. The meter pulse continuity in rotating flowmeters should be in accordance with *MPMS* Chapter 4.3. The generated flowmeter pulse can be observed by an oscilloscope, whose time base is set to a minimum of one full cycle, to verify meter pulse continuity of the flowmeter.

c. The repeatability of nonrotating flowmeters will be a function of the rate of change in pulse frequency at a constant flow rate. To apply pulse-interpolation techniques to nonrotating flowmeters, the meter pulse continuity of the flowmeter should be in accordance with *MPMS* Chapter 4.3 to maintain the calibration accuracy.

d. The size and shape of the signal generated by the flow meter should be suitable for presentation to the pulse-interpolation system. If necessary, the signal should undergo amplification and shaping before it enters the pulse-interpolation system.

5 Electronic Equipment Testing

The proper operation of pulse interpolation electronics is crucial to accurate meter proving. A functional field test of the total system should be performed periodically to ensure that the equipment is performing correctly. This may simply be a hand calculation verifying that the equipment correctly calculates the interpolated pulses per 4.6.2, or if need be, a complete certification test as described in 4.6.3.2. if a problem is suspected.

6 Functional Operations Test Requirements

Normal industry practice is to use a microprocessor based prover computer to provide the pulse interpolation functions. The prover computer should provide diagnostic data displays or printed data reports which show the value of all parameters and variables necessary to verify proper operation of the system by hand calculation. These parameters and variables include, but are not limited to, timers T_1 and T_2, the number of whole flowmeter pulses N_m and the calculated interpolated pulses N_1.

Using the diagnostic displays provided, the unit should be functionally tested by performing a sequence of prove runs and analyzing the displayed or printed results.

7 Certification Test

Certification tests should be performed by the prover computer manufacturer prior shipment of the equipment, and if necessary, by the user on a scheduled basis, or as mutually agreed upon by all interested parties. The certification tests provided in this chapter do not preclude the use of other tests that may be performed on an actual field installation.

A block diagram of the certification test equipment is provided in Figure A-2.

An adjustable, certified, and traceable pulse generator with an output uncertainty equal to or less than 0.001% is installed that provides an output signal of frequency F'_m, simulating a flowmeter pulse train. This signal is connected to the flowmeter input of the prover flow computer.

A second adjustable, certified, and traceable pulse generator with an output uncertainty equal to or less than 0.001% is installed that provides an output pulse signal separated by time period T_2, simulating the detector switch signals. This signal is connected to the detector switch inputs of the prover computer.

The pulse interpolation function is more critical when there are fewer flowmeter pulses collected between the detector switches. Set the output frequency of the first generator to produce a frequency equal to the flowmeter that has the lowest number of pulses per unit volume to be proved with the equipment, at the highest proving flowrate expected.

The pulse interpolation function is also more critical when there are fewer clock pulses collected between the detector switches. Set the pulse period of the second generator to provide a volume time, T_2 equal to that which would be produced by the prover detectors at the fastest proving flowrate expected.

Example: A small volume prover with a waterdraw volume of 0.81225 barrels will be used to prove a turbine meter (K Factor 1000 pulses per barrel) at a maximum of 3000 barrels per hour.

Volume time T_2 for 0.81225 barrels at 3000 barrels per hour:

$$= 3000 \times 0.81225 / 3600$$

$$T_2 = 0.676875 \text{ seconds}$$

Flowmeter frequency F_m produced by flowmeter (K Factor 1000) at 3000 barrels per hour:

$$= 3000 \times 1000 / 3600$$

$$F_m = 833.33333 \text{ hertz.}$$

The calculated interpolated flowmeter pulses N_I are simply the simulated flowmeter frequency F'_m times the simulated volume time T_2.

$$= 833.33333 \times 0.676875$$

$$N_I = 564.0625$$

Verify the actual results displayed or printed by the prover computer under test, ensuring that they are within ± 0.01% of the calculated value.

It is possible to select a simulation frequency F_m above whose pulse period is an exact multiple of time period T_2, thereby synchronizing the simulated flowmeter pulses and detector signals. If this is the case, it will be necessary to modify either the simulated flowmeter frequency F'_m, or the simulated detector switch period T_2 slightly to ensure that the interpolated pulses will include a fractional part of a pulse.

8 Manufacturer's Certification Tests

Certification tests should be performed at a number of simulated conditions. These conditions should encompass the prover device's range of prover volume times, T_2, and flowmeter pulse frequencies, F_m. The manufacturer must provide, on request, a test certificate detailing the maximum and minimum values of prover volume time, T_2, and flowmeter frequency, F_m, that the equipment is designed to accept.

If the pulse-interpolation electronics are tested and verified using the equipment and procedures shown, they can be used during a flowmeter proving operation with confidence that they will contribute an uncertainty of less than ± 0.01% to the overall uncertainty of the proving operations within the pulse-signal-frequency range tested.

APPENDIX A—PULSE-INTERPOLATION CALCULATIONS

A.1 General

The double-chronometry method of pulse interpolation is described in 4.6.2. Figure A-1 is a diagram of the electrical signals required for the technique. The technique provides the numerical data required to resolve a fractional portion of a single whole flowmeter pulse. Double-chronometry pulse interpolation requires using the following three electrical counters: $CTR\text{-}N_m$ to count whole flowmeter pulses, $CTR\text{-}T_1$ to count the time required to accumulate the whole flowmeter pulses, and $CTR\text{-}T_2$ to count the time between detector signals, which define the displaced prover volume.

The double-chronometry technique reduces the total number of whole flowmeter pulses normally required for the displaced volume to fewer than 10,000 to achieve a discrimination uncertainty of 0.02% (± 0.01% of the average) for a proof run.

The required time/pulse discrimination guidelines are presented in 4.6.2 and shall be used in conjunction with a prover designed in accordance with the sizing parameters described in *MPMS* Chapter 4.3.

The examples given in A.2, which conform to the guidelines in 4.6.2, each represent a single case of defined data and are not necessarily representative of all available pulse-interpolation methods.

A.2 Examples

A.2.1 EXAMPLE 1—INTERPOLATED PULSE CALCULATION

The following data are given:

F_c = clock frequency used to measure the time intervals, in hertz > $(20{,}000/N_I)F_m$.

F_m = flowmeter pulse output frequency (the maximum value for analysis), in hertz
= 520.

N_m = total number of whole flowmeter pulses
= 200 (CTR-N_m).

N_I = number of interpolated flowmeter pulses
= $(T_2/T_1)N_m$.

T_1 = time interval counted for the whole flowmeter pulses (N) in seconds
= 2.43914 (CTR-T_1).

T_2 = time interval between the first and second volume detector signals (that is, the displaced prover volume), in seconds
= 2.43917 ($CTR\text{-}T_2$).

If the required pulse-interpolation uncertainty is better than ± 0.01%, then

$$100{,}000 > (20{,}000/200 \text{ pulses})(520 \text{ hertz}),$$
$$> (100)(520),$$
$$> 52{,}000.$$

Note: The period of the clock is the reciprocal of the frequency, $T = 1/F$. The period of 1 clock pulse is therefore $1/100{,}000$ hertz, or 0.00001 second. The discrimination of the clock is $0.00001/2.43914$, or 0.0004%. The requirement for the value of F_c and the discrimination requirement in 4.6.2 are therefore satisfied.

To calculate the interpolated pulses,

$$N_I = (2.43917 / 2.43914)(200),$$
$$= (1.00001)(200),$$
$$= 200.002.$$

A.2.2 EXAMPLE 2—CERTIFICATION CALCULATION

Using equipment as shown in Figure A-2, the following data applies:

Simulated data:

F_m = pulse frequency of generator number one simulating meter pulses, in hertz
= 233.000.

T_2 = pulse period of generator number two simulating detector signals, in seconds
= 1.666667.

Observed data at prover computer being tested:

N_m = number of whole flowmeter pulses
= 388.

T_1 = number of clock pulses accumulated during whole flowmeter counts N_m
= 166,523.

T_2 = number of clock pulses accumulated during simulated prove volume
= 166,666.

Note that both timers T_1 and T_2 accumulated > 20,000 clock pulses, satisfying the discrimination requirement detailed in 4.6.2.

Comparison of results:

N'_I = calculated interpolated pulses based on certified pulse generators,

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= $F'_m \times T_2$,

= 233 x 1.666667,

= 388.33341.

N_1 = calculated interpolated pulses based on prover computer observations,

= $N_m(T_2/T_1)$,

= 388 x 166666/166523,

= 388.33319.

The certification test agreement required between N'_1 and N_1, is better than ± 0.01%. then

$$(N'_1 - N_1)/N'_1 < 0.0001$$

$$(388.33341 - 388.33319) / 388.33341 = 0.0000005$$

The test device results agree with calculated results based on traceable pulse generator data within 0.00005%. The certification test run is acceptable.

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= 233 x 1.666667,

= 388.33341.

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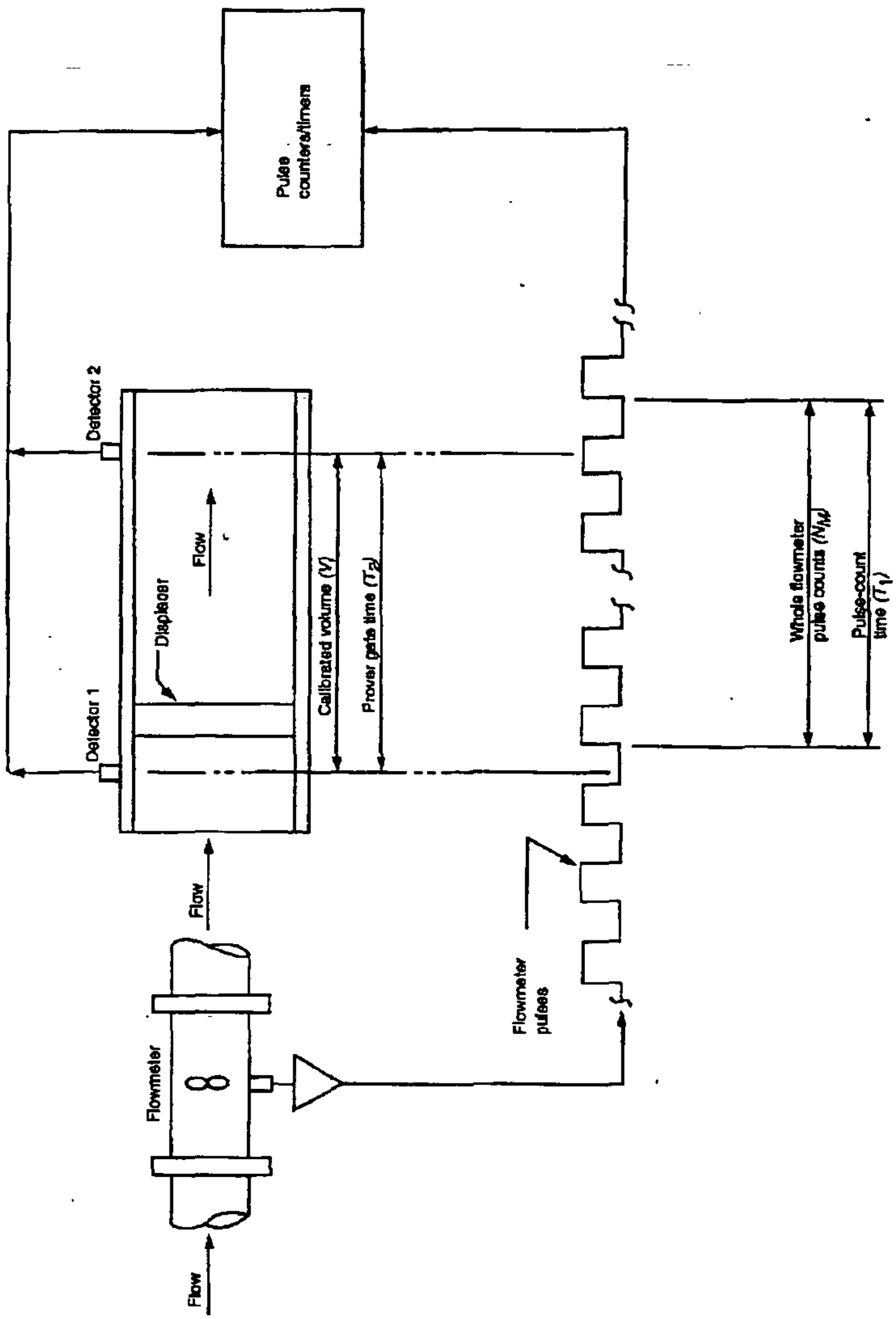
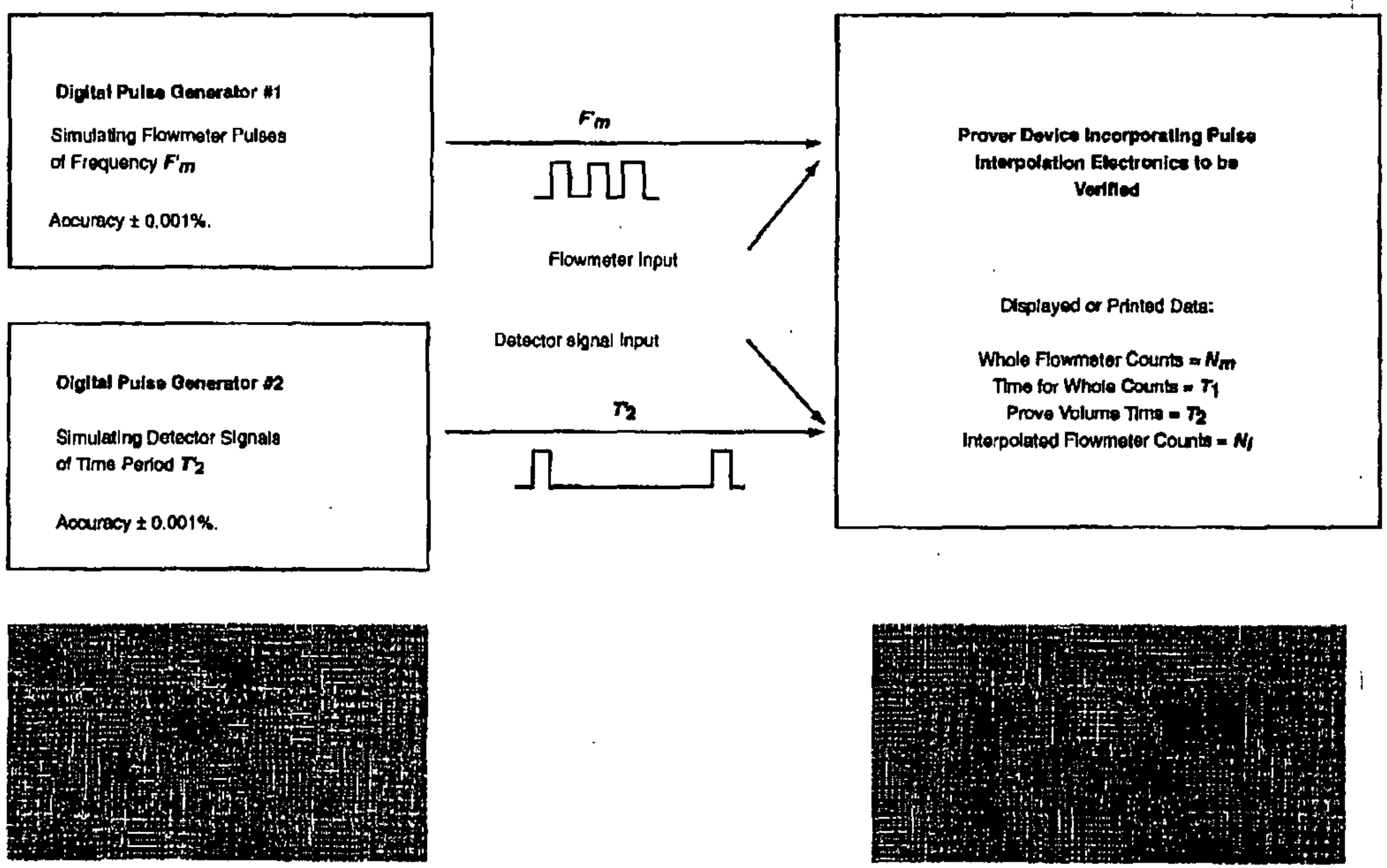
$$(388.33341 - 388.33319) / 388.33341 = 0.0000005$$

The test device results agree with calculated results based on traceable pulse generator data within 0.00005%. The certification test run is acceptable.



Note: The interpolated number of pulses N_1 is equal to $N_M(T_2/T_1)$

Figure A-1—Double-Chronometry Timing Diagram



Note: The certification test run is acceptable when $(N'_I - N_I)/N'_I$ is within ± 0.0001

Figure A-2—Certification Test Equipment for Double-Chronometry Pulse Interpolation Systems

Manual of Petroleum Measurement Standards Chapter 4—Proving Systems

Section 8—Operation of Proving Systems

Measurement Coordination

FIRST EDITION, NOVEMBER 1995

American
Petroleum
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Chapter 4—Proving Systems

SECTION 8—OPERATION OF PROVING SYSTEMS

4.8.1 Introduction

This guide is intended to provide essential information on the operation of the various meter-proving systems used in the petroleum industry.

In the petroleum industry, the term *proving* is used to refer to the testing of liquid petroleum meters. A meter is proved by comparing a known prover volume to an indicated meter volume. The meter and prover volumes are then subjected to a series of calculations using correction factors to convert volumes to standard conditions for the effects of temperature and pressure to establish a meter factor.

Liquid petroleum meters used for custody transfer measurement require periodic proving to verify accuracy and repeatability and to establish valid meter factors.

Conventional pipe provers, small volume provers, master-meter provers, and tank provers vary in size and may be permanently installed or mobile. These prover types are described in API MPMS Chapter 4.2 and in more detail in their respective sections of this chapter of the *API Manual of Petroleum Measurement Standards* (MPMS).

4.8.1.1 SCOPE AND FIELD OF APPLICATION

This guide provides information for operating meter provers on single-phase liquid hydrocarbons. It is intended for use as a reference manual for operating proving systems.

The requirements of API MPMS Chapter 4.8 are based on customary practices for crude oils covered by Table 6A and products covered by Table 6B in API MPMS, Chapter 11.1. Much of the information in API MPMS Chapter 4.8 is applicable to other fluids. Specific requirements for other fluids should be agreeable to the parties involved.

4.8.1.2 DEFINITION OF TERMS

4.8.1.2.1 *Meter proving* is the comparison of a known prover volume to the indicated meter volume; the meter and prover volumes are then subjected to a series of calculations using correction factors for temperature, pressure, and API gravity (or relative density) to establish a meter factor.

4.8.1.2.2 *A meter factor* is a dimensionless number obtained by dividing the volume of liquid passed through the meter (as measured by a prover during proving) by the corresponding meter-indicated volume, both at standard conditions.

.8.1.2.3 *Base prover volume* is the volume displaced between detectors at standard conditions, in other words, 15°C (60°F), 101.325 kPa (0 psig).

4.8.1.2.4 *A proving run or calibration run* consists of one round trip of a bidirectional prover, one pass of a unidirectional prover, one filling of a tank prover, or one test run with a master meter.

4.8.1.3 API REFERENCED PUBLICATIONS

API

Manual of Petroleum Measurement Standards (MPMS)

Chapter 1, "Vocabulary"

Chapter 4, "Proving Systems," Section 2, "Conventional Pipe Provers"; Section 3, "Small Volume Provers"; Section 4, "Tank Provers"; Section 5, "Master-Meter Provers"; Section 6, "Pulse Interpolation"

Chapter 5, "Metering," Section 2, "Measurement of Liquid Hydrocarbons by Displacement Meters"; Section 3, Measurement of Liquid Hydrocarbons by Turbine Meters"; Section 4, "Accessory Equipment for Liquid Meters"; Section 5, "Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems"

Chapter 7, "Temperature Determination," Section 2, "Dynamic Temperature Determination"

Chapter 11, "Physical Properties Data," Section 1, "Volume Correction Factors"

Chapter 12, "Calculation of Petroleum Quantities," Section 2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"

Chapter 13, "Statistical Aspects of Measuring and Sampling," Section 2, "Statistical Methods of Evaluating Meter Proving Data"

4.8.2 Pertinent Information, Applicable to Meter Proving Systems in Chapter 4.8

4.8.2.1 THE NEED TO PROVE

A meter in service should be periodically proved to confirm its accuracy. The previously determined meter factor may no longer be applicable due to changes in fluid characteristics, operating conditions, and meter wear. Specific reasons for proving meters include the following:

a. The meter has been opened for inspection or repair.

b. The meter calibrator has been changed or requires changing.

c. Any of the meter accessories have been changed, repaired, or removed.

d. Changes in operating conditions have occurred, such as

API gravity, relative density, viscosity, temperature, pressure, or flow rate.
e. Contractual requirements exist, such as scheduled meter maintenance based on volume throughput and/or elapsed time.

4.8.2.2 TYPICAL METERING INSTALLATIONS

Typical metering installations are shown in Figure 1 and Figure 2. There are many variations encountered because of specific design requirements. Mobile provers are usually used with single meter installations. Installations with multiple meters usually have a permanently installed prover.

4.8.2.3 PREPARATION FOR PROVING WITH A MOBILE PROVER

This section summarizes the preparatory work that should be done in a specific sequence.

The specification of the mobile prover must be reviewed to ensure that the prover is suitable for the flow rate, pressure, and the temperature of the metering facility. Pressure and temperature ratings must satisfy all regulations and standards. Prover materials must be compatible with the metered liquids. Elastomers are especially susceptible to damage from incompatibility. The elastomers of the sphere/piston, flange o rings and gaskets, valve seals/seats, hoses, swivel fittings, and so forth, must be compatible with the liquid.

Check that the product in the prover is compatible with the current product to prevent contamination. If incompatible, it may be necessary to drain and flush the prover.

On arrival at the site, the operator should (a) report to the site supervisor to arrange for assistance, (b) identify the meter to be proved, (c) identify connections, (d) arrange for electric power (if required), (e) arrange for disposal of liquid (if not returned to the pipe line), (f) set up traffic barriers, and so on.

The prover should be properly positioned, leveled, braked, and electrically grounded. If a vapor recovery system is used during normal metering operations, consideration should be given to operating the vapor recovery system during the meter proving. Before removing blind flanges or end caps from the connecting stubs, make absolutely certain there is no pressure behind the flanges. Always inspect the hoses before and after connecting the prover for signs of wear and damage. Make all necessary electrical connections.

4.8.2.4 TEMPERATURE, PRESSURE, AND DENSITY MEASUREMENTS

Use thermometers or temperature transducers with the highest practical scale resolution as recommended in API MPMS Chapter 7.2, and record as recommended in API MPMS Chapter 12.2.

Pressure gauges or pressure transducers should be selected to a scale resolution as recommended in API MPMS Chapter 4 and recorded as recommended in API MPMS Chapter 12.2.

Density (API gravity or relative density) is determined by using either a densitometer, a thermohydrometer or hydrometer and thermometer, with density resolution equivalent to 0.1 degree API gravity or better, and recorded as recommended in API MPMS Chapter 12.2.

4.8.2.5 INDICATED VOLUME CORRECTION

4.8.2.5.1 Meter Factor

A meter is a mechanical device and is affected by slippage, drag, and wear. A meter reacts differently when metering different liquids. A meter factor is used to correct the indicated volume to the actual metered throughput.

The meter factors CTL and CPL (see API MPMS Chapter 12.2) are used to correct the indicated meter volume to gross standard volume on a measurement ticket. A meter factor is the ratio of the gross standard volume of liquid passed through the prover (GSV_p) to the indicated standard volume of the meter (ISV_m), expressed by the following equation:

$$MF = GSV_p / ISV_m$$

Meter and prover volumes shall be corrected to base conditions (for example, 60°F, 0 psig). The values of GSV_p and ISV_m shall always be expressed in the same units. This makes the meter factor a nondimensional number.

See API MPMS Chapter 12.2.

4.8.2.5.2 K-Factor

Some meters such as turbines may not be equipped with a counter that reads directly in units of volume. Their output is a series of electrical pulses (n) that is proportional to the volume (v) passed through the meter. *K-factor* is defined as the number of pulses generated by the meter per unit volume, as expressed as the following:

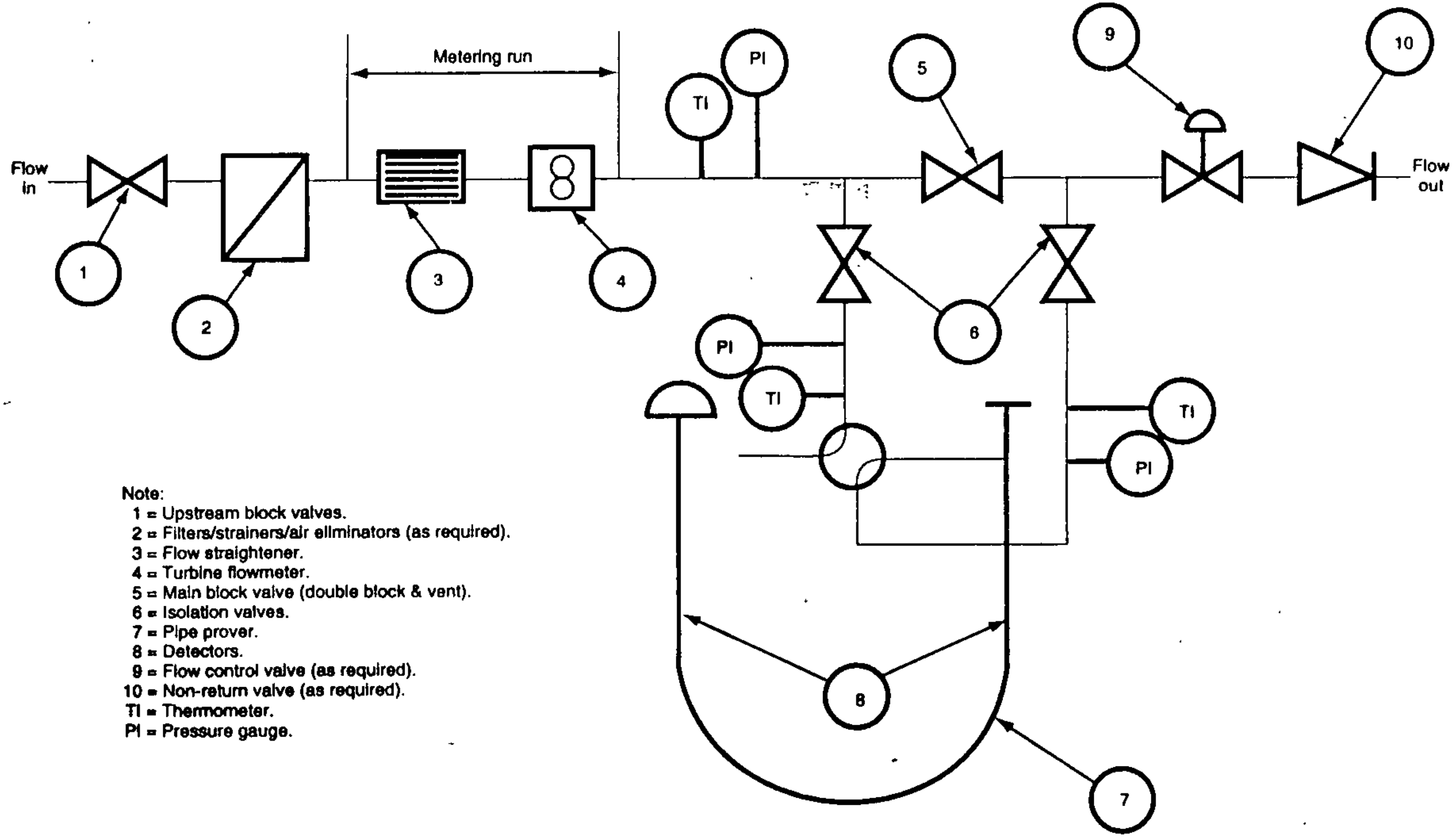
$$K = n / v$$

A new K-factor may be determined during each proving to correct the indicated volume to gross volume. If a new K-factor is not used, a constant K-factor may be used, and the new meter factor will correct indicated volume to gross volume.

4.8.2.6 PULSE GENERATING METERS

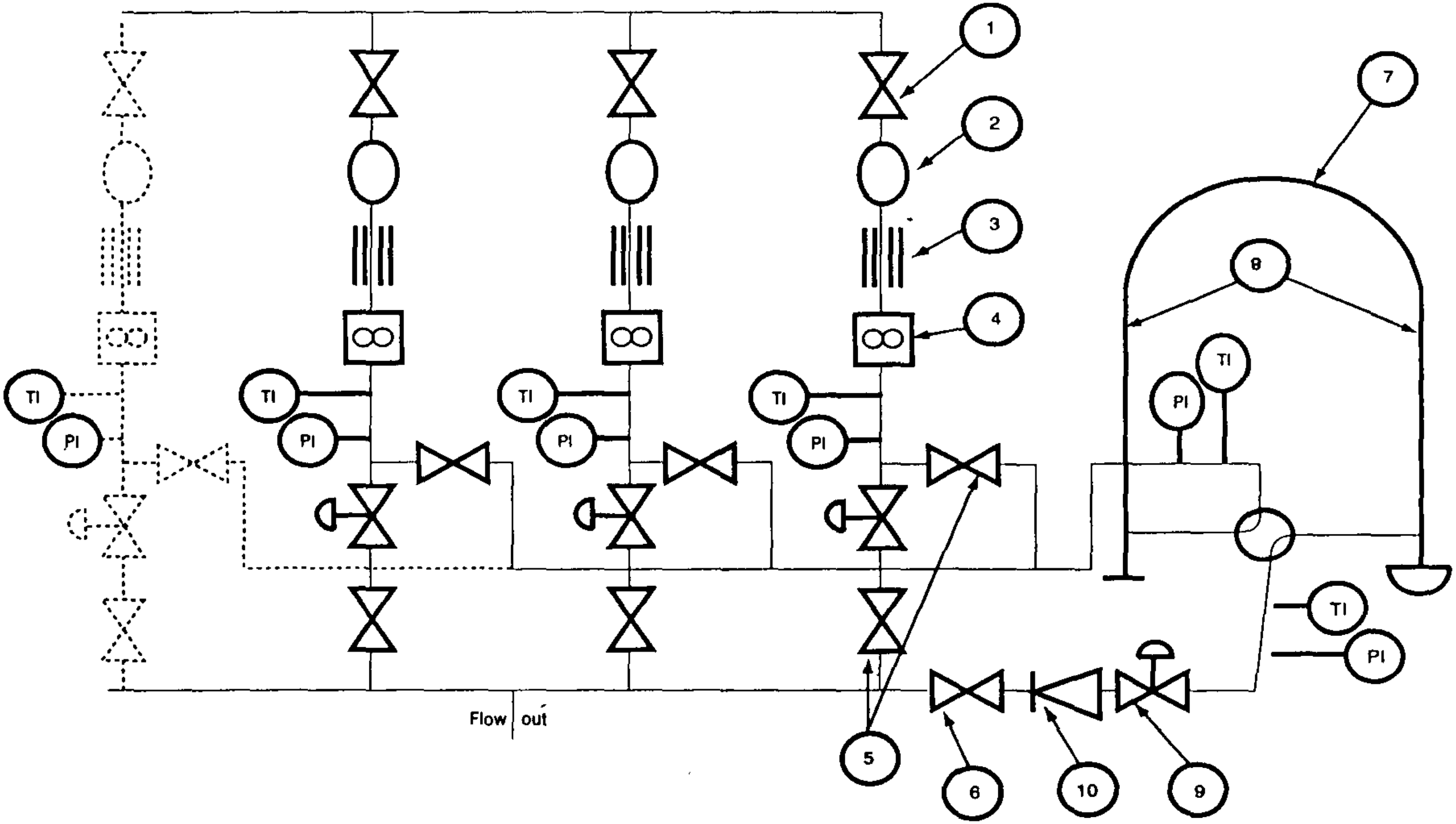
A meter must produce a high-resolution electrical pulse to drive a proving counter. Two basic types of pulse-generating meters commonly used in the petroleum industry are turbine and displacement meters.

A turbine meter uses the energy of the fluid stream to turn



Note:
1 = Upstream block valves.
2 = Filters/strainers/air eliminators (as required).
3 = Flow straightener.
4 = Turbine flowmeter.
5 = Main block valve (double block & vent).
6 = Isolation valves.
7 = Pipe prover.
8 = Detectors.
9 = Flow control valve (as required).
10 = Non-return valve (as required).
TI = Thermometer.
PI = Pressure gauge.

Figure 1—Simple Turbine Flowmeter Installation



Note:
1 = Upstream block valves; 2 = Filters/strainers/air eliminators (as required); 3 = Flow straighteners; 4 = Turbine flowmeters; 5 = Main blockvalves (double block-and-bleed); 6 = Isolation valve; 7 = Pipe prover; 8 = Detectors; 9 = Flow control valves (as required); 10 = Non-return valve (as required); TI = Thermometer; PI = Pressure gauge.

Figure 2—Typical Multi-Stream Metering Installation

a bladed rotor which produces an electrical signal that is proportional to flow.

A displacement meter mechanically separates the liquid into discrete quantities of fixed volume. The rotation of the displacement meter is used to drive a pulse-generating device with its output proportional to flow.

4.8.2.7 PULSE INTEGRITY CHECK

The displacement-meter pulse generator should be checked for pulse integrity. One method is to check the number of pulses per revolution of the disk. Each time the slotted disk used to generate pulses completes a revolution, a fixed number of pulses (1000 for example) should be generated. A magnetic or optical switch on the disc starts and stops the proving counter. The proving counter should indicate 1000 pulses plus or minus 1 pulse (that is, 999 to 1001 pulses).

This procedure should be repeated until at least the minimum number of pulses equals one pass of the prover displacer. If the pulse integrity check fails, then the meter drive train, the pulse generator, the counter, cables, or connections are faulty and should be repaired or replaced before proving is undertaken.

Turbine meter pulse integrity can be checked by displaying the pulse train on an oscilloscope. A missing pulse may be the result of a loose or missing turbine meter rim button or blade. If a nonuniform pulse train is produced, the meter should be repaired or replaced before proving is resumed.

4.8.2.8 POTENTIAL PROVING PROBLEMS

The meter and all of its associated equipment (such as gear trains, registers, compensators, and counters) must be maintained in good working order, both mechanically and electrically. The meter should also be inspected whenever its performance is in question, if mechanical or electrical problems exist, or as required by contract or regulations.

The meter should be operated in the linear portion of its performance curve, and the prover should be operated within its flowrate limitations. The meter should be proved as close as practical to the same conditions under which it normally operates. Meter performance is dependent upon flow rate. Therefore, during proving it is essential that flow rate be maintained as steady as possible within the normal operating flow range of the meter.

4.8.2.8.1 Flow Conditioning

A strainer or filter should be provided upstream of the meter to protect it from being damaged by foreign materials and entrained solids.

Downstream of a partially opened valve or a pipe fitting, the cross-sectional velocity will be nonsymmetrical. This velocity profile has little or no effect on the performance of displacement meters, but seriously affects turbine meters. Flow conditioning upstream and downstream of a turbine meter should be per API MPMS, Chapter 5, Section 3.

It is essential that the pressure in the meter and the prover be higher than the vapor pressure of the liquid. With turbine meters, this *back pressure* must not be less than that specified in API MPMS, Chapter 5, Section 3. A common method of preventing vaporization is the use of a back-pressure control device downstream of the meter.

Entrained vapor will cause erroneous proving results. Any time a system is filled with liquid, all vapors must be vented. If the venting is not properly done, vapor left in the line will subsequently be swept through the meter/proving system.

When liquid is withdrawn from a tank with a low liquid level, a vortex at the tank discharge may form, causing air or vapor to be drawn into the meter stream. A vortex breaker may be installed in the tank to prevent vortex formation, and an air/vapor eliminator is often installed upstream of the meter to prevent vapor from flowing through the meter.

4.8.2.8.2 Temperature Variations

For best results, the prover temperature and the meter temperature should be stabilized. When a prover has been off line, more time is required for temperature equilibrium to be attained. The ability to detect temperature changes during proving is essential if accurate results are to be obtained with a meter prover.

4.8.2.8.3 Valve(s) Leakage

During proving, it is essential that all liquid flowing through the meter flows through the prover. Therefore, the sphere interchange in a unidirectional prover, the four-way valve in a bidirectional prover, and every valve between the meter and the prover must seal leak-tight when closed. Any leakage through the valves will cause an error in proving. These valves should be of a double block-and-bleed type or of a similar valving configuration to insure seal integrity. All valves to the prover from other meter runs must be isolated without leakage during proving. Drains, vents, and relief valves must seal during proving.

The space between the seals on a double block- and-bleed valve or valving configuration is connected to a small bleed valve, pressure gauge, or pressure switch to verify seal integrity. Seal integrity should be checked each time a valve is closed.

4.8.2.8.4 Effect of Wear, Damage, and Deposits on Meters and Straightening Sections

As a displacement or turbine meter wears, its meter factor will gradually change. Therefore, all meters should be proved at regular intervals.

Turbine meters and their straightening sections with tube-bundles or vanes are susceptible to collecting foreign objects traveling in the flow stream. They should be inspected and cleaned periodically.

Turbine meters are especially susceptible to the effects from deposits because they are velocity devices. Layering or coating of the meter's internals will change the velocity of the liquid flowing through the meter and cause the meter to register incorrectly.

Temperature changes can affect the mechanical clearances of displacement meters, as well as the viscosity of the fluid being metered. This may result in changes in slippage.

4.8.2.8.5 Electronic Equipment and Instrumentation

All electrical and electronic equipment, such as counters, switches, interconnecting cables, and grounding cables, shall be periodically inspected for condition and for proper installation and operation. Operating procedures may require special permission or permits before equipment is connected.

A counter may miss some of the pulses generated by the meter, in which case the counter will read low. Counting too few pulses is usually caused by setting the sensitivity control on the counter too low, or by an electrical fault which has developed. By adjusting the sensitivity control or by eliminating the electrical fault, the trouble can usually be corrected.

A counter may include signals from outside sources as pulses. These signals, not generated by the meter, will cause the counter to read high. Signals not generated by the meter can originate from electrical power supplying the counter, electrical welding equipment, radio transmitters, and so forth. These pulses may be intermittent and difficult to detect. See API MPMS, Chapter 5, Section 5.

Signal transmission cables should be kept as far away from power cables as possible and should cross power cables at right angles. Shielded signal transmission cable is normally grounded only at the instrument-receiving end to prevent a ground loop (current that travels along the shield and adversely affects the signal transmission).

4.8.2.8.6 Flow Rate Variations

Meter performance is dependent upon flow rate; thus, flow rate during proving shall be maintained at or near the normal operating flow rate.

4.8.2.9 METER REGISTRATION (HEAD) CHECK

Compare the meter register (indicated volume) to the proving-counter registration. This can be done by manually gating (starting and stopping) a prover counter connected to the transmitter, based on a significant volume registered by the meter counter or register. The pulses displayed on the prover counter are then compared to the volume displayed on the mechanical register. If the meter generates 8400 pulses per barrel, the prover counter should show approximately 84,000 pulses for each 10 barrels on the register.

4.8.2.10 FREQUENCY OF METER PROVING

The frequency required for proving varies from several times a day to twice a year or even longer depending upon the value of the liquid, cost/benefit to prove, meter proving history, meter system stability, and variations of operating systems.

For large volumes or different liquids, a permanently installed prover is normally used. The meters should be proved whenever the flow rate, temperature, pressure, API Gravity (relative density), or viscosity changes significantly. Normally, time or volume is used to determine when the meter should be proved.

When metering a single or similar liquid, the meter factor is normally applied forward to the meter's indicated volume until the meter is reproved. Normally, there is a prescribed deviation limit between consecutive meter factors on the same or similar liquid. When this deviation limit is exceeded, the previous and the new meter factors are normally averaged and applied to the indicated volume during this period. If the deviation limit is consistently exceeded, it may be appropriate to reduce the interval between meter proving. It may also be appropriate to inspect and repair the meter and the proving system.

When batching operations permit, a new meter factor should be determined for each batch. This applies to batching operations involving different liquids or lengthy down time. When a meter is proved during a batch, the meter factor should be applied forward until the meter is reproved during the batch. If the meter is reproved during the batch, a deviation limit may be installed between consecutive meter factors, or the meter factors may be averaged. When this deviation limit is exceeded, the previous and new meter factors are normally averaged and applied to the meter's indicated volume between these provings. If it is impractical to prove each batch, meter factors are normally applied forward until the next proving, as is the case with nonbatching operations.

The proving frequency for new systems should start at short intervals and be extended to longer intervals as confidence increases in the system. See API MPMS Chapter 13.2 for statistical evaluation of meter proving data.

4.8.2.11 PROVER RECALIBRATION FREQUENCY

Typically a prover's base volume is originally certified at the manufacturer site by the water draw method in the presence of the purchaser and other interested parties. Prover volumes may change as the result of worn or faulty detector switches; the reduction of internal coating thickness; or loss of internal material due to oxidization, abrasion, or the accumulation of foreign material (such as wax) buildup. Subsequent calibration is required whenever a change in base volume could have occurred.

Six considerations determine how frequently a prover should be recalibrated. They are usage, time, calibration history, calibration cost/benefit, contractual requirements, and value of the metered liquids. Usage causes wear, and time contributes to deterioration of the prover.

For the recommended procedure for calibrating a prover, refer to API MPMS Chapters 4 and 12.2. Recalibration of provers should occur when any one of the following conditions exist:

a. Alterations or repairs which affect the certified volume are made to the prover.
b. A meter control chart indicates a change in prover volume.
c. The maximum interval indicated below has elapsed.
  1. Three years for small volume provers and mobile provers.
  2. Five years for permanently installed pipe provers.
  3. Five years for permanently installed tank provers.
  4. Three months for master meter provers.

The prover displacer and the inside surface of the prover should be inspected periodically. The surface of a sphere or the contact edge of a piston cup or seal may indicate the internal condition of the prover. If these surfaces or edges are scored or worn, this may indicate that the prover requires further inspection or repair and may require recalibration.

4.8.2.12 FILLING AND PRESSURING THE PROVER

This section refers to conventional pipe provers, small volume provers, and master meter provers. This section does not pertain to tank provers, which are covered in 4.8.5.4.

After checking that end closures and any openable fittings are properly fastened and that all vent and drain valves are closed, proceed with filling the prover in the following sequence:

a. Partially open the prover isolation valve to fill the prover slowly.
b. Observe the system for leaks. Wait until the system is completely filled and the connections have been shown to be leak-tight. Verify the seal integrity of all vents, drains, reliefs, and all double block-and-bleed valves.
c. Open the vents to allow discharge of air/gas when the fluid is admitted into the prover.
d. Fully open the prover inlet and outlet valves.
e. Close the valve to divert all flow through the prover.
f. Operate the prover and continue to vent the high points until no air is observed.
g. Close the vents when air or vapor is no longer observed.

4.8.2.13 CERTIFICATION

Verify that the prover has a valid calibration certificate and that the certificate is for the prover being used, by verifying the prover serial number with the serial number on the certificate. If a conventional pipe prover is being used, check to ensure that the prover volume between detectors is sufficient to accumulate a minimum of 10,000 pulses. If not, pulse interpolation techniques are required. Since some provers have more than one calibrated volume, verify that the proper calibration certificate is being used.

If a tank prover is used, verify that the prover volume is equal to a minimum of one minute of the maximum operating flow rate. See API MPMS, Chapter 4.4.

If a master meter is used, all data that is used to develop the master meter factor(s), including the prover calibration report, certificate, and master meter factor(s) reports should be available.

If a small volume prover is used, verify that the interpolation system has a valid and current calibration certification. Refer to API MPMS, Chapter 4, Sections 3 and 6.

4.8.3 Conventional Pipe Provers

4.8.3.1 PRINCIPLE OF OPERATION

The basic principle on which the pipe prover operates is shown in Figure 3. A sphere or piston known as a *displacer* is installed inside a specially prepared length of pipe. When the prover is connected in series with a meter, the displacer moves through the pipe and forms a sliding seal against the inner wall of the pipe so that it always travels at the same speed as the liquid flowing through the pipe.

In some conventional provers, the displacer is a piston with elastomer or plastic seals. However, in most conventional provers, the displacer is an elastomer sphere. To provide good sealing, the pipe bore must be smooth.

At two or more points in Figure 3, there are devices known as *detectors* fixed to the pipe wall. These detectors emit an electric signal when the displacer reaches them. The signal from the first detector switch is used to start the electronic counter, which accumulates pulses from the meter. When the displacer reaches the second detector, its signal stops the proving counter. The number of pulses shown on the proving counter is the total pulses generated by the meter while the displacer was travelling between the two detectors. Conventional pipe provers (both bidirectional and unidirectional) are those that have a volume between detectors that permits a minimum acculuation of 10,000 direct (unaltered) pulses from the meter. Thus a unidirectional prover typically accumulates a minimum of 10,000 pulses per proving run, and a bidirectional, prover typically accumulates a minimum of 20,000 pulses per proving run. Direct (unaltered) pulses include those that are the output of high frequency pulse generators, considered to be a "part of" the meter. It should also be noted that

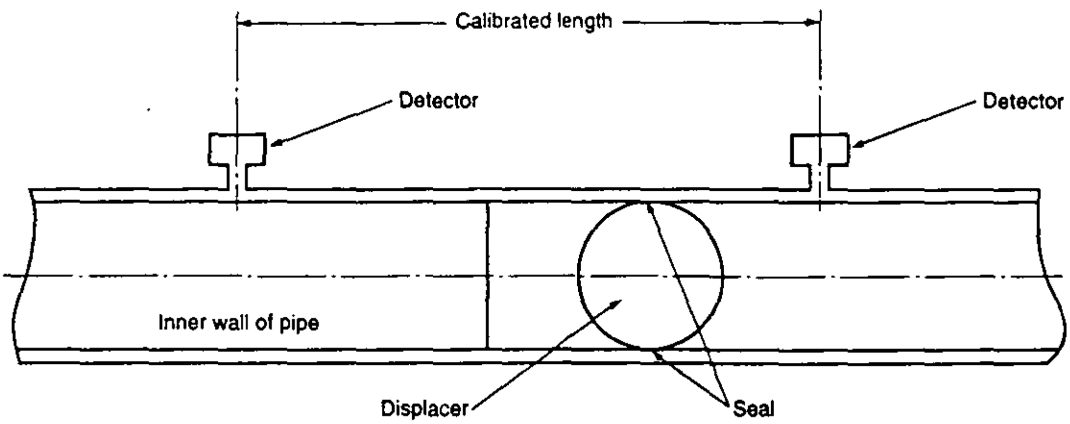


Figure 3—Calibration Section of Pipe Prover

there are occasions when 10,000 pulses cannot be accumulated during proving passes. This may occur because of a change or a constraint in operating conditions. Agreement between parties to use less than 10,000 pulses per proving pass is required in these instances.

4.8.3.1.1 Prerun Requirements

A prerun (or run-up) length of pipe is essential. This length is the distance between the entry of the displacer and the first detector switch of sufficient length to give the valve time to close and seal before the displacer reaches the detector. This type of prover must never be used at more than its rated flow rate, or this prerun length may not be adequate. As an alternative, some provers are provided with mechanical means of holding the displacer near the beginning of its travel until the valve is fully seated; by this means the prerun length can be shortened considerably.

4.8.3.1.2 The Bidirectional Conventional Prover

Bidirectional provers can use either a sphere or a piston as a displacer. Spheres are more commonly used because they will go around bends, and the prover can be built in the form of a compact loop, as in the example shown in Figure 4.

A four-way valve is normally used to reverse the flow through the prover. The sphere in Figure 4 is shown in the position that it occupies at the end of a proving run. The sphere will start to travel on its return pass when the four-way valve begins to reverse the flow, but it will not reach its full speed until the movement of the four-way valve is complete.

Displacer detectors are never quite symmetrical in their operation, and consequently the effective calibrated volume when the displacer travels between detector 1 and detector 2 will not be quite the same as when the displacer travels between detector 2 and detector 1. The calibrated base volume of the prover is the sum of both directions and is termed the *round trip volume*. The prover counter totals the pulses collected in both directions.

4.8.3.1.3 The Unidirectional Conventional Prover

A unidirectional prover is shown in Figure 5. It uses a sphere displacer and sphere interchange. The sphere interchange is for receiving, holding, and launching the sphere. After falling through the interchange, the sphere enters the flowing stream of liquid and is swept around the loop of pipe. At the end of its pass, the sphere enters the sphere transfer valve, where it lies until the next proving pass. The calibrated base volume of the prover is the one-way volume between the detector switches.

4.8.3.2 EQUIPMENT DESCRIPTION

4.8.3.2.1 Detector Switches

The detectors fitted to a pipe prover are highly sensitive devices. The most common type of pipe-prover detector switch uses a ball-end steel plunger, which projects through the wall of the pipe a short distance. When the sphere makes contact, it forces the plunger to actuate the switch. Replacement procedures must conform with manufacturers' recommendations.

Replacing a detector switch may change the prover volume. Replacement or adjustment of detector switches on bidirectional provers is less critical than on unidirectional provers. The decision to recalibrate a bidirectional prover should be made on a case-by-case basis. When a detector is replaced or adjusted on a unidirectional prover, recalibration should occur at the earliest possible opportunity. A record should be kept of the time and date of the replacement.

4.8.3.2.2 Prover Displacers

The majority of pipe prover displacers are hollow spheres made of an oil resistant elastomer such as nitrile, neoprene,

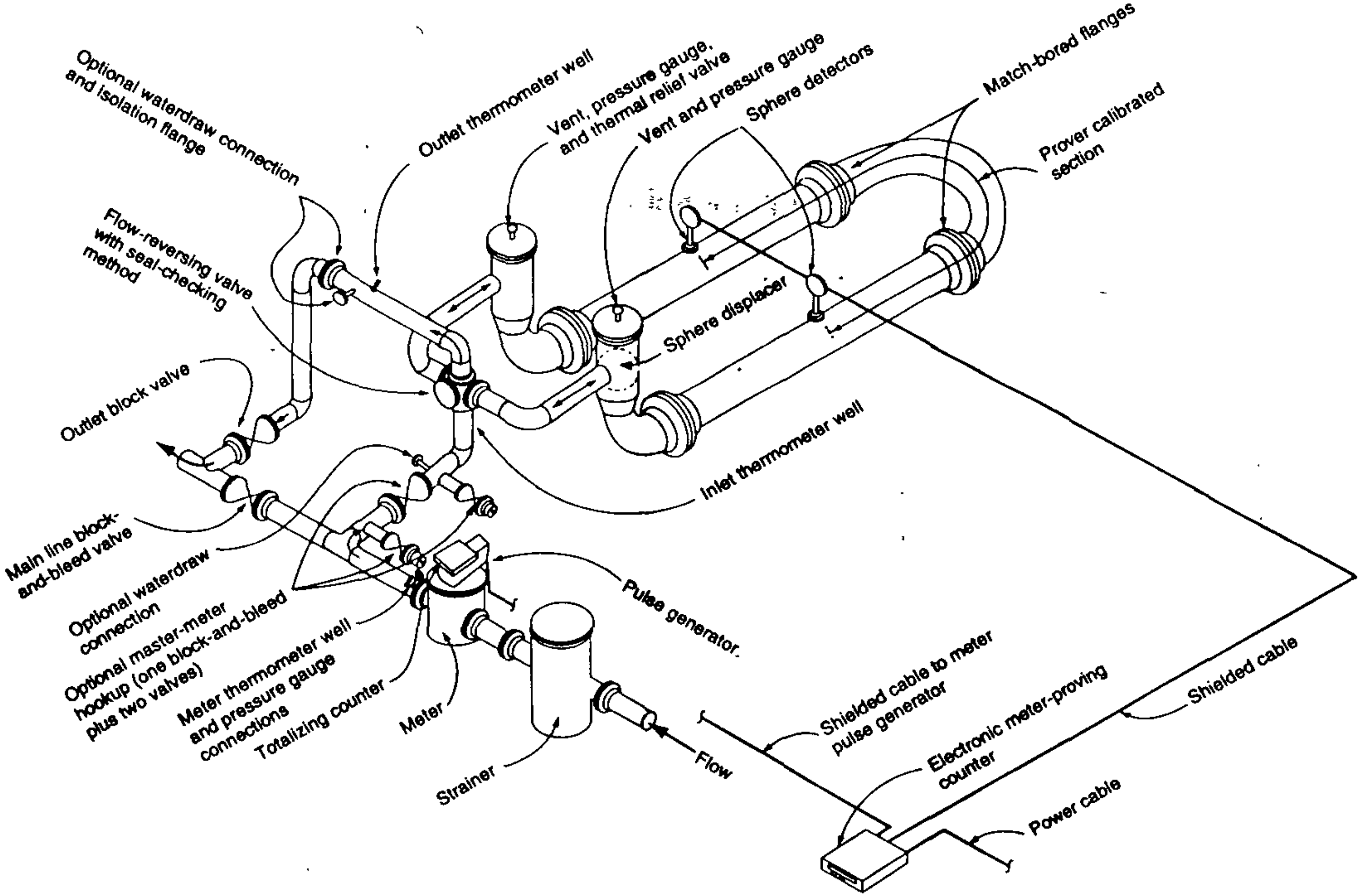


Figure 4—Typical Bidirectional U-Type Sphere Prover System

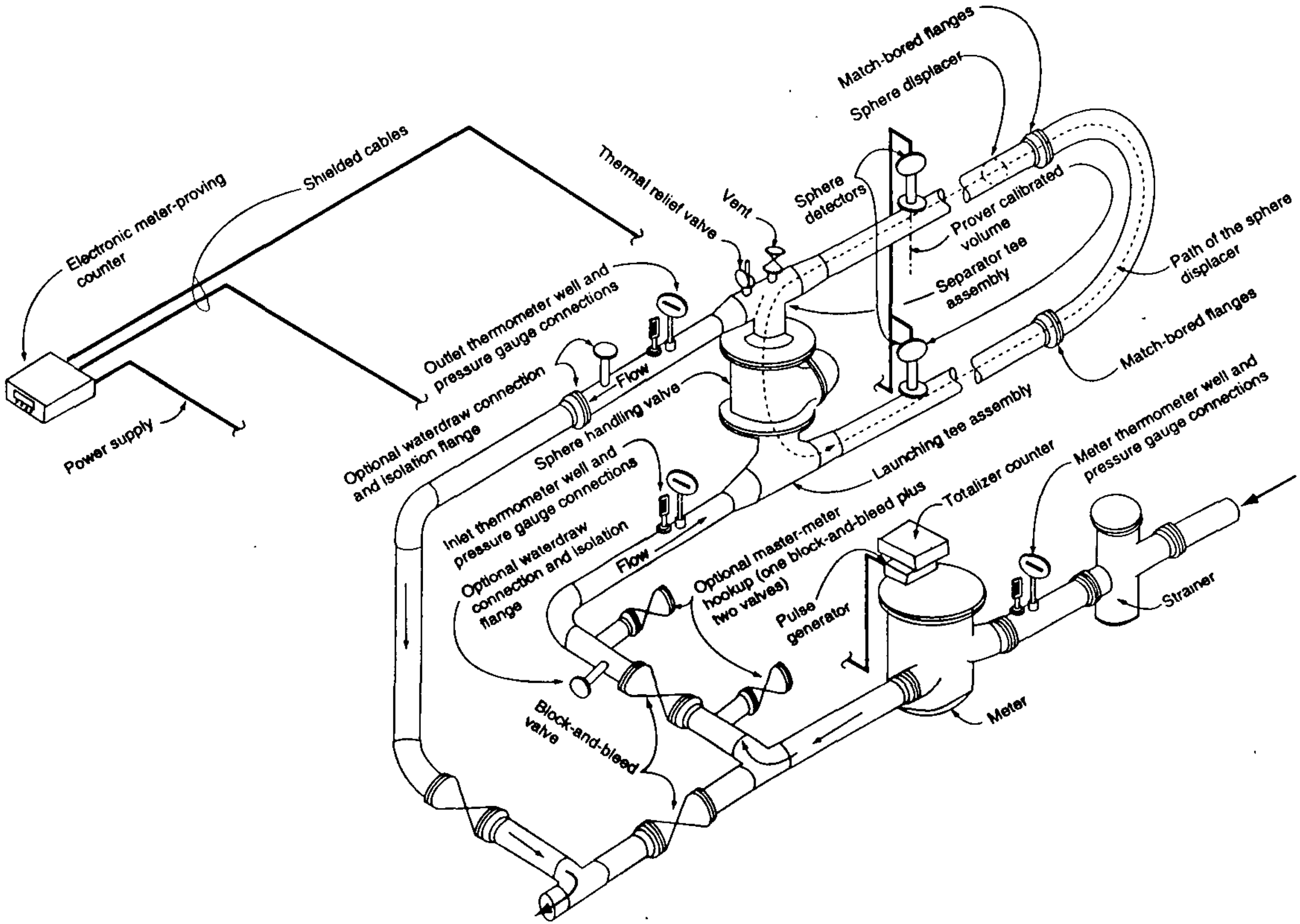


Figure 5—Typical Unidirectional Return-Type Prover System

or polyurethane. These displacers are fitted with an inflation valve, or valves, and are intended to be inflated with water or glycol to a diameter which maintains an effective seal in the prover bore without creating excessive sliding friction. The manufacturer will usually specify the amount (typically between 2 and 4 percent) by which the sphere diameter needs to exceed the pipe bore. Small bore provers may employ a sphere made of solid elastomer.

Spheres should not be stored in an inflated condition on a flat surface. They should either be suspended in a net or supported by a hollowed-out bed of sand to prevent the development of a flat spot.

If a piston is used as a displacer it may be fitted with cup-type seals, especially in older provers. In many of the modern piston provers, the seals are made of teflon with stainless steel backup rings.

4.8.3.3 INSPECTION

The internal surfaces should be inspected for coating failures, adhesions (any foreign material build-up on the internal surface), or corrosion that would change the calibrated volume of the prover. If the prover is internally coated, the lining should be checked for coating wear or failure which would cause the calibrated volume to increase. The most likely location for such failures will be in the elbows.

The displacer should be removed from the prover and examined at the intervals prescribed by the manufacturer or by the operating company. The sphere or seals should be inspected and replaced if there is any sign of mechanical damage or of softening by chemical action. Spheres should also be inspected for roundness and proper inflation. This is done with either a sizing ring supplied by the manufacturer or a tape measure.

A piston prover displacer may be subjected to a leak test. This may be done by positioning the displacer so that its seals straddle a pressure tap in the prover wall where a bleed valve is located so pressure may be applied between the seals. Pressure may also be applied through the body of the piston to the seal area. Other means for checking seal leakage may be provided by the prover manufacturer.

4.8.3.4 PREPARATION

Examples of meter proving forms are shown in Figures 6 and 7. Other forms or documents may be required before proving is started. Refer to API MPMS, Chapter 12.2 for meter factor calculation requirements.

Check that end closures and any openable fittings are properly fastened and that all vent and drain valves on the prover are closed. Proceed with filling the prover as follows:

a. Partially open the prover inlet valve to fill the prover slowly.

b. Observe the system for leaks. Wait until the system is completely filled and the connections have been shown to be leak-tight before fully opening the prover inlet valve.

c. Open vents to allow discharge of air or vapor when fluid is admitted into the prover.

d. At this point the prover outlet valves may be safely opened.

e. After all the connecting valves are fully opened, the meter divert valve between the prover inlet and outlet valves may then be closed.

f. Operate the prover displacer at least one proving cycle and vent the high points. The vents should be checked repeatedly until it is certain that no vapor remains in the prover.

g. Verify the seal integrity of all vents, drains, reliefs, and double block-and-bleed valves between the meter and the outlet of the prover.

4.8.3.5 OPERATING PROCEDURES

Maintain the flow through the proving system until stable conditions of pressure, temperature, and flow rate exist. Once stability is achieved, proving operations may proceed.

Determine the actual flow rate on the first pass of the displacer and make spot checks thereafter. Determine the meter temperature and pressure during each pass of the displacer. When using a bidirectional prover, record the meter temperature and pressure, using the average of readings taken for each pass of any given round trip.

Using both inlet and outlet thermometers and pressure gauges, determine the average prover temperature and pressure during each pass. The average prover temperature and pressure is recorded on a round trip basis in the case of a bidirectional prover.

If using a bidirectional prover, record the reading of the prover counter at the end of each round trip of the displacer. For a unidirectional prover, record the reading of the prover counter at the end of each pass of the displacer.

Repeat the proving operation until the required minimum number of proving runs (per agreement between parties) are attained. As a measure of repeatability, the range of the proving set is determined as follows:

$$\text{Range of Repeatability} = \frac{\text{Maximum Value} - \text{Minimum Value}}{\text{Minimum Value}} \times 100$$

Assess the repeatability of the set of results, and if necessary carry out additional runs in an attempt to gain the required repeatability. If suitable repeatability is not obtained, discontinue the proving operation and refer to Appendix B.

4.8.3.6 ASSESSMENT OF RESULTS

One common practice is to require a minimum of five consecutive runs that agree within a range of 0.05 percent. Another common practice requires a minimum of five out of six consecutive runs that agree within a range of 0.05 percent. For low volume locations including some LACT units, a minimum of three consecutive runs that agree within

LOCATION

DATE	AMBIENT TEMP	REPORT NO

PROVER DATA

BASE VOLUME AT 60°F AND "0" psi.	SIZE	WALL
bbl.		

PREVIOUS REPORT

FLOW RATE	FACTOR	DATE
bbl/hr.		

METER DATA

SERIAL NO	METER NO.	PULSES/bbl.	TEMP. COMP.	MANUF.	SIZE	MODEL

FLOW RATE	NON-RESET TOTALIZER
bbl/hr.	

RUN DATA

TEMPERATURE		PRESSURE		TOTAL PULSES	RUN NO.
PROVER AVG.	METER	PROVER	METER		
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					AVG.

C_{ts} = CORRECTION FOR TEMPERATURE ON STEEL

C_{ps} = CORRECTION FOR PRESSURE ON STEEL

C_{tl} = CORRECTION FOR TEMPERATURE ON LIQUID TABLE 6 OR TABLE 24 FOR LPG s

C_{pl} = CORRECTION FOR PRESSURE ON LIQUID

LIQUID DATA

TYPE	API GRAVITY	SPECIFIC GRAVITY	R.V. PRESS	BATCH/TENDER NO
	AT 60°F	AT 60°F		

FIELD CALCULATIONS

PROVER VOLUME X [C_{ts} X C_{ps} X C_{tl} X C_{pl}] = CORRECTED PROVER VOLUME

AVERAGE PULSES ÷ PULSES/bbl = GROSS METER VOL. X [C_{tl} USE ONLY FOR NON-TEMP. COMP. METER X C_{pl}] = CORRECTED METER VOLUME

CORRECTED PROVER VOLUME ÷ CORRECTED METER VOLUME = METER FACTOR X C_{pl} LIQUID CORR. FOR PRESS. AT METERING COND. = COMPOSITE FACTOR USE FOR CONSTANT PRESSURE APPLICATIONS

REMARKS, REPAIRS, ADJUSTMENTS, ETC., ______________________________

SIGNATURE	DATE	COMPANY REPRESENTED

Figure 6—General Purpose Meter Proving Report for Use With Pipe Provers

Meter No. 292 Report No. 3 Date: DECEMBER 20, 1994
Owner and/or operating company: D P & C PETROLEUM PIPELINE COMPANY
Location of meter being proving: BELL RECEIVING STATION Totalizer: 897665
Meter, S/N AK-12345 Size: 4 inch Type: TURBINE Model: BM-4444
Last overhaul date: 10/20/94 Old Seals: 456789 & 456790 New: 457201 & 457202

Prover calibration date: JULY 4, 1994 Prover Calibration Certificate No. 200007
Small Volume Prover (serial number) SP-5555 Small Volume, Single Wall, Unidirectional 12", External Detectors

Prover outside diameter	>>>>>	14.000	OD (inches)	APIobs	45.8	Product
Prover inside diameter	>>>>>	12.250	ID (inches)	Tobs	80.0	JET FUEL
Prover wall thickness	>>>>>	0.875	WT (inches)	APIb	44.0	

Pass No.	Whole Pulses N	Seconds of pulses Time 1	Seconds per pass Time 2	Pulses per second Frequency	Interpolated Pulses N'	Flowrate Gross GPM	Pulses/Gal. Gross K Factor
1	377	1.21005	1.21121	311.557	377.36	747.32	25.014
2	378	1.21353	1.21127	311.488	377.30	747.28	25.010
3	378	1.21363	1.21137	311.462	377.30	747.22	25.010
4	377	1.21030	1.21123	311.493	377.29	747.31	25.009
5	377	1.21030	1.21125	311.493	377.30	747.29	25.010

Pass No.	Interpolated Pulses per Proving Run/Pass			Temperature in degrees F Tp	Tm	Pressure in psig Pp	Pm
1	N'	=	377.36	75.9	75.4	115	104
2	N'	=	377.30	75.9	75.5	115	104
3	N'	=	377.30	76.0	75.5	115	104
4	N'	=	377.29	76.1	75.5	115	104
5	N'	=	377.30	76.1	75.6	115	104

Average data per run >>>>>>> 377.31 76.0 75.5 115 104
Test range percent (%) 0.019 75.0 = Temperature of Invar Rod
Nominal K Factor >>>>>>> 25.000 NKF = Pulses per Indicated Unit Gallon

BASE PROVER VOLUME		15.086	BPV = Prover Volume @ 60 deg. F & 0 psig
CTSp	17-4 PH	1.0002	Ga = 0.0000120 Gl = 0.0000008 / deg F
CPSp	Stainless Steel	1.0001	E = Modulus of Elasticity E = 28500000
CTLp		0.9918	Tables 5B & 6B, API Standard 2540
CPLp		1.0007	"Fp"factor from 11.2.1 (Pe = 0) = 0.00000614
CCFp		0.9928	CCFp = (CTSp * CPSp * CTLp * CPLp)
GROSS STANDARD VOLUME		14.977	GSVp = (BPVp * CCFp)
INDICATED VOLUME OF METER		15.092	IVm = N'avg / NKF
CTLm		0.9921	Tables 5B & 6B, API Standard 2540
CPLm		1.0006	"Fm" factor from 11.2.1 (Pe = 0) 0.00000613
CCFm		0.9927	CCFm = (CTLm * CPLm)
INDICATED STANDARD VOLUME		14.982	ISVm = (IVm * CCFm)

METER FACTOR	0.9997	@ Flow rate of =	747 Gallons per Minute
K FACTOR	25.008	Pulses per Gallon	

CPL @ Normal Pressure Composite M Factor = 1.0004
of 110 psig = 1.0007 Composite K Factor = 24.991

Meter Proving History		>>>>>	Date	Meter Factor	GPM	APIb	Degrees F	psig
Initial MF	1	>>>>>	08/20/94	1.0002	770	44.2	74.5	102
Previous	4	>>>>>	11/20/94	0.9991	732	44.4	78.0	110
Current	5	>>>>>	12/20/94	0.9997	747	44.0	76.5	104

Remarks & history >>>>> Meter overhauled on October 20, 1994 before the initial proving
Initial to Current MF >>>>> Long-term change percent (%) since the initial proving -0.05
-0.05
Previous to Current MF >>>>> Short-term change percent (%) since the last proving +0.06

Signed by: ______________________________

Figure 7—Meter Proving Report With Pulse Interpolation

a range of 0.5 percent may be required. Alternative methods are described in Appendix A.

The evaluation of repeatability of the proving data is normally performed with raw meter pulses. If conditions cannot be held constant, it may be necessary to compare the range temperature compensated raw pulses or meter factors for each run. This is particularly true when proving LACT displacement meters equipped with mechanical temperature compensators where the temperature varies during the proving process.

If the repeatability of the meter runs is unacceptable, it is recommended to implement another series of runs. If the repeatability of a second set is within the prescribed range, this set of results may be used. If the repeatability remains unacceptable, it is necessary to stop proving and look for the cause of the problem.

A common practice is to limit the change in consecutive meter factors of proving periods to ±0.25 percent or less. This is a measure of reproducibility and is determined as follows:

$$\text{Range of Reproducibility} = \frac{\text{New Meter Factor} - \text{Old Meter Factor}}{\text{Old Meter Factor}} \times 100$$

Changes in the linearity of the historical meter factors over time is also a good check for prover functioning. Historical meter factor data should be maintained and is best assessed by keeping a control chart which is a graph of meter factor plotting against the dates of tests. A specimen control chart is shown in Figure 8. See also API MPMS, Chapter 13.2.

4.8.3.7 TROUBLE-SHOOTING

To help operators evaluate a system more quickly, the experience of a number of prover operators has been compiled in Appendix B.

Common problems are listed, as well as the usual causes and the typical methods of solving each. The guide contains tables which give the corrective action needed to rectify the fault once its cause has been ascertained.

4.8.4 Small Volume Provers

4.8.4.1 PRINCIPLE OF OPERATION

Small volume provers have a volume between detectors that does not permit a minimum accumulation of 10,000 direct (unaltered) pulses from the meter. Small volume provers require meter pulse-interpolation techniques to increase the resolution (see API MPMS, Chapter 4.6).

This high resolution pulse determination permits the volume between detector switches to be substantially less in a small volume prover than would be permitted in a conventional pipe prover. Typical small volume provers are illustrated in Figures 9, 10, and 11. Additional information on small volume provers is contained in API MPMS, Chapter 4.3.

Since the volume of a small volume prover is less than a conventional pipe prover, high-precision detectors are normally used with pulse-interpolation techniques. Double chronometry pulse-interpolation is a method of counting a

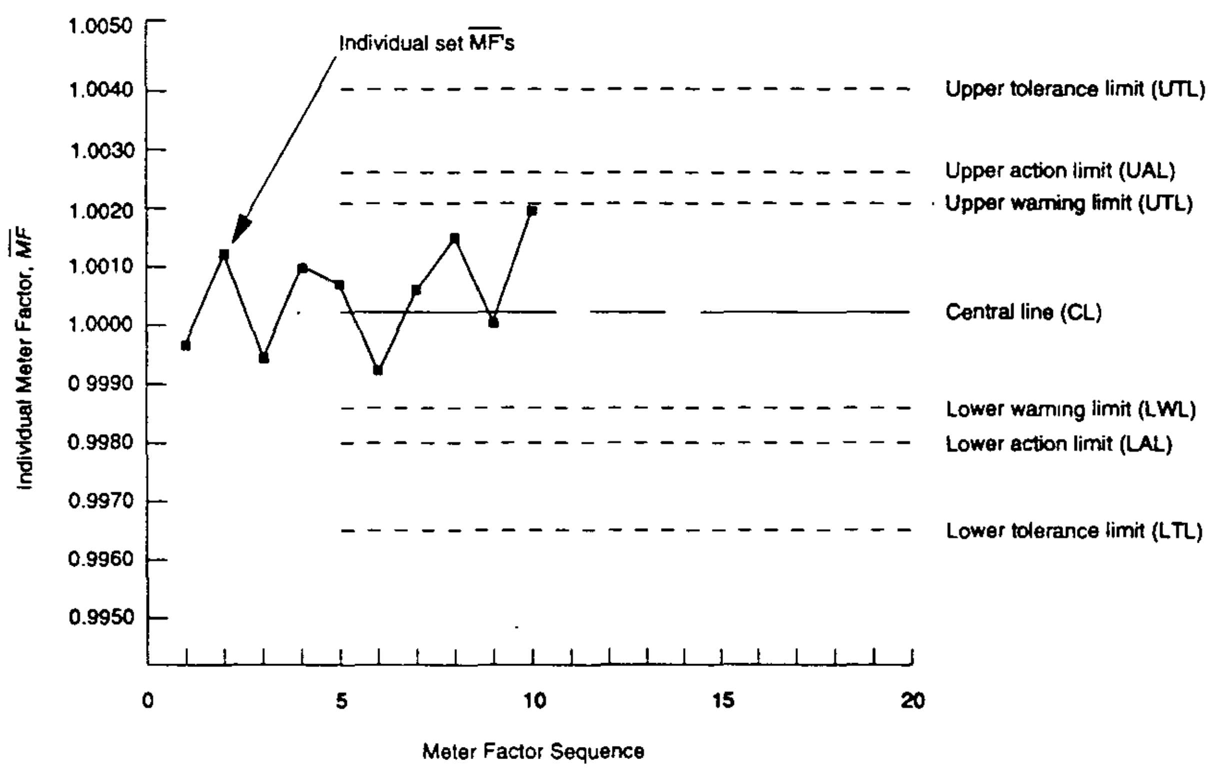


Figure 8—Control Chart for Individual Meter Factors

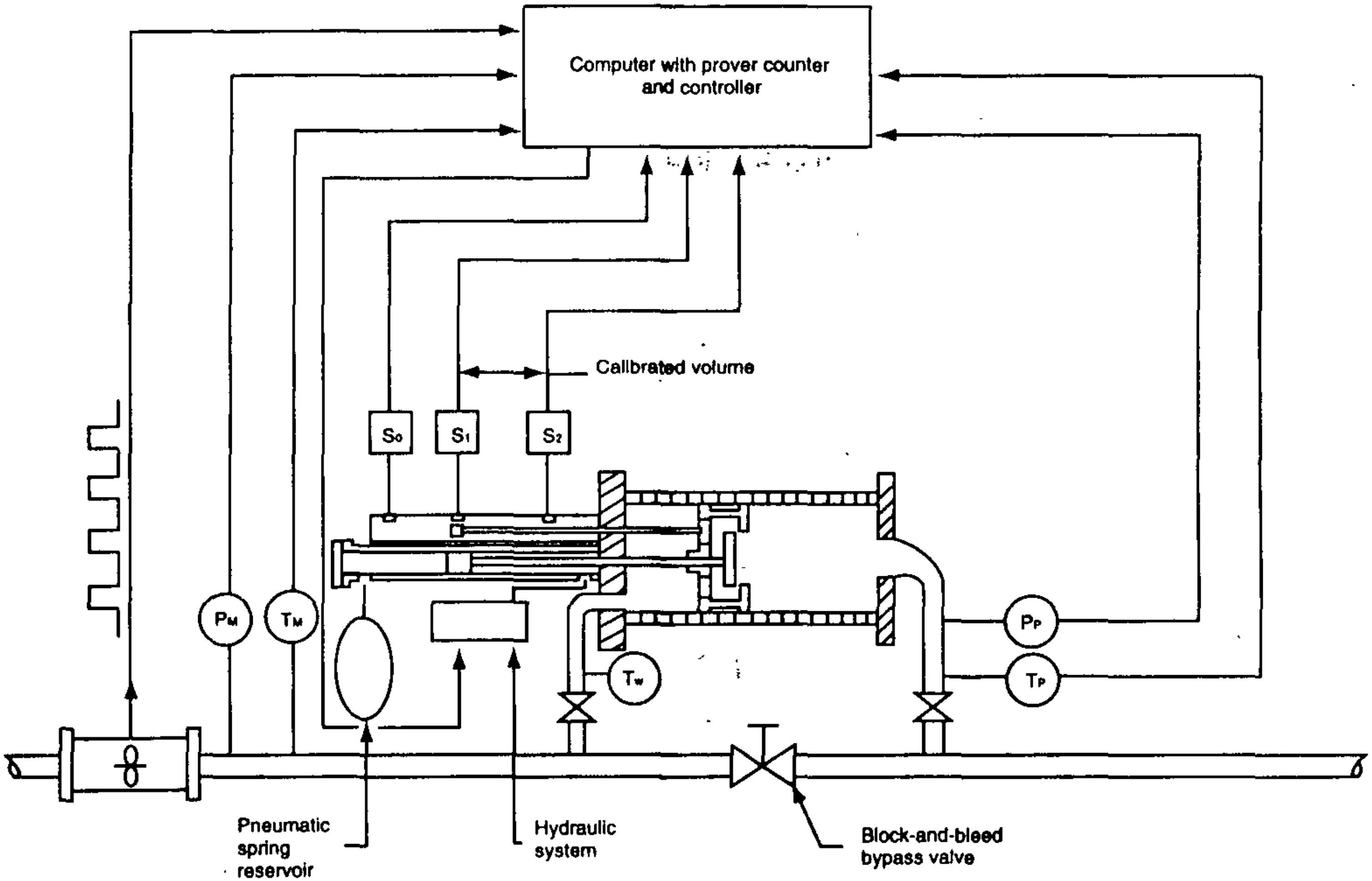


Figure 9—System Overview of SVP With Internal Valve

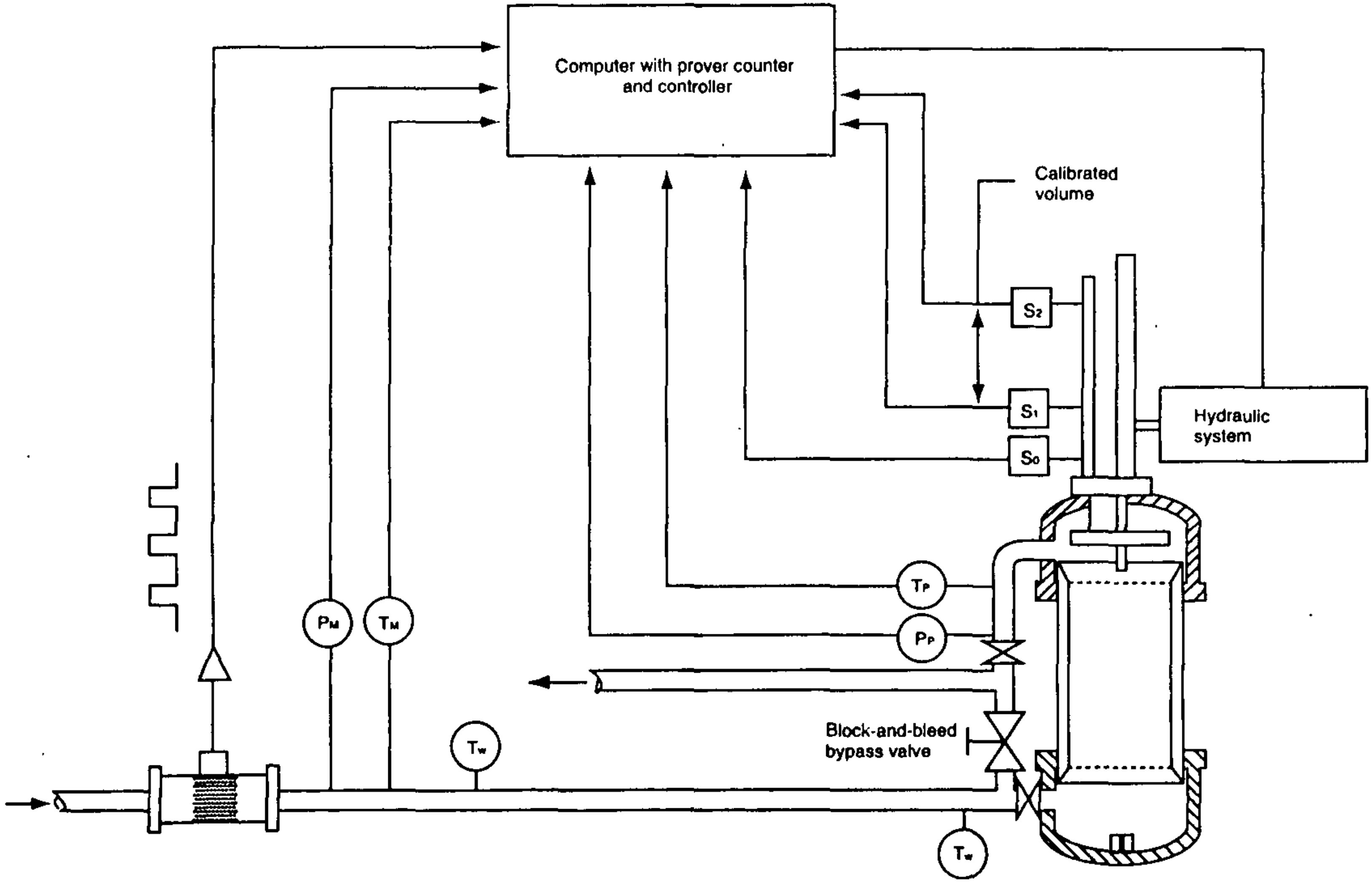


Figure 10—System Overview of SVP With Pass-Through Displacer With Displacer Valve

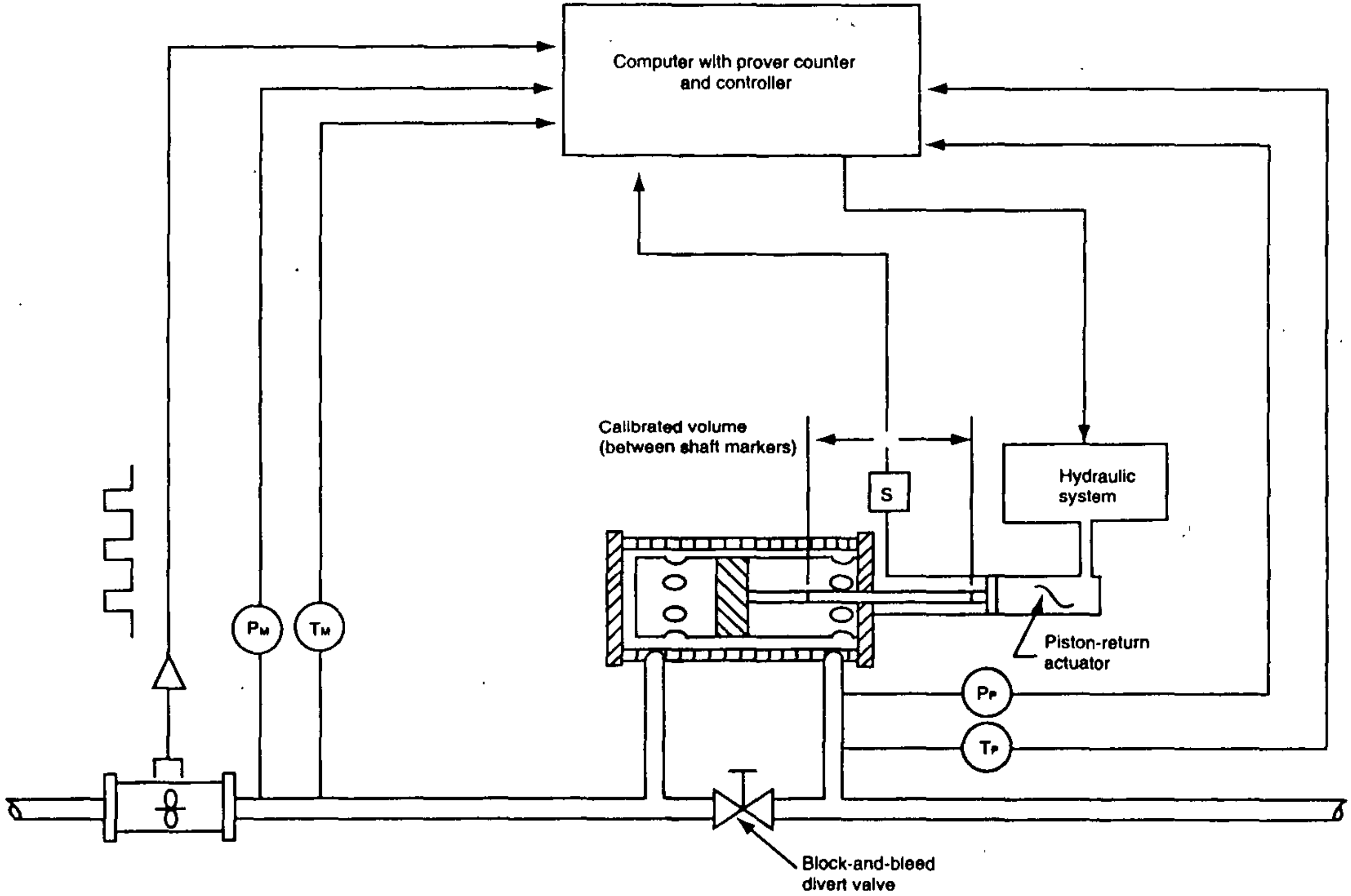


Figure 11—System Overview of SVP With Internal Bypass Porting With External Valve

series of whole meter pulses and multiplying by the ratio of the time between the detector switches and the time to accumulate the whole meter pulses.

Pulse interpolators are electronic devices that allow a meter pulse resolution to at least one part in 10,000. They perform best with meters whose pulses are emitted uniformly. This method results in a calculation of meter pulses to a discrimination of at least 1 part in 10,000.

4.8.4.2 EQUIPMENT DESCRIPTION

Small volume provers may be of any configuration to include bidirectional or unidirectional sphere or piston provers such as shown in Figure 12.

4.8.4.2.1 Pulse Interpolators

Pulse interpolators are electronic devices that allow a meter pulse resolution to at least one part in 10,000. They perform best with meters whose pulses are emitted uniformly. Pulse interpolation is described in detail in API MPMS, Chapter 4, Section 6.

4.8.4.2.2 Prover Displacers

Small volume prover displacers may be either sphere or piston type. Piston displacers typically have dual hollow ring seals made of teflon with stainless steel backup rings. Sphere displacers are typically nitrile, neoprene, or polyurethane and

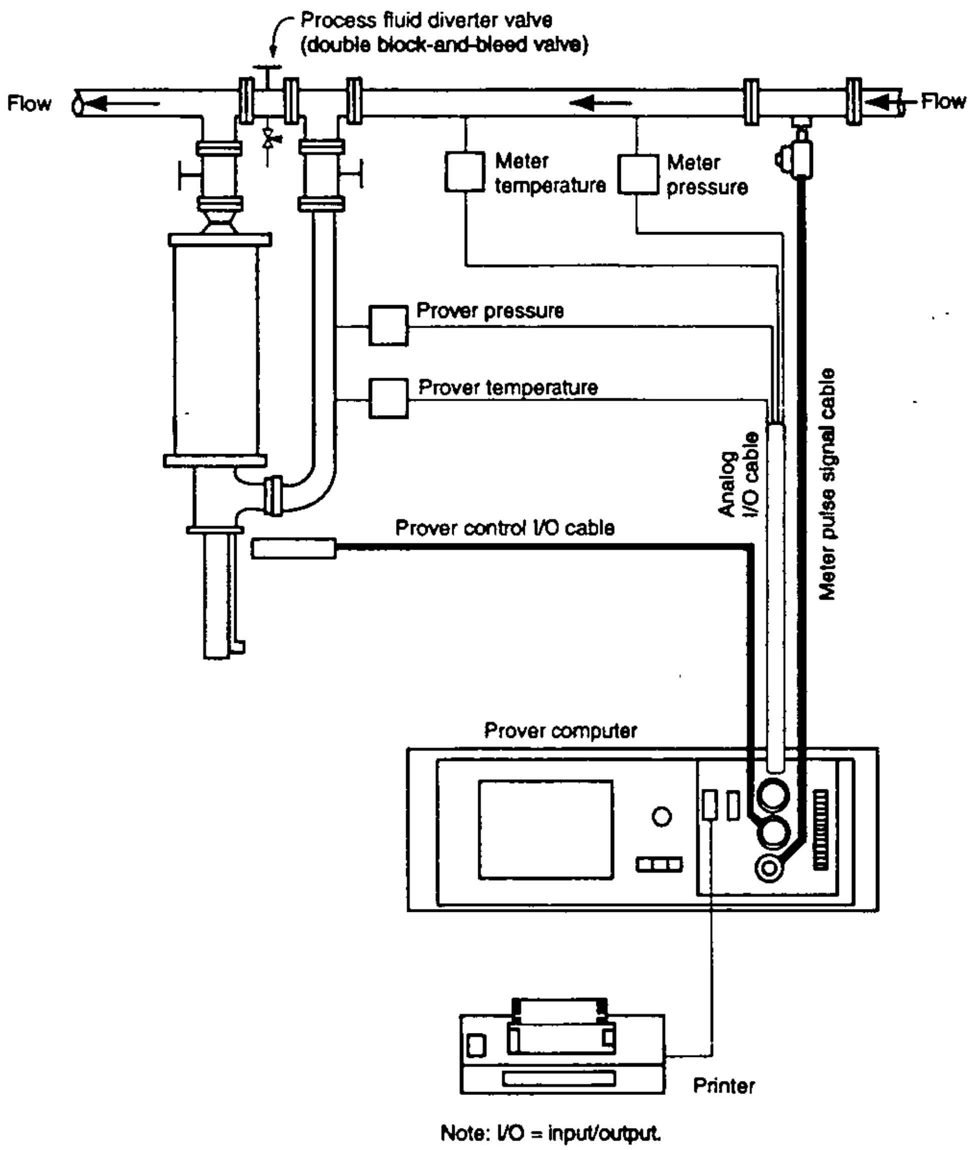


Figure 12—Small Volume Prover Automatic Computing System

are fitted with inflation valves. See Figure 13 for a System Overview of a Unidirectional Sphere Displacer.

4.8.4.2.3 Detector Switches

The detectors along with the pulse interpolation electronics are the most critical elements of a small volume prover. Special designs may be used, for example optical, and most are relatively delicate. When the prover uses optical detector switches, they must be protected from any external light source during operation. Any outside source of light can have a detrimental effect on proving results. For other types of detector switches, see 4.8.3.2.1.

4.8.4.3 INSPECTION

Seal integrity should be periodically verified since any leakage has a significant effect on proving results. To perform a seal integrity test, refer to the manufacturer's recommendations.

4.8.4.4 PREPARATION

An example of a meter-proving form was shown in Figure 7. Other meter proving reports are shown in Figures 14 and 15. Other forms or documents may be required before proving is started. Refer to API MPMS, Chapter 12.2 for meter factor calculation requirements.

4.8.4.5 OPERATING PROCEDURES

Operate the proving system until stable conditions of pressure, temperature, and flow rate exist. Once stability is achieved, proving operations may proceed as follows.

Determine the actual flow rate on the first run of the displacer and make spot checks thereafter. Determine the meter temperature and pressure during each pass of the displacer. Record the average pressure and temperature of each valid run and average them all.

Assuming the prover is equipped with both inlet and outlet thermometers and pressure gauges, determine the average prover temperature and pressure during each pass. The average prover temperature and pressure is recorded on a round trip basis in the case of a bidirectional prover.

If the prover is equipped with only one thermowell, the thermowell should be located at the prover outlet. Determine the prover temperature during each pass of the displacer and record the average during each pass of a bidirectional prover.

In the case of a bidirectional prover, record the reading of the prover counter at the end of each round trip of the displacer. For a unidirectional prover, record the reading of the prover counter at the end of each pass of the displacer.

Repeat the proving operation until the required minimum number of proving runs (per agreement between parties) are attained. As a measure of repeatability, the range of the proving set is determined as follows:

$$\text{Range of Repeatability} = \frac{\text{Maximum Value} - \text{Minimum Value}}{\text{Minimum Value}} \times 100$$

Assess the repeatability of the set of results, and if necessary carry out additional runs in an attempt to gain the required repeatability. If suitable repeatability is not obtained, discontinue the proving operation and look for the cause of the trouble listed in Appendix B.

4.8.4.6 ASSESSMENT OF RESULTS

For common practices refer to Section 4.8.3.5. Flowmeters that have a non-uniform pulse output such as displacement meters with mechanical gear-driven pulsers may require averaging groups of prover passes and comparing the repeatability between the group averages. Refer to API MPMS, Chapter 4, Section 6, and to Appendix A.

4.8.4.7 TROUBLE-SHOOTING

To help operators find faults in a system more quickly, the experience of a number of prover operators has been compiled in Appendix B.

Common problems are listed, as well as the usual causes and the typical methods of solving each.

Finally, the tables in the guide gives the corrective action needed to rectify the fault once its cause has been ascertained. The prover manufacturer's trouble-shooting guide should be referred to for any problems that may relate to the specific make or prover being used.

4.8.5 Tank Provers

4.8.5.1 PRINCIPLES OF OPERATION

A tank prover is a calibrated vessel used to measure the volume of liquid passed through a meter. The known volume of the tank prover is compared to the meter's indicated volume to determine the meter factor or meter accuracy factor.

Tank provers are not recommended for viscous fluids. It is suggested that a displacement-type master meter and a pipe prover be used with viscous products.

4.8.5.2 EQUIPMENT DESCRIPTION

A tank prover is an open or closed volumetric measure that generally has a graduated top neck and may have a graduated bottom neck. The volume is established between a shutoff valve or bottom-neck graduation and an upper-neck graduation.

The two basic types of tank provers are the open type (atmospheric pressure), and the closed type (pressure containing). Both of these come in a variety of configurations to meet the needs of the service required. Refer to Figures 16 and 17 which illustrate the types referred to previously.

4.8.5.3 INSPECTION

Inspect the prover tank for any dents that are not recorded on the calibration certificate, any foreign objects or clingage inside the tank, or failure of an internal coating that would

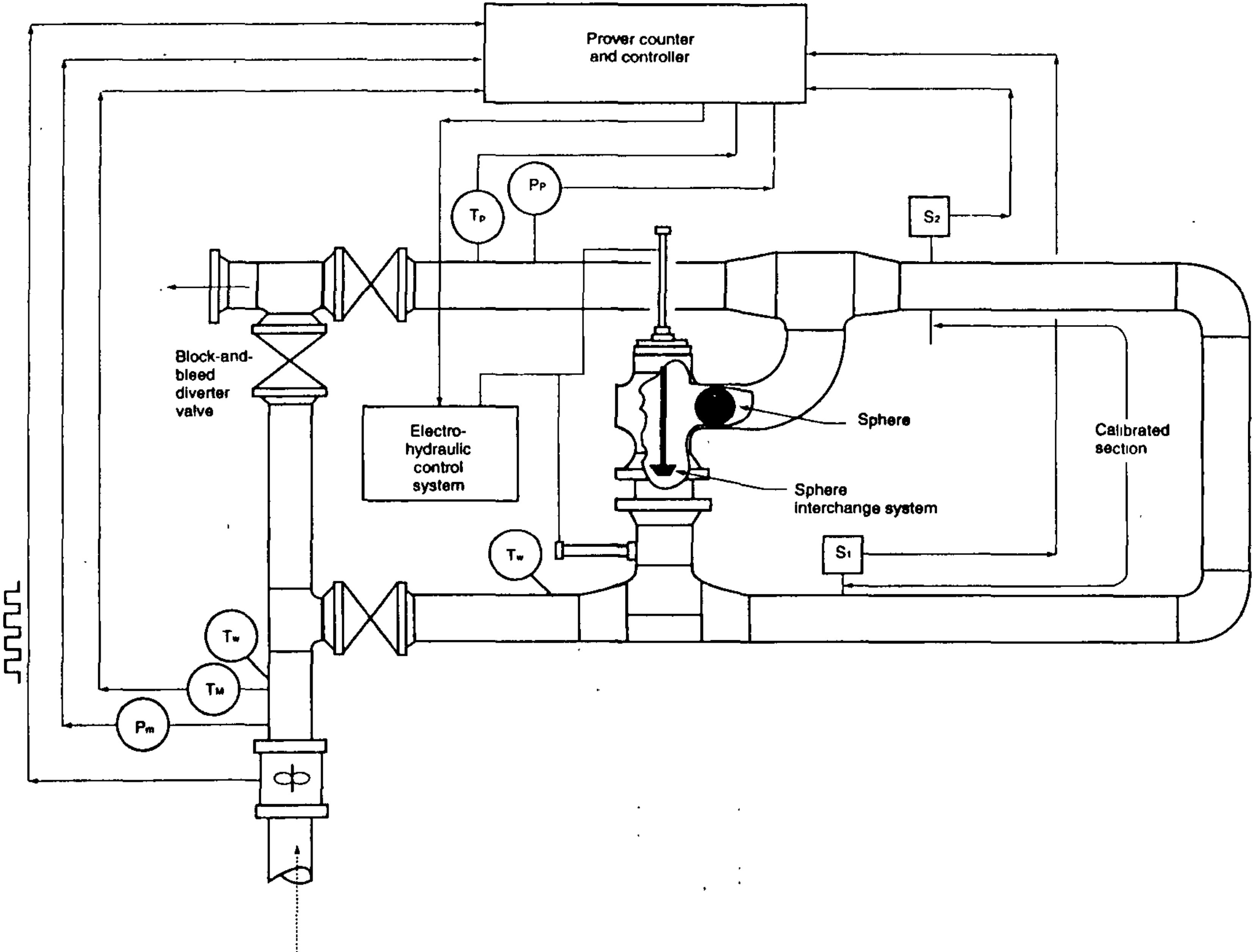


Figure 13—System Overview of Unidirectional Sphere Displacer With Interchange System

LOCATION	TENDER	LIQUID	°API	DATE	AMBIENT TEMP	REPORT NO

METER DATA						
SERIAL NO.	METER NO.	PULSES/bbl	TEMP. COMPENSATED	MANUFACTURER	SIZE	MODEL

FLOW RATE	NON-RESET COUNTER

PREVIOUS REPORT NO ______		
FLOW RATE	FACTOR	DATE
bbl/hr.		

MASTER METER DATA	MAKE. ______ SIZE ______ MODEL ______ SERIAL NO. ______					
1	CLOSING READING, bbls/gals					
2	OPENING READING, bbls/gals					
3	INDICATED VOLUME (LINE 1 − LINE 2)					
4	TEMPERATURE AT METER, °F					
5	PRESSURE AT METER, psig					
6	MASTER METER FACTOR					
7	C_{tl}					
8	C_{pl}					
9	CCF (LINE 6 × LINE 7 × LINE 8)					
10	CORRECTED PROVER VOLUME (LINE 3 × LINE 9)					

PROVED METER DATA						
11	CLOSING METER READING, bbls/gals					
12	OPENING METER READING, bbls/gals					
13	INDICATED VOLUME (LINE 11 − LINE 12)					
14	TEMPERATURE AT METER, °F					
15	PRESSURE AT METER, psig					
16	C_{tl}					
17	C_{pl}					
18	CCF (LINE 16 × LINE 17)					
19	CORRECTED METER VOLUME (LINE 13 × LINE 18)					
20	METER FACTOR (LINE 10 ÷ LINE 19)					

METER FACTOR (AVERAGE VALUE)	X	C_{pl} LIQUID CORRECTION FOR PRESSURE AT METERING CONDITIONS	=	COMPOSITE FACTOR USE FOR CONSTANT PRESSURE APPLICATION

SIGNATURE	DATE	COMPANY REPRESENTATIVE

Figure 14—Meter Proving Report for Master Meter Method

LOCATION	TENDER	LIQUID	°API	DATE	AMBIENT TEMP.	REPORT NO

PROVER DATA	
NOMINAL VOLUME AT 60°F AND "0" psig.	SERIAL NO.
gal/bbl	

PREVIOUS REPORT NO ______		
FLOW RATE	FACTOR	DATE
bbl/hr		

METER DATA					
SERIAL NO.	METER NO	TEMP COMPENSATED	MANUFACTURER	SIZE	MODEL
		☐ YES ☐ NO			

FLOW RATE	NON-RESET COUNTER
bbl/hr	

REMARKS, REPAIRS, ADJUSTMENTS, ETC.

PROVER TANK VOLUME DATA		RUN NO. 1	RUN NO. 2	RUN NO. 3	RUN NO. 4
1	DELIVERY TO TANK, gal/bbls				
2	TANK TEMPERATURE (AVERAGE) °F				
3	C_{ts}				
4	C_{tl}				
5	COMBINED CORRECTION FACTOR (LINE 3 × LINE 4)				
6	CORRECTED PROVER VOLUME (LINE 1 × LINE 5)				
PROVED METER DATA					
7	FINAL METER READING				
8	INITIAL METER READING				
9	INDICATED VOLUME BY METER, bbls (LINE 7 − LINE 8)				
10	INDICATED VOLUME BY METER, gals (LINE 7 − LINE 8) OR (42 × LINE 9)				
11	TEMPERATURE AT METER, °F				
12	PRESSURE AT METER, psig				
13	C_{tl} USE 1.000 IF TEMP COMPENSATED				
14	C_{pl}				
15	CCF (LINE 13 × LINE 14)				
16	CORRECTED METER VOLUME (LINE 10 × LINE 15)				
17	METER FACTOR (LINE 6 ÷ LINE 16)				

METER FACTOR (AVERAGE VALUE)	×	C_{pl} LIQUID CORRECTION FOR PRESSURE AT METERING CONDITIONS	=	COMPOSITE FACTOR USE FOR CONSTANT PRESSURE APPLICATION

SIGNATURE	DATE	COMPANY REPRESENTATIVE

Figure 15—Meter Proving Report for Tank Prover Method

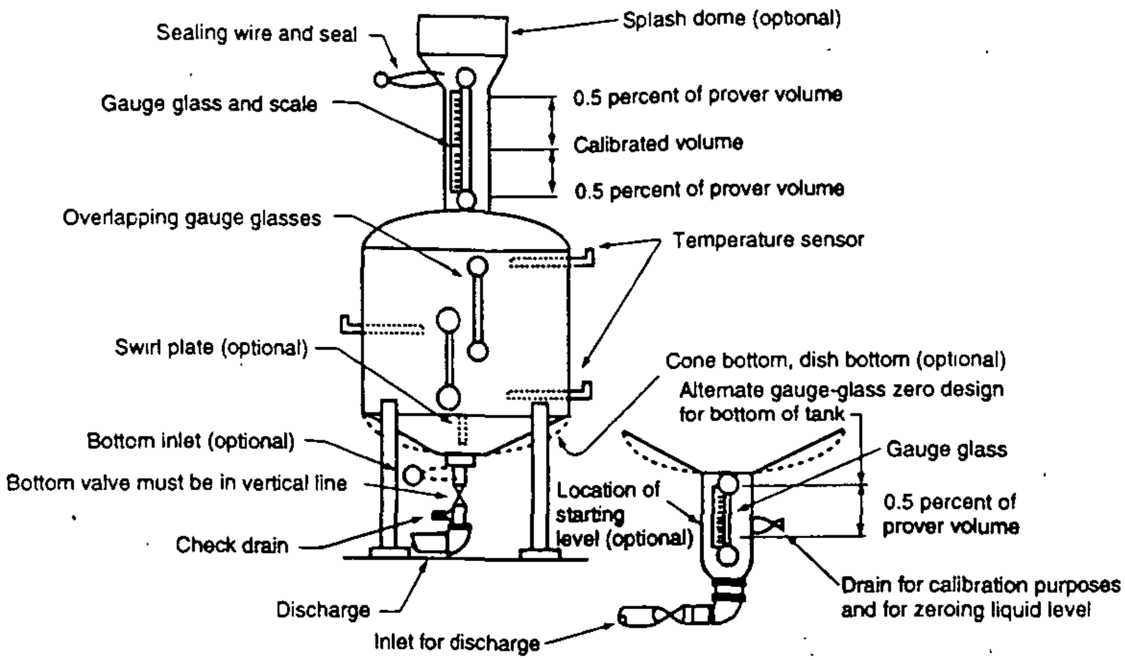


Figure 16—Open Stationary Prover Tank (Drain-to-Zero or Bottom Gauge-Glass Type)

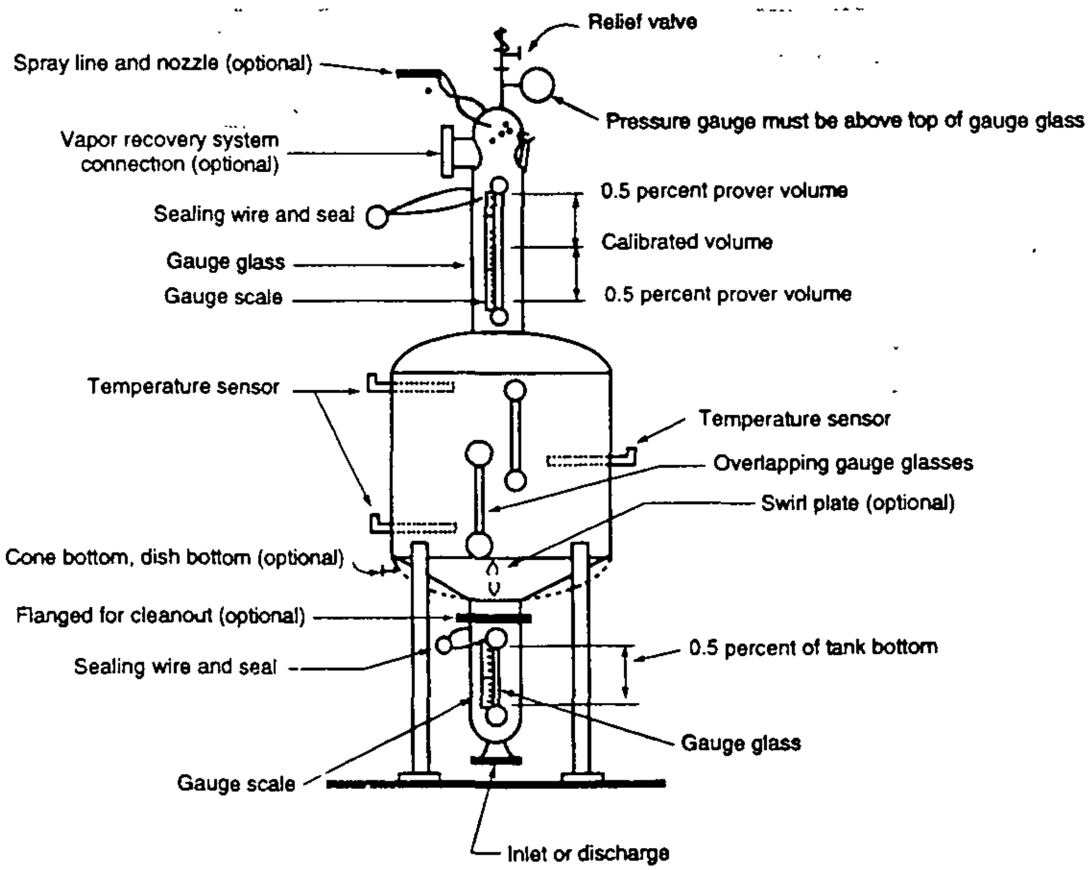


Figure 17—Closed Stationary Tank Prover

have an effect on the calibrated volume of the prover tank. Verify that the gauge scales are sealed. Also check for a current and valid calibration certificate.

4.8.5.4 PREPARATION

Examples of meter proving forms were shown earlier in Figures 6 and 7. Other forms or documents may be required before proving is started. Refer to API MPMS, Chapter 12.2 for meter factor calculation requirements.

Check that all connections are properly made and isolation/diverter valves are properly aligned. Verify the integrity of all vents, drains, reliefs, and double block-and-bleed valves between the meter and the prover. Proceed with the preparations as follows:

a. The initial step prior to the first proof run is to wet down the prover tank. Fill the tank with metered liquid. Check the level indicators on the tank. Then empty the tank.
b. If the tank is equipped with a lower-gauge glass, close the main drain valve just prior to the liquid level reaching the zero mark. Allow a minimum of 30 seconds drain down time (or that which is stated on the calibration report); then using the small drain valve, drain the liquid to the zero mark. Whatever drain time is allowed after closing the main drain valve and drawing the liquid down to zero must be used on all subsequent proof runs.
c. If the tank is not equipped with a lower-gauge glass, leave the drain valve open until continuous flow ceases and dripping starts. The drip should be allowed to continue for a minimum of 30 seconds (or that which is stated on the calibration report) before closing the drain valve. Whatever drip time allowed between flow cessation and closing the drain valve must be used on all subsequent proof runs.
d. When reading gauge glasses, read the bottom of the meniscus for transparent liquids and the top of the meniscus for opaque liquids.
e. If the system has vapor recovery, the vapor recovery should have makeup gas or must be disconnected prior to emptying the prover so that air can enter the prover and prevent a vacuum that could damage the prover.

4.8.5.5 OPERATING PROCEDURES

There are two unique features of an open tank prover. The first is that vapor is allowed to escape (evaporate) from within the tank as the tank is filled. If a vapor recovery system is used during normal metering operations, consideration should be given to operating the vapor recovery system during the meter proving.

The second unique feature is that the meter is operated from as *stop-run-stop* condition. Thus the meter experiences a static-to-dynamic and back-to-static cycle of operation. This method of operation depicts normal operating conditions of the prover/meter system.

It is important to use consistent tank prover operating techniques without interruption to obtain satisfactory repeatability between consecutive proof runs. Flow rate through the meter during the proof runs should replicate the operating conditions during normal use.

a. Using a tank prover report or worksheet record the appropriate meter, tank, and flow data as indicated in the meter factor calculation section of API MPMS, Chapter 12.2.
b. Record the meter register, or zero the proving counter if one is being used. Record the reading of the prover tank's bottom gauge glass, if so equipped. These become the opening readings for this proving run.
c. Start the flow through the meter into the tank.
d. While the tank is filling, record the average meter temperature and verify that the meter is operating at the desired proving rate.
e. Stop the meter flow when the liquid level is within the upper gauge scale range.
f. Record the prover tank temperature. If the tank has more than one thermometer, the recorded temperature is the average of all thermometer readings.
g. Record the meter register or the proving counter reading and the prover tank's upper gauge glass reading. These are the closing readings for this proving run.
h. Calculate the meter factor for this run as outlined in API MPMS, Chapter 12.2. This completes one proving run. The next proving run is initiated by draining down and zeroing the tank as just described, and then starting over with the steps described previously.
i. At least two consecutive proving runs in which the meter factors agree within a 0.05 percent range are required. The average of these meter factors is the final meter factor. If an adjustment to the meter factor is made mechanically, that is, with a calibrator or mathematically, additional runs typically are made to confirm that the meter factor is correct.
j. Upon conclusion of the proving operation, if a prover tank is a portable unit, isolate the prover from the flow stream; drain down; remove all connections made; and prepare the tank for removal from the site. If the tank is permanently located, isolate the prover from the flow stream; drain down; and place the tank in a protected idle mode.

4.8.5.6 ASSESSMENT OF RESULTS

Common practice is to require a minimum of two consecutive runs that agree within a range of 0.05 percent. If the repeatability of the meter factor is unacceptable, it may be necessary to carry out additional proving runs. If the repeatability is within the prescribed range, these results may be used. But if the repeatability remains unacceptable, it is necessary to stop proving and look for the cause of the problem.

4.8.5.7 TROUBLE-SHOOTING

To help operators evaluate a system more quickly, the experience of a number of prover operators has been compiled in Appendix B. Common problems are listed, as well as the usual causes and the typical methods of solving each. The table also gives the corrective action needed.

4.8.6 Master Meter Provers

A proving operation is considered a direct proving when a meter is proved against a prover. Indirect proving is when a meter is proved by a master meter that has been proved by the direct method.

Master meter proving is used when proving by the direct method cannot be accomplished because of logistics, time, space, and cost considerations.

Satisfactory results can be achieved by using the master meter method; however, the master-meter method introduces additional uncertainties for the meter being proved. When practical, uncertainties may be reduced by proving the master meter under similar line-meter operating conditions prior to, during, or after proving the line meter.

4.8.6.1 PRINCIPLE OF OPERATION

A master meter is a meter selected, well maintained, and operated as a reference for the proving of another meter. The master meter factors should be linear over the expected range of operating conditions and shall have a history of consistent performance.

The calibration of the master meter shall be performed under conditions similar to those expected during the line meter proving. A curve of master meter factors should be established over the range of flow rates to be encountered while proving a line meter. The meter factor applied to the master meter shall be the average of proof runs on a similar liquid and within 10 percent of the flow rates expected during the proving of the line meter.

Either the standing start-and-stop or the running start-and-stop method of proving may be used. With the standing start-and-stop method, the meter registration is read before and after the proving run with flow stopped to determine indicated volume. With the running start-and-stop method, the flow is uninterrupted, and the proving counters must be simultaneously started and stopped.

4.8.6.2 EQUIPMENT DESCRIPTION

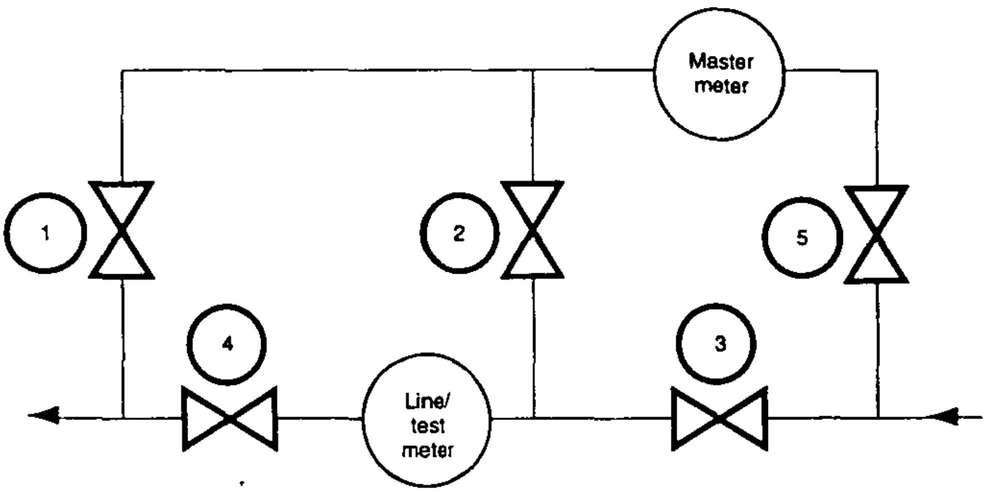
The master meter output/registration must not be mechanically temperature compensated. The master meter must not have a mechanical adjustor or calibrator between the primary element and the output/registration. When proving a meter with a master meter, the same meter output and instrumentation accessories must be connected to the master meter as were used when the master meter was proved to establish its meter factor.

Typically, master meters are displacement or turbine meters because of the repeatability requirements of proving (see API MPMS, Chapter 4.5).

4.8.6.3 INSPECTION

Prior to the meter-proving operation the master meter prover and line meter to be proved shall be inspected to ensure proper operation. This inspection shall include, but not be limited to, the following steps:

a. Ensure that all liquid flowing through the line meter to be proved, and only that liquid, passes through the master meter with no leakage or diversion between meters. Refer to Figure 18 for an illustration of a master meter/line meter manifold, which permits the removal of either meter for calibration or servicing. Double block-and-bleed valves ensure that no leakage or diversion can occur either during proving or line-meter operation.



Note: 1, 2, 3 = double-block-and-bleed; 4, 5 = shut-off valve.

Figure 18—Typical Master Meter Manifold

b. Verify that all temperature, pressure, and density measurement devices to be used during the proving operation are properly installed, recently calibrated or verified, and operating within acceptable tolerances as stated in API MPMS, Chapters 7 and 12.2.

c. All electronic instrumentation such as counters, switches, and interconnecting wiring shall be inspected for proper installation and operation. Care should be taken to ensure that all electrical pulse transmission cable is properly shielded and grounded.

d. It is essential that a run of sufficient quantity be made to verify the ratio between the pulse transmitter and the meter register. See API MPMS, Chapter 4.5.

4.8.6.4 PREPARATION

Examples of meter-proving forms were shown earlier in Figures 6 and 7. Master meter calibration reports and curves, and other forms or documents may be required before proving is started. Refer to API MPMS, Chapter 12.2 for meter factor calculation requirements.

The master meter should be installed as close as possible to the line meter to minimize temperature and pressure differences between the meters. The master meter normally is installed downstream of the line meter. The following steps should be taken:

a. If the master meter has an electrical output, care should be taken to ensure all electrical equipment is properly grounded to prevent errors from electrical noise.

b. If the master meter is permanently piped in a manifold with the line meter to be proved, the isolation valves should be opened and the flow directed through both meters.

c. Before the meter proving is made, the two meters shall be operated at the desired flow rate for a period of time sufficient to purge the system of vapor and to achieve steady temperature, pressure, and flow rate.

4.8.6.5 OPERATING PROCEDURES

Each proving run shall be of sufficient volume to discriminate volume units to 1 part in 10,000. In the case of loading rack meters, each proving run should depict the start up, shutdown, and interim flow patterns of a normal loading. If electronic counters and high resolution meter transmitters are used to register metered volume, at least 10,000 pulses must be collected during the proving run.

Once the proving operation is started, it should be carried to conclusion in a continuous process, without interruption or delay. The following steps should be taken:

a. Using a work sheet or master meter proving report (see Figure 6), record the appropriate meter and flow data as indicated in the factor calculations section of API MPMS, Chapter 12.2.

b. With flow through the meters, a proving run is initiated by simultaneously gating both meter counters on. Meter temperature and pressure are recorded for both meters during the proving run. Flow rate through the meters during the proving operation should be within 10 percent of the rate at which the line meter will operate. The flow rate must remain relatively stable for all proving runs entered in the meter factor calculation.

c. After sufficient volume has passed through the meters, the counters are simultaneously gated off. The indicated counter readings for the run are recorded. This completes one run.

d. There are various ways of assessing whether the repeatability of a set of readings is acceptable. The repeatability should not exceed the limits agreed upon by all parties. In some circumstances, statutory authorities or government departments will set the limits for the range of a set of results. One method of conducting a proving is to make five consecutive meter proof runs within 0.05 percent. "Within a range of 0.05 percent" is defined as a value that does not exceed 0.05 when applying the following formula:

$$\frac{\text{Maximum Value} - \text{Minimum Value}}{\text{Minimum Value}} \times 100$$

e. Checks should be made during the proving to ensure all equipment is functioning properly and all test parameters are remaining within their constraints.

f. Meter factor calculations shall be made as detailed in API MPMS, Chapter 12.2. An example "Meter Proving Report for the Master Meter Method" was shown in Figure 14.

g. After completion of the proving operation, the master meter should be isolated from the flow stream if the meter is permanently installed, or disconnected if the meter is portable. A master meter should not be on stream any longer than necessary for the proving operation. This precaution is to limit meter wear and resulting factor shift.

h. Thermometers, pressure gauges, counters, and any other proving equipment that is not a permanent part of the manifolding should be removed and stored until the next proving.

4.8.6.6 ASSESSMENT OF RESULTS

A common practice is to require a minimum of two consecutive runs that agree within a range of 0.05 percent. If the repeatability of the meter factor is unacceptable, it may be necessary to carry out additional proving runs. If the repeatability is within the prescribed range, these results may be used. But if the repeatability remains unacceptable, it is necessary to stop proving and look for the cause of the problem.

4.8.6.7 TROUBLE-SHOOTING

To help operators evaluate a system more quickly, the experience of a number of prover operators has been compiled in Appendix B. Common problems are listed, as well as the usual causes and the typical methods of solving each. The tables give the corrective action needed.

APPENDIX A—ESTIMATING RANDOM UNCERTAINTY

Chapter 13.1 of API MPMS states that the 95-percent level of statistical confidence is recommended for evaluating uncertainties associated with commercial applications of petroleum measurement. It is also stated that in certain limited circumstances, a different degree of (statistical) confidence may be required.

The random uncertainty of the average value of a set of meter proving runs can be estimated in accordance with Chapter 13.1 at the 95-percent confidence level as follows:

$$a(MF) = \frac{[t(95, n-1)][w_{(n)}]}{(\sqrt{n})(D_{(n)})}$$

Where:

$a(MF)$ = random uncertainty of the average of a set of meter proving runs.
$t(95, n\text{-}1)$ = student "t" distribution factor for 95 percent confidence level and n-1 degrees of freedom (see Table 2 of API 13.1).
$w_{(n)}$ = range of values (high minus low) in the meter proving set.
n = number of meter proving runs.
$D_{(n)}$ = conversion factor for estimating standard deviation for n data points (see Table 1 of API 13.1).

For the common practice of five proving runs that agree within a range of 0.0005, the random uncertainty of the average of this set can be estimated as follows:

$$a(MF) = \frac{(2.770)(0.0005)}{(\sqrt{5})(2.326)} \pm 0.00027$$

For meter proving sets of 3 to 25 proving runs, a variable range limit can be calculated that maintains the same random uncertainty in the average value of 5 runs that agree within a range of 0.0005. These variable range limits are as shown in Tables A-1 and A-2.

Table A-1—Variable Range Criteria
for ±0.00027 Random Uncertainty in Average Meter Factor

Number of Proving Runs, n	Moving (Variable) Range Limit
3	0.0002
4	0.0003
5	0.0005
6	0.0006
7	0.0008
8	0.0009
9	0.0010
10	0.0012
11	0.0013
12	0.0014
13	0.0015
14	0.0016
15	0.0017
16	0.0018
17	0.0019
18	0.0020
19	0.0021
20	0.0022

For low volume locations such as small LACT units where five runs within a range of 0.0005 may not be practical or cost effective, three runs within a range of 0.0005 may be practiced. The random uncertainty of the average of three proving runs that agree within a range of 0.0005 is as follows:

$$a(MF) = \frac{(4.303)(0.0005)}{(\sqrt{3})(1.693)} = \pm 0.00073$$

For meter proving sets of three to fifteen proving runs, a variable range limit can be calculated that maintains the same random uncertainty in the average of three runs that agree within a range of 0.0005. These variable range limits are as shown in Table A-2.

Table A-2—Variable Range Criteria
for ±0.00073 Random Uncertainty in Average Meter Factor

Number of Proving Runs, n	Moving (Variable) Range Limit
3	0.0005
4	0.0009
5	0.0014
6	0.0017
7	0.0021
8	0.0025
9	0.0028
10	0.0032
11	0.0034
12	0.0037
13	0.0040
14	0.0043
15	0.0046

The *scatter* in erratic meter proving data can be normalized by averaging the results of several meter proving runs and comparing the averages of these small sets for agreement with deviation limits. In these instances, at least three consecutive proving runs are recommended for each set. The averages of two or more of these sets can be compared for agreement of meter-proving deviation limits.

Table B-1—Trouble-Shooting Guide for Pipe Prover Operators-Part 1

Symptom	Location and Possible Cause	Test/Inspection	Corrective Action
1 Poor Repeatability	1 Entrapped air/vapor	Open vent with sphere traveling, check for air/vapor. (This may not give positive response because of possible air/gas pockets.)	a Check for air in fluid to prover, vent all high points, and run prover several times and vent b Increase meter back pressure
	2 Flashing in 4-way diverter valve or sphere-handling valve	Measure pressure at the valve at maximum flow rate and see it in accordance with specification	Increase pressure by using back pressure valve
	3 Isolating valve leakage	Check double block-and-bleed for leakage.	a. Seat valve more firmly by increasing actuator or hand-wheel torque. b. Repair valve. c. Cycle valve to remove debris
	4 Leakage in 4-way diverter valve or sphere-handling valve	Check double block-and bleed for leakage.	a. Seat valve more firmly by increasing actuator or hand-wheel torque b Repair valve. c Cycle valve to remove debris.
	5 Cycle time of 4-way diverter valve or sphere-handling valve	Check double block-and-bleed closure before sphere reaches the first detector	Increase speed of operation of the valve or decrease flow rate through the prover.
	6. Detector(s)	Check detectors against external signal source. Use ohm meters to check continuity of switch closure	Calibration may be required if detector(s) are adjusted or changed.
		Check for corrosion on terminals.	Clean terminals.
		Inspect mechanical parts of detectors.	Clean and repair as needed
	7 Temperature Variation	Verify temperature measurements	Stabilize temperature at meter and prover
	8 Sphere	Remove, inspect for cuts, blister, abrasions and/or deterioration. Check roundness and sizing	Inflate or deflate if necessary, replace if damaged.
	9 Piston	Apply bleed test to check for leakage and inspect seals for cuts, abrasions and deterioration	Replace seals if necessary.
	10 Meter bearing wear	Dismantle and inspect. Analyze pulse train with oscilloscope.	Repair/replace as required
	11 Accessory gear wear	Analyze pulse train with oscilloscope	Repair/clean as needed
	12 Turbine meter straightening section	Remove and inspect for damage and foreign material	Repair/clean as required

Table B-1—Trouble-Shooting Guide for Pipe Prover Operators-Part 1 (continued)

Symptom	Location and Possible Cause	Test/Inspection	Corrective Action
	13. Random electrical interference	Identify sources. Analyze pulse train with oscilloscope.	Reroute cable. Use shielded cable. Check cable ground connection
	14. Cavitation in meter	a) Draw sample and observe for stability at atmospheric pressure b) If unstable, measure equilibrium vapor pressure of liquid c) Measure pressure downstream of the meter d) Evaluate back pressure	Increase pressure.
	15. Pulse generator faulty	At constant flow rate check that pulse frequency is constant. Pulse integrity check. Analyze pulse train with oscilloscope	Repair/replace as required
	16. Faulty calibrater	Analyze pulse train with oscilloscope. Adjust Up/down, evaluate MF changes.	Repair/replace as required
2. Poor Linearity	1. Cycle time of 4-way diverter valve or sphere handling valve.	Evaluate MF changes. See 5 above.	Repair/replace as required. See 5 above
	2. Temperature variation.	Verify temperature measurements.	Stabilize temperature at meter and prover
	3. Bearing wear	Dismantle and inspect	Repair/replace as required
	4. Damaged DM rotor Damaged TM	Dismantle and inspect. Analyze pulse train with oscilloscope	Repair/replace as required
	5. Drag or wear, gears, couplers, etc	Head check or successive runs	Re-align/replace as required.

Table B-2—Trouble-Shooting Guide for Pipe Prover Operators-Part 2

Symptom	Location and Possible Cause	Corrective Action
Miscellaneous problems encountered when proving.		
a. Less meter registration factor increase	Meter	Rebuild meter.
Less meter registration factor increase	Meter	Replace bearings
More or less, meter registration factor increase/decrease	Meter calibrator	Lubricate or replace.
Less meter registration factor increase	Prover temperature too low	Stabilize temperature.
b. More meter registration factor decrease	Prover temperature too high reading	Check thermometer.
More meter registration factor decrease	Fluid viscosity increase	Stabilize viscosity.
Less meter registration factor decrease	Build-up on pipe wall	Investigate reason for build-up/clean prover.
Severe change in MF	Malfunction in ATC assembly	Hot/cold test.
Severe decrease in MF	Collaspsed bulb and bellows	Replace B & B.
Severe increase in MF	Malfunction of calibrator Inner-mechanical problems	Repair/replace.
Severe decrease in MF	Displacer undersized	Size/replace.

Table B-3—Trouble-Shooting Guide for Small Volume Prover Operators

Symptom	Location and Possible Cause	Test/Inspection	Corrective Action
	PROVER		
1. Poor repeatability	1. Entrapped air/gas in prover	Open prover vents to see if air/gas is present.	Open vents and cause displacer to travel until air/gas is removed.
	2. Leakage by isolation valves	Check double block-and-bleed.	a. Open and reclose valve. b. Seat valve more firmly by increasing torque. c. Replace seats.
	3. Leakage at bypass or diverter valve	Check double block-and-bleed.	a. Seat valve more firmly by applying more pressure. b. Replace seals
	4. Leakage by displacer	Check for leak by method recommended by manufacturer.	Replace seal(s).
	5. Cavitation in proving system	Measure pressure loss through the meter/proving system to see if within specification.	a. Reduce flow rate. b. Increase back-pressure on proving system.
	6. Detector(s)	Check detectors for proper operation.	If faulty replace detectors. Shield optical switches from ambient light.
	7. Electronics, pulse	Check per instructions in API MPMS Chapter 4, Section 6.	Adjust/repair/replace as required.
	8. Improper plenum pressure	Verify plenum pressure per manufacturer's specification.	Adjust as required.
	METER		
	1. Internal wear	Dismantle and inspect.	Repair/replace as required.
	2. Random electrical interference	Trace and eliminate interference.	Remove or replace problem.
	3. Cavitation in meter	Measure pressure a few pipe diameters downstream of the meter at a maximum low rate and see if within specifications.	Increase pressure by using back pressure.
	4. Pulse generator, fault	At uniform flow rate check that pulse frequency is constant.	a. Check gear train. b. Repair/replace as required.
	5. Turbine meter straightening section	Remove and inspect for damage or blockage by foreign object.	Repair or replace as required. Clean out foreign object.
	PROVER		
2. Poor linearity	1. Leakage through bypass or diverter valve	Same as 3 above.	Same as 3 above.
	2 Temperature variation	Measure temperature accurately.	Correct for temperature effects at meter and prover.
	3 Bearing wear	Dismantle and inspect.	Replace/repair as required.
	4 Cavitation	Check pressure loss through proving system	Apply back pressure and or reduce flowrate.

Table B-3—Trouble-Shooting Guide for Small Volume Prover Operators (continued)

Symptom	Location and Possible Cause	Test/Inspection	Corrective Action
	PROVER (continued)		
	5. Pulse generator, fault	At constant flowrate check that pulse frequency is constant.	a. Check gear train. b. Repair/replace as required
	6. Damaged rotor	Dismantle and inspect.	Repair/replace as required.

Table B-4—Trouble-Shooting Guide for Master-Meter Prover Operators

Symptom	Location and Possible Cause	Test/Inspection	Corrective Action
	MASTER-METER PROVER		
1. Poor repeatability	1. Cavitation	Apply excessive back pressure for a brief period.	Adjust back pressure to appropriate level.
	2. Pulse generator, fault	At uniform flowrate check that pulse frequency is constant.	Repair or replace as required.
	3. Electrical noise	Check for random electrical interference.	Trace and eliminate interference.
	4. Entrapped air/gas and/or cavitation	Open vents slowly, then close.	Locate air/gas source and eliminate.
	5. Worn meter parts	Dismantle and inspect.	Reassemble with new parts as required and reprove master-meter.
	6. Leaking valves	Check for full open/close position and leak tightness.	Repair or replace as required.
	FIELD-METER		
	1. Cavitation	Same as 1 above.	Same as 1 above.
	2. Pulse generator, fault	Same as 2 above.	Same as 2 above.
	3. Temperature variation	Measure temperature often and accurately.	Correct for temperature effects on field-meter and master-meter.
	4. Worn meter parts	Same as 5 above.	Same as 5 above.
	5. Turbine meter straightening section	Remove and inspect for damage.	Repair or replace as required.
	6. Pressure variation	Check gauges.	Look for cavitation. Check back pressure.
	7. Temperature variation	Check temperature sensors.	Maintain stable flow condition.

Table B-5—Trouble-Shooting Guide for Tank Prover Operators

Symptom	Location and Possible Cause	Test/Inspection	Corrective Action
	PROVER		
1. Poor repeatability	1. Inconsistent drain down time.	Measure drain down time.	Follow drain down time on calibration certificate.
	2. Drain valve leaks	Fill prover to capacity read upper scale and let stand for 15 minutes, then then read scale again to see if any leakage.	Repair valve w/o removing. Replace valve and recalibrate
	3. Unstable prover	Try rocking by applying a modest force.	Level prover and make secure.
	4. Unsatisfactory fill condition	Fill pipe must always drain completely or always retain the same amount of fluid before and after each run.	a. Secure fill pipe position b. Provide vent in fill pipe.
	5. Unstable flowrate	Monitor flowrate.	a. Secure flowrate control valve. b. Stabilize back pressure.
	6. Vaporization	Lower flowrate.	Change fill procedure.
	METER		
	1. Bearing wear	Dismantle and inspect.	Replace/repair as required.
	2. Counter does not repeat	Remove counter and hold input shaft firmly while resetting, to see if it resets to zero each time.	a. Repair/replace as required. b. Check gear backlash in meter head.
	3. Meter cavitation	Apply excessive back pressure for a brief time.	Adjust back-pressure according to requirements.
	4. Meter calibrator	Isolate and test temperature mechanism.	Repair/replace as required.

Manual of Petroleum Measurement Standards Chapter 5—Liquid Metering

Section 2—Measurement of Liquid Hydrocarbons by Displacement Meters

Measurement Coordination Department

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Chapter 5—Liquid Metering

SECTION 2—MEASUREMENT OF LIQUID HYDROCARBONS BY DISPLACEMENT METERS

5.2.1 Introduction

Chapter 5.2 is intended to describe methods of obtaining accurate measurements and maximum service life when displacement meters are used to measure liquid hydrocarbons.

A displacement meter is a flow-measuring device that separates a liquid into discrete volumes and counts the separated volumes. The meter carries through its measuring element a theoretical swept volume of liquid, plus the slippage for each stroke, revolution, or cycle of the moving parts. The registered volume of the displacement meter must be compared with a known volume that has been determined by proving, as discussed in Chapter 4.

It is recognized that meters other than the types described in this chapter are used to meter liquid hydrocarbons. This publication does not endorse or advocate the preferential use of displacement meters, nor does it intend to restrict the development of other types of meters. Those who use other types of meters may find sections of this publication useful.

5.2.2 Scope

This section of Chapter 5 covers the characteristics of displacement meters and discusses appropriate considerations regarding the liquids to be measured, the installation of a metering system, and the selection, performance, operation, and maintenance of displacement meters in liquid-hydrocarbon service.

5.2.3 Field of Application

The field of application of this section is all segments of the petroleum industry in which dynamic measurement of liquid hydrocarbons is required. This section does not apply to the measurement of two-phase fluids.

5.2.4 Referenced Publications

The current editions of the following standards, codes, and specifications are cited in this chapter:

API

Manual of Petroleum Measurement Standards

Chapter 4, "Proving Systems"
Chapter 4.2, "Conventional Pipe Provers" (in press)
Chapter 5, "Metering"
Chapter 5.4, "Instrumentation or Accessory Equipment for Liquid Hydrocarbon Metering Systems"
Chapter 7.2, "Dynamic Temperature Determination"
Chapter 8, "Sampling"
Chapter 11.1, "Volume Correction Factors" (ASTM[1] D 1250, ISO[2] 91.1)
Chapter 12, "Calculation of Petroleum Quantities"
Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"
Chapter 13, "Statistical Aspects of Measuring and Sampling"
Chapter 13.2, "Meter Factor Control Charts" (in press)

5.2.5 Design Considerations

The design of displacement-meter installations should take into account the following considerations:

a. The installation should be able to handle the maximum and minimum flow rates, the maximum operating pressure, and the temperature range of the liquid to be measured. If necessary, the installation should include protective devices that keep the operation of the meter within design limits.
b. The installation should ensure a maximum, dependable operating life. Strainers, filters, air/vapor eliminators, or other protective devices may be provided upstream of the meter to remove solids that could cause premature wear or gases that could cause measurement error.
c. The installation should ensure adequate pressure on the liquid in the metering system at all temperatures so that the fluid being measured will be in the liquid state at all times.
d. The installation should provide for proving each meter and should be capable of duplicating normal operating conditions at the time of proving.
e. The installation should comply with all applicable regulations and codes.

5.2.6 Selecting a Meter and Accessory Equipment

Chapter 5.4 provides guidelines for selecting the appropriate equipment. In addition, the manufacturer should be

[1]American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103.
[2]International Organization for Standardization, 1430 Broadway, New York, New York 10018.

consulted, and detailed consideration should be given to the following items:

a. The properties of the metered liquids, including viscosity, vapor pressure, toxicity, corrosiveness, and lubricating ability. Toxic and environmentally controlled fluids must receive special consideration to prevent and control potential leaks or spills.
b. The operating flow rates and whether the flow is continuous, intermittent, fluctuating, bidirectional, or reversible.
c. Accuracy requirements.
d. The class and type of piping connections and materials and the dimensions of the equipment to be used.
e. The space required for the meter installation and the proving facility.
f. The range of operating pressures, acceptable pressure losses through the meter, and whether pressure on the liquid is adequate to prevent vaporization.
g. The operating temperature range and the applicability of automatic temperature compensation.
h. Effects of corrosive contaminants on the meter and the quantity and size of foreign matter, including abrasive particles, that may be carried in the liquid stream.
i. The types of readout and printout devices or systems to be used (see Chapter 5.4) and the standard units of volume or mass that are required.
j. The method by which a meter in a bank of meters can be put on or taken off line as the total rate changes and the method by which it can be proved at its normal operating rate.
k. The type, method, and frequency of proving (see Chapter 4).
l. The method of adjusting a meter's registration.
m. The need for accessory equipment, such as pulsers, additive injection apparatus, combinators, and devices for predetermining quantity. When meter-driven mechanical accessory devices are used, caution must be taken to limit the total torque applied to the metering element (see Chapter 5.4).
n. Automatic pressure lubrication for nonlubricating or dirty liquids.
o. Valves in the meter installation. Valves require special consideration, since their performance can affect measurement accuracy. The flow- or pressure-control valves on the main-stream meter run should be capable of rapid, smooth opening and closing to prevent shocks and surges. Other valves, particularly those between the meter or meters and the prover (for example, the stream diversion valves, drains, and vents) require leakproof shutoff, which may be provided by a double block-and-bleed valve with telltale bleed or by another similarly effective method of verifying shutoff integrity.
p. Maintenance methods and costs and spare parts that are needed.
q. Requirements and suitability for security sealing.

5.2.7 Installation

Figure 1 is a schematic diagram of a typical meter station. Meters shall be installed according to the manufacturer's instructions and shall not be subjected to undue piping strain and vibration. Flow conditioning is not required for displacement meters.

5.2.7.1 VALVES

5.2.7.1.1 If a bypass is permitted around a meter or a battery of meters, it should be provided with a blind or positive-shutoff double block-and-bleed valve with a telltale bleed.

5.2.7.1.2 In general, all valves, especially spring-loaded or self-closing valves, should be designed so that they will not admit air when they are subjected to vacuum conditions.

5.2.7.1.3 Valves for intermittent flow control should be fast acting and shock free to minimize the adverse effects of starting and stopping liquid movement.

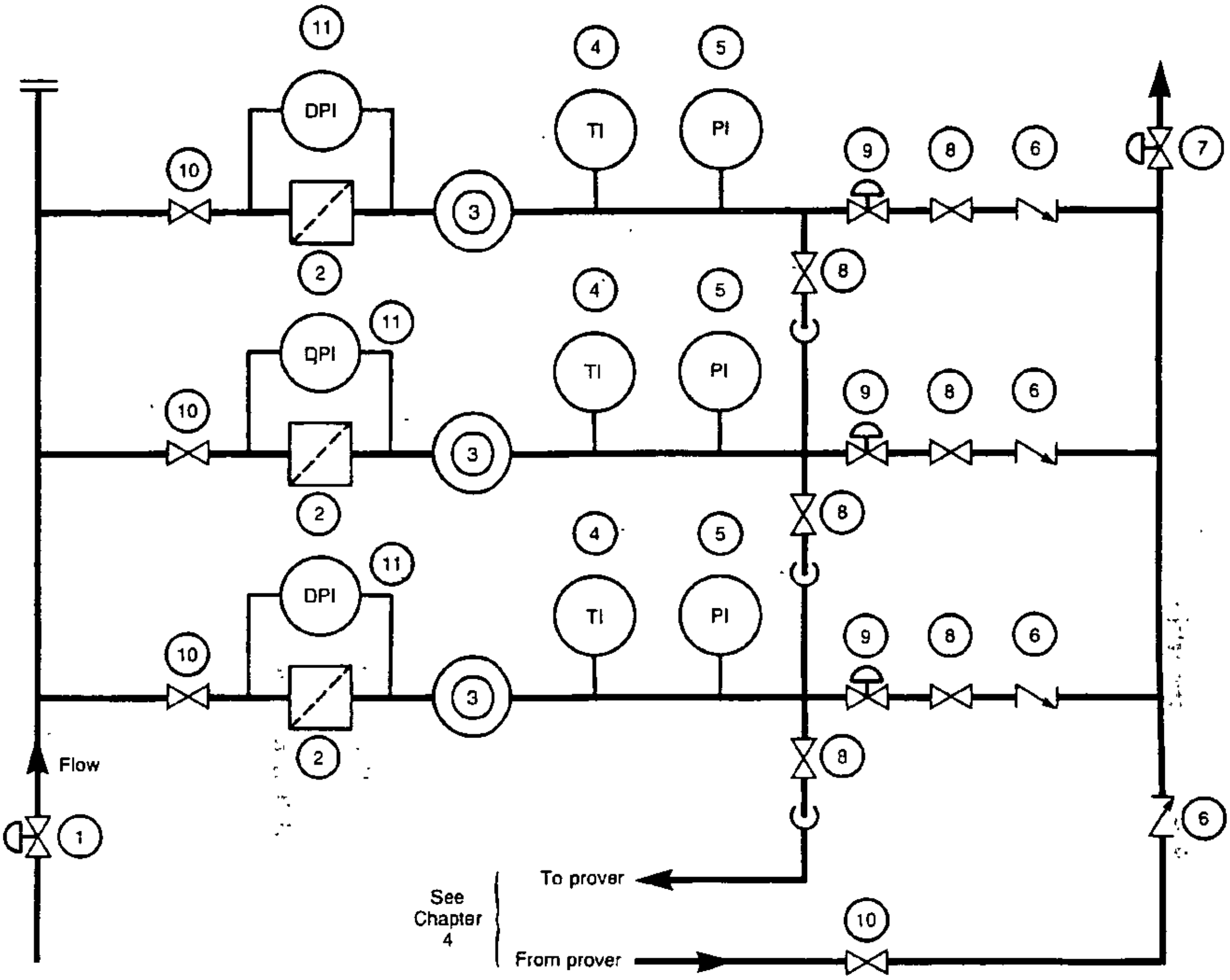
5.2.7.1.4 A flow-limiting device, such as a flow rate control valve or a restricting orifice, should preferably be installed downstream of the meter. The device should be selected or adjusted so that sufficient pressure will be maintained to prevent vaporization.

5.2.7.2 PIPING INSTALLATION

5.2.7.2.1 Meters are normally installed in a horizontal position. The manufacturer shall be consulted if space limitations dictate a different position.

5.2.7.2.2 Where the flow range is too great for any one meter or where continuous service is needed, a bank of meters may be installed in parallel. Each meter in the bank shall be operated within its minimum and maximum flow rates. A means shall be provided to balance flow through each meter.

5.2.7.2.3 Meters shall be installed so that they will have a maximum, dependable operating life. This requires that protective devices be installed to remove from the liquid abrasives or other entrained particles that could stop the metering mechanism or cause premature wear. Strainers, filters, sediment traps, settling tanks, water separators, a combination of these items, or any other suitable devices can be used. They should be properly sized and installed so that they do not adversely affect the operation of the meter. Protective devices may be installed singly or in an



1. Pressure-reducing valve—manual or automatic, if required.
2. Filter, strainer, and/or vapor eliminator (if required) for each meter or whole station.
3. Displacement meter.
4. Temperature measurement device.
5. Pressure measurement device.
6. Check valve, if required
7. Control valve, if required
8. Positive-shutoff double block-and-bleed valves.
9. Flow control valve, if required.
10. Block valve, if required.
11. Differential pressure device, if required.

Note: All sections of the line that may be blocked between valves shall have provisions for pressure relief (preferably not to be installed between the meter and the prover).

Figure 1—Typical Schematic Arrangement of Meter Station With Three Displacement Meters

interchangeable battery, depending on the importance of continuous service. Monitoring devices should be installed to determine when the protective device needs to be cleaned.

5.2.7.2.4 Meters shall be installed so that they will perform satisfactorily within the viscosity, pressure, temperature, and flow ranges that will be encountered.

5.2.7.2.5 Meters shall be adequately protected from pressure pulsations and excessive surges and from excessive pressure caused by thermal expansion of the liquid. This kind of protection may require the installation of surge tanks, expansion chambers, pressure-limiting valves, relief valves, or other protective devices. When pressure relief valves are located between the meter and the prover, a means of detecting spills from the valves shall be provided.

5.2.7.2.6 A back-pressure valve may be required to maintain the pressure on the meter and the prover above the fluid vapor pressure. In general, displacement meters do not accelerate fluid velocity and are not subject to the resulting pressure reduction that can cause vaporization (cavitation) in other types of meters.

Whenever possible, flow-limiting devices should be installed downstream of the meter and the proving system. An alarm may be desirable to signal that flow rates have fallen below the design minimum. If a pressure-reducing device is used on the inlet side of the meter, it shall be installed as far upstream of the meter as possible. The device shall be installed so that sufficient pressure will be maintained on the outlet side of the meter installation to prevent any vaporization of the metered liquid.

5.2.7.2.7 Any condition that contributes to the release of vapor from the liquid stream shall be avoided through suitable system design and through operation of the meter within the flow range specified by the manufacturer. The release of vapor can be minimized or eliminated by maintaining sufficient back pressure downstream of the meter. This can be achieved by installing the appropriate type of valve (back-pressure, throttling, or reducing) downstream of the meter.

The manufacturer's review and recommendation will be useful in determining the required back-pressure condition.

5.2.7.2.8 Each meter shall be installed so that neither air nor vapor can pass through it. If necessary, air/vapor elimination equipment shall be installed as close as possible to the upstream side of the meter. The vapor vent lines on air/vapor eliminators shall be of adequate size. The safety of the venting system should be given special design consideration. Air eliminators cannot vent when they are operating below atmospheric pressure, and under adverse conditions, they may even draw air into the system. A tight-closing check valve in the vent line will prevent air from being drawn into the system under these conditions.

5.2.7.2.9 Meters and piping shall be installed so that accidental drainage and vaporization of liquid is avoided. The piping shall have no unvented high points or pockets where air or vapor may accumulate and be carried through the meter by the added turbulence that results from increased flow rate. The installation shall prevent air from being introduced into the system through leaky valves, piping, glands of pump shafts, separators, connecting lines, and so forth.

5.2.7.2.10 Lines from the meter to the prover shall be installed to minimize the possibility of air or vapor being trapped. Manual bleed valves should be installed at high points so that air can be drawn off before proving. The distance between the meter and its prover shall be minimized. The diameter of the connecting lines shall be large enough to prevent a significant decrease in flow rate during proving. In multimeter stations, throttling valves may be installed downstream of the meters to regulate flow through the prover while each meter is being proved.

5.2.7.2.11 Piping shall be designed to prevent the loss or gain of liquid between the meter and the prover during proving.

5.2.7.2.12 Special consideration should be given to the location of each meter, its accessory equipment, and its piping manifold so that mixing of dissimilar liquids is minimized.

5.2.7.2.13 For meters designed to flow in one direction only, provision shall be made to prevent flow in the opposite direction.

5.2.7.2.14 A means of measuring temperature shall be provided to enable correction of thermal effects on the stream or meter. The capability to obtain the stream temperature inside the meter body is desirable. Some meters allow for installation of a temperature-measuring device in the meter body; however, this is impractical with many meters because of the way they are constructed or because of the type of temperature-measuring device that is selected.

If it is impractical to mount the temperature-measuring device in the meter, the device should be installed either immediately downstream or upstream of the meter. Where several meters are operated in parallel on a common stream, one temperature-measuring device in the total stream, located sufficiently close to the meter inlets or outlets, is acceptable if the stream temperatures at each meter and at the sensing location agree within the tolerance specified in Chapter 7.2. Test thermowells should be provided near each meter to verify that the stream temperatures are identical.

Refer to Chapter 7.2 for additional information.

5.2.7.2.15 To determine meter pressure, a gauge, recorder, or transmitter of suitable range and accuracy shall be installed near the inlet or outlet of each meter.

5.2.7.2.16 A heat-traced manifold that maintains a heavy hydrocarbon in a sufficiently liquid state to permit measurement by a displacement meter shall be designed to meet the following objectives:

a. An excessively high temperature cannot occur.
b. The temperature cannot fall below the level at which the viscosity of the liquid becomes too great for the displacement meter at the required flow rates.

Temperature control is especially important when the meter is not operating. The meter manufacturer should be consulted about high and low limits for viscosity and temperature.

5.2.7.3 ELECTRICAL INSTALLATIONS

Displacement-meter systems may include a variety of electrical or electronic accessories, as discussed in Chapter 5.4. The electrical systems shall be designed and installed to meet the manufacturer's recommendations and the applicable hazardous area classifications, to preclude signal and noise interference from nearby electrical equipment, and to minimize the possibility of mechanical damage to the components.

5.2.8 Meter Performance

Meter performance is defined by how well a metering system produces, or can be made to produce, accurate measurements.

5.2.8.1 METER FACTOR

Either of two methods of meter proving may be used, depending on the meter's intended application and anticipated operating conditions.

5.2.8.1.1 With the first method of proving, the meter calibrator mechanism is adjusted until the change in meter reading during a proving equals or nearly equals the volume measured in the prover.

Adjusted meters are most frequently used on retail delivery trucks and on truck and rail-car loading racks, where it is desirable to have direct-reading meters without having to apply mathematical corrections to the reading. An adjusted or direct-reading meter is correct only for the liquid and the flow conditions at which it was proved.

5.2.8.1.2 With the second method of proving, the meter calibrator mechanism is not required or is not adjusted, and a meter factor is calculated. The meter factor is a number obtained by dividing the actual volume of liquid passed through the meter during proving by the volume registered by the meter. For subsequent metering operations, the actual throughput or measured volume is determined by multiplying the volume registered by the meter by the meter factor (see Chapter 4 and Chapter 12.2).

When direct reading is not required, the use of a meter factor is preferred for several reasons. It is difficult or impossible to adjust a meter calibrator mechanism to register with the same resolution that is achieved when a meter factor is determined. In addition, adjustment generally requires one or more reprovings to confirm the accuracy of the adjustment. In applications where the meter is to be used with several different liquids or under several different sets of operating conditions, a different meter factor can be determined for each liquid and for each set of operating conditions.

For most pipelines, terminals, and marine loading and unloading facilities, meters are initially adjusted to be correct at average conditions, and the mechanisms are sealed at that setting. Meter factors are then determined for each petroleum liquid and for each set of operating conditions at which the meters are used. This method provides flexibility and maintains maximum accuracy.

5.2.8.1.3 An assessment of meter performance can best be made by monitoring a meter factor for a given petroleum liquid over an extended period of time. Chapter 13 describes methods for monitoring meter history and performance.

Similarly, meter performance for calibrated meters can be assessed by monitoring the frequency, extent, and direction of the mechanical adjustments that are necessary to maintain calibration.

5.2.8.1.4 The following variable conditions may affect the meter factor:

a. Flow rate.
b. Viscosity of the liquid.
c. Temperature of the liquid.
d. Pressure of the flowing liquid.
e. Cleanliness and lubricating qualities of the liquid.
f. Change in measuring-element clearances due to wear or damage.
g. Torque load required to drive the register, printer, and all accessory equipment.
h. Malfunctions in the proving system (see Chapter 4).

5.2.8.2 CAUSES OF VARIATIONS IN METER FACTOR

There are many factors that can change the performance of a displacement meter. Some factors, such as the entrance of foreign matter into the meter, can be remedied only by eliminating the cause of the problem. Other factors depend on the properties of the liquid being measured; these must be overcome by properly designing and operating the metering system.

The variables that have the greatest effect on the meter factor are flow rate, viscosity, temperature, and foreign matter (for example, paraffin in the liquid). If a meter is proved and operated on liquids with inherently identical properties, under the same conditions as in service, the highest level of accuracy may be expected. If there are changes in one or more of the liquid properties or in the operating conditions between the proving and the operating cycles, then a change in meter factor may result, and a new meter factor must be determined.

5.2.8.3 VARIATIONS IN FLOW RATE

Meter factor varies with flow rate. At the lower end of the range of flow rates, the meter-factor curve may become less reliable and less consistent than it is at the middle and higher rates. If a plot of meter factor versus flow rate has been developed for a given set of operating conditions, it is possible to select a meter factor from the curve; however, if a proving system is permanently installed, it is preferable to reprove the meter and apply the value determined by the reproving. If a change in total flow rate occurs in a bank of two, three, or more displacement meters installed in parallel, the usual procedure is to avoid overranging or underranging an individual meter by varying the number of meters in use, thereby distributing the total flow among a suitable number of parallel displacement meters.

5.2.8.4 VARIATIONS IN VISCOSITY

The meter factor of a displacement meter is affected by changes in viscosity that result in variable slippage. Viscosity may change as a result of changes in the liquids to be measured or as a result of changes in temperature that occur without any change in the liquid. It is therefore important to take into account the parameters that have changed before a meter factor is selected from a plot of meter factor versus viscosity. It is preferable to reprove the meter if the liquid changes or if a significant viscosity change occurs.

5.2.8.5 VARIATIONS IN TEMPERATURE

In addition to affecting the viscosity of the liquid, changes in the temperature of the liquid have other important effects on meter performance, as reflected in the meter factor. For example, the volume displaced by a cycle of movements of the measuring chambers is affected by temperature. The mechanical clearances of the displacement meter may also be affected by temperature. Higher temperatures may partially vaporize the liquid, cause two-phase flow, and severely impair measurement performance.

5.2.8.5.1 When a displacement meter is proved, the temperature of the liquid in the meter and in the prover should be the same. If the temperature is not the same, both volumes must be corrected to a volume at a base or reference temperature so that a correct meter factor can be obtained. For such corrections, the petroleum measurement tables in Chapter 11.1 should be used in accordance with Chapter 12.2.

5.2.8.5.2 Either an automatic temperature compensator or a manually calculated temperature correction based on the observed average temperature of the delivery may be used to correct registered volume to a volume at a base or reference temperature.

5.2.8.6 VARIATIONS IN PRESSURE

5.2.8.6.1 If the pressure of the liquid when it is metered varies from the pressure that existed during proving, the relative volume of the liquid will change as a result of its compressibility. The potential for error increases in proportion to the magnitude of the difference between the proving and operating conditions. For greatest accuracy, the meter should be proved at the operating conditions (see Chapter 4 and Chapter 12).

The physical dimensions of the meter will also change as a result of the expansion or contraction of its housing under pressure. The use of double-case meters prevents this problem.

5.2.8.6.2 Volumetric corrections for pressure effects on liquids that have vapor pressures above atmospheric pressure are referenced to the equilibrium vapor pressure of the liquid at a standard temperature, 60°F, 15°C, or 20°C, rather than to atmospheric pressure, which is the typical reference for liquids with measurement-temperature vapor pressures below atmospheric pressure. Both the volume of the liquid in the prover and the registered metered volume are corrected from the measurement pressure to the equivalent volumes at the equilibrium vapor pressure at 60°F, 15°C, or 20°C.

This is a two-step calculation that involves correcting both measurement volumes to the equivalent volumes at equilibrium vapor pressure at the measurement temperature. The volumes are then corrected to the equivalent volumes at the equilibrium vapor pressure at 60°F, 15°C, or 20°C. A detailed discussion of this calculation is included in Chapter 12.2.

5.2.9 Operation and Maintenance

This section covers recommended operating practices for displacement-meter installations. All operating data that pertain to measurement, including the meter-factor control charts, should be accessible to interested parties.

5.2.9.1 CONDITIONS THAT AFFECT OPERATIONS

5.2.9.1.1 The overall accuracy of measurement by displacement meter depends on the condition of the meter and its accessories, the temperature and pressure corrections, the proving system, the frequency of proving, and the variations, if any, between operating and proving conditions. A meter factor obtained for one set of conditions will not necessarily apply to a changed set of conditions.

5.2.9.1.2 Displacement meters should be operated with the manufacturer's recommended accessory equipment and within the range of flow rates specified by the manufacturer. Meters should be operated only with liquids whose properties were considered in the design of the installation.

5.2.9.1.3 If a displacement meter is to be used for bidirectional flow, meter factors shall be obtained for flow in each direction.

5.2.9.1.4 Failure to remove foreign matter upstream of a displacement meter may result in both mismeasurement and damage. Strainers, filters, or other protective devices should be placed upstream of the meter bank.

5.2.9.2 PRECAUTIONS FOR OPERATING NEWLY INSTALLED METERS

When a new meter installation is placed in service, particularly on newly installed lines, foreign matter can be carried to the metering mechanism during the initial passage of liquid. Protection should be provided from malfunction or damage by foreign matter, such as air or vapor, slag, debris, welding splatter, thread cuttings, or pipe compound. Following are suggested means of protecting the meter from foreign matter:

a. Temporarily replace the meter with a spool.
b. Put a bypass around the meter.
c. Remove the metering element.
d. Install a protective device upstream of the meter.

5.2.9.3 INSTRUCTIONS FOR OPERATING METER SYSTEMS

Definite procedures both for operating metering systems and for calculating measured quantities should be furnished to personnel at meter stations. Following is a list of items that these procedures should include, along with chapters of the API *Manual of Petroleum Measurement Standards* that can be used for reference and assistance in developing these operating guidelines:

a. A standard procedure for meter proving (Chapter 4).
b. Instructions for operating standby or spare meters.
c. Minimum and maximum meter flow rates and other operating information, such as pressure and temperature.
d. Instructions for applying pressure and temperature correction factors (Chapter 12.2).
e. A procedure for recording and reporting corrected meter volumes and other observed data.
f. A procedure for estimating the volume passed, in the event of meter failure or mismeasurement.
g. Instructions in the use of control charts and the action to be taken when the meter factor exceeds the established acceptable limits (Chapter 13).
h. Instructions regarding who should witness meter provings and repairs.
i. Instructions for reporting breaks in security seals.
j. Instructions in the use of all forms and tables necessary to record the data that support proving reports and meter tickets.
k. Instructions for routine maintenance.
l. Instructions for taking samples (Chapter 8).
m. Details of the general policy regarding frequency of meter proving and reproving when changes of flow rate or other variables affect meter accuracy (Chapters 4 and 5).
n. Procedures for operations that are not included in this list but that may be important in an individual installation.

5.2.9.4 METER PROVING

5.2.9.4.1 Each displacement meter should contain a permanent prover or connections for a portable prover or master meter to obtain and demonstrate the use of meter factors that represent current operations. The proving methods selected shall be acceptable to all parties involved (see Chapter 4).

5.2.9.4.2 The optimum frequency of proving depends on so many operating conditions that it is unwise to establish a fixed time or throughput interval for all conditions. In clean fluid service at substantially uniform rates and temperatures, meter factors tend to vary little, necessitating less frequent meter proving. More frequent proving is required with fluids that contain abrasive materials, in LP gas service where meter wear may be significant, or in any service where flow rates and/or viscosities vary substantially. Likewise, frequent changes in product types necessitate more frequent provings. In seasons of rapid ambient temperature change, meter factors vary accordingly, and proving should be more frequent. Study of the meter-factor control chart, which should include data on liquid temperature and rate, will aid determination of the optimum frequency of proving (see 5.2.9.5).

5.2.9.4.3 Provings should be frequent (every tender or every day) when a meter is initially installed. After frequent proving has shown that the meter factors for any given liquid are being reproduced within narrow limits, the frequency of proving can be reduced if the factors are under control and the overall repeatability of measurement is satisfactory to the parties involved.

5.2.9.4.4 A meter should always be proved after maintenance. If the maintenance has shifted the meter-factor values, the period of relatively frequent proving should be repeated to set up a new factor data base by which meter performance can be monitored. When the values have stabilized, the frequency of proving can again be reduced.

5.2.9.5 METHODS OF CONTROLLING METER FACTORS

5.2.9.5.1 Meter factors can be controlled with a suitable statistical control method. Chapter 13.2 addresses meter measurement control methods and other methods of analysis that use historical comparison of meter-factor data to monitor meter performance.

5.2.9.5.2 Meter-factor control charts are essentially plots of successive meter-factor values along the abscissa at the appropriate ordinate value, with parallel abscissae representing $\overline{X} \pm 1\sigma$, $\overline{X} \pm 2\sigma$, and $\overline{X} \pm 3\sigma$, where $\overline{X}$ is the arithmetic mean meter-factor value and σ is the standard deviation or other tolerance-level criterion (for example, ± 0.0025 or ± 0.0050). A control chart can be maintained for each displacement meter in each product or grade of crude at a specified rate or range of rates for which the meter is to be used.

5.2.9.5.3 Meter-factor control methods can be used to provide a warning of measurement trouble and to show when and to what extent results may have deviated from accepted norms. The methods can be used to detect trouble, but they will not define the nature of the trouble. When trouble is encountered or suspected, the measurement system should be systematically checked. The following problems commonly occur in displacement-meter systems:

a. The physical properties of the liquid change.
b. The moving parts or bearing surfaces of the displacement meter become worn or fouled with foreign matter.
c. Isolation and diversion valves leak.
d. The proving system and its components require maintenance (see Chapter 4).
e. Air becomes trapped somewhere in the manifolding. (This possibility must be remedied by either procedure or equipment).
f. The gear train components, above or below the proving pickup, malfunction.
g. The calibration of pressure-, temperature-, and density-sensing devices has to be checked.
h. When a tank prover is used, the act of opening and closing the diversion valve is unduly slow. (Opening and closing should be smooth and rapid).

5.2.9.6 METER MAINTENANCE

5.2.9.6.1 For maintenance purposes, a distinction should be made between parts of the system that can be checked by operating personnel (parts such as pressure gauges and mercury thermometers) and more complex components that may require the services of technical personnel. Displacement meters and associated equipment can normally be expected to perform well for long periods. Indiscriminate adjustment of the more complex parts and disassembly of equipment is neither necessary nor recommended. The manufacturer's standard maintenance instructions should be followed.

5.2.9.6.2 Meters stored for a long period shall be kept under cover and shall have protection to minimize corrosion.

5.2.9.6.3 Establishing a definite schedule for meter maintenance is difficult, in terms of both time and throughput, because of the many different sizes, services, and liquids measured. Scheduling repair or inspection of a displacement meter may best be accomplished by monitoring the meter-factor history for each product or grade of crude oil. Small random changes in meter factor will naturally occur in normal operation, but if the value of these changes exceeds the established deviation limits of the control method, the cause of the change should be investigated, and any necessary maintenance should be provided. Using deviation limits to determine acceptable normal variation strikes a balance between looking for trouble that does not exist and not looking for trouble that does exist.

Manual of Petroleum Measurement Standards Chapter 5—Liquid Metering

Section 3—Measurement of Liquid Hydrocarbons by Turbine Meters

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Chapter 5—Liquid Metering

SECTION 3—MEASURING LIQUID HYRDROCARBONS BY TURBINE METERS

5.3.1 Introduction

Chapter 5.3 is intended to describe methods of obtaining accurate measurements and maximum service life when turbine meters are used to measure liquid hydrocarbons.

A turbine meter is a flow-measuring device with a rotor that senses the velocity of flowing liquid in a closed conduit (see Figure 1). The flowing liquid causes the rotor to move with a tangential velocity that is proportional to volumetric flow rate. The movement of the rotor can be detected mechanically, optically, or electrically and is registered on a readout. The actual volume that passes the meter and is registered on a readout is determined by proving against a known volume, as discussed in Chapter 4.

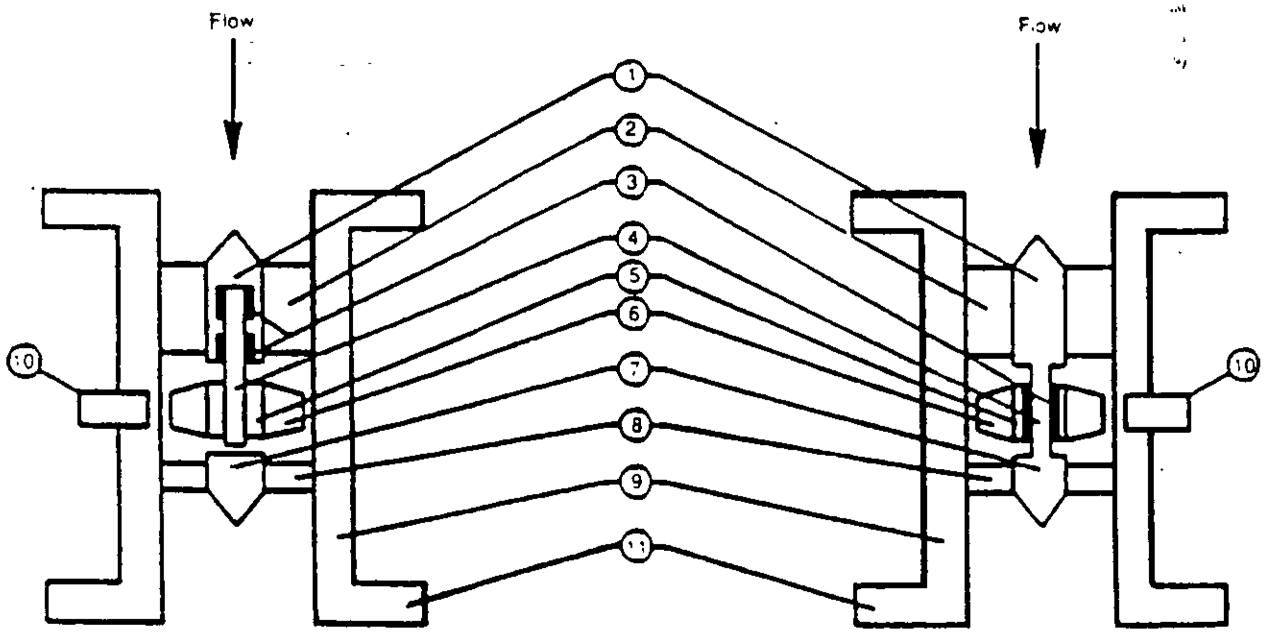
It is recognized that meters other than the types described in this chapter are used to meter liquid hydrocarbons. This publication does not endorse or advocate the preferential use of turbine meters, nor does it intend to restrict the development of other types of meters. Those who use other types of meters may find sections of this chapter useful.

5.3.2 Scope

This section of Chapter 5 defines the application criteria for turbine meters and discusses appropriate considerations regarding the liquids to be measured, the installation of a turbine metering system, and the performance, operation, and maintenance of turbine meters in liquid-hydrocarbon service.

5.3.3 Field of Application

The field of application of this section is all segments of the petroleum industry in which dynamic measurement of liquid hydrocarbons is required. This section does not apply to the measurement of two-phase fluids.



1. Upstream stator.
2. Upstream stator supports
3. Bearings
4. Shaft
5. Rotor hub
6. Rotor blade
7. Downstream stator
8. Downstream stator supports
9. Meter housing
10. Pickup
11. End connections

Figure 1—Names of Typical Turbine-Meter Parts

5.3.4 Referenced Publications

The current editions of the following standards, codes, and specifications are cited in this chapter:

API

Manual of Petroleum Measurement Standards

Chapter 4, "Proving Systems"
Chapter 5, "Metering"
Chapter 5.4, "Instrumentation or Accessory Equipment for Liquid Hydrocarbon Metering Systems"
Chapter 5.5, "Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems"
Chapter 7.2, "Dynamic Temperature Determination"
Chapter 8, "Sampling"
Chapter 11, "Physical Properties Data"
Chapter 12, "Calculation of Petroleum Quantities"
Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"
Chapter 13, "Statistical Aspects of Measuring and Sampling"
Chapter 13.2, "Meter Factor Control Charts" (in press)
Chapter 14.3, "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids" (AGA[1] Report No. 3)

5.3.5 Design Considerations

The design of turbine-meter installations should take into account the following considerations.

a. The installation should be able to handle the maximum and minimum flow rates, the maximum operating pressure, and the temperature range and type of liquid to be measured. If necessary, the installation should include protective devices that keep the operation of the meter within design limits.

b. The installation should ensure a maximum, dependable operating life. Strainers, filters, air/vapor eliminators, or other protective devices may be provided upstream of the meter to remove solids that could cause premature wear or gases that could cause measurement error.

c. The installation should ensure adequate pressure on the liquid in the metering system at all temperatures so that the fluid being measured will be in the liquid state at all times.

d. The installation should provide for proving each meter and should be capable of duplicating normal operating conditions at the time of proving.

e. The installation should ensure appropriate flow conditioning both upstream and downstream of the meter or meters.

f. The installation should comply with all applicable regulations and codes.

5.3.6 Selecting a Meter and Accessory Equipment

Chapter 5.4 provides guidelines for selecting the appropriate equipment. In addition, the manufacturer should be consulted, and detailed consideration should be given to the following items:

a. The properties of the metered liquids, including viscosity, density, vapor pressure, corrosiveness, and lubricating ability.

b. The operating flow rates and whether flow is unidirectional or bidirectional, continuous, intermittent, or fluctuating.

c. The performance characteristics that are required for the application (see Figure 2).

d. The range of operating pressures, acceptable pressure losses through the meter, and whether pressure on the liquid is adequate to prevent vaporization.

e. The operating temperature range and the applicability of automatic temperature compensation.

f. The space required for the meter installation and the proving facility (see Figure 3).

g. Effects of corrosive contaminants on the meter and the quantity and size of foreign matter, including abrasive particles, that may be carried in the liquid stream.

h. The types of readout and printout devices to be used, signal preamplification (see Chapter 5.4), and the standard units of volume or mass that are required.

i. The compatibility of meter readout equipment and flow rate indicators and the method of adjusting meter registration, if applicable (see Chapter 5.4).

j. The class and type of pipe connections and materials and the dimensions of the equipment to be used.

k. The method by which a meter in a bank of meters can be put on or taken off line as the total rate changes and the method by which it can be proved at its normal operating rate.

l. Power supply requirements for continuous or intermittent meter readout (see Chapter 5.4).

m. Electrical code requirements.

n. The type, method, and frequency of proving (see Chapter 4).

[1] American Gas Association, 1515 Wilson Boulevard, Arlington, Virginia 22209.

o. Maintenance methods and costs and spare parts that are needed

p. The fidelity and security of pulse-data transmission systems (see Chapter 5.5).

5.3.7 Installation

Details for the installation of turbine meters are provided in 5.3.7.1 through 5.3.7.4. Figure 3 is a typical schematic diagram for a turbine-meter system with unidirectional flow.

5.3.7.1 FLOW CONDITIONING

5.3.7.1.1 The performance of turbine meters is affected by liquid swirl and nonuniform velocity profiles that are induced by upstream and downstream piping configurations, valves, pumps, joint misalignment, protruding gaskets, welding projections, or other obstructions. Flow conditioning shall be used to overcome swirl and nonuniform velocity profiles

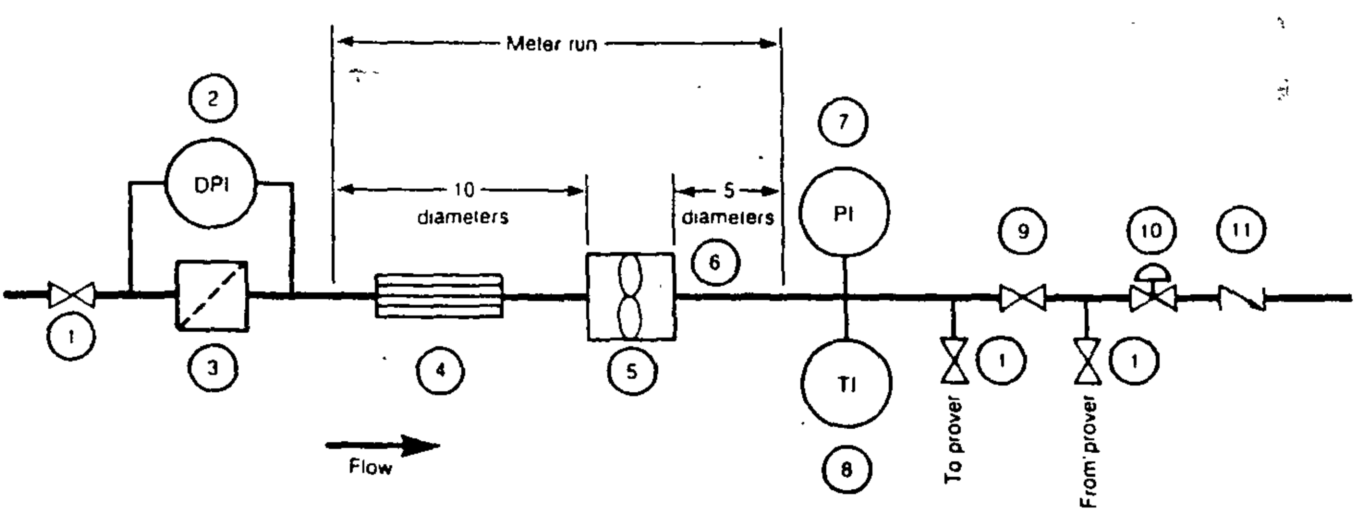
5.3.7.1.2 Flow conditioning requires the use of sufficient lengths of straight pipe or a combination of straight pipe and straightening elements that are inserted in the meter run upstream (and sometimes downstream) of the turbine meter (see Figure 4).

5.3.7.1.3 When only straight pipe is used, the liquid shear, or internal friction between the liquid and the pipe wall, shall be sufficient to accomplish the required flow conditioning. Appendix A should be referred to for guidance in applying the technique. Experience has shown that in many installations, pipe lengths of 20 meter-bore diameters upstream of the meter and 5 meter-bore diameters downstream of the meter provide effective conditioning.

5.3.7.1.4 A straightening element usually consists of a cluster of tubes, vanes, or equivalent devices that are inserted longitudinally in a section of straight pipe (see Figure 4). Straightening elements effectively assist flow conditioning by eliminating liquid swirl. Straightening elements may also consist of a series of perforated plates or wire-mesh screens, but these forms normally cause a larger pressure drop than do tubes or vanes.

5.3.7.1.5 Proper design and construction of the straightening element is important to ensure that swirl is not generated, since swirl negates the function of the flow conditioner. The following guidelines are recommended to avoid the generation of swirl:

a. The cross-section should be as uniform and symmetrical as possible.



1 Block valve, if required
2 Differential pressure device, if required
3 Filter, strainer, and/or vapor eliminator (if required) for each meter or whole station
4 Straightener assembly per Figure 4
5 Turbine meter
6 Straight pipe
7 Pressure measurement device
8 Temperature measurement device
9 Positive shutoff double block-and-bleed valve
10. Control valve, if required
11 Check valve, if required

Note: All sections of line that may be blocked between valves should have provisions for pressure relief (preferably not installed between the meter and the prover)

Figure 3—Schematic Diagram of a Turbine Meter

b. The design and construction should be rugged enough to resist distortion or movement at high flow rates.
c. The general internal construction should be clean and free from welding protrusions and other obstructions.

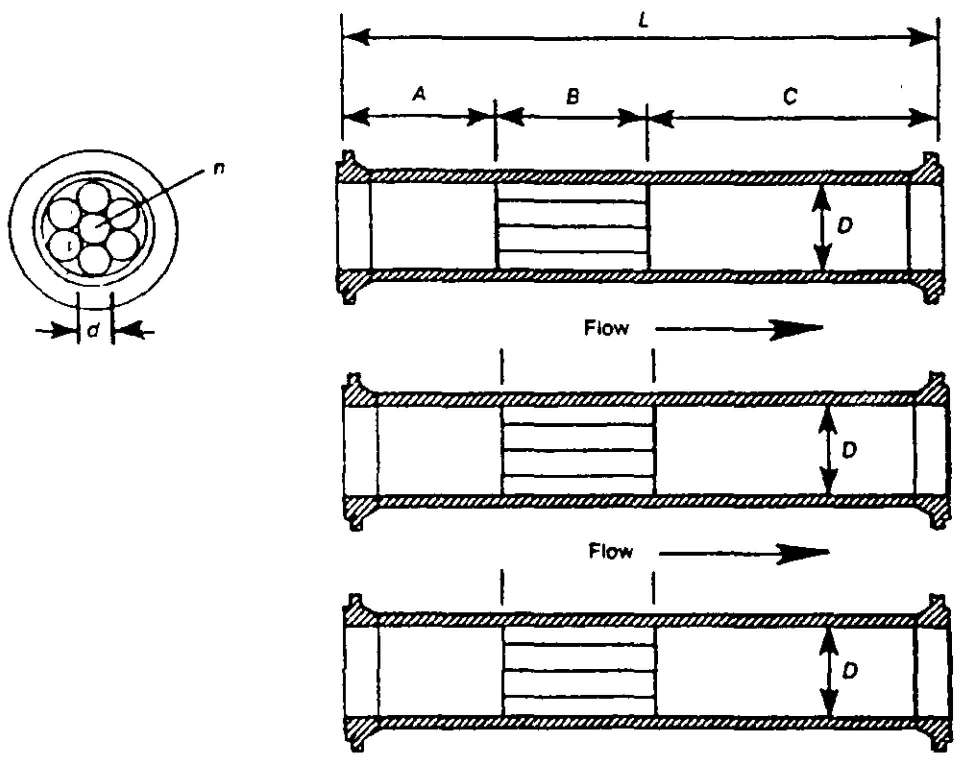
5.3.7.1.6 Flow-straightening sections shall be used, and there shall be ample distance between the meter run and any pumps, elbows, valves, or other fittings that may induce swirl or a nonuniform velocity profile. Flanges and gaskets shall be internally aligned, and gaskets shall not protrude into the liquid stream. Meter flanges shall be doweled or matched by some method to ensure that the straightening sections and the meter are properly aligned during and after assembly.

5.3.7.2 VALVES

5.3.7.2.1 The valves in a turbine-meter installation require special consideration, since their performance can affect measurement accuracy. The flow- or pressure-control valves on the main-stream meter run should be capable of rapid, smooth opening and closing to prevent shocks and surges. Other valves, particularly those between the meter or meters and the prover (for example, the stream diversion valves, drains, and vents) require leakproof shutoff, which may be provided by a double block-and-bleed valve with telltale bleed or by another similarly effective method of verifying shutoff integrity.

5.3.7.2.2 If a bypass is permitted around a meter or a battery of meters, it shall be provided with a blind or a positive shutoff double block-and-bleed valve with telltale bleed.

5.3.7.2.3 All valves, especially spring-loaded or self-closing valves, shall be designed so that they will not admit air when they are subjected to vacuum conditions.



Note. This figure shows assemblies installed upstream of the meter. Downstream of the meter, 5D minimum of straight pipe should be used.

L = overall length of straightener assembly ($\geq 10D$)
A = length of upstream plenum ($2D$–$3D$)
B = length of tube or vane-type straightening element ($2D$–$3D$)
C = length of downstream plenum ($\geq 5D$)
D = nominal diameter of meter.
n = number of individual tubes or vanes (≥ 4)
d = nominal diameter of individual tubes ($B/d \geq 10$)

Figure 4—Examples of Flow-Conditioning Assemblies With Straightening Elements

5.3.7.2.4 Valves for intermittent flow control should be fast acting and shock free to minimize the adverse effects of starting and stopping liquid movement.

5.3.7.3 PIPING INSTALLATION

5.3.7.3.1 Figure 3 is a schematic diagram that provides a working basis for the design of a turbine-meter assembly and its related equipment. Certain items may or may not be required for a particular installation; others may be added if necessary.

5.3.7.3.2 Turbine meters are normally installed in a horizontal position. The manufacturer shall be consulted if space limitations dictate a different position.

5.3.7.3.3 Where the flow range is too great for any one meter or its prover, a bank of meters may be installed in parallel. Each meter in the bank shall operate within its minimum and maximum flow rates. A means shall be provided to balance flow through each meter.

5.3.7.3.4 Meters shall be installed so that they will not be subjected to undue stress, strain, or vibration. Provision shall be made to minimize meter distortion caused by piping expansion and contraction.

5.3.7.3.5 Measurement systems shall be installed so that they will have a maximum, dependable operating life. This requires that in certain services protective devices be installed to remove from the liquid abrasives or other entrained particles that could stop the metering mechanism or cause premature wear. If strainers, filters, sediment traps, settling tanks, water separators, a combination of these items, or any other suitable devices are required, they shall be sized and installed to prevent flash vaporization of the liquid before it passes through the meter. Protective devices may be installed singly or in an interchangeable battery, depending on the importance of continuous service. In services where the liquid is clean or the installed meter does not require or warrant protection, omission of protective devices may be acceptable. Monitoring devices should be installed to determine when the protective device needs to be cleaned.

5.3.7.3.6 Measurement systems shall be installed and operated so that they provide satisfactory performance within the viscosity, pressure, temperature, and flow ranges that will be encountered.

5.3.7.3.7 Meters shall be adequately protected from pressure pulsations and excessive surges and from excessive pressure caused by thermal expansion of the liquid. This kind of protection may require the installation of surge tanks, expansion chambers, pressure-limiting valves, pressure relief valves, and/or other protective devices. When pressure relief valves or pressure-limiting valves are located between the meter and the prover, a means of detecting spills from the valves shall be provided.

5.3.7.3.8 Conditions that contribute to vaporization of the liquid stream shall be avoided through suitable system design and through operation of the meter within the flow range specified by the manufacturer. Vaporization can be minimized or eliminated by maintaining sufficient back pressure in and immediately downstream of the meter. This is generally accomplished by placing a back-pressure valve downstream of the meter to maintain pressure on the meter and the prover above the vapor pressure of the liquid. In some operations, the normal system pressure may be high enough to prevent vaporization without the use of a back-pressure valve.

For low-vapor-pressure liquids, the numerical value of the minimum back pressure should be calculated as follows.

$$P_b = 2\Delta p + 1.25p_v$$

Where,

P_b = minimum back pressure, in pounds per square inch gauge.

Δp = pressure drop across the meter at the maximum rate of flow, in pounds per square inch.

p_v = absolute vapor pressure at the maximum operating temperature, in pounds per square inch absolute.

With high-vapor-pressure liquids, it may be possible to reduce the coefficient of 1.25 to some other practical and operable margin. In either case, the recommendations of the meter manufacturer should be considered (see Figure 5).

5.3.7.3.9 When a flow-limiting device or a restricting orifice is required, it should be installed downstream of the meter run. An alarm may be desirable to signal that flow rates have fallen below the design minimum. If a flow-limiting or other pressure-reducing device is installed on the inlet side of the meter, it shall be installed as far as possible upstream of the meter run and shall maintain enough pressure on the outlet side of the meter run to prevent any vaporization of the metered liquid.

5.3.7.3.10 Each meter shall be installed so that neither air nor vapor can pass through it. If necessary, air/vapor elimination equipment shall be installed upstream of the meter. The equipment shall be installed as close to the meter as is consistent with good practice, but it must not be so close that it creates swirl or a distorted velocity profile at the entry to the meter. Any vapors shall be vented in a safe manner.

5.3.7.3.11 Meters and piping shall be installed so that accidental drainage or vaporization of liquid is avoided. The piping shall have no unvented high points or pockets where air or vapor could accumulate and be carried through the meter by the added turbulence that results from increased flow rate. The installation shall prevent air from being introduced into the system through leaky valves, piping, glands of pump shafts, separators, connnecting lines, and so forth.

5.3.7.3.12 Lines from the meter to the prover shall be installed to minimize the possibility of air or vapor being trapped. Manual bleed valves should be installed at high points so that air can be drawn off before proving. The distance between the meter and its prover shall be minimized. The diameter of the connecting lines shall be large enough to prevent a significant decrease in flow rate during proving. Flow-rate control valves may be required downstream of each meter, particularly in multimeter installations, to keep the proving flow rate equal to the normal operating rate for each meter.

5.3.7.3.13 Piping shall be designed to prevent the loss or gain of liquid between the meter and the prover during proving.

5.3.7.3.14 Special consideration should be given to the location of each meter, its accessory equipment, and its piping manifold so that mixing of dissimilar liquids is minimized.

5.3.7.3.15 Most turbine meters will register flow in both directions, but seldom with identical meter factors. If flow must be restricted to a single direction because of meter design, flow in the opposite direction shall be prevented.

5.3.7.3.16 A thermometer, or a thermometer well that permits the use of a temperature-measuring device, shall be installed in or near the inlet or outlet of a meter run so that metered stream temperatures can be determined. The device shall not be installed upstream within the flow-conditioning sections or downstream closer than the manufacturer's recommended position. If temperature compensators are used, a suitable means of checking the operation of the compensators is required. Refer to Chapter 7.2 for additional information.

5.3.7.3.17 To determine meter pressure, a gauge, recorder, or transmitter of suitable range and accuracy shall be installed near the inlet or outlet of each meter.

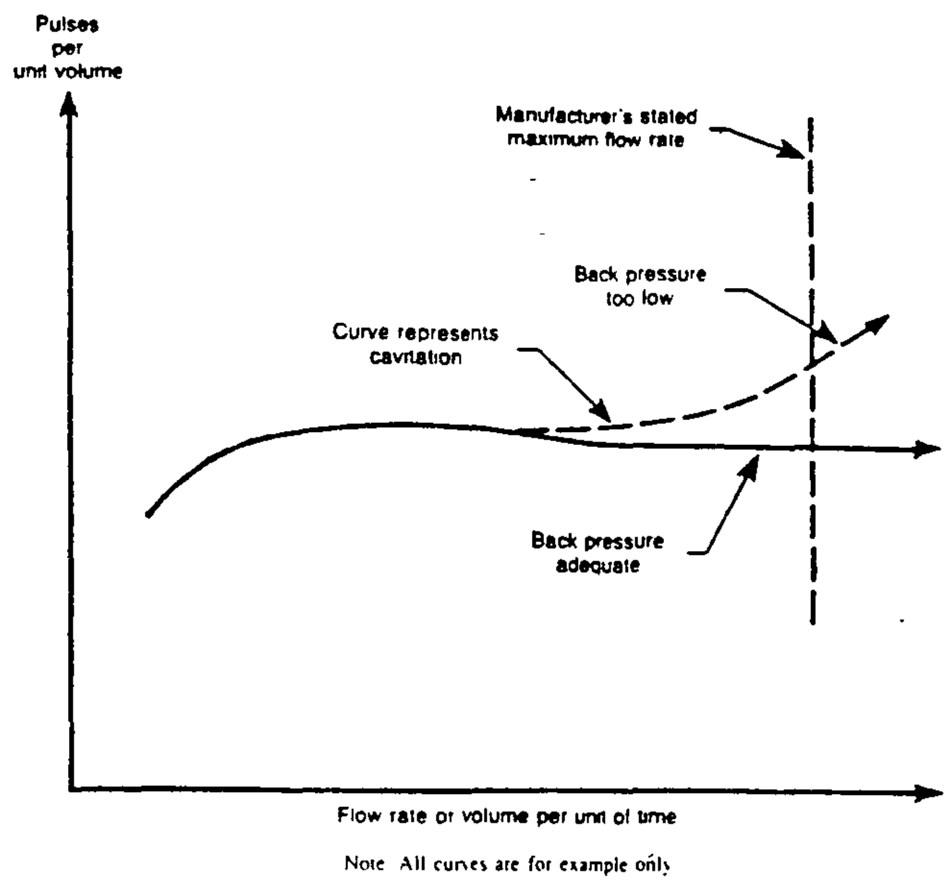


Figure 5—Effects of Cavitation on Rotor Speed

5.3.7.4 ELECTRICAL INSTALLATIONS

Turbine meters usually include a variety of electrical or electronic accessories, as discussed in Chapter 5.4. The electrical systems shall be designed and installed to meet the manufacturer's recommendations and the applicable hazardous area classifications and to minimize the possibility of mechanical damage to the components. Since turbine meters usually provide electrical signals at a relatively low power level, care must be taken to avoid signal and noise interference from nearby electrical equipment (see Appendix B).

5.3.8 Meter Performance

Meter performance is defined by how well a metering system produces, or can be made to produce, accurate measurements.

5.3.8.1 METER FACTOR

Meter factors shall be determined by proving the meter under conditions of rate, viscosity, temperature, density, and pressure similar to those that exist during intended operation.

Meter performance curves can be developed from a set of proving results. The curve in Figure 2 is called a linearity curve.

The following conditions may affect the meter factor:

a. Flow rate.
b. Viscosity of the liquid.
c. Temperature of the liquid.
d. Density of the liquid.
e. Pressure of the flowing liquid.
f. Cleanliness and lubricating qualities of the liquid.
g. Foreign material lodged in the meter or flow-conditioning element.
h. Changes in mechanical clearances or blade geometry due to wear or damage.
i. Changes in piping, valves, or valve positions that affect fluid profile or swirl
j. Conditions of the prover (see Chapter 4)

5.3.8.2 CAUSES OF VARIATIONS IN METER FACTOR

Many factors can change the performance of a turbine meter. Some factors, such as the entrance of foreign matter into the meter, can be remedied only by eliminating the cause. Other factors, such as the buildup of deposits in the meter, depend on the characteristics of the liquid being measured, these factors must be overcome by properly designing and operating the meter system.

The variables that have the greatest effect on the meter factor are flow rate, viscosity, temperature, and foreign matter (for example, paraffin in the liquid). If a meter is proved and operated on liquids with inherently identical properties, and operating conditions such as flow rate remain similar, the highest level of accuracy can be anticipated. If there are changes in one or more of the liquid properties or in the operating conditions between the proving and the operating cycles, a change in meter factor may result, and a new meter factor must be determined.

5.3.8.3 VARIATIONS IN FLOW RATE

At the low end of the range of flow rates, the meter-factor curve may become less linear and less repeatable than it is at the medium and higher rates (see Figure 2, Applications A and B). If a plot of meter factor versus flow rate has been developed for a particular liquid and other variables are constant, a meter factor may be selected from the plot for flow rates within the meter's working range; however, for greatest accuracy, the meter should be reproved at the new operating flow rate.

5.3.8.4 VARIATIONS IN VISCOSITY

Turbine meters are sensitive to variations in viscosity Since the viscosity of liquid hydrocarbons changes with temperature, the response of a turbine meter depends on both viscosity and temperature. High-density liquid hydrocarbons typically present the greatest problem. The viscosity of light hydrocarbons such as gasolines essentially remains the same over wide temperature changes, and the meter factor remains relatively stable. In heavier, more viscous hydrocarbons such as crude oils, the change in meter factor can be significant because of the viscosity changes associated with relatively narrow temperature changes. It is advisable to reprove the meter under conditions that closely approximate normal operating conditions.

5.3.8.5 VARIATIONS IN TEMPERATURE

In addition to affecting changes in viscosity, significant variations in the temperature of the liquid can also affect meter performance by causing changes in the physical dimensions of the meter and in the apparent volume measured by the meter as a result of thermal expansion or contraction of the liquid. The tables and formulas in Chapter 11 may be used to calculate the extent of liquid expansion or contraction. For greatest accuracy, the meter should be proved in the range of normal operating conditions

5.3.8.6 VARIATIONS IN DENSITY

A change in the density of the metered liquid can result in significant differences in meter factor in the lower flow ranges, thereby requiring the meter to be proved.

For liquids with a relative density of approximately 0.7 or less, consideration must be given to raising the value of the meter's minimum flow rate to maintain linearity. The amount of increase in lower flow rates will vary depending on meter size and type. To establish the minimum flow rate, several provings should be made at different rates until a meter factor that yields an acceptable linearity and repeatability can be determined.

5.3.8.7 VARIATIONS IN PRESSURE

If the pressure of the liquid when it is metered varies from the pressure that existed during proving, the relative volume of the liquid will change as a result of its compressibility. (The physical dimensions of the meter will also change as a result of the expansion or contraction of its housing under pressure.) The potential for error increases in proportion to the difference between the proving and operating conditions. For greatest accuracy, the meter should be proved at the operating conditions (see Chapter 4 and Chapter 12).

Volumetric corrections for the pressure effects on liquids with vapor pressures above atmospheric pressure are referenced to the equilibrium vapor pressure of the liquid at the standard temperature, 60°F, 15°C, or 20°C, rather than to atmospheric pressure, which is the typical reference for liquids with measurement-temperature vapor pressures below atmospheric pressure. Both the volume of the liquid in the prover and the registered metered volume are corrected from the measurement pressure to the equivalent volumes at the equilibrium vapor presssure at the standard temperature, 60°F, 15°C, or 20°C.

This is a two-step calculation that involves correcting both measurement volumes to the equivalent volumes at equilibrium vapor pressure at measurement temperature. The volumes are then corrected to the equivalent volumes at the equilibrium vapor pressure at the standard temperature, 60°F, 15°C, or 20°C. A detailed discussion of this calculation is included in Chapter 12.2.

5.3.9 Operation and Maintenance

This section covers recommended operating and maintenance practices for turbine meters. All operating data pertaining to measurement, including the meter-factor control charts, should be accessible to interested parties.

5.3.9.1 CONDITIONS THAT AFFECT OPERATION

5.3.9.1.1 The overall accuracy of measurement by turbine meter depends on the condition of the meter and its accessories, the temperature and pressure corrections, the proving system, the frequency of proving, and the variations, if any, between operating and proving conditions. A meter factor obtained for one set of conditions will not necessarily apply to a changed set of conditions.

5.3.9.1.2 Turbine meters should be operated within the specified flow range and operating conditions that produce the desired linearity of registration (see Figure 2). They should be operated with the equipment recommended by the manufacturer, and only with liquids whose properties were considered in the design of the installation.

5.3.9.1.3 If a bidirectional turbine meter is used to measure flow in both directions, meter factors shall be obtained for each direction of flow. The meter factors can be determined by a prover that has proper manifolding and the required protective equipment and flow conditioning located both upstream and downstream of the meter.

5.3.9.1.4 Failure to remove foreign matter upstream of a turbine meter and its flow-conditioning system may result in meter damage or mismeasurement. Precautions should be taken to prevent the accumulation of foreign material, such as vegetation, fibrous materials, hydrates, and ice, in the turbine-meter run.

5.3.9.2 PRECAUTIONS FOR OPERATING NEWLY INSTALLED METERS

When a new meter installation is placed in service, particularly on newly installed lines, foreign matter can be carried to the metering mechanism during the initial passage of liquid. Protection should be provided from malfunction or damage caused by foreign matter, such as slag, debris, welding spatter, thread cuttings, and pipe compound. Following are suggested means for protecting the meter from foreign matter:

a. Temporarily replace the meter with a spool.
b. Put a bypass around the meter.
c. Remove the metering element.
d. Install a protective device upstream of the meter.

5.3.9.3 INSTRUCTIONS FOR OPERATING METER SYSTEMS

Definite procedures both for operating metering systems and for calculating measured quantities should be furnished to personnel at meter stations. Following is a list of items that these procedures should include, along with chapters of the API *Manual of Petroleum Measurement Standards* that can be used for reference and assistance in developing these operating guidelines:

a. A standard procedure for meter proving (Chapter 4).
b. Instructions for operating standby or spare meters.
c. Minimum and maximum meter flow rates and other operating conditions, such as pressure and temperature.
d. Instructions for applying pressure and temperature correction factors (Chapter 12.2).
e. A procedure for recording and reporting corrected meter volumes and other observed data.
f. A procedure for estimating the volume passed, in the event of meter failure or mismeasurement.
g. Instructions in the use of control methods and the action to be taken when the meter factor exceeds the established acceptable limits (Chapter 13).
h. Instructions regarding who should witness meter provings and repairs.
i Instructions for reporting breaks in any security seals.
j. Instructions in the use of all forms and tables necessary to record the data that support proving reports and meter tickets.
k. Instructions for routine maintenance.
l. Instructions for taking samples (Chapter 8).
m. Details of the general policy regarding frequency of meter proving and reproving when changes in flow rate or other variables affect meter accuracy (Chapters 4 and 5).
n. Procedures for operations that are not included in this list but that may be important in an individual installation.

5.3.9.4 METER PROVING

5.3.9.4.1 Each turbine-meter installation should contain a permanent prover or connections for a portable prover or master meter. The selection of proving methods shall be acceptable to all parties involved (see Chapter 4).

5.3.9.4.2 The optimum frequency of proving depends on so many operating conditions that it is unwise to establish a fixed time or throughput interval for all conditions. In clean liquid service at substantially uniform rates and temperatures, meter factors tend to vary little, necessitating less frequent meter proving. More frequent proving is required with liquids that contain abrasive materials, in LP gas service where meter wear may be significant, or in any service where flow rates and/or viscosities vary substantially. Likewise, frequent changes in the type of product necessitate more frequent provings In seasons of rapid ambient temperature change, meter factors vary accordingly, and proving should be more frequent. Studying the meter-factor control chart or other historical performance data that include information on liquid temperature and flow rate will aid determination of the optimum frequency of proving (see 5.3.9.5).

5.3.9.4.3 Provings should be frequent (every tender or every day) when a meter is initially installed. After frequent proving has shown that meter-factor values for any given liquid are being reproduced within narrow limits, the frequency of proving can be reduced if the factors are under control and the overall repeatability of measurement is satisfactory to the parties involved.

5.3.9.4.4 A meter should always be proved after maintenance. If the maintenance has shifted the meter-factor values, the period of relatively frequent proving should be repeated to set up a new data base by which meter performance can be monitored. When the values have stabilized, the frequency of proving can again be reduced.

5.3.9.5 METHODS OF CONTROLLING METER FACTOR

5.3.9.5.1 Meter factors can be controlled with a suitable statistical control method. Chapter 13.2 addresses meter measurement control methods and other methods of analysis that use historical comparison of meter-factor data to monitor meter performance.

5.3.9.5.2 Meter-factor control charts are plots of successive meter-factor values along the abscissa at the appropriate ordinate value, with parallel abscissae representing $\bar{X} \pm 1\sigma$, $\bar{X} \pm 2\sigma$, and $\bar{X} \pm 3\sigma$, in which $\bar{X}$ is the arithmetic mean or average meter-factor value and σ is the standard deviation or other tolerance level criterion (for example, ± 0.0025 or ± 0.0050). A control chart can be maintained for each turbine meter in each product or grade of crude at a specified rate or range of rates for which the meter is to be used.

5.3.9.5.3 Meter-factor control methods can be used to provide a warning of measurement trouble and to show when and to what extent results may have deviated from accepted norms. The methods can be used to detect trouble, but they will not define the nature of the trouble. When trouble is encountered or suspected, the following components of the measurement system should be systematically checked (not necessarily in the following order):

a. The liquid and its physical properties.
b. The moving parts and bearing surfaces of the turbine meter.
c. Isolation and diversion valves.
d. Detector switches in the prover and appurtenances of the tank prover.
e. The displacer in the prover.
f. Other parts of the meter and meter run.
g. Pressure-, temperature-, and density-sensing devices.
h. Pulse counters, preamplifiers, signal transmission system, power supply, pickup coils, and all readout devices.

i. Strainers, filters, air eliminators, water removal equipment, and flow conditioners.

j. The operating conditions of the meter system and the prover, when they differ from design conditions.

5.3.9.6 METER MAINTENANCE

5.3.9.6.1 For maintenance purposes, a distinction should be made between parts of the system that can be checked by operating personnel (parts such as pressure gauges and mercury thermometers) and more complex components that may require the services of technical personnel. Turbine meters and associated equipment can normally be expected to perform well for long periods. Indiscriminate adjustment of the more complex parts and disassembly of equipment are neither necessary nor recommended. The manufacturer's standard maintenance instructions should be followed.

5.3.9.6.2 Meters stored for a long period shall be kept under cover and shall have protection to minimize corrosion.

5.3.9.6.3 Establishing a definite schedule for meter maintenance is difficult, in terms of both time and throughput, because of the many different sizes, services, and liquids measured. Scheduling repair or inspection of a turbine meter can best be accomplished by monitoring the meter-factor history for each product or grade of crude oil (see Chapter 13). Small random changes in meter factor will naturally occur in normal operation, but if the value of these changes exceeds the established deviation limits, the cause of the change should be investigated, and any necessary maintenance should be provided. Using deviation limits to determine acceptable normal variation strikes a balance between looking for trouble that does not exist and not looking for trouble that does exist.

APPENDIX A—FLOW-CONDITIONING TECHNOLOGY WITHOUT STRAIGHTENING ELEMENTS

A.1 Scope

Effective flow conditioning can be obtained by using adequate lengths of straight pipe upstream and downstream of the meter. Appendix A presents an empirical method for computing the length of upstream straight pipe required for various installation configurations and operating conditions.

Experience has shown that a nominal length of 20 diameters of meter-bore piping upstream of the meter and 5 diameters of meter-bore piping downstream of the meter provide effective conditioning in many installations, however, the required length of upstream piping should be verified for each installation using the method presented in this appendix. This technique does not predict the length of straight pipe required downstream of the meter. A minimum of 5 diameters of meter-bore piping should be provided downstream of the meter unless a different length is supported by the manufacturer's recommendations or tests.

A.2 Calculation of Upstream Flow-Conditioning Length

Based on empirical data, the length of straight pipe required upstream of the meter can be calculated as follows

$$L = (0.35D)\,(K_s/f)$$

Where

L = length of upstream meter-bore piping, in feet.
D = nominal meter bore, in feet.
K_s = swirl-velocity ratio, dimensionless.
f = Darcy-Weisbach friction factor, dimensionless.

Note: During the 1984-86 review and update of Chapter 5.3, First Edition, it was discovered that the friction factor, f, in Equation A-1 was incorrectly identified as the Fanning pipe friction factor. The working group determined that the factor is actually the Darcy-Weisbach friction factor, the group located the original documentation, implemented the correction, and placed it on file at API. Values of the swirl-velocity ratio, K_s, for several piping configurations are shown in Figures A-1 through A-5. The data were derived from Chapter 14.3.

A.3 Sample Calculation

A.3.1 PROBLEM

Determine the length of straight pipe run upstream of a 6-inch turbine meter for each of the configurations shown in Figures A-1 through A-5 under the following conditions:

$$Q = 2000 \text{ gallons per minute}$$
$$\text{Viscosity } (v') = 1.9 \text{ centistokes}$$
$$D = 6/12 = 0.5 \text{ feet}$$

$$\text{Reynolds number } (R_n) = \frac{263.6Q}{Dv'}$$
$$= \frac{(263.6)(2000)}{(0.5)(1.9)}$$
$$= (5.55)(10^5)$$
$$f \doteq 0.0175$$

Note: The value for f is for $R_n = (5.55)(10^5)$ and a relative roughness of 0.0004 for new steel pipe. The value is taken from L. F. Moody, "Friction Factors for Pipe Flow," *Transactions of the American Society of Mechanical Engineers*, November 1944, Vol. 66, p. 671.

A.3.2 SOLUTION

From Equation A-1,

$$L = (0.35D)(K_s/f)$$
$$L/D = 0.35K_s/f$$
$$= 0.35K_s/0.0175$$
$$= 20K_s$$

Table A-1 lists values for L and L/D in Figures A-1 through A-5 based on $L/D = 20K_s$. Since values of K_s are treated as relative coefficients in A.5, the empirical coefficient K_s is assigned a value of 1.00 to agree with the basic recommendation of 20 diameters of straight pipe for the average installation.

A.4 Conclusions

The L/D ratio is inversely proportional to the pipe-friction factor and directly proportional to the swirl-velocity ratio.

Since $1/f$ is minimum for conditions of maximum pipe roughness for any given Reynolds number in the region of turbulent flow, the best straightening for a minimum length of straight pipe occurs with a pipe of maximum roughness.

Equation A-1 is the result of grouping many relatively undefinable conditions in the flow stream and should therefore not be considered a rigorous presentation. However, the simplicity of the equation and its ability to provide answers commensurate with experience suggest that it can

Table A-1—Values for L and L/D for Figures A-1 Through A-5

Figure No.	K_s	L (inches)	L (feet)	L/D Ratio
A-1	0.75	90	7.5	15
A-2	1.00	120	10.0	20
A-3	1.25	150	12.5	25
A-4	2.00	240	20.0	40
A-5	2.50	300	25.0	50

be used reliably The real value of Equation A-1 stems from the definition of the fundamental relationship of the swirl-conditioning characteristics within a length of straight pipe.

A.5 Laminar Flow (Special Case)

Since $1/f$ is a function of Reynolds number, R_n, Equation A-2 can be written as follows:

$$L/D = (K_{1am})(R_n)(K_s)$$
$$= (K_{1am})\frac{\rho VD}{\mu}(K_s)$$

Where:

K_{1am} = an empirical factor
V = velocity of the fluid.
ρ = density of the fluid
μ = absolute viscosity of the fluid

Therefore, in the special case of laminar flow, L/D is directly proportional to the velocity, pipe diameter, and mass density of the liquid and inversely proportional to dynamic viscosity.

Note. The material presented in this appendix is based on *Factors Influencing L D Ratio for Straight Pipe Flow Straighteners Associated with Turbine Flowmeters* by M. H. November, Engineering Report No 65, Potter Aeronautical Corporation, [Union, New Jersey], January 4, 1967. Revision A to the report is dated February 16, 1967, and Revision B is dated February 26, 1967 According to the copies of the correspondence with Mr. November that are now on file with the API Measurement Coordination Department, many individuals, as well as a committee, reviewed this method. The material was published in API Standard 2534 (now out of print) and subsequently in Chapter 5 3 of the *Manual of Petroleum Measurement Standards*.

During the 1984-86 review and update of this section of the *Manual of Petroleum Measurement Standards*, it was discovered that the friction factor f, in Equation A-1 was incorrectly identified in the previous edition as the Fanning pipe friction factor This factor is actually the Darcy-Weisbach friction factor

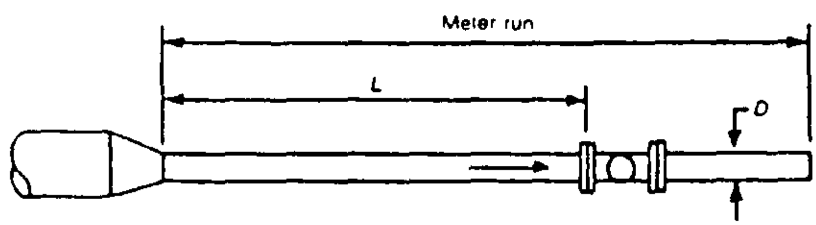


Figure A-1—Piping Configuration in Which a Concentric Reducer Precedes the Meter Run (K_s = 0.75)

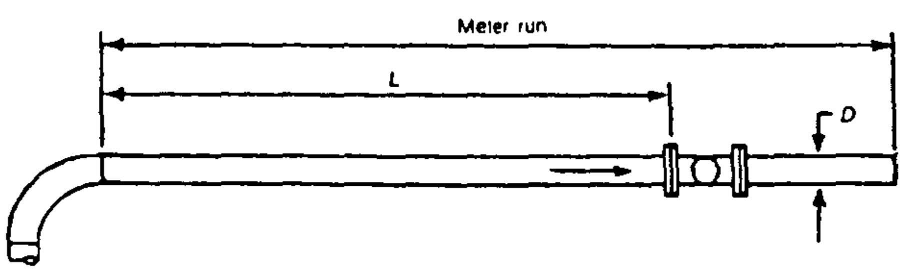


Figure A-2—Piping Configuration in Which a Sweeping Elbow Precedes the Meter Run (K_s = 1.0)

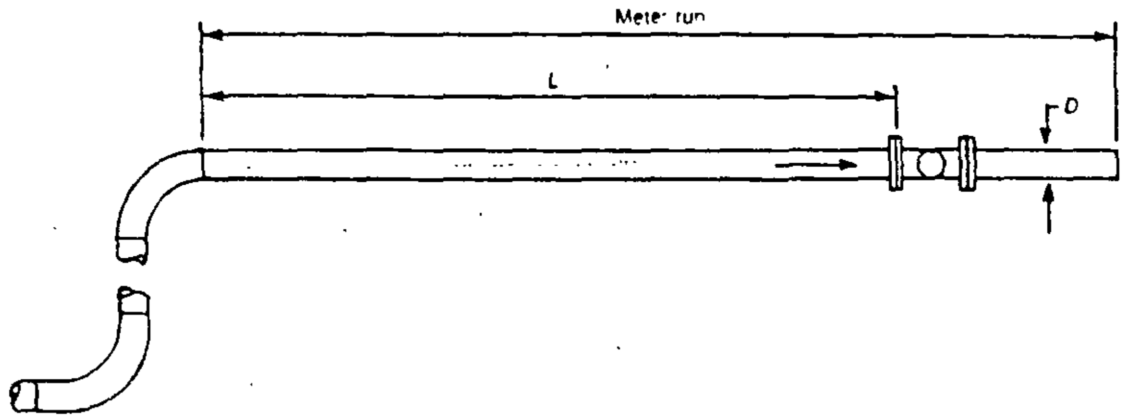


Figure A-3—Piping Configuration in Which Two Sweeping Elbows Precede the Meter Run (K_s = 1.25)

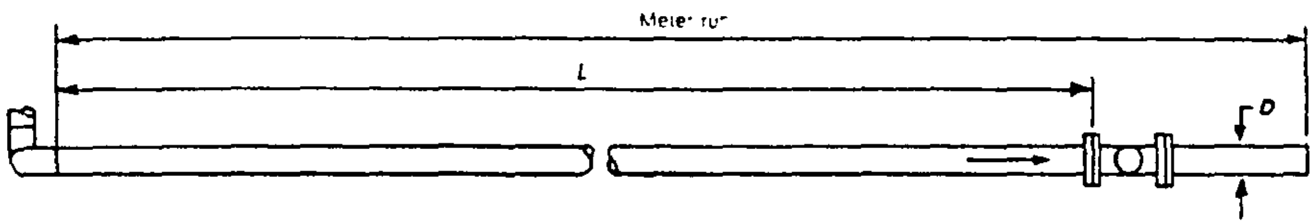
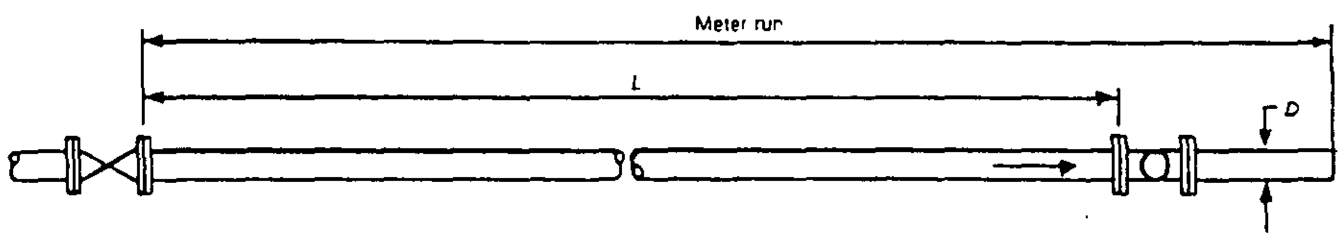


Figure A-4—Piping Configuration in Which Two Sweeping Elbows at Right Angles Precede the Meter Run (K_s = 2.0)



Note: When a fully open valve precedes the meter run, K_s = 1.0. When a partially open valve precedes the meter run, K_s = 2.5

Figure A-5—Piping Configuration in Which a Valve Precedes the Meter Run

APPENDIX B—SIGNAL GENERATION

B.1 Introduction

Appendix B supplements and clarifies the information on electrical installation requirements.

B.2 Generation of Electrical Signals

The principal types of devices that produce electrical signals and are used with turbine meters are described in B.2.1 through B.2.4.

B.2.1 INDUCTANCE SYSTEM

In an inductance system, the rotating element of the turbine meter employs permanent magnets that may be embedded in the hub or the blade tips or attached to the rotor shaft or to a ring driven by the rotor. Regardless of the design, magnetic flux from a moving magnet induces a voltage in a pickup coil that is located near the magnetic field.

B.2.2 VARIABLE RELUCTANCE SYSTEM

In a variable-reluctance system, a fixed permanent magnet is centered inside the pickup coil housing so that a variation in magnetic flux results from the passage of a highly permeable, magnetic rotor material near the pickup coil.

B.2.3 PHOTOELECTRIC SYSTEM

In a photoelectric system, a beam of light is interrupted by the blades of the rotor or by elements of a member that is driven by the rotor so that a pulsed signal output is developed.

B.2.4 MAGNETIC REED-SWITCH SYSTEM

In a magnetic reed-switch system, the contacts of a reed switch are opened and closed by magnets embedded in the rotor or in a rotating part of the turbine meter. The switch action interrupts a constant input so that a pulsed signal output is produced.

B.3 Summary

Of the four systems described, only the inductance and variable-reluctance systems are true generators, since both output frequency and voltage magnitude are proportional to rotor speed. The photoelectric and magnetic reed-switch systems both require the application of an external constant voltage that is interrupted by the sensing devices so that a nearly pure, square-wave output results. The frequency of the output signal is directly proportional to rotor speed, the voltage magnitude varies only between zero and the input voltage and is not related to rotor speed.

The inductance and variable reluctance systems are low-power-level devices because they generate only a few milliwatts of electrical power. This output may be locally amplified, and in some instances shaped, at the turbine meter. The amplifier output may then be considered a high-level output. The photoelectric and reed-switch systems are generally high-level devices, because the output level is controlled by the input voltage that they require. Ideally, devices that have a high power level are less susceptible to noise problems because of the increased signal-to-noise ratio; however, each system has definite frequency limitations that must be considered when one system is weighed against the other.

Manual of Petroleum Measurement Standards Chapter 5—Metering

Section 4—Accessory Equipment for Liquid Meters

Measurement Coordination

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American Petroleum Institute

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FOREWORD

This five-part publication consolidates and presents standard calculations for metering petroleum liquids using turbine or displacement meters. Units of measure in this publication are in International System (SI) and United States Customary (USC) units consistent with North American industry practices.

This standard has been developed through the cooperative efforts of many individuals from industry under the sponsorship of the American Petroleum Institute and the Gas Processors Association.

API Chapter 5 of the *Manual of Petroleum Measurement Standards* contains the following sections:

- Section 1, "General Considerations for Measurement by Meters"
- Section 2, "Measurement of Liquid Hydrocarbons by Displacement Meters"
- Section 3, "Measurement of Liquid Hydrocarbons by Turbine Meters"
- Section 4, "Accessory Equipment for Liquid Meters"
- Section 5, "Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems"

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Suggested revisions to this publication are invited and should be submitted to Measurement Coordination, Exploration and Production Department, American Petroleum Institute, 1220 L Street, N.W., Washington, D. C. 20005.

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Chapter 5—Metering

SECTION 4—ACCESSORY EQUIPMENT FOR LIQUID METERS

5.4.1 Introduction

API Chapter 5.4 of the *Manual of Petroleum Measurement Standards* is intended to be a guide for the selection and application of accessory equipment that is used with liquid hydrocarbon meters to obtain accurate measurements and optimum service life. Selecting the kinds of accessory equipment that are described in this chapter depends on the function, design, purpose, and manner in which a specific measurement installation is to be used.

This publication does not endorse or advocate the preferential use of any specific type of equipment or metering system, nor does it intend to restrict the development of any particular meter, instrument, or accessory equipment.

5.4.2 Scope

This section of API MPMS Chapter 5 describes the characteristics of accessory equipment generally used with displacement and turbine meters in liquid hydrocarbon service. Having a knowledge of these characteristics helps the designers and operators of turbine and displacement meter installations to provide satisfactory volume measurement results. Certain minimum requirements for devices that monitor temperature, density, and pressure are discussed in this chapter. System hardware, such as valves, vents, and manifolding, is not discussed in this chapter.

5.4.3 Field of Application

The field of application of this section is all segments of the petroleum industry that require dynamic measurement of liquid hydrocarbons by displacement or turbine meters.

5.4.4 Definitions

Terms used in this publication are defined in 5.4.4.1 through 5.4.4.3.

5.4.4.1 *Accessory equipment* is any device that enhances the utility of a measurement system, including readouts, registers, monitors, and liquid- or flow-conditioning equipment.

5.4.4.2 A *readout* is a device that displays numbers or symbols and incorporates electric or electronic measures.

5.4.4.3 A *register* is a mechanical device that displays numbers.

5.4.5 Referenced Publications

The current editions of the following standards are cited in this chapter:

API
Manual of Petroleum Measurement Standards
Chapter 4.3, "Small Volume Provers"
Chapter 4.6, "Pulse Interpolation"
Chapter 5.2, "Measurement of Liquid Hydrocarbons by Displacement Meters"
Chapter 5.3, "Measurement of Liquid Hydrocarbons by Turbine Meters"
Chapter 7.2, "Dynamic Temperature Determination"
Chapter 9, "Density Determination"
Chapter 12.2, "Calculation of Liquid Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors"

5.4.6 Selecting Accessory Equipment for Meters

Accessory devices should be selected so that trouble will not arise from the following:

a. Environment. Temperature and humidity extremes should be evaluated, and the installation should be protected accordingly. Electrical safety factors (including the hazardous area classification), electromagnetic and radio frequency interference, weatherproofing, fungusproofing, and corrosion should be considered.
b. Maintenance. Easy access should be provided for maintenance, and spare parts that have been recommended by the manufacturer should be obtained.
c. Compatibility. The readout device or register must be compatible with the meter and its transmission system.
d. Installation. All equipment must be installed and operated according to the manufacturer's recommendations and must conform to all applicable regulations and codes.

5.4.7 Shaft-Driven (Mechanical) Accessories

A variety of shaft-driven accessories are applied to displacement meters and sometimes to turbine meters. A mechanical linkage, usually a gear train, transmits force and motion from the rotating measurement element to the exterior of the meter, where the accessories are attached. Care should be exercised in selecting the number and type of accessories so that excessive torque, which can overload the meter, is avoided. This section discusses some of the accessory devices that are now being used.

5.4.7.1 ADJUSTER (CALIBRATOR)

A mechanical meter adjuster, or calibrator, changes the drive-system gear ratio between the volume-sensing portion of the meter and the primary register. The calibrator adjusts the register so that it is direct reading (that is, it provides a unity meter factor). For example, if precisely 100.0 units of volume are delivered by a meter, the register should be adjusted to indicate 100.0 units. Adjusters may be gear changing, friction driven, or clutch driven; depending on the design, the adjustment range may cover from 1 to 10 percent of throughput.

Different types of adjusters are capable of handling different torque loads. Friction-driven and clutch-driven adjusters show decreased sensitivity and repeatability when torque is increased. Increased torque reduces life in all types of adjusters. If adjustment to a unity meter factor is not required, the adjusting device should be omitted from the meter, and a direct drive shaft to the register should be installed.

5.4.7.2 REGISTER

A shaft-driven primary register is attached directly to the meter. The primary register displays the selected standard units of measurement, such as gallons, barrels, or cubic metres; the register also displays fractions of these units, if required. A primary register may be a totalizer only or a totalizer with a separate nonresettable register. A primary register is usually secured and sealed to the meter to prevent tampering (see 5.4.13).

5.4.7.3 PRINTER

A shaft-driven primary printer may accompany a primary register. The primary printer records on a measurement ticket the amount of liquid that is delivered. The ticket is printed in standard units of measurement, such as gallons, barrels, or cubic meters, and in fractions of these units, if required.

Impact or pressure-roller printers are capable of printing one or more paper copies. The number of copies is limited by the type of paper and the clarity that is required. Mechanical printers usually show the lowest digit to the nearest whole number. Ticket forms are inserted, printed, and removed manually.

5.4.7.4 TEMPERATURE COMPENSATOR

A temperature compensator is a variable-ratio mechanism located in the meter's drive train. It has a temperature sensor that works with the variable-ratio mechanism to correct the flowing volume to standard reference temperature, 60°F, 15°C, or 20°C. The temperature compensator must be set for the appropriate thermal coefficient of expansion of the liquid hydrocarbon that is measured.

The location of the temperature compensator in relation to primary or other accessory readout devices depends on which of the devices are to be compensated and which are to remain uncompensated.

5.4.7.5 PULSE GENERATOR

A pulse generator provides pulses in a quantity that is directly proportional to meter throughput. Pulsing devices can have various types of output signal, including switch closures, square-wave signals, and sine-wave signals. The devices can also have various frequency outputs. Low frequency is usually required for registration; high frequency is required for meter proving.

5.4.7.6 REMOTE TRANSMISSION

A remote-transmission device is used to transmit a measurement signal to a remote device, such as a driving device, that in turn can operate most meter shaft-driven accessories.

5.4.7.7 PRESET DEVICE

A preset device can be preset for any quantity of meter throughput. At the preselected quantity, the device will stop the flow of liquid or will perform desired functions automatically. It may or may not be an indicating device.

5.4.7.8 GEAR-CHANGE ADAPTER

A gear-change adapter changes the output shaft speed by a fixed ratio and is sometimes used to achieve a given output for accessory devices.

5.4.7.9 RIGID EXTENSION

A rigid extension is a convenience device used to elevate meter accessories some distance above the meter itself. The device is also used to isolate meter accessories from adverse environmental conditions at the meter.

5.4.7.10 ANALOG GENERATOR

An analog generator allows a meter to generate a DC voltage that is proportional to meter speed. The generator's voltage signal can be used to remotely indicate or control flow rate or related tasks.

5.4.7.11 RATE-OF-FLOW INDICATOR

A rate-of-flow indicator is a mechanical device that is mounted on a meter and indicates the meter's flow rate by driving a tachometer-type indicator.

5.4.7.12 SWIVEL ADAPTER

A swivel adapter is a convenience device that allows accessories mounted above the swivel to rotate without changing indication or registration.

5.4.7.13 ANGLE ADAPTER

An angle adapter is a convenience device that allows a counter/printer to be mounted at an angle for better accessibility and visibility.

5.4.7.14 DUAL ADAPTER

A dual adapter is used to mount two sets of shaft-driven accessories on a single meter. The device is often used with a temperature compensator on one side so that both compensated and uncompensated meter readings are available.

5.4.7.15 RIGHT-ANGLE TAKEOFF

A right-angle takeoff is a device in the meter's drive train that is used to provide a rotating external output shaft for operating mechanical accessories that are mounted externally to the meter.

5.4.7.16 SHIFTER ADAPTER

A shifter adapter is used for mounting two sets of shaft-driven accessories on a single meter so that only one set of shaft-driven accessories can be driven at a time. The device is generally used in conjunction with tender change in pipeline operation, where the total volume of a tender must be retained while registration is in process on the alternate printer or register. The means of shifting, which may be manual or mechanical, transfers the meter drive train from one set of accessories to the other. The adapter can be equipped with an optional indicator to show its position.

5.4.7.17 COMBINATOR

A combinator is used to combine the output of two or more meters into a single output that can then be used to drive desired accessories.

5.4.7.18 KEY-LOCK COUNTER

A key-lock counter is usually used in conjunction with the unattended operation of a bulk-plant metering system. The equipment provides a totalizer for any person who has authorized access to the system. Access is gained through keys and locks that connect the totalizer to the meter drive train, which actuates the system.

5.4.7.19 DIFFERENTIAL DRIVE

A differential drive is used to detect the difference in output between two meters in batching or blending systems. The device is generally mounted on one meter and equipped with a drive connection from another meter.

5.4.7.20 COMPUTING COUNTER/PRINTER

A computing counter/printer is generally used on tank trucks that make home deliveries so that total price can be provided when a delivery is completed. The device is a shaft-driven computing mechanism that can be manually set to enter price per unit volume and applicable taxes. At the conclusion of the delivery, the extended price is available immediately. The device may also be equipped with a ticket printer for preparing invoices. (See 5.4.8.12 for information about electrically driven computing counters/printers.)

5.4.8 Pulse-Driven (Electronic) Accessories

A variety of pulse-driven accessories can be used with both displacement and turbine meters. The pulses generated by high-resolution pulsers for displacement meters and the inherent pulses generated by most turbine meters represent discrete units of volume and can be used to provide input signals to the equipment discussed in 5.4.8.1 through 5.4.8.12.

5.4.8.1 ELECTRONIC ADJUSTER (CALIBRATOR OR SCALER)

An electronic adjuster, also called a factoring counter, manipulates the pulse signal to achieve a unit meter factor for direct reading of volume. The device is generally capable of being calibrated to one part in 10,000.

5.4.8.2 READOUT

An electrically driven primary readout indicates volumes in the desired standard units of measurement, such as gallons, barrels, or cubic meters; it also indicates fractions of these units, if required. The accuracy of the readout depends on system resolution, which is proportional to the number of pulses per unit volume.

Electromechanical registers are limited in speed. Their adequacy should therefore be considered before a decision is made about installation. Electronic readouts are not limited in speed, but they depend on electrical power for proper performance. During a power failure, standby power is needed to verify and retain meter registration if a mechanical means is not available.

5.4.8.3 PRINTER

Several types of electrical printers are available. The two common ones include electromechanical mechanisms in the final stages. The first type is designed so that each adjacent digit advances the next digit into position as it would in a mechanical totalizer. This type of printer is simple, inexpensive, and widely used, but it has limited speed and longevity.

The second type of printer includes individual digit modules that remain in a rest position until they are called on to print the throughput volume that is stored in a memory. This type of printer has high resolution, high speed, and exceptional longevity.

5.4.8.4 FLOW COMPUTER

Many types of electronic flow computers are available that accept meter output signals, and other sensor signals, to calculate volume or mass flow quantities as required. Flow computers display, transmit, and print data that can be used for operational or custody transfer purposes. A flow computer can be designed for a single meter run or a bank of meters.

In addition to meter signals, some flow computers accept signals from pressure, temperature, and density devices that allow the calculation of gross and net flow rates and totals. The flow computer should have provisions to accurately calibrate input or output signals. Security measures should be provided to prevent unauthorized access and alteration of the flow computer memory or user configuration. Security may be hardware, such as key locks or switches, or software passwords. Also, the flow computer should have means of internal processor and circuit error checking to ensure the integrity of calculated results.

5.4.8.5 PRESET TOTALIZER

A preset totalizer is a totalizing counter that actuates a contact closure when the measured volume equals a value that was preselected on a manually adjustable counter.

5.4.8.6 PROVING COUNTER

A proving counter is a high-resolution digital-pulse totalizer that provides a display of the high-frequency pulsed output from the meter. Pulse totalizers are started and stopped with an on/off gating circuit that is operated from the prover's mounted detector or detectors, which identify the passing of a calibrated volume of fluid. The totalizer may be an electromechanical counter or an electronic counter. If the counter is attached to a small volume prover, as described in API MPMS Chapter 4.3, the device will constitute a sophisticated electronic system that has the capability to quantify fractions of a pulse cycle, using the pulse interpolation techniques discussed in API MPMS Chapter 4.6.

5.4.8.7 FLOW-RATE INDICATOR

A flow-rate indicator converts an input signal to a visual display of flow rate in the desired units. The device is used for general operational information and to monitor system flow rate during meter proving.

5.4.8.8 FREQUENCY CONVERTER

A frequency converter converts an input frequency, or a pulse train, to a proportional analog signal for retransmission to other devices, such as recorders or controllers, that require analog input signals.

5.4.8.9 STEPPER DRIVE

A stepper drive converts a frequency input to an acceptable form for driving a stepper motor. The stepper motor then rotates at a speed that is proportional to the input frequency. The device can be used to drive various mechanical devices that require a rotary input (for example, counters, ticket printers, and compensators).

5.4.8.10 TEMPERATURE COMPENSATOR

A temperature compensator combines an input signal from a volume meter and an input from a temperature sensor to provide a corrected output to standard reference temperature, 60°F, 15°C, or 20°C.

5.4.8.11 COMBINATOR

A combinator accepts two or more simultaneous input frequencies and displays their sum total.

5.4.8.12 COMPUTING COUNTER/PRINTER

A computing counter/printer is generally used on tank trucks that make home deliveries so that the total price can be computed and printed as soon as the delivery is completed. This electrically driven device is also equipped to manually enter price per unit volume and applicable taxes, thereby allowing the extended price to be available immediately when the transaction is completed. The device is available with a ticket-printing function for preparing invoices.

5.4.9 Interface Connections to Pulse-Driven Accessories

Interface connections, as described in this chapter, are the connections between the meter's volume-sensing device (usually electromechanical) and its driven equipment.

5.4.9.1 SHIELDED CABLE

The signal from a volumetric meter in a measurement system is in the form of a pulse train. The accuracy of the measurement system depends on the security with which the pulse signals are transmitted and received.

Noise is a spurious signal that may be picked up either electrically or magnetically by the transmission lines or equipment. It can be picked up electrically through capacitance coupling to other conductors; it can be picked up magnetically through induction. The amount of noise and the cost of removing it depend on the type of equipment, the length of the transmission line, and the proximity of the source. Acceptable pulse transmission can usually be maintained between volumetric meters that are coupled within 1000 feet of each other and electronic equipment that has shielded twisted-pair conductors if a signal of ample strength (≥100 millivolts peak to peak) is transmitted. Shielding shall be grounded at the receiving end only to prevent ground-loop effects. The cables should be routed so that proximity to sources of electrical interference is avoided.

5.4.9.2 PREAMPLIFIER

A preamplifier may be used to shape the pulse of the meter output so that the performance of downstream accessories will be enhanced. If a long transmission line is required, a preamplifier should be considered. The preamplifier should always be located at the meter, the source of the signal, so that the original low-level signal will be amplified and increased to a satisfactory level. The shield conductor shall be grounded at the receiving end only to prevent ground-loop effects.

5.4.10 Installing Pulse-Driven Accessories

5.4.10.1 A system that transmits data consists of at least three components: a meter (pulse producer), a transmission line (pulse carrier), and a readout device (pulse counter and display). These three components must be compatible, and each component must meet the specifications recommended by the manufacturers of the meter and accessory equipment.

5.4.10.2 Electrical noise is a troublesome element in systems that have low-level signal outputs. Even in high-level output systems, noise and spurious electrical signals must be eliminated. Noise signals are superimposed on meter signals by electromagnetic induction, electrostatic or capacitive coupling, or electrical conduction.

5.4.10.3 Great care should be exercised in effectively isolating the meter system from external electrical influences. To minimize unwanted noise, earth grounding shall be separate from other grounding networks. Shielding the transmission cables of meter and prover detectors is essential.

5.4.10.4 Every meter system must meet two requirements to operate properly. First, the readout device shall be sensitive enough to respond to every pulse produced by the meter throughout its operating range. Second, the signal-to-noise ratio shall be high enough to prevent spurious electrical signals from influencing the readout device.

5.4.10.5 A meter's output signal may be viewed as a train of electrical pulses in which each pulse represents a discrete volume of liquid passing through the meter. One approach to producing electrical pulses is to use magnetic induction to directly translate the rotational motion of the meter into electrical energy. Another approach is to supply external electrical power to a proximity or photosensing device.

With the first approach, both pulse frequency and amplitude are generally proportional to flow rate. With the second approach, only pulse frequency is proportional to flow rate since the amplitude of the output voltage is nearly constant.

5.4.10.6 Most electronic readout devices condition a wave form to count each pulse or to measure the frequency of meter output so that flow rate can be indicated. Since signals may have a relatively low power level, installation conditions shall be suitable for low power level signals. The recommendations described in this chapter do not apply to all meters; they are related only to systems that have low power level signals.

5.4.10.7 The following pulse characteristics influence proper operation of the meter system:

a. Amplitude. Any readout device that is connected to a pulse producer, or meter, shall be sensitive enough to operate when the pulse amplitudes are generated over the rated flow range.

b. Frequency. The readout device shall be able to cope with the maximum output frequency of the pulse producer, or meter, when it reaches its highest expected flow rate.

c. Width. After shaping, the duration of every pulse generated by the pulse producer, or meter, shall be long enough to be detected and counted by the readout device.

d. Shape. A sine-wave output shall not be used, without preamplification and shaping, to operate a readout device that requires a square-wave input.

5.4.10.8 In an electrical transmission installation, great care should be exercised to maintain the signal amplitude at the highest level possible and to reduce the magnitude of noise. The following steps should be taken to maintain the optimum signal level:

a. Minimize the length of the transmission line from the meter to the readout device.

b. Ensure the correct impedence.

c. Use the most technically compatible signal transmission cable that is available, as recommended by the equipment manufacturer.

d. If dictated by the transmission distance or the manufacturer's requirements, introduce a signal preamplifier into the turbine meter's transmission system.

e. Ensure that voltages supplied to preamplifiers and constant-amplitude pulse-generating systems are of proper magnitude and do not exceed the maximum noise level or ripple requirements specified by the equipment manufacturer.

f. Ensure that all pickup coils are securely mounted and properly located.

g. Periodically inspect and clean all terminals and connectors.

h. Replace components that give a weakened signal as a result of deterioration.

5.4.11 Protection/Control Equipment Conditioners

Protection/control equipment is used with displacement and turbine meters to ensure the most accurate and reliable performance. This includes, but is not limited to, flow control, pressure control, and removal of unwanted foreign material, such as dirt, water, or gas.

5.4.11.1 STRAINERS—FILTERS

Foreign material, such as rust, scale, welding beads, slag, sand, and gravel, may damage a meter system or may adversely affect its performance. A strainer is usually installed upstream of the meter as a protective device. It includes a basket or barrier (usually made of metal cloth or screen) that stops and collects foreign material before it enters the meter. The mesh size varies according to the needs of the meter system; meter manufacturers can provide criteria for selecting mesh size.

A schedule should be followed for cleaning screens. The purpose of the strainer is defeated if the screen becomes loaded to the point of rupturing. A differential pressure gauge or upstream and downstream pressure gauges may be used to indicate the differential pressure across the strainer; the differential pressure will be in proportion to the amount of foreign material that has accumulated. Based on this information, major problems caused by foreign materials can be avoided.

If the flow cannot be stopped for strainer maintenance, dual strainers may be used. Strainers are also available that are cleaned through periodic back washing to a sump or other disposal facility.

5.4.11.2 AIR OR VAPOR ELIMINATORS

Air or vapor in a flowing stream will be measured as liquid and will result in an error in the indicated volume. Large volumes of air, such as those that may exist in an empty piping system, can result in overspeeding and damage to a meter.

Lines to and from tanks are normally kept full of liquid; however, if the same line is used to pump liquid into and out of a tank, air may enter after a delivery is completed. Likewise, operating at unusually low tank levels may allow air or vapor to be drawn into the system. Under these conditions, air elimination equipment is required; additional shutdowns and alarms may also be required.

High vapor pressure liquids, such as liquefied petroleum gas, are handled under pressure conditions that are intended to maintain the product in the liquid phase. If adequate pressure is not maintained, the liquids may flash or vaporize. In such cases, a vapor separator or condensing tank must be installed in the system if the problem cannot be corrected by another means.

Air eliminators are normally not required on pipeline installations where flow does not originate from nearby tanks; however, a means of manual venting should be provided at strategic locations so that air or vapor can be released during startup and after maintenance.

Selecting the size and type of air separator for an installation requires that careful consideration be given to piping and other equipment and to the operating details of the system. These details should include the quantity of air, the type of liquid being handled (with particular reference to its viscosity and foaming characteristics), the size and length of piping, the type and location of the pumps, and the rate of flow. The piping downstream of the separator/eliminator must remain filled with liquid to prevent air or vapor from being measured along with the liquid.

5.4.11.3 CONTROL OF FLOW

Most installations include a manually or power-operated valve for starting, controlling, and stopping the flow of liquid. In general, power-operated valves should open and close slowly to prevent flow and pressure surges.

To avoid overspeeding a meter, it may be necessary to include a control that will limit the maximum rate of flow to the rated maximum of the meter. In multimeter installations, a control valve is normally used downstream of each meter to balance flow when one or more meters are taken off line or when proving takes place. If it is necessary to prevent the flow of liquid from reversing direction, a valve that allows flow in only one direction should be used.

A minimum back pressure must be maintained to prevent liquid from vaporizing or flashing (see API MPMS Chapters 5.2 and 5.3). This may require the use of a back-pressure controller and a control valve that can maintain the required back pressure under any line pressure.

If a meter is equipped with a counter that can be preset for delivering a particular volume, the on/off valve is usually controlled by the counter so that the flow can be stopped at the proper time. The preset counter may be linked to the valve by mechanical, electrical, or other means.

Pressure-reducing valves are commonly employed in pipelines to reduce pressure to a level that is suitable to meter or station manifolding. Care must be exercised to ensure that pressure is not reduced enough for vaporization to occur. It is not good practice to throttle immediately upstream of a flow meter since this may create flow disturbances and cause measurement error.

5.4.12 Monitors

Some conditions and properties of liquid hydrocarbons have a greater effect on measurement accuracy than do others; monitors may therefore be desirable to assess the temperature, pressure, density, and viscosity of the flowing liquid. For example, a 1°C change in gasoline temperature can produce a volume change of 0.12 percent (a 1°F change can produce a volume change of 0.07 percent), and a change in pressure of 7 kilopascals (1 pound per square inch) in the same product affects volume by only 0.0008 percent. In this case, the equivalency relationship between pressure and temperature is 960 kilopascals to 1°C (80 pounds per square inch to 1°F).

When the temperature of a metered stream is determined for correcting the thermal effects on the stream or meter, obtaining the stream temperature inside the meter body is most desirable. Some meters provide for a temperature-measuring device installed in the meter body; however, this is impractical with many meters because of the way they are constructed or the type of temperature-measuring device that is selected.

If it is impractical to mount the temperature-measuring device in the meter, the device should be installed either immediately downstream or immediately upstream of the meter. In liquid turbine meters, the temperature-measuring device should be located immediately downstream of the downstream flow-conditioning tube. Where several meters are manifolded in parallel, one temperature sensor located in the total liquid stream is acceptable if the temperatures at each meter and at the temperature-sensor location are in accordance with Table 1 in API MPMS Chapter 7.2.

5.4.12.1 THERMOMETERS

The accuracy and resolution of a thermometer used in a measurement system should be appropriate for the meter's needs and scale of operation. Since metering requires the highest accuracy possible, the equipment should allow for precise reading and should be checked or calibrated frequently.

API MPMS Chapter 7.2 discusses in greater detail the requirements for temperature measurements associated with meters.

5.4.12.2 TEMPERATURE/PRESSURE-AVERAGING INSTRUMENTS

Temperature/pressure-averaging instruments determine the temperature and pressure of a metered quantity on a volumetric or time-paced basis. The devices also accurately determine average conditions if instantaneous line conditions are changing.

5.4.12.3 TEMPERATURE RECORDERS

Recording liquid temperatures on a chart facilitates the averaging of temperatures over a period of time. The accuracy of the recorded temperatures cannot be greater than that of the temperature-sensing device. Recorded temperatures are often less accurate. The sensing, recording, and chart-integration parts of a temperature recorder should be calibrated periodically.

5.4.12.4 PRESSURE GAUGES

Pressure gauges must be selected to suit the range of expected operating pressures. They should be checked frequently against a master gauge or a deadweight tester, and necessary adjustments should be made.

5.4.12.5 PRESSURE RECORDERS

The range of a pressure recorder should be suited to the expected range of the metering operation and should not be wider than required. The instrument's indicator and its sensing device should be checked frequently with a master gauge or a deadweight tester, and necessary adjustments should be made.

5.4.12.6 HYDROMETERS

Floating bulb-type hydrometers are used to determine the relative density or API gravity required for the volume correction calculations described in API MPMS Chapter 12.2. Refer to API MPMS Chapters 9 and 11 for instructions to be followed and tables to be used in converting readings to standard reference conditions.

5.4.13 Security

Consideration should be given to sealing the meter systems to prevent or identify unauthorized attempts at tampering with or manipulating system components. The accuracy, usefulness, and output of a measurement system can be compromised in many ways, resulting in the loss of credit for hydrocarbon liquids that pass through the meter. Meter systems are often equipped with security seals made of wire, plastic, or paste that when broken or disturbed indicate possible tampering. Electronic systems can also be secured with key locks, access codes, and so forth. Each system should be reviewed to define its exposure risk and to identify appropriate seal locations and techniques.

5.4.13.1 SECURITY FOR DISPLACEMENT METERS

Common seal points for displacement meter installations are meter cover and accessory stack flange bolts, meter counter mounting bolts, calibrator and compensator adjustments, right angle drive covers, and covers for electrical conduits and control boxes.

5.4.13.2 SECURITY FOR TURBINE METERS

Common seal points for turbine meter installations are the mechanical counter enclosures, pickup mounting fittings, preamplifier housings, electrical conduit covers, and control box covers. Sealing electrically operated systems that have

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ERRATA

On Page 7, the last sentence in 5.4.13.2 was inadvertently cut off, it should read as follows:

5.4.13.2 SECURITY FOR TURBINE METERS

Common seal points for turbine meter installations are the mechanical counter enclosures, pickup mounting fittings, preamplifier housings, electrical conduit covers, and control box covers. Sealing electrically operated systems that have many accessories, power supplies, and readouts becomes burdensome; the equipment is often housed in a building or enclosure that can be locked or sealed to meet the system's needs.

Manual of Petroleum Measurement Standards Chapter 6—Metering Assemblies

Section 1—Lease Automatic Custody Transfer (LACT) Systems

Measurement Coordination Department

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Chapter 6—Metering Assemblies

SECTION 1—LEASE AUTOMATIC CUSTODY TRANSFER (LACT) SYSTEMS

6.1.1 Introduction

This publication has been prepared as a guide for the design, installation, calibration, and operation of a lease automatic custody transfer (LACT) system.

A LACT system is an arrangement of equipment designed for the unattended custody transfer of liquid hydrocarbons from producing leases to the transporting carrier. The system must determine net volume and quality, provide for fail-safe and tamperproof operation, and meet requirements of accuracy and dependability as agreed to by mutually concerned parties, such as the producer, the transporter, the royalty owner, and federal, state, and municipal regulatory bodies.

6.1.1.1 COMPLIANCE

Compliance with the provisions of this standard may result in an approach to accuracy or may establish safeguards that are not necessary under all conditions. When not required, those portions of this standard not considered applicable may be disregarded with the mutual agreement of all parties concerned. The compulsory verb form "shall," while not necessarily binding for all conditions, has been used when a deviation from the standard is likely to adversely affect the satisfactory operation of a system that is designed for optimum operation under typical producing conditions.

6.1.1.2 FUTURE DEVELOPMENTS

Although this standard presents the concurrence of the industry on system requirements for lease automatic custody transfer, it is not intended in any way to restrict future developments. Equipment now exists in the design or field-proving stages that may further improve the art of lease automatic custody transfer. The industry encourages such developments, and when concerned parties mutually agree to use such systems or components, every effort should be made to expedite their use and standardization.

6.1.2 Scope

This publication describes the metering function of a LACT unit and is intended to complement API Specification 11 N, *Specification for Lease Automatic Custody Transfer (LACT) Equipment.* LACT equipment includes a meter (either displacement or turbine), a proving system (either fixed or portable), devices for determining temperature and pressure and for sampling the liquid, and a means of determining nonmerchantable oil. Many of the aspects of the metering function of a LACT unit are considered at length in other parts of this manual and are referenced in 6.1.4.

6.1.3 Field of Application

The field of application of this publication is the unattended and automatic measurement by meter of hydrocarbon liquids produced in the field and transferred to a pipeline in either a scheduled or a nonscheduled operation.

Note: The information contained in Chapter 6.7 should also be considered when measuring viscous fluids by meter.

6.1.4 Referenced Publications

Many of the aspects of the metering function are discussed at length in other parts of this manual. Please refer to the following chapters for more information.

API

Manual of Petroleum Measurement Standards

Chapter 4—"Proving Systems"
Chapter 5.1, "General Considerations for Measurement by Meters"
Chapter 5.2, "Measurement of Liquid Hydrocarbons by Displacement Meters"
Chapter 5.3, "Measurement of Liquid Hydrocarbons by Turbine Meters"
Chapter 6.7, "Metering Viscous Hydrocarbons"
Chapter 7—"Temperature Determination"
Chapter 8—"Sampling"
Chapter 8.2, "Automatic Sampling of Petroleum and Petroleum Products"
Chapter 9—"Density Determination"
Chapter 10—"Sediment and Water"
Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"

Spec 11N *Specification for Lease Automatic Custody Transfer (LACT) Equipment*

6.1.5 Requirements for All LACT Systems

The requirements for all LACT systems are as follows:

a. When hydrocarbon liquids are measured and transferred, the fluid should be stable to permit subsequent storage during transportation without abnormal evaporation losses.

b. During custody transfer, provisions shall be made for determining net standard volume. (See Chapter 12.2.)

c. Temperature measurements, recordings, or corrections applicable to volumetric measurement shall be made in accordance with Chapter 7.

d. Temperature and pressure measurements (either recorded or indicated) shall be taken, and corrections applicable to volumetric measurements shall be made in accordance with Chapter 12.2. The method of performing temperature compensation is a matter of negotiation but should be accomplished by use of volume-weighted temperature-averaging devices or temperature compensators for optimum accuracy.

e. A representative sample of transferred oil for determining density (API gravity), sediment and water content, and any other physical properties required shall be obtained. (See Chapter 8, Chapter 9, and Chapter 10.)

f. The merchantability of hydrocarbon liquids should be established when they are transferred; that is, when the liquids are within a specified density (API gravity) range, do not contain more than a specified sediment and water percentage, are at an acceptable temperature, and are of an acceptable Reid vapor pressure. A means shall be provided to stop the flow of oil to the carriers system and to the sampling system if the oil becomes unmerchantable

g. A means should be provided to control flow rates, periods of flow, and net quantities of oil delivered into the carriers system.

h. A means shall be provided to stop the flow of oil into the carriers system at or before completion of delivery of the leases assigned allowable capacity.

i. The control and recording system shall include fail-safe components to prevent mismeasurement or hazardous operating conditions in the event of a power or system functional failure of any of the system's components required for the LACT.

j. All components of the system that require periodic calibration and/or inspection should be accessible for inspection by all parties involved in the custody transfer transaction. Adjustment, repair, or replacement will be performed by those responsible for the operation of the system. The design of the system shall provide a means for readily detecting leakage throughout the system, for example, double-block and bleed-type valves, sight drains, or pressure instruments.

k. The piping system shall not have connections or bypasses that would permit liquids to be transferred without measurement and shall be designed or equipped so that a reverse flow of liquid through the measuring device cannot occur.

l. A means shall be provided to lock or seal components that affect control or indicate measurement of quantity or quality. Unless this requirement has been specifically waived, such components shall be unlocked or unsealed only after prior notice to and consent of the parties concerned.

m. System malfunctions shall be anticipated, and deliveries that could occur during such periods shall be estimated. This requirement may be met by independent gross fluid delivery-recording systems, that is, by using a dual-head meter and temperature recorder, by using a meter in series, or by recording temperature or pressure or other instruments that indicate periods of flow. In installations where such apparatus is not used, prior agreement should be established for calculating or estimating procedures that will be followed in instances of measurement system malfunction.

n. Sediment and water content and density (API gravity) measurements shall be made from composite samples obtained by automatic samplers of acceptable design. Samplers shall be installed in accordance with Chapter 8.2.

6.1.5.1 SAMPLING

In most cases, accounting for a crude oil run is determined on the basis of net standard volume, which includes corrections for meter factor, temperature, pressure, and sediment and water content. Therefore, the composite sample accumulated in a run period and any portion used for the determination of density (API gravity) and sediment and water content must represent all crude oil delivered during that run period. When density (API gravity) and sediment and water content are based on a sample from the composite sample of the run, the procedures used must ensure that this secondary sample is representative of the composite sample. (See Chapter 8 for additional details.) The sampling should be proportioned to the flow rate through the meter.

6.1.5.2 MAINTAINING ALLOWABLES

When regulatory agencies apply production allowables, runs from the LACT system shall conform to but shall not exceed these allowances. Automatic means shall be used to accomplish this requirement. The system must be fail-safe, tamperproof, and sealed so that neither the producer nor the carrier can change the arrangement without the consent and/or knowledge of the other party.

System devices must be capable of being pre-set and verified for a predetermined volume that will approach but not exceed the lease allowable. When the predetermined volume has been reached, the arrangement used must prevent any further movement of oil from the lease until it is manually reset. The arrangement must be adjustable so that changes in production allowables are accommodated. Registers and counters should be readily visible so that oil deliveries can be checked at any time.

6.1.5.3 MONITORING QUALITY

Means shall be provided to prevent water-contaminated oil or slugs of water from entering a carrier's system. The parties shall agree on the maximum permissible sediment and water content of the crude oil. One such satisfactory automatic device which detects water is an instrument that measures capacitance (dielectric constant of the liquid stream). This device should be installed in a vertical riser in the piping before the meter and should be used to actuate controls so that water-contaminated oil is not delivered to the pipeline. A time-delay element may be incorporated into the monitor system.

6.1.6 Displacement and Turbine Meter LACT Systems

Practical methods for obtaining accurate measurements of lease oil runs, using either a displacement or a turbine meter, with equipment arranged to meet the requirements defined in this chapter are outlined in 6.1.6.1 through 6.1.6.5. (See Chapters 5.1, 5.2, and 5.3 for details on meter selection.)

6.1.6.1 INSTALLATION

LACT systems that use meters shall be designed in accordance with applicable industry codes or standards. Each item essential to quantity and quality control shall be located so that it will consistently perform its function.

Figure 1 is a schematic flow diagram showing the principal components of a meter-equipped LACT unit. All items shown may be used in an installation, but if certain components are not required for the integrity of quantity and quality control, they may be omitted.

6.1.6.2 SPECIFIC REQUIREMENTS

The design and function of a LACT system are matters of negotiation. These negotiations determine which of the requirements are applicable. However, when the quantity or quality measurement or control depends on compliance with the requirement, the specific conditions detailed in 6.1.1.1 shall apply.

LACT systems that use meters shall maintain fluid pressure throughout the measurement system in excess of the product bubble-point pressure by an amount sufficient to prevent the formation of vapor. If vapor is introduced into the measurement system, the measurement will be inaccurate. When vapor removers are specified, they shall be sized for releasing vapor to the atmosphere or to a suitable vapor recovery system at rates equal to or greater than the normal flow rates of the liquid. Vapor outlet lines from removers shall comply with safety standards. When the design of storage facilities ensures fluid-packed line conditions leading to the meter, vapor removers may not be required. Either the producer or the carrier may require the installation of a dielectric or capacitance instrument, more commonly referred to as a water monitor. This monitor will automatically stop or divert flow before liquid is delivered to the meter when the carrier's specifications are not met. The water monitor shall be located upstream from the meter and shall be in operation at all times during delivery. The carrier shall specify the maximum water setting of the instrument.

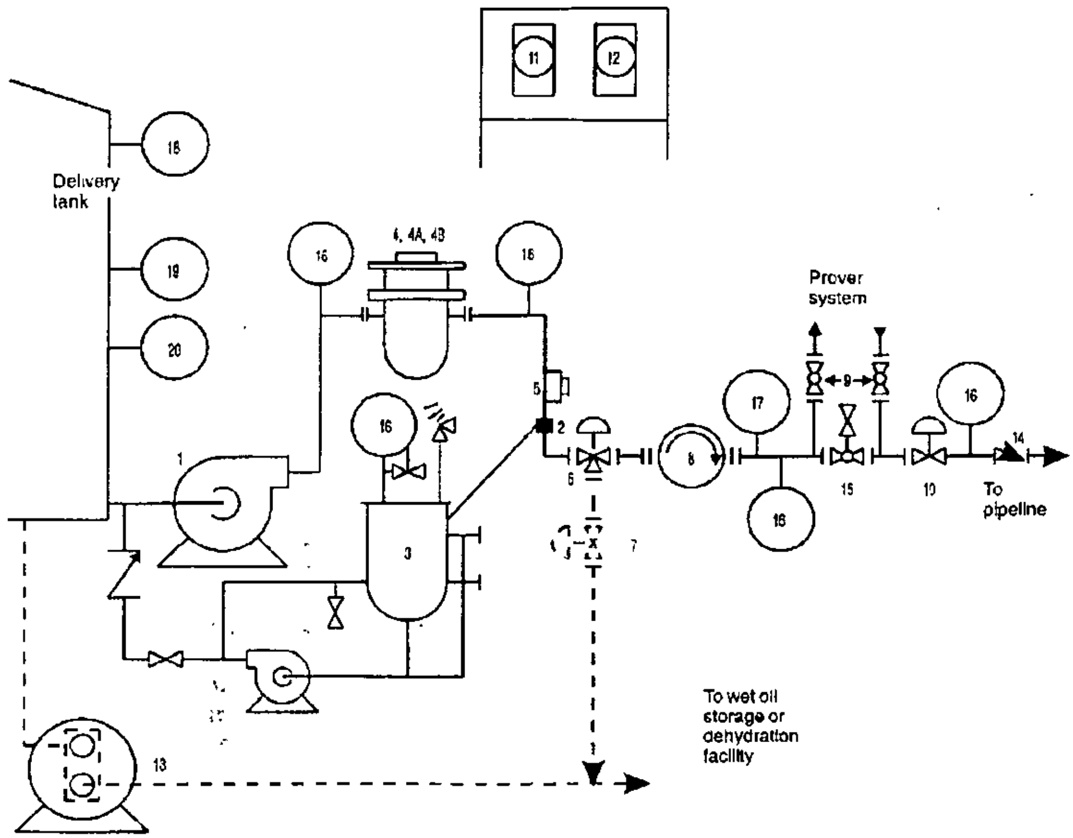
Meters shall be operated within the manufacturer's recommended flow rates and at a rate as near as possible to the rate at the time of the meter proving when the meter factor was obtained. A back-pressure control valve is necessary to maintain a constant flow rate and pressure independent of downstream conditions. Meters shall not be subjected to pressure pulsations, flow rate surges and shall not be subjected to shock pressures caused by quick-closing valves. When temperature compensators with density selectors are used, they shall be adjusted for the density (API gravity) of the metered liquids. When temperature variations result in mismeasurement, temperature stabilization and monitoring may be required. The carrier may require that a pressure surge and/or suction tank be installed upstream from the LACT system to ensure that fluid-packed line conditions lead to the meter and to protect the meter from flow rate surges. "Weathering" the crude oil, expansion chambers, and other such requirements may be required by the carrier to prevent unstable metering conditions.

When system pressure requires the use of the oil compressibility factor and pressure may not remain constant, flow weighted pressure-averaging devices or pressure recorders may be required. (See Chapter 12.2 for computing C_{pl}.) When required by operating conditions that change sufficiently to alter the meter factor beyond acceptable limits, such as temperature variations and the associated viscosity changes, the oil temperature shall be maintained reasonably constant and shall be approximately the same as the proving temperature.

6.1.6.3 FACILITIES AND PROCEDURES FOR PROVING DISPLACEMENT AND TURBINE METERS

Proving procedures for each LACT location should be agreed to by the parties concerned (See Chapter 4.) Copies of the agreement should be furnished to both the operating personnel and proving personnel. Such procedures should include:

a. A step-by-step method to be followed at the location.
b. A procedure for checking valves for leakage before and during the proving operation.
c. A preliminary inspection or operation of the proving equipment.
d. The locations and specifications of seals to be inspected at time of proving.



1. Charging pump and motor
2. Sampler
3. Sample container and circulation pump
4. Strainer
   a. Integral air/gas eliminator (optional)
   b. Separate air/gas eliminator (optional)
5. Water monitor probe
   Note: The monitor chassis may be mounted with the electrical control system or directly on the monitor probe
6. Diverter valve
7. Wet oil back-pressure valve (optional)
8. Custody transfer meter and accessories
9. Block valve
10. Back-pressure valve
    Note: Locate the back-pressure valve upstream of the prover loop for tank provers.
11. Power panel
12. Control equipment (for example, water monitor, allowable counter, and shutdown system)
13. Recirculation pump (optional)
14. Check valve
15. Double-block and bleed-valve
16. Pressure measurement device
17. Temperature measurement device
18. Level control—start
19. Level control—stop
20. Low level control (optional)

Note: This simplified diagram indicates primary components necessary for typical LACT units but is not intended to indicate preferred locations.

Figure 1—Typical Displacement or Turbine Meter LACT Unit Schematic Diagram

e. The notification and witnessing required when seals are broken for maintenance purposes.
f. The location, type, scale division, and methods for reading the thermometers used in the proving process.
g. The location, type, scale division, and methods of reading pressure instruments used in proving.
h. The specifications of a proving run, such as:
   1. The number of times the prover tank should be filled.
   2. Specifying the number of runs for a pipe prover.
   3. Defining a minimum time and/or volume if the master-meter method is used.
i. The repeatability criteria for runs to be used and the number of runs to be averaged to obtain a new meter factor
j. The normal period between required meter provings. The period between provings may be established either on a throughput or on an elapsed-time basis. This period may be amended based on individual location meter performance records.
k. The normal date and time of provings or the notice to be given to witnessing parties when a proving schedule is established.
l. The witnessing required for provings.
m. The standard of consistency desired between meter factors obtained from consecutive provings.
n. The procedure to be followed when the desired consistency is not obtained, either in the results of consecutive runs during an attempted proving or in meter factors obtained from consecutive provings.
o. The frequency of inspection or the frequency and method of recalibration or calibration verification of the basic proving device.
p. The content for the forms to be used to record meter-proving data, complete with sample calculations and references to tables used for correction factors and conversions.

The proving record for each meter shall be kept on file for at least the same period as the meter tickets to which it applies or for a period mutually agreed to by the parties concerned. At least one copy of each official proving record should be supplied to each party concerned.

6.1.6.4 DISPLACEMENT AND TURBINE METER SYSTEM OPERATION

The operation of a meter system will vary depending on the characteristics of the liquid, the design of the installation, the type of pipeline facility connection, and the operating schedule of the pipeline. To be successful, a system must satisfy the requirements of the producer and the carrier. Before an installation is completed, operating sequences should be checked to ensure that the requirements of all interested parties have been met. The following cases are typical, and the items to be checked are suggested as guides for system studies.

6.1.6.4.1 Case A—Normal Delivery to a Gravity Flow Pipeline in Nonscheduled Operation

a. When the liquid level in the delivery tank reaches the normal high working level, the charge pump starts and the control valve opens to the pipeline, admitting flow through the meter.
b. When the valve reaches its open-to-pipeline position, the automatic sampler begins sampling as soon as the meter starts turning.
c. Under normal conditions, delivery to the pipeline continues until the liquid level reaches the normal low-level position.
d. The back-pressure valve then closes the pipeline outlet, the charge pump stops, and the automatic sampler stops sampling when the meter stops turning.

6.1.6.4.2 Case B—Normal Delivery to a Pressurized Pipeline in Nonscheduled Operation

a. When the liquid level in the delivery tank reaches the normal high working level, the charge pump starts and the control valve opens to the pipeline, admitting flow through the meter.
b. When the valve reaches its open-to-pipeline position, the pipeline shipping pump starts and the automatic sampler begins sampling as soon as the meter starts turning.
c. Under normal conditions, delivery to the pipeline continues until the liquid level reaches the normal low-level position.
d. The charge pump stops, the back-pressure valve closes the pipeline outlet, and the pipeline shipping pump is shut down.

6.1.6.4.3 Case C—Normal Delivery to a Pipeline in Scheduled Operation

Some pipeline systems are operated on a schedule whereby it is desirable to admit oil only during a certain interval. For this arrangement, the operation sequence shall be the same as for nonscheduled delivery (6.1.6.4.1 and 6.1.6.4.2) except that a time-interval controller shall be added to the circuit that overrides the normal high working level control.

6.1.6.5 NONMERCHANTABLE OIL INTERRUPTION

In each of the three cases, the following procedures shall be followed:

a. After delivery to the pipeline has begun, if nonmerchantable oil flows continuously past the water monitor for a predetermined time interval, the charge pump is automatically stopped unless the pump is required to circulate oil for treatment.

b. The valve closes, stopping flow to the pipeline.

c. The automatic sampler remains energized in case of inadvertent flow through the meter.

d. The controls lock out the transfer of oil to the pipeline until the nonmerchantable oil has been treated to meet specifications. The LACT unit can be designed to restart automatically after a period of recirculation.

Manual of Petroleum Measurement Standards
Chapter 6—Metering Assemblies

Section 3—Service Station Metered Fuel–Dispensing Systems

Measurement Coordination

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SECTION 3—SERVICE STATION METERED FUEL–DISPENSING SYSTEMS

6.3.1 Introduction

This section of Chapter 6 of the API *Manual of Petroleum Measurement Standards* pertains to service station metering systems used for dispensing motor fuels (except liquefied petroleum gas fuels) to road vehicles at relatively low flow and pressure. Since these systems are used in custody-transfer service, they must meet certain performance requirements and may be required to conform to federal, state, and municipal regulations, codes, and laws. The regulations, codes, and laws may have specific restrictions that must be taken into account in the design and installation of service station metered fuel-dispensing systems.

This section does not focus on service station design as such. It focuses instead on the meter, its appurtenances, and the associated elements that may have a bearing on measurement accuracy.

6.3.2 Scope

This section of Chapter 6 of the API *Manual of Petroleum Measurement Standards* offers guidance on the selection, installation, performance, and maintenance of two common types of metered motor-fuel-dispensing systems: the submersible pump system (often called *a remote pump system, a pressurized pump system*, or *a submerged pump system*) and the self-contained-pump system (often called *a suction-pump system* or *a self-contained system*).

6.3.3 Pertinent Publications

6.3.3.1 REFERENCED PUBLICATIONS

The most recent editions of the following recommended practice and handbook are cited in this section of Chapter 6 of the API *Manual of Petroleum Measurement Standards*.

API
- RP 1615 *Installation of Underground Petroleum Product Storage Systems*

NIST[1]
- Handbook 44 *Specifications, Tolerances, and Other Technical Requirements for Weighing and Measuring Devices*

[1]National Institute of Standards and Technology, U.S. Department of Commerce, Gaithersburg, MD 20899.

6.3.3.2 OTHER PERTINENT PUBLICATIONS

Many aspects of metering are dealt with at length in parts of the API *Manual of Petroleum Measurement Standards* other than this one. Please refer to the following chapters of the *Manual* for more information. Please also refer to the following recommended practice for more information.

API
- *Manual of Petroleum Measurement Standards (MPMS)*
  - Chapter 4, "Proving Systems"
  - Chapter 5, "Metering"
- RP 1621 *Bulk Liquid Stock Control at Retail Outlets*

6.3.4 Field of Application

The systems described in this section of Chapter 6 of the Manual are meant primarily for use in small-to-medium-capacity service stations, large multipump stations, convenience stores, and truck stops or for use in relatively low-flow aircraft-and-marine-motor-fuel-dispensing systems. To a lesser extent, they can apply to fleet-fueling systems, although these are generally outside the jurisdiction of the weights-and-measures authorities.

6.3.5 Dispensing Systems

6.3.5.1 BASIC DISPENSING SYSTEM

A basic dispensing system consists of a fuel reservoir, a pump, a meter and register, provision for air elimination and thermal expansion, miscellaneous valves and piping, and a discharge hose and nozzle. The system may also include other enhancements, such as leak detection, vapor recovery, and safety devices.

6.3.5.2 TYPES OF DISPENSING SYSTEMS

The two most common types of dispensing systems are the submersible pump system (often called *a remote pump system, a pressurized pump system*, or *a submerged pump system*) and the self-contained pump system (often called *a suction-pump system* or *a self-contained system*). Both are wet hose systems that include an antidrain valve inside the delivery nozzle to prevent the hose from being drained when the system is inoperative. Without the antidrain valve, the meter could creep ahead before the next delivery, thereby overstating the delivered volume.

6.3.6 Submersible Pump System

In a submersible pump system, the pump is located at the bottom of the fuel reservoir, and it pushes the fuel under pressure through the complete system. A single submersible pump may serve one or several dispensing hoses simultaneously.

An important advantage of this system is that during operation, fuel is under pressure and little possibility exists for the fuel to vaporize and have an adverse effect on measurement accuracy. Once the piping system is purged, the submerged pump cannot pump air into the system. A check valve at the pump discharge head prevents backflow in the piping when the system is inoperative. If backflow or emptying does occur—allowing air to enter the pipe connecting the pump to the pump discharge head—the air will be purged from the pipe when the pump is activated for subsequent dispensing and the pipe is repressurized with fuel.

Since submersible pump systems are pressurized, a means for detecting leaks in the piping is usually provided. The systems also include an impact safety valve beneath each dispenser to stop the flow of fuel if a dispenser is struck or damaged. Pressure from thermal expansion is relieved through a thermal relief valve in or near the check valve in the pump discharge head.

Figure 1 illustrates a typical submersible pump system.

6.3.7 Self-Contained-Pump System

A self-contained-pump system is a dispensing system whose dispenser contains the pump that draws its fuel. In this system, fuel is drawn from the fuel reservoir up through piping to the pump within the island dispenser. From that point on, the pump pushes the fuel through the balance of the system. In this system—unlike a submersible pump system—no dispenser impact valve is utilized in suction piping since a break usually terminates fuel flow. Although self-contained-pump systems are less costly in certain applications, they tend to vaporize fuel as it is sucked upwards by the pump from underground storage.

Note: Caution must be exercised not to exceed the manufacturer's recommendations for vertical lift and overall horizontal length of piping during installation and application. Otherwise, an operational problem might follow.

In self-contained-pump systems, air is allowed to enter the piping because the system's positive displacement pump can

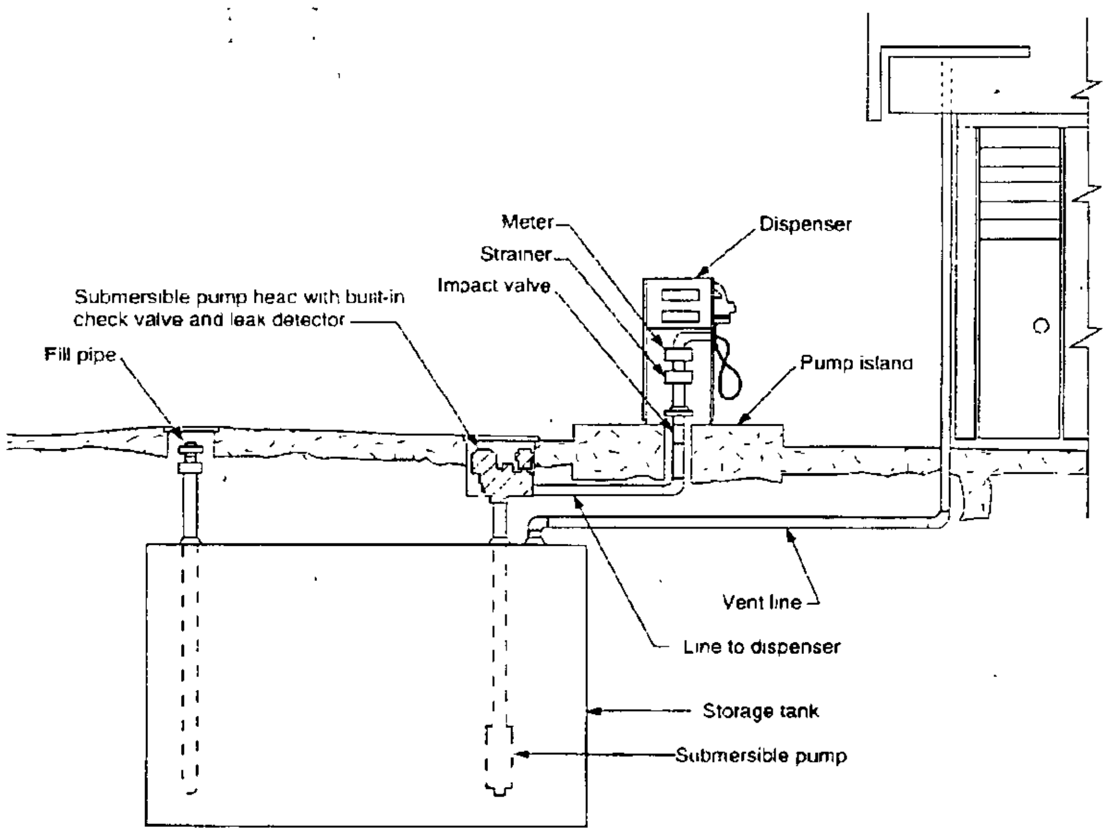

Figure 1—Metering System With Submersible Pump

effectively pump air. However, a foot valve on the suction pipe near the bottom of the fuel reservoir prevents backflow when the pump is deactivated. To remove air, the fuel is passed through an air eliminator, located on the discharge side of the pump in the dispenser. The air eliminator allows air entrained in the fuel to settle out after passing from the high-pressure chamber to the low-pressure chamber of the eliminator. Once air is separated from the fuel, it is vented to the atmosphere. The vent must never be plugged or restricted, because if it is, air will enter the meter.

Unlike submersible pump systems, which have thermal relief for fuel expansion built into the pump head, self-contained-pump systems relieve into the low-pressure chamber of the air eliminator. The excess fluid is fed back into the system when the pump is operated.

Figure 2 illustrates a typical self-contained-pump system.

6.3.8 System Selection

In adverse conditions such as long underground lines, high vertical lift, relatively high ambient temperatures, and high geographic elevations, submersible pump systems have an advantage over self-contained-pump systems. These conditions may cause poor performance in a self-contained-pump system. In addition, fuel vaporization could cause the meter of a self-contained-pump system to behave erratically.

Self-contained-pump systems perform very well where lines are relatively short and buried to a satisfactory depth, temperature limits are not exceeded, and barometric pressure is never low.

6.3.9 Meter and Register

6.3.9.1 METER

Generally, meters used in service station dispensing systems are of the sealed piston type, which is accurate over a relatively broad flow range—typically 2–15 gallons per minute. The accuracy requirement for a new installation is approximately 0.25 percent. Strainers installed upstream of the meter should be cleaned periodically to protect the meter.

The meter is equipped with an adjustable calibration mechanism for use when the meter is proved against a standard test volume. Tampering with the calibration mechanism

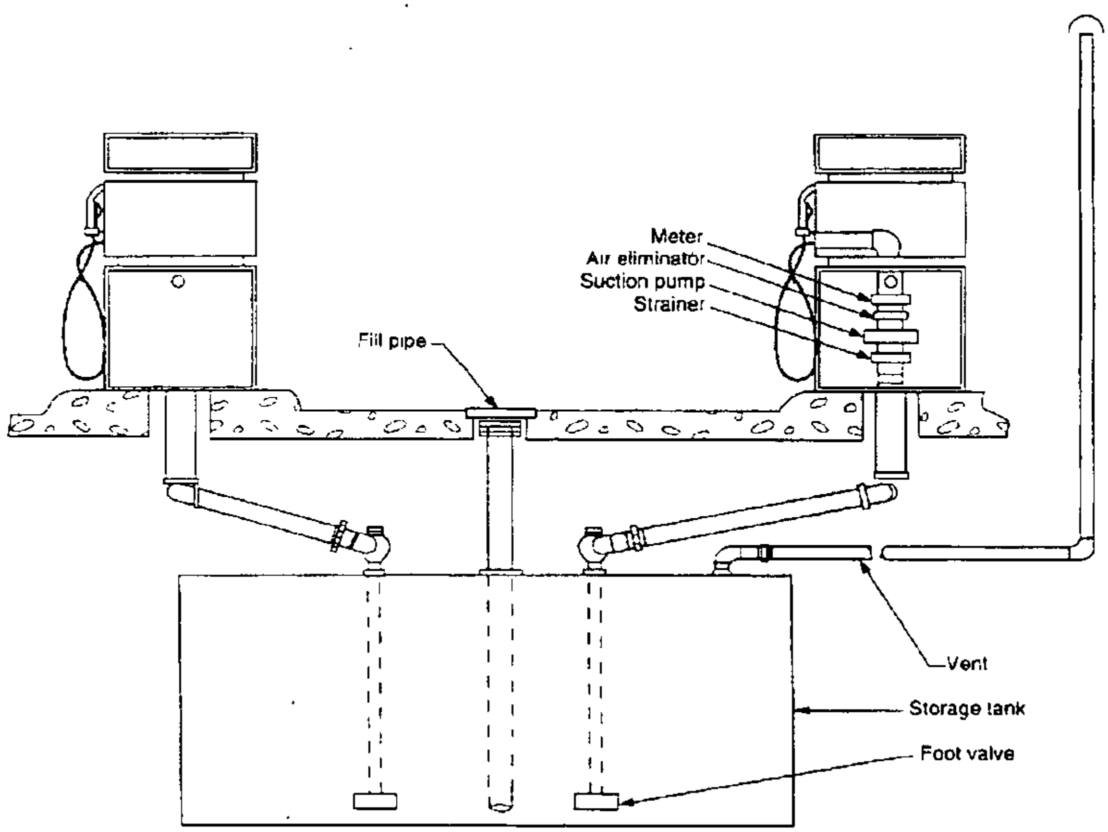

Figure 2—Metering System With Self-Contained Pumps

is indicated by broken seals. The calibration mechanism must be sealed by authorized weights-and-measures personnel.

6.3.9.2 INDICATING REGISTER

The register may be of the mechanical type or the digital electronic type. In either type, the register computes the total sales by multiplying the posted price per gallon of the particular fuel delivered times the number of gallons (with any fraction thereof) of fuel delivered.

The register is interlocked to the delivery hose to the extent that a subsequent delivery cannot be made until the register is reset to zero gallons and zero dollars.

Registers should display both the transaction gallonage and the totalizer reading of all gallons dispensed through the register. All information displayed should be as defined by NIST Handbook 44.

6.3.10 Installation

Underground piping associated with self-contained-pump systems should be kept as short as possible and installed at an appropriate depth to prevent or minimize fuel vaporization. Underground product tanks should be maintained in a secure environment; this can be done by providing facilities for locking or sealing the fill pipe cover. API Recommended Practice 1615 recommends procedures for the installation of underground gasoline tanks and piping at service stations. Authorized weights-and-measures personnel must prove and seal the meters in a new installation before the dispensing system can be placed in service.

6.3.11 Meter Proving

Motor fuel dispenser meters are proved on a regular basis, generally annually. Proving is performed by authorized weights-and-measures personnel by dispensing a discrete quantity—usually 5 gallons—into a field test measure. The quantity indicated on the dispenser register must compare with the quantity deposited in the test measure within the designated tolerance for the flow rate used. Acceptance tolerances may vary slightly among the various local approval authorities. (Refer to NIST Handbook 44 for nationally specified tests and tolerances.) A security seal must be applied to the meter calibrator and a seal of approval must be applied to the dispenser before the dispenser is placed in custody-transfer service.

6.3.12 Maintenance

Line filters and strainers must be cleaned or replaced frequently to prevent unnecessary flow restrictions and to protect the meter.

Flow nozzles must be tested periodically to determine whether antidrain valves successfully retain product in the wet hose.

Delivery hoses and retraction mechanisms must be examined to ensure that they are in good condition and functioning properly.

Periodic inventory reconciliation should be performed by checking whether computed sales totals balance against existing inventory plus the actual product delivered.

CAUTION: Care must be taken to ensure that all equipment components (gaskets, seals, valve trim, hoses, and the like) and construction materials are compatible with today's product additives, oxygenates, and octane improvers.

6.3.13 Additional Considerations

Recently, increased public concern for protection of the environment has generated new legislation and code regulations that require the following:

a. Corrosion protection for exposed underground metallic components.
b. Tank overfill protection.
c. Tank fill containment.
d. Underground monitoring to detect possible spills or leaks.
e. Vapor recovery.

Some jurisdictions have gone even further and now require secondary containment of the underground portions of a dispensing system. For further information, see API Recommended Practice 1615.

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Section 6—Pipeline Metering Systems

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Chapter 6—Metering Assemblies

SECTION 6—PIPELINE METERING SYSTEMS

6.6.1 Introduction

The three principal characteristics of a pipeline that affect the selection of the type of measurement equipment best suited to it are:

a. The high fixed cost, which makes continuous operation desirable.
b. The capacity, which implies large volumes and high rates.
c. The need for efficient operation and maximum accuracy in measuring the throughput of the system.

The advantages of dynamic measurement (metering) over static measurement (gauging) for pipeline oil movements are provided in Chapter 5.1.

This chapter deals with liquid hydrocarbons (crude oils, condensates, refined products, and hydrocarbon mixtures). Two-phase fluids are not included.

Individuals concerned with installing measurement equipment for liquid hydrocarbons of high vapor pressures, such as ethane-propane mixes, propylenes, and so on, may find this chapter useful; however, special additional precautions may be required.

6.6.2 Scope

This chapter provides guidelines for selecting the type and size of meter(s) to be used to measure pipeline movements. Types of accessories and instruments that may be desirable are specified, and the relative advantages and disadvantages of the methods of proving meters by tank prover, by conventional pipe prover, by small volume prover, and by master meter are discussed. This chapter also includes discussions on obtaining the best operating results from a pipeline-meter station.

6.6.3 Field of Application

The information provided in this chapter may be applied to the following systems:

a. Gathering systems from production facilities to a main crude oil storage or pipeline system.
b. Crude oil pipelines.
c. Refined product pipelines.
d. Liquefied petroleum gas (LPG) pipelines.

6.6.4 Referenced Publications

Many of the aspects of the metering functions are considered at length in other parts of this manual. Please refer to the following chapters for more information.

API
Manual of Petroleum Measurement Standards
- Chapter 4—"Proving Systems"
- Chapter 4.3, "Small-Volume Provers"
- Chapter 5—"Metering"
- Chapter 5.1, "General Considerations for Measurement by Meters"
- Chapter 5.2, "Measurement of Liquid Hydrocarbons by Displacement Meter"
- Chapter 5.3, "Measurement of Liquid Hydrocarbons by Turbine Meters"
- Chapter 5.4, "Accessory Equipment for Liquid Meters"
- Chapter 5.5, "Fidelity and Security of Flow Measurement Pulsed-Data Transmission Systems"
- Chapter 8—"Sampling"
- Chapter 12.2, "Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters"
- Chapter 13.2, "Statistical Evaluation of Meter Proving Data" (under development)

6.6.5 Meter Station Design

As defined in this publication, a metering station on a pipeline system is one where custody transfer measurement takes place through one or more meters. When a pipeline-metering system is designed, the objective is to obtain optimum measurement accuracy for custody transfers regardless of the volume handled. The measurement accuracy of the system depends on meters, provers, valves, and other equipment selected for that measurement system.

Other considerations for a meter station design include providing for future expansion and upgrades, accessibility of the equipment for maintenance, and accuracy verification.

Chapters 4 and 5 of this manual should be consulted for further requirements common to all proving and metering systems.

6.6.5.1 METER SELECTION

Although displacement meters (see Chapter 5.2) and turbine meters (see Chapter 5.3) are the most commonly used meters in pipeline applications, other types of meters are not excluded if they serve the intended purpose.

Meter selection is discussed in Chapter 5.1. In general, turbine meters are preferred for high-flow rate and low-viscosity applications. In high-pressure applications, capital and installation costs of turbine meters may be less. However, in crude oil service viscosity, wax content or the presence of fibrous material may limit the use of turbine meters. When the relative merits of displacement and turbine meters are evaluated, both maintenance and operating costs should be considered. Maintenance costs for displacement meters may be significant when liquids with poor lubricity or abrasive characteristics are handled. Turbine meter maintenance costs are usually low, but maintenance of adequate back-pressure to ensure accuracy may result in higher power costs.

Before selecting a meter, the designer must know or have a good estimate of the following:

a. The range of physical and chemical characteristics of the liquid in:

1. Viscosity, lubricity, and pour-point
2. Density (API gravity).
3. Corrosive, abrasive, fibrous, wax, or other foreign material.
4. Vapor pressure.

b. The range of flow rates and pressures.

c. The range of liquid temperature and ambient temperatures that will be encountered.

d. The duration of operation (continuous or intermittent).

e. The location of the meter station and whether its control is to be local or remote, attended or unattended.

6.6.5.1.1 Viscosity

The linearity of a displacement meter improves as the viscosity of the fluid being metered increases. This improvement is a result of decreased slippage in the meter. (See Chapter 5.2.)

Turbine meters generally perform with a broader linear range in lower viscosities. (See Chapter 5.3.)

Turbine meters would normally be selected for use with low-viscosity refined products, such as propane, gasoline, diesel oil, and so on, because of their longer service life, greater rangeability, and equal or better accuracy than a displacement meter on these types of products. (See Chapter 5.1.)

6.6.5.1.2 Density

The rating of a displacement meter is generally not affected by the density of the liquid that it must measure. In installations where turbine meters are used, the linear range of the meter tends to shift with density. (See Chapter 5.3.) In general, a turbine meter's normal flow range shifts to a higher range as density decreases. Conversely, for higher density liquids, the pressure drop across the meter increases more rapidly as flow rate increases.

6.6.5.1.3 Corrosive, Abrasive, and Foreign Materials

Abrasive solids, acid or alkaline chemicals, and some salts are typical foreign materials in a petroleum liquid that can harm a meter and its operation. If displacement meters are intended for use with liquids containing relatively large amounts of abrasive or corrosive materials, the manufacturer should be consulted about the materials used for meter construction.

In general, a limited amount of fine abrasives and corrosive contaminants have less effect on the life and performance of a turbine meter because solids in suspension continue to flow uninterrupted through the meter. Corrosive contaminants do not affect, to any marked degree, typical stainless steel turbine meters. On the other hand, displacement meters are more affected by fine abrasives because of the close clearances of the moving parts and because the standard materials of construction can be affected by reactive chemicals. Conversely, fibrous materials, weeds, and wax, which are sometimes present in crude oils, have little effect on displacement meters. However, these contaminants tend to become lodged on rotor blades and straightening sections of turbine meters and affect their operation.

6.6.5.1.4 Vapor Pressure

The vapor pressure of the liquid to be metered is a factor in determining the pressure rating required for the meter and the meter manifold. Vapor pressure also has a bearing on the type of pressure control equipment and valves needed to maintain a liquid phase and accurate measurement.

6.6.5.1.5 Flow Rate

The selected meters shall have the capacity to handle the minimum and maximum expected pipeline flow rate. Displacement meters are normally selected for continuous operation at about 75 percent of the manufacturer's nameplate capacity, if the liquid has reasonable lubricity. The capacity of displacement meters is reduced to as low as 40 percent of nameplate capacity for liquids with poor lubricity, such as butane or propane. Turbine meters may be operated at full nameplate capacity and beyond, but because pressure drop increases with flow rate, power costs may be a factor in choosing the most suitable size of meter.

Optimum accuracy may require displacement meters to be operated at rates above 20 percent of maximum nameplate capacity. Turbine meters, depending on fluid characteristics, may require operation at rates above 40 percent of maximum nameplate capacity for optimum accuracy.

6.6.5.1.6 Temperature

When pipelines generally operate in moderate ambient temperature ranges, special temperature considerations in meter selection or installation are seldom necessary. However, if abnormal temperatures are anticipated, such as high temperatures that may be required for handling high pour-point liquids, consultation with meter manufacturers may be required before meter selection. In addition, handling of hot hydrocarbon liquids may require insulation, heat tracing, or both, of meter manifolding and exposed sections of the tank or lines feeding the meters.

In cold climates, it may be necessary to protect a meter's auxiliary equipment (such as counters and printers) by installing a heated shelter over the meter to prevent failure of the auxiliary equipment. This precaution becomes more critical when electronic equipment is used. Changes in the temperature of a hydrocarbon liquid cause changes in its viscosity. In turn, this change results in a shift of meter factor and a possible shift in normal operating range.

6.6.5.1.7 Continuous or Intermittent Service

Both displacement and turbine meters are designed for either continuous or intermittent service. However, for continuous operation, some arrangement must be provided for standby metering or alternate methods of measurement to cope with normal meter maintenance, scraper runs, or equipment trouble. (See 6.6.5.2.)

6.6.5.1.8 Location

Displacement meters with mechanical registers are well suited to small capacity systems and remote locations. They do not necessarily require uninterrupted electric power and electronic equipment to provide a readout of quantity measured as turbine meters do.

6.6.5.2 METER SIZING

6.6.5.2.1 General Considerations

In new meter stations, the system may be more flexible and less costly if a bank of meters in parallel is installed rather than a single large meter and a single large prover. If an existing prover is to be used, then the new meters selected should be compatible with the existing prover. See Chapter 4 for size limitations of provers.

6.6.5.2.2 Sizing Displacement Meters

If a new measurement system is to be installed, the size of the displacement meters (see Chapter 5.2) may be decided by using the following steps:

a. Determine the maximum and minimum meter station flow rates expected.
b. If pipeline flow cannot be interrupted, provide a spare meter run so that measurement may continue at the normal rate if the primary meter fails.
c. Size each displacement meter for normal operation at 75 percent of its maximum nameplate capacity.

In most cases when a tank prover is to be used, a minimum of two meters in parallel will be required because flow from the meter to be proved has to be stopped immediately before and after proving. It may not be practical to interrupt the pipeline flow to achieve this requirement except in cases of small lease automatic custody transfer (LACT) gathering systems.

Final selection depends on the performance desired, the space available, and the size and cost (capital and operating) of the meters, prover, associated valves, piping, and auxiliary equipment.

6.6.5.2.3 Sizing Turbine Meters

Sizing a turbine meter requires more detailed considerations than that for a displacement meter because turbine meter performance is more likely to be affected by liquid density and viscosity. (See Chapter 5.3.) Turbine meters tend to be chosen for meter stations that are operated at higher flow rates and lower viscosities.

Fibrous and foreign material tends to get caught on turbine meters in service. It is, therefore, desirable to have a spare meter that can be rotated with the operating meter to allow for disengaging and flushing away fibrous and foreign material before the meter is returned to service. When flow cannot be interrupted, it is desirable to have an alternate meter run so that the contaminated meter can be removed, inspected, and cleaned. In crude oil service and when permissible, it may be desirable to have a back-flushing system that permits reverse flow for a short period to remove material trapped on the turbine blades.

When the size and number of meters needed to meet the required station flow rate are determined, the viscosity and density must be considered. As viscosity increases, the range of flow over which the meter's linearity is acceptable decreases; therefore, greater meter capacity may be required to satisfy a given flow rate. As the density of a liquid decreases, the entire linear portion of the performance curve moves toward the higher flow rates; that is, a liquid with a density of around 0.5 may effectively have the meter over-ranged by a factor of 1.5 times its maximum nameplate capacity with no appreciable increase in pressure loss.

Because the performance of turbine meters tends to improve with increased size, caution should be exercised before smaller sizes are selected, especially for crude oil service. Thus, a simple formula to determine the number of meters required for a specific application cannot be given. Manufacturers should be consulted for particular applications.

6.6.5.3 INSTRUMENTATION AND ACCESSORIES

Accessory equipment and instrumentation for meters are discussed in Chapter 5.4. Accessories widely used in pipeline meter stations include those described in 6.6.5.3.1 through 6.6.5.3.9.

6.6.5.3.1 Strainers and Filters

Strainers and filters incorporated into pipeline-metering stations should not be used to clean the stream for quality improvement. They should be used only to remove solids that might otherwise damage a meter or create uncertainty of measurement.

Meters can be protected individually or as a bank. With displacement meters, the strainer can be installed immediately upstream from the meter. (See Chapter 5.2.) With turbine meters, the problem of liquid swirl has to be considered. A pipeline-meter station and a filter or strainer should be placed well upstream from the meter run. (See Chapter 5.3.)

Strainers used in crude oil service should be equipped with a coarse basket (usually four mesh is sufficient) to protect the meter-straightening vane and prover from damage by foreign material other than sediment and water. The use of too fine a mesh often defeats the purpose of the strainer because the possible accelerated accumulation of trash may create excessive pressure drop across the strainer. This could lead to rupture of the basket or to vaporization of the liquid. Either of these events affect measurement accuracy. Therefore, it is usually desirable to monitor the pressure differential across a basket with an alarm system or other suitable means.

6.6.5.3.2 Water Separators and Water Monitors

Water separators and water monitors are generally confined to uses in crude oil gathering and aircraft fueling systems. Monitors are sometimes used at initiating meter stations of a pipeline when suction is taken from crude oil or jet fuel storage tanks and when it is practical to prevent water from entering the system.

In gathering systems, a water monitor is installed upstream from the meter to suspend shipments to the pipeline automatically if the water content exceeds a pre-set value. This monitor may be used to prevent water from entering the pipeline or its storage system

6.6.5.3.3 Back-Pressure Valves

A back-pressure valve shall be installed downstream from the meter station if the line resistance downstream is insufficient to maintain pressure on the system consistently high enough to prevent vaporization at all operating conditions. In all systems, adequate back-pressure must be maintained to ensure accurate measurement. For turbine meters, the minimum back-pressure should be approximately twice the pressure drop across the meter at maximum flow rate plus 1.25 times the absolute vapor pressure of the liquid at maximum operating temperature. (See Chapter 5.3.7.3.8.)

These approximate rules vary with the application. For example, turbine meters generally require more back-pressure than an equivalent displacement meter (in nameplate capacity) because of the turbine meter's flowpath, which accelerates the velocity and thus reduces static pressure that can cause vaporization or gas release and subsequent cavitation. Although back-pressure is a critical requirement for measurement, excessive back-pressure may result in excessive power costs. A back-pressure valve should be of fail-safe design. It should resist flow as pressure decreases and open as liquid pressure increases. A flow control valve may double as a back-pressure valve when it is placed downstream of the meter.

6.6.5.3.4 Flow Control Valves

If the flow rate needs to be limited through a pipeline-meter station, the manually or automatically operated control valve, should be installed downstream from the meter so that vapor breakout occurring in the valve does not affect measurement. However, such an arrangement may imply that the pressure in and around the meter manifold would require pressure ratings to be one or more levels higher. In the case of displacement meters, this situation would considerably increase the cost of the meters, filters, strainers, and other accessories used with them. In the case of turbine meters, the added cost for a higher pressure rating may be lower, but the cost of accessories may still be a factor.

If, for reasons of cost, the flow control valve needs to be installed upstream from the meter, installation should be as far upstream as practical. In the case of a turbine meter, installation of the control valve should be at least 50 pipe diameters upstream from the meter. If the action of the control valve causes vapor breakout, the vapor must be removed from the stream before it reaches the meter. Installation of a back-pressure valve downstream from the meter may still be required to maintain pressure on the meter. (See 6.6.5.3.3.)

6.6.5.3.5 Air Removers

Air removers (air eliminators) should be installed upstream from the meter if air or vapors might enter the metered stream and adversely affect measurement. However, in most installations, the entrance of air may be more practically prevented by automatic air-sensing shut-off systems than by removing the air once it has entered the flowing stream. This is particularly true of crude oil service.

Air removers operate by reducing stream velocity through an expansion of cross section. This principle allows entrained lighter gases to escape upwards if the viscosity of the liquid is not too great to delay or halt the process. A series of baffles assists in the separation. As air, gas, or vapor accumulates, a float valve opens and allows escape.

In a pipeline-meter station, if a high vacuum (negative head) could possibly exist, a check valve should be installed in vent lines to prevent air being drawn into the air remover. It is also advisable in pipeline-meter stations to install one or more vent valves at high points in the station manifolding. This precaution allows the air to be bled off after maintenance or drain-downs.

6.6.5.3.6 Flow Conditioning

Pipeline-meter stations that use turbine meters shall have a flow-conditioning section installed upstream and a recovery section installed downstream of each meter. See Chapter 5.3 for a full description of the arrangement and the details of the effect of piping configurations on swirl. Flow conditioning is not usually required in installations where displacement meters are used.

6.6.5.3.7 Displacement Meter Counters

Frequently, a small-numeral, mechanical, non-resettable totalizer counter that registers in whole, appropriate units is used on displacement meters to indicate metered throughput. In addition to the non-resettable totalizer, a mechanical, resettable, large-numeral counter that registers in fractions of a unit (that is, a cubic meter or barrel) for use when proving into tank-type provers may be included on the meter. The smallest fractional increment to be displayed on the large-numeral counter depends on the size of prover used.

Large-numeral, resettable counters may be used wherever they offer an advantage, provided that indicated volumes of oil measured are read from the non-resettable counter. Large-numeral counters may be fitted with a monitor switch that can be used to pulse a remote register or to detect meter failure. This switch should be operated by the non-resettable counter. This feature can be valuable at unattended stations.

A high-resolution pulse transmitter and high-resolution proving counter are required when proving a displacement meter with a pipe prover. (See Chapter 4 for details.)

6.6.5.3.8 Turbine Meter Counters

Turbine meters generally are connected to one non-resettable totalizer counter that reads in whole units per meter and that indicates the metered throughput. Additional counters, such as prover or net counters, may be added as the need arises without affecting meter performance. A discrete high-resolution pulse-proving counter that is gated by the prover's detector switches is required for proving a turbine meter. (See Chapter 5.4 for information on counters and Chapter 5.5 for information on electronic pulse transmission systems.)

6.6.5.3.9 Ticket Printers

Ticket printers are discussed in detail in Chapter 5.4. Mechanical and electrical printers are the two most common types.

Mechanical printers are generally used with displacement meters because they can be coupled directly to the meter's output shaft and do not require an external power source. A mechanical printer can also be used with a turbine meter, but in this arrangement, pulses generated by the meter drive a stepper motor which, in turn, drives the register and printer. (See Chapter 5.4.)

Electrical or electrical-mechanical printers can be used with either type of meter, but they require an electric signal, generated by the meter, to be electrically coupled to the printer. Electrical printers are generally suited to turbine meters which directly generate electric signals. They are also used for totalizing a number of meters or for remote readout. Although an external power source is required, electrical printers have the advantage of minimizing torque on the meter output. (See Chapter 5.4 for a further description.) Dual registers and printers can be used to facilitate swings from batch to batch either manually or automatically. Multiple meter-pulse combinators, temperature-compensating equipment, and similar devices are discussed in Chapter 5.4. Special attention must be given to the installation of electronic systems to ensure that extraneous pulses are not registered. Shielded conductors, proper grounding of equipment, and shielding are essential. (See Chapter 5.5.)

6.6.5.4 SAMPLING

Because pipeline movements are measured in batches or tenders that may differ appreciably in liquid properties (viscosity and density), the stream interfaces must be sampled to segregate batches for meter proving and to assign meter factors to be applied to each batch. Other aspects of sampling (for example, determining crude oil quality) that require representative samples be taken by proportional sampling techniques are discussed in Chapter 8.

6.6.5.5 PROVING

A pipeline-meter station shall have either a fixed prover, connections for a portable prover, or master-meter proving. Chapter 4 should be consulted before the proving arrangements for a station are designed. The four standard methods of proving by conventional pipe prover, small-volume prover, tank prover, or master-meter prover are described in Chapter 4. See Chapter 12.2 for an explanation of the standard methods of calculating petroleum quantities and determining meter factors. The decisions reached as a result of design deliberations in 6.6.5.1 and 6.6.5.2 will largely determine the selection of the most suitable meter-proving systems.

6.6.5.5.1 Tank Provers

Tank provers have a capital cost advantage over pipe provers in fixed installations. In small-capacity or remote pipeline-meter locations without electric power, tank provers can be used for accurate proving of displacement meters. The tank prover is not readily adapted to automation or remote control. Tank provers have the disadvantage of requiring two or three tank fillings per meter proof, which have to be returned to a line under pressure. Reproducible drainage of prover tank walls is also critical. This feature is a further disadvantage of tank provers over pipe provers and master meters.

Tank provers are not suitable for high-vapor pressure products because the product may be lost by evaporation from an open-tank prover during the prover operation. Tank provers may not be suitable for viscous liquids that may not completely drain from the inner surfaces of the tank prover during drain-down between proving runs.

6.6.5.5.2 Conventional Pipe Provers

Conventional pipe provers are readily adapted to automation and remote control and are capable of fast, easy, and reproducible proving in either a fixed or portable arrangement. Conventional pipe provers are relatively expensive, but if used by a number of small stations in the portable or mobile mode, their capital cost can be disbursed accordingly. In most large or new stations, conventional pipe provers have advantages over other methods.

A portable pipe prover can be equipped with its own power supply, making it usable at a meter station where power is not available.

6.6.5.5.3 Small-Volume Provers

Small-volume provers share the advantages of conventional pipe provers and, being small, are well adapted to portable applications. (See Chapter 4.3 for details.)

6.6.5.5.4 Master-Meter Provers

Master-meter proving is used when other prover methods are not practical. It is sometimes used as a backup to the other proving systems, and with small changes to the station manifold, it can be applied to any existing station. A master meter can be used in conjunction with a mobile pipe or tank prover to prove operating meters at any station.

6.6.5.6 TYPICAL PIPELINE-METER STATION LAYOUTS

Figure 1 shows a schematic diagram of a typical displacement meter installation. Figure 2 shows a typical turbine meter installation. The expected measurement conditions of each installation dictate what options are necessary; not all options shown in the schematics may be required, and options not shown may still be required.

6.6.6 Meter Station Operation

This publication is intended to assist the designer of a pipeline-meter station to select and install the equipment appropriate to the needs of its proposed operation. Chapters 4 and 5 contain much information that applies to pipeline-meter station design, selection, and installation, and these chapters also contain most of the information affecting their operation and maintenance.

The operator of a pipeline-meter station, therefore, knowing the type of liquids involved, the type and size of meters and proving systems provided, and the range of values of the principal variable—rate, viscosity, temperature pressure, and density—should review those parts of Chapter 5 that deal with meter performance, operation, and maintenance, bearing in mind the considerations described in 6.6.7.

6.6.7 Meter Performance

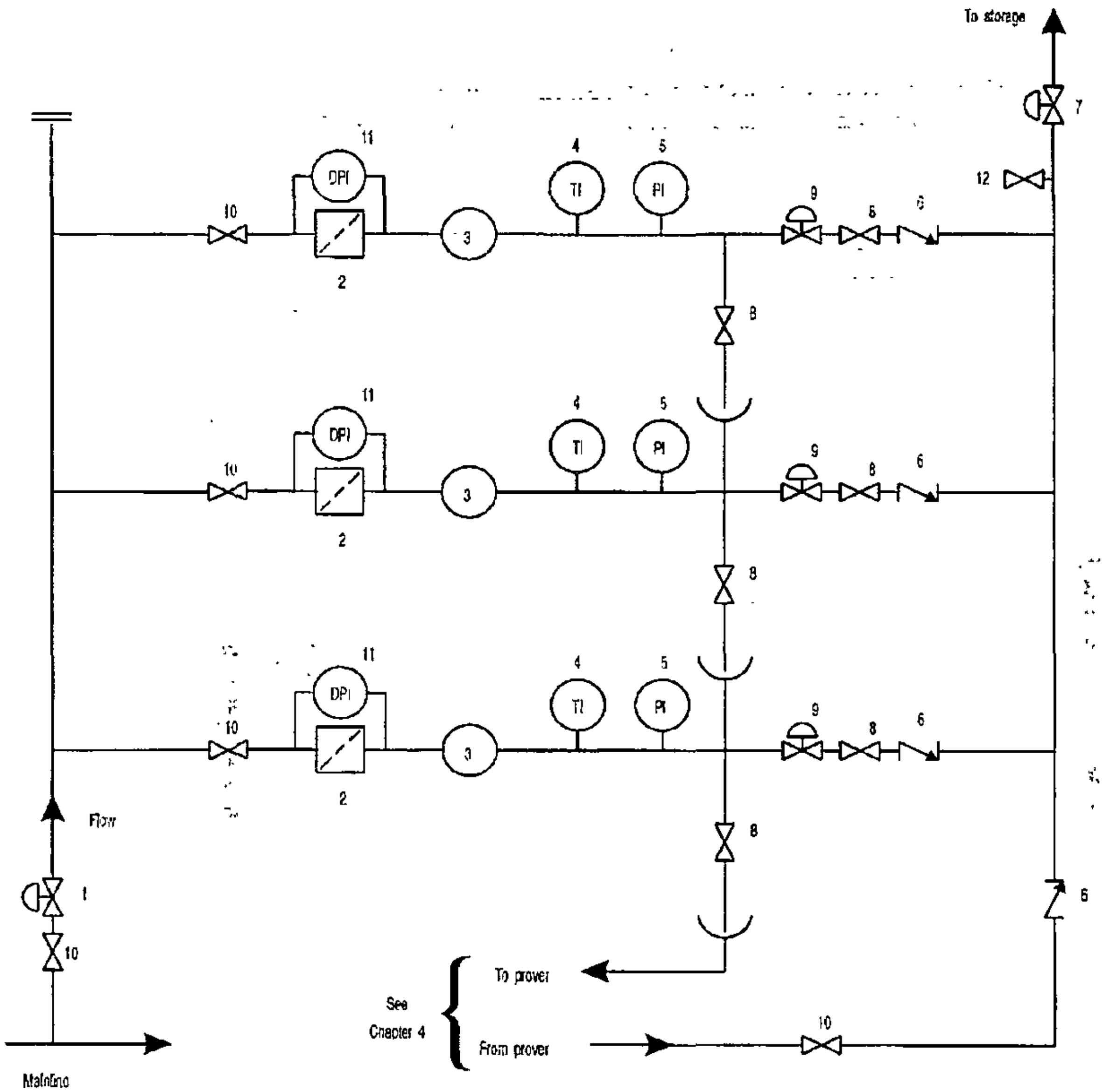
Meter performance is a general expression and is used to indicate how satisfactorily a meter can continuously measure the actual volume of liquid passing through it. It is most often shown as a characteristic or performance curve, which is a plot of meter factor versus rate. Because a meter factor is applied to the indicated volume in all pipeline-metering systems involving liquid hydrocarbons, the usefulness of the characteristic curve lies in its ability to show by how much a meter factor will change with a given change in rate. Individual curves should be made for each product or grade of crude oil.

Meter performance can also be plotted as meter factor versus any operating parameter, that is, viscosity, temperature, and so forth. However, when the liquid properties change significantly (for example, when a new batch or tender is to be measured), a new meter factor should be developed by re-proving. The most common presentation of meter performance is a plot of meter factor versus rate at stable operating conditions. Meter proving should be done frequently if maximum accuracy is essential.

6.6.7.1 NET STANDARD VOLUMES

The custody transfer measurement of hydrocarbon liquids is performed to obtain a quantity definition that is the basis for commercial transactions. This quantity is most often expressed as a net standard volume. Net standard volumes are volumes corrected for meter factor, for the effects of temperature and pressure on both the liquid and the steel of the prover used to determine the meter factor, and for sediment and water content, if applicable.

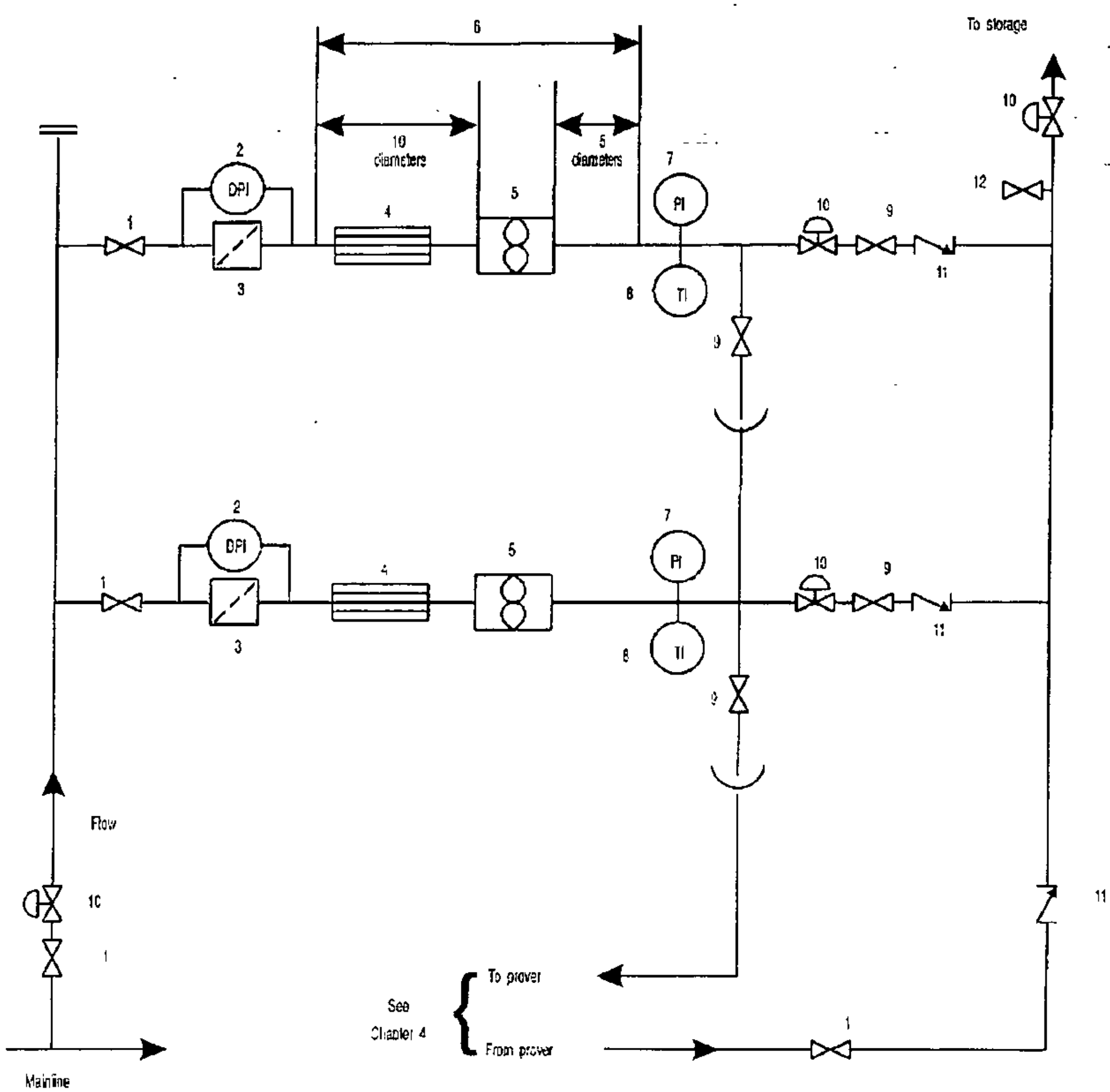
The standard methods for calculating a prover's base volume, a meter factor, and a measurement ticket are detailed



1. Pressure-reducing valve-manual or automatic, if required.
2. Filter, strainer and/or vapor eliminator (if required) for each meter or whole station.
3. Displacement meter.
4. Temperature measurement device.
5. Pressure measurement device
6. Check valve, if required
7. Control valve, if required.
8. Positive shut-off, double block and bleed valves.
9. Flow control valve, if required.
10. Block valve, if required.
11. Differential pressure device, if required.
12. Sampler, proportional to flow.

Note: This simplified diagram indicates primary components for typical stations but is not intended to indicate preferred locations. All sections of the line that may be blocked between valves should have provisions for pressure relief (preferably not to be installed between the meter and the prover).

Figure 1—Typical Schematic Arrangement of Pipeline-Meter Station With Three Displacement Meters



1. Block valve, if required.
2. Differential pressure device, if required.
3. Filter, strainer and/or vapor eliminator (if required) for each meter or whole station.
4. Straightener assembly.
5. Turbine meter.
6. Meter run (straight pipe).
7. Pressure measurement device.
8. Temperature measurement device
9. Positive shut-off, double block and bleed valve
10. Control valve, if required.
11. Check valve, if required.
12. Sampler, proportional to flow

Note: This simplified diagram indicates primary components for typical stations but is not intended to indicate preferred locations. All sections of the line that may be blocked between valves should have provisions for pressure relief (preferably not to be installed between the meter and the prover).

Figure 2—Typical Schematic Arrangement of Pipeline-Meter Station With Two Turbine Meters

in Chapter 12.2. The derivation and calculation of all the correction factors that enter therein are also described in Chapter 12.2. Standard conditions to which most volumes are corrected are 60°F and 14.73 pound per square inch absolute.

6.6.7.2 METER PROVING

Refer to Chapters 4 and 5 for general guidelines on meter proving.

In a pipeline-metering system, additional consideration should be given to proving the meters each time there is a change of product through the metering assembly. Other considerations may include changes in flow rate, temperature, or pressure that may cause a measurable change in meter factor.

6.6.7.3 METER FACTOR CONTROL CHARTS

Another way of plotting a meter's performance is by keeping a meter factor control chart for each product or grade of crude oil. (See interim Chapter 13.2.) Such a control chart is essentially a plot of meter factor versus time, that is, a graphical record of meter factor values over months or years. Because control charts show valid limits for random distribution of meter factor values, they can be used as an aid in judging the correct frequency of proving and the acceptable repeatability of values during a proof and also in deciding when inspection or maintenance is needed.

A log book of preventive and repair maintenance should be kept at each meter station for each meter so that costs and performance can be compared from time to time. A notation on the control charts should also be made.

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Manual of Petroleum Measurement Standards Chapter 12—Calculation of Petroleum Quantities

Section 2—Calculation of Liquid Petroleum Quantities Measured by Turbine or Displacement Meters

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Chapter 12—Calculation of Petroleum Quantities

SECTION 2—CALCULATION OF LIQUID PETROLEUM QUANTITIES MEASURED BY TURBINE OR DISPLACEMENT METERS

12.2.0 Introduction and Purpose

Before the compilation of this publication, which is part of the API *Manual of Petroleum Measurement Standards*, calculation procedures and examples of calculations were mixed in with former API measurement standards dealing with provers, meters, tank gaging, and so forth. The writing of the former standards was spread over a period of 25 years or more; each standard was written by a different group of persons; and each group was faced with slightly different requirements. As a result, the calculation procedures lacked coherence and the interpretations of words and expressions varied. Because the data was spread over so many standards comparisons of the finer points of calculations were difficult.

Moreover, when most of the former standards were written, mechanical desk calculators were widely used for calculating measurement tickets, and tabulated values were used more widely than is the case today. Rules for rounding and the choice of how many significant figures to enter in each calculation were often made up on the spot. With the advent of computers and of solid state scientific desk calculators, it soon became apparent, to discerning practitioners, that a × b × c was not necessarily identical with c × a × b or with b × c × a. For different operators to obtain identical results from the same data, the rules for sequence, rounding, and significant figures have to be spelled out. This publication aims, among other things, at spelling out just such a set of minimum rules for the whole industry. Nothing in this publication precludes the use of more precise determinations of temperature, pressure, and density (gravity) or the use of more significant digits, by mutual agreement among the parties involved.

The present publication consolidates and standardizes calculations pertaining to metering petroleum liquids using turbine or displacement meters and clarifies terms and expressions by eliminating local variations of such terms. The compilation of this publication would not have been possible even 5 years ago because the methods and equipment used in dynamic measurement of petroleum liquids have greatly advanced in the recent past. It is therefore timely, perhaps overdue; but it is not a denial of former methods so much as a refinement and clarification of them. The purpose of standardizing calculations is to produce the same answer from the same data regardless of who or what does the computing.

12.2.1 Scope

This publication defines the various terms (be they words or symbols) employed in the calculation of metered petroleum quantities. Where two or more terms are customarily employed in the oil industry for the same thing, this publication selects what should become the new standard term, for example, "run tickets," "receipt and delivery tickets," and the like are herein simply "measurement tickets."

The publication also specifies the equations which allow the values of correction factors to be computed. Rules for sequence, rounding, and significant figures to be employed in a calculation are given. In addition, some tables, convenient for manual as well as computer calculations, are provided.

12.2.2 Referenced Publications

The following publications are referenced throughout this publication.

API

Manual of Petroleum Measurement Standards

	Chapter 1, "Vocabulary"
	Chapter 4, "Proving Systems"
	Chapter 11.1, "Volume Correction Factors" (Standard 2540)
	Chapter 11.2 (Standard 1101, Table II)
	Chapter 11.4.2, (Standard 1101, Table I)
Std 1101	*Measurement of Petroleum Liquid Hydrocarbons by Positive Displacement Meter*

NBS[1]

Handbook 105-3	*Specifications and Tolerances for Reference Standards and Field Standards*
Monograph 62	*Testing of Metal Volumetric Standards*
Handbook 91	*Experimental Statistics*

[1]National Bureau of Standards, Washington, D.C. 20234.

12.2.3 Field of Application

The field of application of this publication is limited to liquid hydrocarbons having a density greater than 0.500, measured by a turbine or displacement meter and prover, including those hydrocarbons that by suitable adjustments of temperature and pressure are liquids while being measured. Two-phase fluids are not included (though it may be found useful in such situations) except insofar as sediment and water may be mixed in with crude oil (see the definition of sediment and water in Chapter 1, "Vocabulary").

12.2.4 Hierarchy of Accuracies

There is an inevitable or natural hierarchy of accuracies in petroleum measurement. At the top are test measures which are usually calibrated by the National Bureau of Standards or a certified laboratory. From this level downwards any uncertainty in a higher level must be reflected in all the lower levels as a bias (that is, as a systematic error). Whether such bias will be positive or negative is unknown; uncertainty carries either possibility.

To expect equal or less uncertainty in a lower level of the hierarchy than exists in a higher level is unrealistic. The only way to decrease the random component of uncertainty in a given measurement system or method is to increase the number of determinations and then find their mean value. The number of digits in intermediate calculations of a value can be larger in the upper levels of the hierarchy than in the lower levels; but the temptation to move towards imaginary significance must be tempered or resisted by a wholesome respect for realism.

The hierarchy of accuracies in this publication is structured, in general, as shown in Table 1.

Rules for rounding, truncating, and reporting final values are given for each level of the hierarchy in 12.2.6, 12.2.7, and 12.2.8. Rounding in this manual conforms to National Bureau of Standards Handbook 91, Chapter 22, as reprinted in Appendix D.

12.2.5 Principal Correction Factors

Designation of correction factors by symbols rather than by words is recommended because, first, expressions are abbreviated; second, algebraic manipulations are facilitated; third, the similarities of expressions are pointed out subject only to the particular liquid or metal involved; and fourth, confusion is reduced as, for example, the difference between compressibility (F) of a liquid and the correction factor (C_{pl}), which is a function of F. There are six principal correction factors employed in calculations of liquid quantities; all of them are multipliers. The first correction factor, commonly called the meter factor, is defined as:

MF = a non-dimensional value which corrects a volume as indicated on a meter to the "true" volume (see 12.2.7).

The next four correction factors are employed in calculations of liquid quantities. They are needed because changes in volume from the effects of temperature and pressure upon both the containing vessel (usually made of mild steel) and upon the liquid involved must be accounted for. These four correction factors are:

C_{ts} (or CTS) = the correction factor for the effect of temperature on steel (12.2.5.1).
C_{ps} (or CPS) = the correction factor for the effect of pressure on steel (12.2.5.2).
C_{tl} (or CTL) = the correction factor for the effect of temperature on a liquid (12.2.5.3).
C_{pl} (or CPL) = the correction factor for the effect of pressure on a liquid (12.2.5.4).

While the customary subscripted notation is used in this publication, the allowed upper case notation is needed for computer programming and is convenient in typing.

Finally, there is a correction factor C_{sw} (which is never greater than 1.000) for accounting for the presence of sediment and water in crude oil (see 12.2.8.4).

Additional subscripts may be added to the symbolic notations above to make it clear to what part of the measuring apparatus it applies, namely "p" for prover, "m" for meter, and "M" for measure.

In the worked examples given in this publication, and in the standard calculating procedures recommended, the above six correction factors are applied in a set sequence:

$$MF,\ C_{ts},\ C_{ps},\ C_{tl},\ C_{pl},\ C_{sw}$$

All multiplication within a single operation must be completed before the dividing is started.

12.2.5.1 CORRECTION FOR THE EFFECT OF TEMPERATURE ON STEEL, C_{ts}

Any metal container, be it a pipe prover, a tank prover, or a portable test measure, when subjected to a change in temperature will change its volume accordingly. The volume change, regardless of prover shape, is proportional to the cubical coefficient of thermal expansion of the material of which the container is made. The correction factor for the effect of temperature on steel is called C_{ts}, and it may be calculated from:

$$C_{ts} = 1 + (T - 60)\gamma \qquad (1)$$

Where:

T = temperature in °F of the container walls.
γ = coefficient of cubical expansion per °F of the material of which the container is made.

Table 1—Hierarchy of Accuracies

Paragraph	Level	Correction Factors and Intermediate Calculations to	Volumes, Significant Digits	Temperature Discrimination, to at least, °F
12.2.6	Prover calibration	6 decimal places[a]	5	0.1
12.2.7	Meter proving	4 decimal places	5	0.5
12.2.8	Measurement tickets	4 decimal places	5	1.0

[a] Values are not valid beyond four decimal places for the purpose of correcting volumes to 60°F. However, for correcting for small temperature differences between a meter and a prover, linear interpolation to more decimal places is acceptable.

Thus C_{ts} will be greater than 1 when temperature T is greater than 60°F and less than 1 when temperature T is less than 60°F.

The value of γ (gamma) per °F is 1.86×10^{-5} (or 0.0000186 per °F) for mild or low carbon steels and falls in a range of values from 2.40 to 2.90×10^{-5} per °F for Series 300 stainless steels. The value used in calculation should be that found on the report from the calibrating agency for a test measure or from the manufacturer of a prover. Tables of C_{ts} values against observed temperature will be found in Appendix A of this publication. Values for Series 300 stainless steels are based on the mean value of 2.65×10^{-5} for gamma.

When the volume of the container at standard temperature (60°F) is known, the volume (V) at any other temperature (T) can be calculated from:

$$V_T = V_{60} \times C_{ts} \tag{2}$$

Conversely, when the volume of the container at any temperature (T) is known, the volume at standard temperature (60°F) can be calculated from:

$$V_{60} = V_T/C_{ts} \tag{3}$$

12.2.5.2 CORRECTION FOR THE EFFECT OF PRESSURE ON STEEL, C_{ps}

If a metal container such as a tank prover, a pipe prover, or a test measure is subjected to an internal pressure, the walls of the container will stretch elastically and the volume of the container will change accordingly. While it is recognized that simplifying assumptions enter the equations below, for practical purposes the correction factor for the effect of internal pressure on the volume of a cylindrical container, called C_{ps}, may be calculated from:

$$C_{ps} = 1 + (PD/Et) \tag{4}$$

Where:

P = internal pressure, in pounds per square inch gage.
D = internal diameter, in inches (outside diameter minus twice the wall thickness).
E = modulus of elasticity for container material, 3.0×10^7 pounds per square inch for mild steel or 2.8 to 2.9×10^7 for stainless steel.
t = wall thickness of container, in inches.

A table of C_{ps} values for specific sizes and wall thicknesses of mild steel pipe provers and pressures may be found in Appendix A of this publication. When the volume of the container at atmospheric pressure is known, the volume at any other pressure (P) can be calculated from:

$$V_p = V_{atmos} \times C_{ps} \tag{5}$$

When the volume at any pressure P is known, the equivalent volume at atmospheric pressure can be calculated from:

$$V_{atmos} = V_p/C_{ps} \tag{6}$$

12.2.5.3 CORRECTION FOR THE EFFECT OF TEMPERATURE ON A LIQUID, C_{tl}

If a quantity of petroleum liquid is subjected to a change in temperature, its volume will expand as the temperature rises or contract as the temperature falls. The volume change is proportional to the thermal coefficient of expansion of the liquid, which varies with density (API gravity) and temperature. The correction factor for the effect of temperature on a volume of liquid is called C_{tl}. Its values are given in Tables 6A, 6B, and 6C, which may be found in 11.1 of this manual. Tables 6A, 6B, and 6C are used when the API gravity is known and lies between 0°API and 100°API; 100°API corresponds to a relative density of 0.6112. If the relative density is known Tables 24A, 24B, and 24C should be used, or Table 24 (API Standard 2540) for lower relative densities.

When the volume of a petroleum liquid is known at any temperature (T), the equivalent volume at standard temperature (60°F) can be calculated from:

$$V_{60} = V_T \times C_{tl} \tag{7}$$

When the volume of a petroleum liquid is known at 60°F, the equivalent volume at any temperature T can be calculated from:

$$V_T = V_{60}/C_{tl} \tag{8}$$

12.2.5.4 CORRECTION FOR THE EFFECT OF PRESSURE ON A LIQUID, C_{pl}

If a volume of petroleum liquid is subjected to a change in pressure, it will decrease as the pressure increases and increase as the pressure decreases. The volume change is proportional to the liquid's compressibility factor F, which depends upon both its relative density (API gravity) and the temperature. Values of the compressibility factor F for hydrocarbons will be found in Chapter 11.2 of this manual. The correction factor for the effect of pressure on a volume of petroleum liquid is called C_{pl} and can be calculated from:

$$C_{pl} = \frac{1}{1 - (P - P_e)F} \tag{9}$$

Where:

P = pressure, in pounds per square inch gage.

P_e = equilibrium vapor pressure at the measurement temperature of the liquid being measured, in pounds per square inch gage. P_e is considered to be 0 for liquids which have an equilibrium vapor pressure less than atmospheric pressure (14.73 pounds per square inch absolute) at measurement temperature.

F = compressibility factor for hydrocarbons from Chapter 11.2 of this manual. The value of F for water is 3.2×10^{-6} per pound per square inch.

When P_e is 0, Equation 9 becomes:

$$C_{pl} = \frac{1}{(1 - PF)} \tag{10}$$

When P_e is greater than 0, Equation 9 must be used. Values of P_e for densities between 0.500 and 0.512 are found in Chapter 11.2.

NOTE: A convenient way of determining P_e while proving a meter against a pipe prover is to proceed as follows:
1. Upon conclusion of the last proving run, stop flow through the pipe prover and isolate it from the flowing lines by snutting the appropriate valves.
2. Reduce pressure on the pipe prover by bleeding off liquid until the gage pressure stops falling. This will imply that a vapor space has been created and that the liquid has reached its equilibrium pressure. Shut the bleed valve, and read P_e on the gage, making a record of the temperature at the time.
This procedure may be used for determining P_e for liquid mixtures that do not conform with published charts showing P_e values plotted against the temperature or as a routine procedure.

When the volume of a low vapor pressure liquid is known at any pressure P, the equivalent volume at standard pressure (0 pounds per square inch gage) can be calculated from:

$$V_0 = V_P \times C_{pl} \tag{11}$$

When the volume of a low vapor pressure liquid is known at 0 pounds per square inch gage, the equivalent volume at any pressure P can be calculated from:

$$V_P = V_0/C_{pl} \tag{12}$$

When the volume of high vapor pressure liquid is known at any measurement temperature T and pressure P, the pressure correction is done in two steps. The equivalent volume at such liquid's equilibrium pressure P_e at measurement temperature can be calculated from:

$$V_{pe}@T = V_p \times C_{pl} \tag{13}$$

In this equation C_{pl} is calculated from Equation 9. When this volume is in turn temperature corrected to 60°F using Equation 7, the value of C_{tl} taken from the appropriate table also corrects the volume for the change in pressure from P_e at measurement temperature, to equilibrium pressure at the standard temperature of 60°F. It should be noted that while P_e at measurement temperature T may be higher than standard atmospheric pressure (14.73 pounds per square inch absolute), equilibrium pressure at 60°F may have fallen to atmospheric pressure or less. As noted under Equation 9, the distinction between a low vapor pressure liquid and a high vapor pressure liquid depends on whether its equilibrium pressure is less or greater than atmospheric pressure at measurement temperature.

12.2.5.5 COMBINED CORRECTION FACTOR (CCF)

The recommended method for correcting volumes by two or more correction factors is to first obtain a *CCF* (combined correction factor) by multiplying the individual correction factors together in a set sequence, rounding at each step. Only then multiply the volume by the *CCF*. The set sequence is *MF*, C_{ts}, C_{ps}, C_{tl}, C_{pl}, and C_{sw}, omitting any unused factors.

12.2.6 Calculation of the Volume of Provers

12.2.6.1 PURPOSE AND IMPLICATIONS

The purpose of calibrating a prover is to determine its base volume. The procedures to be used are described in Chapter 4, Sections 2 and 3, of this manual.

Base volume is expressed in barrels or gallons, both of which are multiples of the cubic inch. Whereas the cubic inch does not vary with temperature or pressure, the volume of a metal prover does vary. Therefore, the statement of the base volume of a prover or volumetric standard has to specify standard conditions, namely 60°F and atmospheric pressure.

12.2.6.2 FIELD STANDARDS

Field reference standards, which are described and discussed in Chapter 4, Section 1, are usually calibrated by the National Bureau of Standards or by an approved laboratory. Their reported volumes are expressed either in customary or metric (SI) units at standard conditions. The lastest edition of National Bureau of Standards Handbook 105-3 may be consulted for details of construction, calibration, and so forth.

12.2.6.3 RULE FOR ROUNDING—PROVERS

In calculating a prover volume, determine individual correction factors to six decimal places by using the appropriate formula; interpolation will be required for C_{tl}. Record the combined correction factor (*CCF*) rounded to six decimal places. Multiply the sum of the measured volumes, each of which has been individually adjusted to starting temperature, by the *CCF*, and report the base volume so determined to five significant digits. Round the corrected individual withdrawal volumes to the same number of significant digits as the uncorrected volumes.

12.2.6.4 CALCULATION OF BASE VOLUMES

The procedure for calibrating pipe provers will be found in Chapter 4, Section 2. The following subsections, 12.2.6.4.1 through 12.2.6.4.4, specify the calculation of the base volume of a pipe prover calibrated by the water draw method.

12.2.6.4.1 Initial Step

During the calibration of a pipe prover, the temperature and pressure of the water in the prover at the start of calibration are observed and recorded. Likewise, the temperatures of the individual withdrawals into field standards are observed and recorded.

NOTE: At this point attention is drawn to a long established practice detailed in API Standard 1101, Paragraphs 2123 to 2125, that no correction for C_{su} need be applied in calculating base volume by the water draw method. Such practice is valid only when the prover and the field standard test measures are made of the same material and then only if the temperature in the prover differs by less than 3°F from the temperature in the test measures. Appendix B of this chapter details the corrections required under other conditions and gives an example to illustrate the type of error which can result if these corrections are neglected.

12.2.6.4.2 Corrections Applied to Measured Volumes

In the water draw calibration procedure, the volume observed in the field standards must be subjected to certain corrections in order to determine the base volume of the prover (see Equation B1, Appendix B). The final subscripts mean "p" for prover and "M" for measure.

Thus, the following steps are performed:

1. The volume of water in a field standard must be corrected for the effect of temperature and pressure on the liquid to determine what volume the water occupied when it was in the prover; this is done by multiplying the volume by C_{tw},[2] the value for which can be found in Chapter 11.4.2, and dividing by C_{plp}, the value of which can be computed from Equation 10 using F for water.
2. The volume so determined must then be corrected for thermal expansion of the field standard shell at the measuring temperature by multiplying the certified volume by C_{tsM} (see Equation 3).
3. Finally, the measured volume of the prover so calculated must be corrected for both temperature and pressure effects on the prover pipe in order to obtain the base volume, which is the equivalent volume at standard conditions. These corrections require dividing by C_{psp} and C_{tsp}, respectively. In calculating the values of C_{tsp} and C_{psp} the physical characteristics of the prover metal must be known. Because an accuracy greater than 1 part in 10,000 is desirable in prover base volumes, determine all correction factor values to six decimal places. In practice, when several test measures are filled, the calculation is performed according to Equation B6 in Appendix B in the manner specified in the following example (12.2.6.4.3).

12.2.6.4.3 Example Calculation for a Pipe Prover

The form or record used for a water draw calibration of a pipe prover must make provision for at least the information shown in Figure 1. The values shown are for example only,

[2] C_{tw} is defined as the correction for the temperature difference of the water in the test measure and in the prover; this is not the same as C_{tl} which corrects to 60°F rather than to prover temperature.

A. GENERAL INFORMATION

Calibration report no. ____	Prover serial no. ____
Prover dimensions *10" pipe, 0.365" wall*	Prover type *unidirectional*
Metal *mild steel*	Prover location ____
Date ____	Calibrator's name ____

B. FIELD STANDARDS (TEST MEASURES)

1. Nominal sizes, gallons	*25*	*50*

Figure 1—Example Calculation for a Pipe Prover (Continued on Page 6)

2. Volume, cubic inches		*5775.81*		*11551.80*
3. Serial number		*m*		*n*
C. OBSERVED VALUES				
4. Starting average pressure in prover, psig		*41*		
5. Starting average temperature in prover, °F		*82.0*		
Fill number	*1*	*2*	*3*	*4*
Field standard used	*m*	*n*	*n*	*n*
6. Reported volume	*5775.81*	*11551.80*	*11551.80*	*11551.80*
7. Scale reading				
above zero	—	*+37.5*	*+32.5*	*+3.0*
below zero	*−1.0*	—	—	—
8. Measured volumes (Line 6 + Line 7)	*5774.81*	*11589.30*	*11584.30*	*11554.80*
9. Withdrawal temperature, °F	*82.0*	*82.0*	*82.8*	*84.0*
10. Change from starting temperature (Line 9 − Line 5)	*0*	*0*	*+0.8*	*+2.0*
11. Volume adjustment for temperature difference of water (Chap. 11.4.2)	*1.000000*	*1.000000*	*0.999864*	*0.999670*
12. Volume adjusted to starting temperature (Line 8 × Line 11)	*5774.81*	*11589.30*	*11582.72*	*11550.99*
13. Sum of adjusted volumes, cubic inches		*40,497.82*		

D. CORRECTIONS NEEDED TO CALCULATE BASE VOLUME

14. C_{tsM} for test measures at mean weighted temperature of 82.8°F (see 12.2.5)	*1.000424*
15. C_{tsp} for prover at 82°F	*1.000409*
16. C_{psp} for metal of prover at 41 psig (see 12.2.5.2)	*1.000038*
17. C_{plp} for water in prover at 41 psig (see 12.2.5.4, Equation 10)	*1.000131*

E. BASE VOLUME

If the change from starting temperature (Line 10) weighted for all runs is 3°F or greater or if the metals of the prover and the test measure(s) are not the same, include C_{ts} for both test measures (C_{tsM}) and prover (C_{tsp}).

$$\text{Base volume} = \text{Sum of adjusted volumes (Line 13)} \times \left[\frac{C_{tsM}(14)}{C_{tsp}(15) \times C_{psp}(16) \times C_{plp}(17)}\right]$$

= *40,491.58 cubic inches* at 60°F and O psig = *175.2882 gallons*

= *4.17353 barrels*

If the change from starting temperature (Line 10) weighted for all runs is 3°F or less and the metal of the test measure(s) is the same as that of the prover use the following equation:

$$\text{Base volume} = \text{Sum of adjusted volumes (Line 13)} \times \frac{1}{C_{psp}(16) \times C_{plp}(17)}$$

NOTE: In this worked example, even though the weighted average withdrawal temperature (82.8°F) is less than 3°F different from the starting temperature (82.0°F), corrections for C_{ts} to both test measures and prover have been made in order to show how they are applied to calculate the base volume regardless of what starting and withdrawal temperature may have been (see 12.2.6.4.2). In this example, correcting for C_{ts} alters the result by one part in one hundred thousand. Leaving it out would have the same insignificant effect.

Figure 1—Example Calculation for a Pipe Prover (Continued)

and because the difference between starting prover temperature and field standards temperature is small (less than 3°F) use of the simplified method (see 12.2.6.4.1) is warranted. C_{ts} corrections can be neglected, but they are included in the example for illustration purposes. The word "measure" means the field standard(s) used. The example is limited to one determination, although at least two are required.

12.2.6.4.4 Rounding of Reported Values

The base volume of a prover as computed cannot be more accurate than the volumes of the field standards employed in its calibration, and because of accumulated experimental uncertainties in the calibration process, it will be somewhat less accurate. Experience shows that five significant figures in a computed value, such as the base volume of a prover, is the best that can be expected. Thus, the calculated base volume in the example in Figure 1 should be rounded to five significant figures showing 4.17353 as 4.1735 barrels; 175.2882 gallons as 175.29 gallons; or 40,491.58 cubic inches as 40,492 cubic inches.

12.2.6.4.5 Example Calculation for a Tank Prover

The form or record used for a water draw calibration of a tank prover must make provision for at least the information shown in the example in Figure 2.

It is assumed that this is a field recalibration; that the top and bottom necks do not need recalibration; that any small adjustments to the top or bottom zero marks will be made by sliding the reading scales up or down as needed, and that both scales will then be resealed.

It is further assumed that the difference between starting temperatures and withdrawal temperature is kept small (less than 3°F) so that the C_u for the measures and tank correction can be omitted (see note in 12.2.6.4.1). Since the tank prover is at atmospheric pressure, no pressure correction for either liquid or prover tank shell is required.

The calibration run must be repeated, and if the two runs after correction for temperature agree within 0.02 percent (in this example within 0.200 gallon) the mean value of the two runs becomes the calibrated volume of the prover at 60°F.

The total of the values in Column 6 of Figure 2 is 1001.561 gallons, which is at 80.7°F. Each withdrawal has been corrected to 80.7°F by the correction factor shown in Column 5. Since the field standards and the prover being calibrated are made of the same material (mild steel) and the weighted temperature difference is not greater than 3°F, no further correction is needed to bring the calibrated volume of the prover to 60°F, as the certified volumes of field standards were adjusted to 60°F at the time of their calibration. If the reading on the top neck was, for example, 1001.000 gallons at the start of calibration and as the true volume is now known to be 1001.561 gallons, the top scale will have to be moved downwards 0.561 gallons. If the neck contains 1 gallon per inch (which is usually the case) the top scale will be moved downwards 9/16 or 0.563 inch.[3] An alternative would be to move the zero mark on the bottom neck scale upwards by 9/16 inch. Both scales should be resealed afterwards.

12.2.6.4.6 Rounding of Reported Values

The volume of a tank prover between top reading marks and bottom zero mark in this example was adjusted to 1001 gallons. Applying the five significant figures rule explained in 12.2.6.4.4 requires that the calibrated volume be reported as either 1001.0 gallons after adjustment or 23.833 barrels.

[3] Using a conventionally scaled foot rule, and knowing that 17/32 inch = 0.5313 inch and 9/16 inch = 0.5625 inch, the latter is as close as scale and meniscus reading will allow to be achieved.

A. GENERAL INFORMATION

Calibration report no. ____	Prover serial no. ____
Prover type *Open stationary tank (top & bottom gage glasses)*	Prover location ____
Metal *mild steel*	Nominal capacity ____
Date ____	Calibrator's name ____

B.	FIELD STANDARDS		
1.	Nominal sizes, gallons	*50*	*1*
2.	Delivered volume, gallons	*49.985*	*0.997*
3.	Serial number	*m*	*n*
C.	OBSERVED VALUES		
4.	Prover starting temperature, top, °F	*80.8*	
5.	Prover starting temperature, middle, °F	*80.6*	
6.	Prover starting temperature, bottom, °F	*80.6*	
7.	Prover starting temperature, average, °F	*80.7*	

Figure 2 – Example Calculation for a Tank Prover (Continued on Page 8)

D. CORRECTIONS

1	2	3	4	5	6
Withdrawal	Volume	Temperature °F	t°	Volumetric Correction Factor C_{tdw}	Field Standard Volume at Prover Temperature
1	*49.985*	*80.6*	*−0.1*	*1.000015*	*49.986*
2	*49.985*	*80.6*	*−0.1*	*1.000015*	*49.986*
3	*49.985*	*80.6*	*−0.1*	*1.000015*	*49.986*
4	*49.985*	*80.7*	—	*1.000000*	*49.985*
5	*49.985*	*80.7*	—	*1.000000*	*49.985*
6	*49.985*	*80.8*	*0.1*	*0.999984*	*49.984*
7	*49.985*	*81.0*	*0.3*	*0.999952*	*49.983*
8	*49.985*	*81.1*	*0.4*	*0.999936*	*49.982*
9	*49.985*	*81.1*	*0.4*	*0.999936*	*49.982*
10	*49.985*	*81.2*	*0.5*	*0.999920*	*49.981*
11	*49.985*	*81.3*	*0.6*	*0.999904*	*49.980*
12	*49.985*	*81.4*	*0.7*	*0.999888*	*49.979*
13	*49.985*	*81.5*	*0.8*	*0.999872*	*49.979*
14	*49.985*	*81.7*	*1.0*	*0.999840*	*49.977*
15	*49.985*	*82.0*	*1.3*	*0.999793*	*49.975*
16	*49.985*	*82.4*	*1.7*	*0.999730*	*49.972*
17	*49.985*	*82.5*	*1.8*	*0.999714*	*49.971*
18	*49.985*	*83.0*	*2.3*	*0.999635*	*49.967*
19	*49.985*	*83.1*	*2.4*	*0.999619*	*49.966*
20	*49.985*	*83.5*	*2.8*	*0.999555*	*49.963*
21	*0.997*	*84.0*	*3.3*	*0.999473*	*0.996*
22	*0.997*	*84.0*	*3.3*	*0.999473*	*0.996*
					1001.561

8. Sum of temperature adjusted field standard volumes *1001.561*
9. Final lower gage reading *0*
10. Weighted mean withdrawal temperature, °F *81.6*
11. Change from starting temperature (Line 10 − Line 7) .... *<3°F*

E. CALIBRATED VOLUME

13. The general formula for calibrated volume is:

$$\text{Calibrated volume} = \text{Sum of adjusted volumes} \times \frac{C_{tsM}}{C_{tsp} \times C_{psp} \times C_{plp}}$$

12. Calibrated volume = *1001.561* × *1*

NOTE: Calculations for C_{tsM} and C_{tsp} are shown even though it makes no difference in the calibrated volume to five significant digits. It does demonstrate to the user what he must do if he has temperature differences greater than 3°F or dissimilar metals.

Figure 2—Example Calculation for a Tank Prover (Continued)

12.2.6.4.7 Example Calculation Using the Master Meter Method

The procedure for calibrating a pipe prover using the master meter method will be found in Chapter 4 of this manual.

The first step is to prove the master meter in the liquid selected for the prover calibration. In this example a displacement meter is used, proved against a tank prover. A turbine meter calibrated against a pipe prover may be employed equally well, provided it is not removed from the manifolding of which it is a part at the time of its proving. The flow rate through a master meter, while it is being used to calibrate a prover, should be held within about 2.5 percent of the rate at the time of its proving. An alternative method is to develop an accuracy curve and read off the meter factor for the rate observed during the calibration.

The form or work sheet used to record data and calculations should provide for at least the information shown in Figure 3. Only one worked example of a master meter calibration run is shown in Figure 3 although five runs are desirable in such a calibration.

STEP 1 Proving of the Master Meter

A. GENERAL INFORMATION

Proving report no. ____________ Date ____________ Time ____________

Liquid *motor gasoline at 60.8°API* Rate *715 barrels per hour*

Operator's name ____________ Witness ____________

B. MASTER PROVER INFORMATION

1.	Calibrated volume, barrels	*20.427*
2.	Prover starting temperature, top, °F	*73.6*
3.	Prover starting temperature, middle, °F	*73.6*
4.	Prover starting temperature, bottom, °F	*73.4*
5.	Prover starting temperature, average, °F	*73.5*

NOTE 1: For a gravity of 61° API (that is, 60.8° rounded) Table 6B of Chapter 11.1 gives values for 70°F and 80°F of 0.9931 and 0.9862. Thus the average increment per °F for this span is 0.00069, so for 73.5°F the six digit value will be 0.990685 as shown in Line 9. (See Note 2.)

6.	Pressure, pounds per square inch gage	*0*
7.	C_{tsp} for prover (see 12.2.5.1)	*1.000251*
8.	C_{psp} for prover (see 12.2.5.2)	*1.000000*
9.	C_{tp} for prover (see 12.2.5.3)	*0.990685*
10.	C_{pp} for prover (see 12.2.5.4)	*1.000000*
11.	CCF_p for master prover (Line 7 × Line 8 × Line 9 × Line 10) (see 12.2.5.5)	*0.990934*
12.	Corrected master prover volume, barrels	*20.241809*

C. MASTER METER INFORMATION

13.	Closing reading, barrels	*14683.492*
14.	Opening reading, barrels	*14663.155*
15.	Indicated meter volume	*20.337*
16.	Temperature of metered stream, °F	*73.4*
17.	Pressure in meter, pounds per square inch	*40*
18.	C_{tm} for meter (see 12.2.5.3)	*0.990754*
19.	C_{pm} for meter (see 12.2.5.4)	*1.000328*
20.	CCF_m (Line 18 × Line 19) for master meter (see 12.2.5.5)	*0.991079*
21.	Corrected master meter volume, barrels (Line 15 × Line 20)	*20.155574*

D. METER FACTOR

Meter factor = Line 12 ÷ Line 21

= *1.004278 for this run*

NOTES:

2. As this example is for an open tank prover, the pressure is 0 pounds per square inch gage so C_{pp} and C_{psp} are unity. If a pipe prover is employed, these factors would have other values.

3. Six decimal places in a C_t value are not valid for correcting a volume to 60°F. But six decimal places for correction factors may be employed for correction within a small temperature range such as exists between a prover and a meter. The six decimal places are determined by linear interpolation within a 10°F span, selected from Table 6B, that includes both C_{tp} and C_{tm}.

4. The meter factor to be used in the calibration should be the average for all runs made that meet the repeatability requirements in Chapter 4.

STEP 2 Calibrate the Pipe Prover

A. GENERAL INFORMATION

Nominal or expected prover volume, barrels *40*

Figure 3—Example Calculation Using the Master Meter Method (Continued on page 10)

	Pipe size, inches	16
	Wall thickness, inches	0.375
	Gravity of liquid used, °API	60.8
	Flow rate when master meter was proved, barrels per hour	715
	Tolerable ± 2½ percent flow rate range	697 to 733
B.	PIPE PROVER INFORMATION Data from five runs may be averaged for Lines 22 and 23 and the base volume in Part D.	
22.	Temperature, °F	75.1
23.	Pressure, pounds per square inch gage	100
24.	C_{tsp} for pipe prover (see 12.2.5.1)	1.000281
25.	C_{psp} (see 12.2.5.2)	1.000136
26.	C_{tlp} (see 12.2.5.3)	0.989581
27.	C_{plp} (see 12.2.5.4)	1.000821
28.	*CCF* for pipe prover (Line 24 × Line 25 × Line 26 × Line 27)	0.990807
C.	MASTER METER INFORMATION	
29.	Rate, barrels/hour	705
30.	Temperature, °F	75.6
31.	Pressure, pounds per square inch gage	75
32.	Closing reading	15226.727
33.	Opening reading	15186.254
34.	Indicated meter volume, barrels (Line 32 − Line 33)	40.473
35.	Master meter factor (see Note 5)	1.004284
36.	C_{tlm} for meter (see 12.2.5.3)	0.989236
37.	C_{plm} for meter (see 12.2.5.4)	1.000623
38.	CCF_m (Line 35 × Line 36 × Line 37)	0.994093
39.	Corrected master meter volume, barrels (Line 34 × Line 38)	40.233926
40.	Volume of prover, this run, barrels (Line 39 ÷ Line 28)	40.607228
D.	BASE VOLUME	
	Base volume of pipe prover, barrels, at standard conditions (see Note 6)	40.609

NOTES:
5. Master meter factor (Line 35) does not agree with the value shown for one run in Step 1 Section D as it is assumed that the value used (Line 35) is an average of more than one run.
6. Base volume of pipe prover (D) does not agree with value for one run (Line 36) as it is assumed that at least five runs have been made and averaged. Also base volume to be reported should be realistic; that is, it should be rounded to five significant figures (see 12.2.6.4.2). Any theoretical sacrifice of accuracy that this may entail is largely imaginary and is offset by the advantage of having a standard method of calculating and reporting values.

Figure 3—Example Calculation Using the Master Meter Method (Continued)

12.2.7 Calculation of the Meter Factor

12.2.7.1 PURPOSE AND IMPLICATIONS

Some custody transfers of liquid petroleum measured by meter are sufficiently small in volume or value, or are performed at essentially uniform conditions, so that the meter can be mechanically adjusted to read within a predetermined accuracy. Examples would be retail measurements and some bulk plant measurements into and/or out of tank wagons. However, in most large scale custody transfers when a single meter is used to measure several different liquids or to measure at several different flow rates, meter adjustment for each change is impracticable. In such service, accuracy can be achieved by leaving the calibrator setting undisturbed and sealed, using a dummy calibrator, or dispensing with the calibrator entirely and determining within narrow limits a meter factor for each operating condition. Thus the purpose of determining a meter factor is to ensure accuracy of measurement by batch, regardless of how operating conditions change with respect to density (gravity), viscosity, rate, temperature, pressure, or lubricating properties, by always proving the meter under the specific operating conditions encountered. If any one of the specific operating conditions changes significantly, a new meter factor should be obtained by re-proving the meter.

The definition of meter factor as given in Chapter 1 of this manual is:

> *Meter factor*—A number obtained by dividing the actual volume of liquid passed through a meter during proving by the volume registered by that meter.

From the definition it is clear that:

$$\left.\begin{array}{l}\text{Actual meter}\\ \text{throughput at}\\ \text{operating conditions}\end{array}\right\} = \text{Indicated volume} \times MF \qquad (14)$$

During proving, the temperature and pressure existing in the prover and in the meter are significant in calculating a meter factor. This is so because the actual volume of liquid passed through the meter during proving must be determined indirectly from a knowledge of the exact volume measured in the prover. This calculation involves pressure and temperature differences between the prover and the meter. As a result, standard measurement practice is first to correct the volume of the liquid in the prover to standard conditions (60°F and equilibrium pressure) and then also to correct the indicated volume during proving to what it would have been if the meter had operated at standard conditions.

Thus, in practical terms:

$$MF = \frac{\begin{array}{c}\text{Volume of liquid in the prover}\\ \text{corrected to standard conditions}\end{array}}{\begin{array}{c}\text{Change in meter reading corrected}\\ \text{to standard conditions}\end{array}} \qquad (15)$$

It must be emphasized that a meter factor thus calculated is valid over a range of operating temperatures and pressures limited only by the consideration that the temperature and pressure during metering should not differ from the temperature and pressure during proving sufficiently to cause a significant change in the mechanical dimensions of the meter or in the viscosity of the metered liquid. Whether the differences are significant for a specific application can be determined by re-proving. In the application of meter factors to measurement tickets (see 12.2.8), the concept of a "volume at standard conditions" arises only because bulk custody transfers are measured in volumes which must be converted to a quantity represented by an equivalent volume-at-standard-conditions.

Thus:

$$\begin{array}{l}\text{Actual metered}\\ \text{volume}\end{array} = \begin{array}{l}\text{Indicated}\\ \text{volume}\end{array} \times MF \qquad (16)$$

and

$$\begin{array}{l}\text{Actual metered}\\ \text{quantity}\end{array} = \begin{array}{l}\text{Indicated}\\ \text{volume}\end{array} \times (MF \times C_{tlm} \times C_{plm}) \qquad (17)$$

C_{tlm} and C_{plm} are the appropriate correction factors for determining the equivalent volume at standard conditions from a measured volume at metering conditions.

In some metering applications, the variables MF and C_{plm} in Equation 17 are combined into a "composite meter factor." When such a composite meter factor is applied to the indicated volume of a temperature compensated meter (which automatically applies C_{tlm}), the metered quantity in barrels at standard conditions can be obtained by multiplying indicated volume by the composite MF alone.

It is important not to confuse a standard meter factor (Equation 15) with a composite meter factor. They are not interchangeable.

12.2.7.2 HIERARCHY OF ACCURACIES

Meter factors fit into the hierarchy of accuracies between calibrated prover volumes (12.2.6) and calculation of measurement tickets (12.2.8). Thus temperature readings for proving should be averaged and then rounded to the nearest 0.5°F. Pressure readings for proving should be averaged and then rounded to the nearest scale division, a pressure gage with its appropriate range having previously been selected.

12.2.7.3 RULE FOR ROUNDING—METER FACTORS

In calculating a meter factor, determine the numerator and denominator values separately, with each rounded to at least five significant digits. In intermediate calculations determine individual correction factors to four decimal places. Multiply individual correction factors together, rounding to four decimal places at each step (for each numerator and denominator), and record the combined correction factor (*CCF*) rounded to four decimal places. Divide corrected prover volume by corrected meter volume, and round the resulting meter factor to four decimal places.

12.2.7.4 CALCULATION OF THE METER FACTOR USING A TANK PROVER AND A DISPLACEMENT METER

In calculating a standard meter factor use Equation 15.

Determine the numerator by reading the upper gage glass of the tank; the indicated volume should be recorded to the nearest thousandth of a barrel. If the bottom gage glass was not at zero before the proving run was started, its reading must be added to or subtracted from (as the case may be) the upper gage glass reading, and the algebraic sum recorded as the indicated volume.

To calculate a meter factor, both prover and meter volumes must be in the same units. If the meter registers in barrels, record to 0.001 barrels, or if in gallons to the nearest 0.01 gallon, or to five significant digits. Read all prover

A. GENERAL INFORMATION

Proving report no. ______	Batch ______
API gravity *60.8*	Rate, barrels/hour ______
Meter no. ______	Liquid *motor gasoline*
Prover location ______	Station ______
Date and time ______	Operator ______ (signature)

B. DATA FROM PROVER TANK	Run 1	Run 2
1. Indicated volume, barrels	*20.445*	*20.427*
2. Prover starting temperature, top, °F	*73.6*	*73.6*
3. Prover starting temperature, middle, °F	*73.6*	*73.6*
4. Prover starting temperature, bottom, °F	*73.4*	*73.4*
5. Prover starting temperature, average (rounded), °F	*73.5*	*73.5*
6. C_{tsp} for prover (see Table A-1)	*1.0003*	*1.0003*
7. C_{tlp} for prover (see 11.1, Table 6)	*0.9907*	*0.9907*
8. CCF_p (Line 6 × Line 7)	*0.9910*	*0.9910*
9. Corrected prover volume, barrels (Line 1 × Line 8)	*20.261*	*20.243*
C. DATA FROM METER	**Run 1**	**Run 2**
10. Closing reading, barrels	*14556.595*	*14683.494*
11. Opening reading, barrels	*14536.214*	*14663.155*
12. Indicated volume, barrels	*20.354*	*20.339*
13. Temperature, °F	*73.5*	*73.5*
14. Pressure, pounds per square inch gage	*40*	*40*
15. C_{tlm} for meter (see 11.1, Table 6 or use 1.0000 if meter is temperature compensated)	*0.9907*	*0.9907*
16. C_{plm} for meter	*1.0003*	*1.0003*
17. CCF_m for meter (Line 15 × Line 16)	*0.9910*	*0.9910*
18. Corrected meter volume (Line 12 × Line 17)	*20.171*	*20.156*
19. Meter factor (Line 9 ÷ Line 18)	*1.0045*	*1.0043*
D. METER FACTOR		
The meter factor to be used is the mean of the two runs	*1.0044*	

Figure 4—Example Calculation for a Tank Prover and Displacement Meter

thermometers to 0.1°F, average them, round, and record to 0.5°F. Calculate the correction factors C_{ts} (see 12.2.5.1) and C_{tl} for the prover (see 12.2.5.3) and round them to four decimal places (that is, 0.9962). Multiply C_{ts} by C_{tl} to obtain *CCF* (see 12.2.5.5) and round to four decimal places. Multiply indicated volume by the *CCF* for the prover to obtain the corrected prover volume to 0.001 barrels.

Determine the denominator by subtracting the opening meter reading from the closing meter reading, both read or estimated to 0.001 of a barrel or 0.01 of a gallon. Record this reading as indicated meter volume. Calculate correction factors C_{tl} and C_{pl} for the meter and record to four decimal places. Multiply indicated meter volume by *CCF* for the meter to obtain the corrected meter reading to 0.001 barrel.

Calculate the meter factor by dividing the numerator by the denominator and round the meter factor to four decimal places.

The purpose of the above conventions is to establish standard procedures which will ensure the same results from the same data regardless of who or what does the computing. Any seeming sacrifice of hypothetical maximum accuracy is insignificant and must take second place to consistency. The standard procedures and conventions are based on the use of a simple desk calculator (not a scientific calculator) such as has traditionally been employed in the field, as well as by accounting personnel who may wish to check meter factor calculations. Accordingly, if meter proving reports calculated in the field are subsequently checked by a computer, the computer must be programmed in such a way as to reproduce the conventions described here. Remainders should not be held in memory; roundings should occur as described above.

12.2.7.5 EXAMPLE CALCULATION FOR A TANK PROVER AND DISPLACEMENT METER

A meter factor report form used for a nontemperature compensated displacement meter proved against a tank prover should allow for at least the information shown in Figure 4. Two runs are shown in the example, for each of which a run meter factor calculation is made separately; the two results are then averaged, the result obtained sometimes being called the "meter factor to be used." Note that this procedure differs from that employed with a pipe prover in which pulses, temperature, and pressure are averaged, and the meter factor is calculated from the average values of pulses, temperature, and pressure (see 12.2.7).

12.2.7.6 CALCULATION OF THE METER FACTOR USING PIPE PROVERS

12.2.7.6.1 General

Turbine meters and pipe provers were developed after displacement meters and tank provers; therefore, the procedure for calculating a meter factor for a turbine meter proved against a pipe prover was generally modeled on older procedure, but some changes were made.

Because a pipe prover is subject to the effects of both temperature and pressure on the steel, its base volume (which is at standard conditions) has to be corrected to obtain its volume at proving conditions. The volume of the displaced liquid must then be corrected to the equivalent volume at standard temperature and pressure. This latter value becomes the numerator in Equation 15 and the corrected meter volume becomes the denominator. For this procedure to be applied, the displacement meter must have a high resolution electrical output, that is, a large number of pulses per barrel so that at least 10,000 pulses or their equivalent are obtained.

The other rules and conventions discussed in 12.2.7.4 apply to calculation of a meter factor using a pipe prover and a turbine meter.

NOTE: The proper pulses-per-unit-volume figure for proving calculations.—It is important to bear in mind that when proving a turbine meter, or a displacement meter equipped with a high resolution electrical pulser, the change in the meter reading is rarely determined from the meter's normal totalizer register. Instead, the high speed pulses generated by the meter during the proving run are usually counted and displayed by a separate electronic proving counter. In some cases the pulses generated by the meter are multiplied by a totalizer scaling factor and/or a temperature compensating factor before being counted by the proving counter. In either case, it is critical that the "change in meter reading" required to calculate the meter factor be determined by dividing the number of counts from the counter by exactly the number of proving counts required by the meter's totalizer to register one unit of volume. For a displacement meter this is determined by the pulse per revolution rate of the electrical pulser and the gear ratio driving the mechanical register. For an electronic totalizer, the number of pulses at the meter required to register one unit of volume is generally the inverse of the product of the totalizer's scaler factor and its divider factor. Thus, a meter with its totalizer scaler set to multiply by 0.2500 and its divider set to divide by 100 (or multiply by 0.01) has a counts per unit volume of—

$$\frac{1}{0.2500 \times 0.01} = 400$$

If the pulses from the meter are passed through the scaler before being directed to the prover counter, then the appropriate counts or pulses-per-unit volume would be 100, as only 100 counts would be required at that point to register one unit of volume.

In any case, where the pulses at the point where the prover counter is connected have been corrected by a mechanical or electronic temperature compensator, the meter factor is calculated as for a temperature compensated meter; that is, without applying an additional C_t factor in the denominator. When proving a turbine meter equipped with a temperature compensated totalizer, the meter factor is calculated as for a noncompensated meter if the prover counter is connected directly at the meter. In such a case, C_t is applied in the denominator because the proving pulses are not temperature compensated.

The key distinction is that the pulses or counts-per-unit-volume figure used in the proving report form calculation is determined by the settings and arrangement of the totalizer used with the meter rather than by the particular pulse-per-unit-volume characteristic of the meter itself.

12.2.7.6.2 Example Calculation for a Pipe Prover, Turbine Meter, and Liquid of Low Vapor Pressure

Figure 5 provides an example calculation for a pipe prover with a turbine meter on a liquid of low vapor pressure.

A. GENERAL INFORMATION

Proving report no. ______
API gravity *63.7*
Rate, barrels/hour *1570*
Meter no. ______
Totalizer pulses per barrel *1000*
Date and time ______

Batch ______
Prover dimensions *14" pipe, 0.312" wall*
Liquid ______
Station ______

Operator ______
(signature)

B. DATA FROM PROVING RUNS

	Temperature, °F		Pressure, psig		
Run no.	Prover	Meter	Prover	Meter	Pulse Count
1	*63.0*	*64.5*	*80*	*62*	*17743*
2	*63.0*	*64.5*	*80*	*62*	*17744*
3	*63.5*	*64.5*	*80*	*62*	*17746*

Figure 5 – Example Calculation of a Pipe Prover, Turbine Meter, and a Liquid of Low Vapor Pressure
(Continued on Page 14)

	4	64.0	65.5	80	62	17746
	5	64.0	65.5	80	62	17747
	Averages	63.5	64.9	80	62	17745.2
1.	Averages (rounded)	63.5	65.0	80	62	17745

2. Meter volume

Metered volume = 17745 ÷ 1000 = 17.745 barrels

NOTES:
1. Average temperatures are rounded to the nearest half degree Fahrenheit.
2. Pressures are read to the nearest scale division, which in this case is assumed to be in 2 pound per square inch increments.
3. Pulse count is divided by the totalizer pulses per barrel (in this case 1000) and reported as barrels, rounded to three places.

C. DATA FOR PROVER

3. Base volume of prover, barrels 17.654
4. C_{tsp} (see 12.2.5.1) 1.0001
5. C_{psp} (see 12.2.5.2) 1.0001
6. C_{tlp} (see 12.2.5.3) (see 11.1, Table 6) 0.9975
7. C_{plp} (see 12.2.5.4) 1.0007
8. CCF_p (see 12.2.5.5) (Lines 4 × 5 × 6 × 7) (rounded to four decimal places at each step) 0.9984
9. Corrected prover volume, barrels (Line 3 × Line 8) 17.626

D. DATA FOR METER

10. C_{tlm} (see 12.2.5.3) (see 11.1, Table 6) 0.9965
11. C_{plm} (see 12.2.5.4) 1.0005
12. CCF_m (Line 10 × Line 11) 0.9970
13. Corrected meter volume (Line 9 × Line 12) 17.692

E. METER FACTOR

14. Meter factor (Line 9 ÷ Line 13) 0.9963

Figure 5—Example Calculation for a Pipe Prover, Turbine Meter, and a Liquid of Low Vapor Pressure (Continued)

12.2.7.6.3 Example Calculation for a Turbine Meter, Pipe Prover, and Liquid of Vapor Pressure Above Atmospheric

It is assumed for this example, see Figure 6, that the liquid measured is a propane mix of a specific gravity at 60°F of 0.554 and that a nontemperature compensated turbine meter and bidirectional pipe prover are used.

In this example, the equilibrium pressure P_e is given as 115 pounds per square inch gage determined by the method explained in the note to 12.2.5.4.

The value of F for the meter can be read from the table of compressibilities vs. relative density (see Chapter 11.2) in this case by entering the temperature at 76.5°F and by reading against the column for 0.554 specific gravity, a value of 0.0000285. The value of C_{pl} (Line 11) using Equation 9 works out to 1.0080 rounded to four decimal places.

The value of F for the prover is calculated likewise except that the pressure P is 385 pounds per square inch gage and the temperature t is 77.0°F, giving a value for C_{pl} (Line 6) of 1.0078 rounded.

For C_{tl} values see 12.2.5.3, for C_{ts} see 12.2.5.1, and for C_{ps} see 12.2.5.2, for which references to are also shown in the example.

For both meter and prover a combined correction factor (*CCF*) is calculated according to instructions in 12.2.5.5.

12.2.8 Calculation of Measurement Tickets

12.2.8.1 PURPOSE AND IMPLICATIONS

The purpose of standardizing the terms and arithmetical procedures employed in calculating the amounts of petroleum liquid on a measurement ticket is to avoid disagreement between the parties involved. The standardized procedures for calculation aim at obtaining the same answer from the same measurement data, regardless of who or what does the computing.

A *measurement ticket* is a written acknowledgment of a receipt for delivery of crude oil or petroleum product. If a change in ownership or custody occurs during the transfer, the measurement ticket serves as an agreement between the authorized representatives of the parties concerned as to the measured quantities and tested qualities of the liquids transferred.

Care must be taken to ensure that all copies of a measurement ticket are legible. Standard procedure forbids making corrections or erasures on a measurement ticket unless the interested parties agree to do so and initial the ticket to that effect. Should a mistake be made, the ticket should be marked VOID and a new ticket prepared. If the voided ticket has mechanically printed numbers on it which cannot be reprinted on the new ticket, the voided ticket should be clipped to the new one to support the validity of such printed numbers.

12.2.8.2 TERMS

Standard conditions mean 60°F and atmospheric pressure

A. GENERAL INFORMATION

Proving report no. ______	Prover type ______
Batch ______	Vapor pressure (at operating temperature) *115*
Specific gravity *0.554*	Meter manufacturer ______
Meter size *1½*	Liquid *propane mix*
Totalizer pulses per barrel *13188*	Base prover volume, barrels *2.0734*
Prover dimensions *12" pipe, 0.375" wall*	Station ______
Date and time ______	Operator's name ______
Company ______	______ (signature)

B. DATA FROM PROVING RUNS

Run No.	Temperature, °F Prover	Temperature, °F Meter	Pressure, psig Prover	Pressure, psig Meter	Pulse Count/ Round Trip
1	*76.6*	*76.0*	*385*	*395*	*28629*
2	*76.8*	*76.8*	*385*	*395*	*28626*
3	*76.8*	*76.0*	*385*	*395*	*28635*
4	*77.6*	*77.0*	*385*	*395*	*28634*
5	*77.0*	*77.2*	*385*	*395*	*28633*
6	*77.0*	*76.6*	*385*	*395*	*28631*
Averages	*77.0*	*76.6*	*385*	*395*	*28631.3*
1. Averages (rounded)	*77.0*	*76.5*	*385*	*395*	*28631*

NOTES:

1. Average temperatures are rounded to the nearest half degree Fahrenheit.
2. Pressures are read to the nearest scale division.
3. Pulse count is rounded to the nearest count.

2. Base volume of prover, barrels *2.0734*
3. C_{tsp} (see 12.2.5.1) *1.0003*
4. C_{psp} (see 12.2.5.2) *1.0004*
5. C_{tlp} (see 12.2.5.3) (see 11.1, Table 6) *0.9780*
6. C_{plp} (see 12.2.5.4) *1.0078*
7. CCF_p (Lines 3 × 4 × 5 × 6) *0.9863*
8. Corrected prover volume, barrels (Line 2 × Line 8) *2.0450*

C. DATA FOR METER

9. Metered volume (Line 2 ÷ pulses/barrel)

28631 − 13188 = 2.1710

10. C_{tlm} (see 12.2.5.3) (see 11.1, Table 6) *0.9789*
11. C_{plm} (see 12.2.5.4) *1.0080*
12. CCF_m (Line 10 × Line 11) *0.9867*
13. Corrected metered volume, barrels *2.1421*

D. METER FACTOR

14. Meter factor (Line 8 ÷ Line 13) *0.9547*

Figure 6—Example Calculation for a Turbine Meter and Pipe Prover with a Liquid of a Vapor Pressure Above Atmospheric

(0 pounds per square inch gage). In the case of liquids having an equilibrium pressure above 0 gage at 60°F, the standard conditions are 60°F and the equilibrium pressure of the liquid at 60°F.

A *barrel* is a unit volume equal to 9702.0 cubic inches, and a *gallon* is a unit volume equal to 231.0 cubic inches.

Volumes are expressed in barrels or gallons with the several terms incorporating the word volume having the meanings described below.

Indicated volume is the change in meter reading that occurs during a receipt or delivery. The word *registration*, though not preferred, often has the same meaning.

Gross volume is the indicated volume multiplied by the meter factor for the particular liquid and flow rate under which the meter was proved. This is a volume measurement.

Gross volume at standard temperature is the gross volume multiplied by C_{tl} (see 12.2.5.3), the values of which may be found in Tables 6 or Tables 24 (see Chapter 11.1). If a meter is equipped with a temperature compensator, the change in meter reading during a receipt or delivery will be an indicated volume at standard temperature, which when multiplied by the meter factor becomes a gross volume at standard temperature.

Gross standard volume is the gross volume at standard temperature, corrected also to standard pressure, and is therefore a quantity measurement. The factor for correcting a volume to standard pressure is called C_{pl} (see 12.2.5.4).

In summary (for a nontemperature compensated meter):

$$\text{Gross standard volume} = \left[\begin{pmatrix}\text{Closing}\\ \text{meter}\\ \text{reading}\end{pmatrix} - \begin{pmatrix}\text{Opening}\\ \text{meter}\\ \text{reading}\end{pmatrix}\right] \times [MF \times C_{tl} \times C_{pl}]$$

Net standard volume is the same as gross standard volume for refined products. When referred to crude oil, it means that the determined percentage of sediment and water has been deducted. It is sometimes called "standard barrels of net clean oil." The correction factor for sediment and water (S&W) is:

$$C_{sw} = 1 - \%\ S\&W/100$$

Therefore:

$$\text{Net standard volume} = \left[\begin{pmatrix}\text{Closing}\\ \text{meter}\\ \text{reading}\end{pmatrix} - \begin{pmatrix}\text{Opening}\\ \text{meter}\\ \text{reading}\end{pmatrix}\right] \times [MF \times C_{tl} \times C_{pl} \times C_{sw}]$$

A *reading* or meter reading is the instantaneous display on a meter head. When the difference between a closing and an opening reading is being discussed, such difference should be called an indicated volume.

Measurement ticket is the generalized term used in this publication to embrace and supersede expressions of long standing such as "run ticket," "receipt and delivery ticket," and other terms. It is also used to mean whatever the supporting pieces of paper or readout happen to be in a meter station that is automated, remotely controlled, and/or computerized.

12.2.8.3 RULE FOR ROUNDING—MEASUREMENT TICKETS

In calculating a net standard volume, record temperatures to the nearest whole degree Farenheit and pressures to the nearest scale reading line. Tables of correction factors should be used, with values expressed to four decimal places.

Multiply the meter factor to be used by the correction factors, rounding to four decimal places at each step in this intermediate calculation. Round the combined correction factor (*CCF*, which in this situation includes a meter factor value and C_{tw}) to four decimal places. Round the resulting net standard volume to the nearest whole barrel or whole gallon, as the case may be.

12.2.8.4 CORRECTION FACTORS

The correction factors that apply to measurement tickets, and their notation, are explained in 12.2.5. In measurement tickets for crude oil another correction factor is introduced to allow for known volumes of sediment and water (S&W). The value of this correction factor (C_{sw}) is 1 − [%S&W/100]. Like the corrections for temperature and pressure, it too should be combined into the *CCF* (see 12.2.5.5) when calculating measurement tickets.

12.2.8.5 HIERARCHY OF ACCURACIES

The hierarchy of accuracies assigns measurement ticket values to a level below meter factor calculations because the accumulated uncertainties entering the calibration of provers, and then entering the calculation of meter factors, makes it unrealistic to assign a higher position. Thus, only four decimal places in the correction factors are warranted, and the conventions for rounding and truncating are necessary in order to obtain the same value from the same data regardless of who or what does the computing.

12.2.8.6 STANDARD PROCEDURES

Meter readings shall be truncated so that fractions of a standard unit (barrels or gallons) are eliminated (not rounded) and the indicated volume determined therefrom shall enter the calculation for net standard volume. (Should it be agreed between the interested parties to employ a unit larger than a barrel, such as a unit of 10 barrels, then truncation will eliminate anything less than such a unit.)

For example:

	Displayed Value	Truncated Value
Closing reading	3,867,455.2	3,867,455
Opening reading	3,814,326.9	3,814,326
Volume by difference	53,128.3	53,129

Non-resettable counters should be employed.

Temperature shall be read and rounded to the nearest whole degree Farenheit.

Pressures shall be read and rounded to the nearest scale reading.

12.2.8.7 CONVENTIONS

In order to avoid multiplying a large number (for example, an indicated volume) by a small number (for example, a correction factor) over and over again, and possibly losing significance in the process, obtain the combined correction factor (*CCF*) first and only then, multiply the indicated volume by the *CCF* (see 12.2.5.5). Multiply each correction factor by the next one, and round to four decimal places at each step. Report all correction factors to four decimal places, including the *CCF*.

12.2.8.8 EXAMPLE MEASUREMENT TICKET FOR A LOW VAPOR PRESSURE LIQUID

A measurement ticket form should allow for the recording of at least the data shown in Figure 7 and the calculated values. The example applies to a nontemperature compensated meter.

A. GENERAL INFORMATION

Ticket no. ______	Month/day/year ______
Time started ______	Time finished ______
Measuring station ______	Delivered to ______
Liquid *crude oil*	Batch ______
Sediment and water *0.15%*	API gravity at 60°F (see Note 1) *39.6°API*
Remarks ______	Witness name ______ (signature)
	Operator's name ______ (signature)

B. MEASUREMENT INFORMATION

1.	Closing meter reading (truncated), barrels	*3,867,455*
2.	Opening meter reading (truncated), barrels	*3,814,326*
3.	Indicated volume, barrels	*53,129*
4.	Meter factor *1.0016* from Report No. ______	
5.	Average stream temperature, °F	*88*
6.	C_{tlm} (see 11.1, Table 6)	*0.9860*
7.	Average meter pressure, psig	*370*
8.	C_{plm}	*1.0022*
9.	Sediment and water (if applicable), percent	*0.15*
10.	C_{sw} (For dry, clean products, use 1.0000)	*0.9985*
11.	Combined correction factor, CCF_m (Lines 4 × 6 × 8 × 10)	*0.9983*
12.	Net standard volume, barrels (Line 3 × 11)	*52,507*

NOTE 1: Gravity is assumed to be rounded to .5 degrees API.

Figure 7—Example Measurement Ticket for a Low Vapor Pressure Liquid

APPENDIX A

CORRECTION FACTORS FOR STEEL

Table A-1—Temperature Correction Factors for Mild Steel, C_{ts}
Table A-2—Temperature Correction Factors for Stainless Steel, C_{ts}
Table A-3—Pressure Correction Factors for Steel, C_{ps}

Table A-1—Temperature Correction Factors for Mild Steel

C_{ts} for mild steel having a cubical coefficient of expansion of 1.86×10^{-5} per °F

Observed Temperature, °F	C_{ts} Value	Observed Temperature, °F	C_{ts} Value
−7.2– −1.9	0.9988	73.5– 78.8	1.0003
−1.8– 3.5	0.9989	78.9– 84.1	1.0004
3.6– 8.9	0.9990	84.2– 89.5	1.0005
9.0– 14.3	0.9991	89.6– 94.9	1.0006
14.4– 19.6	0.9992	95.0–100.3	1.0007
19.7– 25.0	0.9993	100.4–105.6	1.0008
25.1– 30.4	0.9994	105.7–111.0	1.0009
30.5– 35.8	0.9995	111.1–116.4	1.0010
35.9– 41.1	0.9996	116.5–121.8	1.0011
41.2– 46.5	0.9997	121.9–127.2	1.0012
46.6– 51.9	0.9998	127.3–132.5	1.0013
52.0– 57.3	0.9999	132.6–137.9	1.0014
57.4– 62.6	1.0000	138.0–143.3	1.0015
62.7– 68.0	1.0001	143.4–148.7	1.0016
68.1– 73.4	1.0002	148.8–154.0	1.0017

NOTE: This table is suitable for application in meter proving; in prover calibration use the formulas. For the formula used to derive the tabulated values and to calculate values, see 12.2.5.1.

Table A-2—Temperature Correction Factors for Stainless Steel

C_{ts} for stainless steel having a cubical coefficient of expansion of 2.65×10^{-5} per °F

Observed Temperature, °F	C_{ts} Value	Observed Temperature, °F	C_{ts} Value
−9.8– −6.1	0.9982	73.3– 76.9	1.0004
−6.0– −2.3	0.9983	77.0– 80.7	1.0005
−2.2– 1.5	0.9984	80.8– 84.5	1.0006
1.6– 5.2	0.9985	84.6– 88.3	1.0007
5.3– 9.0	0.9986	88.4– 92.0	1.0008
9.1– 12.8	0.9987	92.1– 95.8	1.0009
12.9– 16.6	0.9988	95.9– 99.6	1.0010
16.7– 20.3	0.9989	99.7–103.3	1.0011
20.4– 24.1	0.9990	103.4–107.1	1.0012
24.2– 27.9	0.9991	107.2–110.9	1.0013
28.0– 31.6	0.9992	111.0–114.7	1.0014
31.7– 35.4	0.9993	114.8–118.4	1.0015
35.5– 39.2	0.9994	118.5–122.2	1.0016
39.3– 43.0	0.9995	122.3–126.0	1.0017
43.1– 46.7	0.9996	126.1–129.8	1.0018
46.8– 50.5	0.9997	129.9–133.5	1.0019
50.6– 54.3	0.9998	133.6–137.3	1.0020
54.4– 58.1	0.9999	137.4–141.1	1.0021
58.2– 61.8	1.0000	141.2–144.9	1.0022
61.9– 65.6	1.0001	145.0–148.6	1.0023
65.7– 69.4	1.0002	148.7–152.4	1.0024
69.5– 73.2	1.0003	152.5–156.2	1.0025

NOTE: This table is suitable for application in meter proving; in prover calibration use the formulas For the formula used to derive the tabulated values and to calculate the values, see 12.2.5.1.

Table A-3—Pressure Correction Factors for Steel, C_{ps}

(All measurements are in pounds per square inch gage)

Factor C_{ps}	Prover Dimensions									Factor C_{ps}
	6-in. Pipe 0.25-in. Wall	6-in. Pipe 0.280-in. Wall	8-in. Pipe 0.322-in. Wall	8-in. Pipe 0.375-in. Wall	10-in. Pipe 0.365-in. Wall	10-in. Pipe 0.375-in. Wall	12-in. Pipe 0.375-in. Wall	14-in. Pipe 0.312-in. Wall	14-in. Pipe 0.375-in. Wall	
1.0000	0–61	0–69	0–60	0–71	0–54	0–56	0–46	0–34	0–42	1.0000
1.0001	62–183	70–207	61–181	72–214	55–163	57–168	47–140	35–104	43–127	1.0001
1.0002	184–306	208–346	182–302	215–357	164–273	169–281	141–234	105–174	128–212	1.0002
1.0003	307–428	347–484	303–423	358–499	274–382	282–393	235–328	175–244	213–297	1.0003
1.0004	429–551	485–623	424–544	500–642	383–491	394–506	329–421	245–314	298–382	1.0004
1.0005	552–673	624–761	545–665	643–785	492–601	507–618	422–515	315–384	383–466	1.0005
1.0006	674–795	762–900	666–786	786–928	602–701	619–731	516–609	385–454	467–551	1.0006
1.0007	796–918	901–1038	787–907	929–1071	711–819	732–843	610–703	455–524	552–636	1.0007
1.0008	919–1040		908–1028		820–928	844–956	704–796	525–594	637–721	1.0008
1.0009					929–1038	957–1068	797–890	595–664	722–806	1.0009
1.0010							891–984	665–734	807–891	1.0010
1.0011							985–1078	735–804	892–976	1.0011
1.0012								805–874	977–1061	1.0012
1.0013								875–944		1.0013
1.0014								945–1014		1.0014
1.0015										1.0015
1.0016										1.0016
1.0017										1.0017
1.0018										1.0018
1.0019										1.0019
1.0020										1.0020
1.0021										1.0021
1.0022										1.0022
1.0023										1.0023
1.0024										1.0024

Table A-3—Pressure Correction Factors for Steel, C_{ps} (Continued)

(All measurements are in pounds per square inch gage.)

Factor C_{ps}	16-in Pipe 0.375-in Wall	18-in Pipe 0.375-in. Wall	20 in Pipe 0.375-in. Wall	24-in Pipe 0.375-in. Wall	26-in. Pipe 0.375-in. Wall	26-in. Pipe 0.500-in. Wall	30-in. Pipe 0.500-in Wall	30-in. Pipe 0.500-in Wall	Factor C_{ps}
	Prover Dimensions								
1.0000	0– 36	0– 32	0– 29	0– 24	0– 22	0– 30	0– 25	0– 21	1.0000
1.0001	37–110	33– 97	30–087	25– 72	23– 66	31– 89	26– 77	22– 64	1.0001
1.0002	111–184	98–163	88–146	73–120	67–111	90–150	78–129	65–107	1.0002
1.0003	185–258	164–228	147–204	121–169	112–155	151–209	130–181	108–149	1.0003
1 0004	259–331	229–293	205–262	170–217	156–200	210–270	182–232	150–192	1.0004
1.0005	332–405	294–358	263–321	218–266	201–245	271–329	233–284	193–235	1.0005
1.0006	406–479	359–423	322–379	267–314	246–289	330–390	285–336	236–278	1.0006
1.0007	480–553	424–489	380–438	315–362	290–334	391–449	337–387	279–321	1.0007
1.0008	554–627	490–554	439–496	363–411	335–378	450–510	388–439	322–364	1.0008
1.0009	628–700	555–619	497–555	412–459	379–423	511–569	440–491	365–407	1.0009
1.0010	701–774	620–684	556–613	460–508	424–467	570–630	492–543	408–450	1.0010
1.0011	775–848	685–749	614–672	509–556	468–512	631–689	544–594	451–492	1.0011
1.0012	849–922	750–815	673–730	557–604	513–556	690–750	595–646	493–535	1.0012
1.0013	923–995	816–880	731–788	605–653	557–601	751–809	647–698	536–578	1.0013
1.0014	996–1069	881–945	789–847	654–701	602–646	810–870	699–750	579–621	1.0014
1.0015		946–1010	848–905	702–749	647–690	871–929	751–801	622–664	1.0015
1 0016			906–964	750–798	691–735	930–990	802–853	665–707	1.0016
1.0017			965–1022	799–846	736–779	991–1049	854–905	708–749	1.0017
1.0018				847–895	780–824		906–956	750–792	1.0018
1.0019				896–943	825–868		957–1008	793–835	1.0019
1.0020				944–991	869–913			836–878	1.0020
1.0021				992–1040	914–957			879–921	1.0021
1.0021					958–1002			922–964	1.0022
1.0022								965–1007	1.0023
1.0023									1.0024
1.0024									

NOTES:

1. This table is based on the following equation:

$$C_{ps} = 1 + \frac{P_P - P_b D}{E_t}$$

Where:

C_{ps} = steel correction factor for pressure to account for the change in volume with the change in pressure.
P_p = operating or observed pressure, in pounds per square inch gage.
P_b = Pressure, in pounds per square inch gage, at which the base volume of the prover was determined (usually, 0 pounds per square inch gage).
D = internal diameter of the pipe in the prover section, in inches.
E = modulus of elasticity for steel equals (30)(10^6).
t = wall thickness of the pipe in the prover section, in inches.

2. This table is suitable for application in meter proving; in prover calibrations, use the formula (see F12.2.5.2).

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APPENDIX B

CORRECTIONS TO OFFSET THE EFFECTS OF TEMPERATURE ON METAL SHELLS

This appendix presents the derivations of the corrections necessary to offset the effects of temperature on the metal shells of both the field standard test measures and the prover they are used to calibrate.

The general equation for determining the base volume of a prover by water drawing it with field standard test measures is:

$$PBV = [V_M \times C_{tdw}] \times \left[\frac{C_{tsM}}{C_{tsp} \times C_{psp} \times C_{plp}}\right] \quad \text{(B1)}$$

Where:

PBV = the prover base volume at 60°F and 0 pounds per square inch gage.

V_M = the indicated volume in the test measure.

C_{tsM} = the correction for the temperature of the steel shell of the test measure (see 12.2.5.1).

C_{tdw} = the correction for the temperature difference between the water when in the individual test measures and the water when in the prover. (This factor must be used out of sequence.) It can be obtained from tabulated values in Chapter 11.4.2.

C_{plp} = the correction for pressure on the water in the prover (see 12.2.5.4).

C_{tsp} = the correction for the temperature of the steel shell of the prover (see 12.2.5.1).

C_{psp} = the correction for the pressure on the steel shell of the prover (see 12.2.5.2).

For the purpose of discussion, or even of calculation, the two corrections for the temperature of the steel shell can be combined as follows:

$$CC_{ts} = \left(\frac{C_{tsM}}{C_{tsp}}\right) = \left(\frac{1 + (T_M - 60)\gamma_M}{1 + (T_p - 60)\gamma_p}\right) \quad \text{(B2)}$$

Where:

CC_{ts} = the combined correction factor for the effect of temperature on the steel of both the prover and the measure.

T_M and T_p = the temperatures of the steel shells of the measure and the prover, respectively, generally taken as equal to the temperature of the water contained therein.

γ_M and γ_p = the coefficients of cubical expansion of the materials of the measure and the prover, respectively.

Multiplying both the numerator and denominator of Equation B2 by $1 - (T_p - 60)\gamma_p$ and dropping the second order infinitesimals as negligible gives:

$$CC_{ts} = 1 + (T_M - 60)\gamma_M - (T_p - 60)\gamma_p \quad \text{(B3)}$$

Equation B3 is the general case.

For the special case when the prover and the test measures are made of the same material—

$$\gamma_M = \gamma_p = \gamma$$

and

$$CC_{ts} = 1 + (T_M - T_p)\gamma \quad \text{(B4)}$$

For the other special case when the prover and the test measure are at the same temperature but are made of different materials—

$$T_M = T_p = T$$

and

$$CC_{ts} = 1 + (T - 60)(\gamma_M - \gamma_p) \quad \text{(B5)}$$

Equations B4 and B5 are the corrections discussed in Section 7.2 and Section 7.3 of the National Bureau of Standards Monograph 62, *Testing of Metal Volumetric Standards*. The general case value for all combinations of temperatures and materials, however, is covered by Equation B2 and is used in B1.

With respect to Equation B1 it should be noted that in practice the value of C_{tdw} is determined for each test measure withdrawn and applied to the volume in that test measure. These corrected volumes are then summed and the remaining corrections are applied to the sum. In that case T_M is taken as the volume-weighted average temperature of all the measures withdrawn. This practice is acceptable for the normal range of temperature experienced because the cubical coefficient of thermal expansion of the usual metals is only about one-tenth that of water. Equation B1 then becomes:

$$PBV = \Sigma[V_n \times C_{tdw}]i \times \left[\frac{C_{tsM}}{C_{tsp} \times C_{psp} \times C_{plp}}\right] \quad \text{(B6)}$$

It should be noted that while the coefficient of cubical expansion of mild steel is usually 1.86×10^{-5}, the coefficient for stainless steel and other metals generally varies with the composition of the metal, and only those values given by the manufacturer of the test measures or prover should be used.

As an example of the extent to which the failure to apply the steel temperature corrections affects the prover base volume, consider the case where both the measures and the prover are made of mild steel but the temperature in the test measures is 87°F while the temperature in the prover at the beginning of the water draw is 78°F. Then:

$$\frac{C_{tsM}}{C_{tsp}} = \frac{1 + [(87 - 60) \times 1.86 \times 10^{-5}]}{1 + [(78 - 60) \times 1.86 \times 10^{-5}]} = 1.000167$$

Failure to apply these corrections in Equation B6 would therefore result in understating the prover base volume by 0.0167 percent.

Thus it can be seen that the statement in Paragraph 2125 of API Standard 1101, "If the test measure and the prover are made of the same material, no correction of the volume of the prover to 60°F need be made," is true only if the temperature in the prover differs from the temperature in the test measure by 3°F or less.

APPENDIX C

SAMPLE METER PROVING REPORT FORMS

General Purpose Meter Proving Report for Use with Pipe Provers
Meter Proving Report for Tank Prover Method
Meter Proving Report for Master Meter Method

GENERAL PURPOSE METER PROVING REPORT FOR USE WITH PIPE PROVERS

LOCATION	DATE	AMBIENT TEMP.	REPORT NO.

PROVER DATA

BASE VOLUME AT 60°F AND "0" psi.	SIZE	WALL
bbl.		

PREVIOUS REPORT

FLOW RATE	FACTOR	DATE
bbl/hr.		

METER DATA

SERIAL NO.	METER NO.	PULSES/bbl	TEMP. COMP.	MANUF.	SIZE	MODEL

FLOW RATE	NON-RESET TOTALIZER
bbl/hr.	

RUN DATA

TEMPERATURE		PRESSURE		TOTAL PULSES	RUN NO.
PROVER AVG.	METER	PROVER	METER		
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					AVG.

C_{ts} = CORRECTION FOR TEMPERATURE ON STEEL

C_{ps} = CORRECTION FOR PRESSURE ON STEEL

C_{tl} = CORRECTION FOR TEMPERATURE ON LIQUID TABLE 6 OR TABLE 24 FOR LPG s

C_{pl} = CORRECTION FOR PRESSURE ON LIQUID

LIQUID DATA

TYPE	API GRAVITY	SPECIFIC GRAVITY	R.V. PRESS	BATCH/TENDER NO.
	AT 60°F	AT 60°F		

FIELD CALCULATIONS

PROVER VOLUME X [C_{ts} X C_{ps} X C_{tl} X C_{pl}] = CORRECTED PROVER VOLUME

AVERAGE PULSES ÷ PULSES/bbl = GROSS METER VOL. X [C_{tl} USE ONLY FOR NONTEMP. COMP. METER X C_{pl}] = CORRECTED METER VOLUME

CORRECTED PROVER VOLUME ÷ CORRECTED METER VOLUME = METER FACTOR

X C_{pl} LIQUID CORR. FOR PRESS. AT METERING COND. = COMPOSITE FACTOR USE FOR CONSTANT PRESSURE APPLICATIONS

REMARKS, REPAIRS, ADJUSTMENTS, ETC., ____________________

SIGNATURE	DATE	COMPANY REPRESENTED

METER PROVING REPORT FOR TANK PROVER METHOD

LOCATION	TENDER	LIQUID	°API	DATE	AMBIENT TEMP.	REPORT NO.

PROVER DATA	
NOMINAL VOLUME AT 60°F AND "0" psig.	SERIAL NO.
gal/bbl	

PREVIOUS REPORT NO.		
FLOW RATE	FACTOR	DATE
bbl/hr		

METER DATA					
SERIAL NO.	METER NO.	TEMP. COMPENSATED	MANUFACTURER	SIZE	MODEL
		☐ YES ☐ NO			

FLOW RATE	NON RESET COUNTER
bbl/hr	

REMARKS, REPAIRS, ADJUSTMENTS, ETC.

	PROVER TANK VOLUME DATA	RUN NO. 1	RUN NO. 2	RUN NO. 3	RUN NO. 4
1	DELIVERY TO TANK, gal/bbls				
2	TANK TEMPERATURE (AVERAGE) °F				
3	C_{ts}				
4	C_{tl}				
5	COMBINED CORRECTION FACTOR (LINE 3 × LINE 4)				
6	CORRECTED PROVER VOLUME (LINE 1 × LINE 5)				
	PROVED METER DATA				
7	FINAL METER READING				
8	INITIAL METER READING				
9	INDICATED VOLUME BY METER, bbls (LINE 7 − LINE 8)				
10	INDICATED VOLUME BY METER, gals (LINE 7 − LINE 8) OR (42 × LINE 9)				
11	TEMPERATURE AT METER, °F				
12	PRESSURE AT METER, psig				
13	C_{tl} USE 1.000 IF TEMP. COMPENSATED				
14	C_{pl}				
15	CCF (LINE 13 × LINE 14)				
16	CORRECTED METER VOLUME (LINE 10 × LINE 13)				
17	METER FACTOR (LINE 6 ÷ LINE 16)				

METER FACTOR (AVERAGE VALUE)	×	C_{pl} LIQUID CORRECTION FOR PRESSURE AT METERING CONDITIONS	=	COMPOSITE FACTOR USE FOR CONSTANT PRESSURE APPLICATION

SIGNATURE	DATE	COMPANY REPRESENTATIVE

METER PROVING REPORT FOR MASTER METER METHOD

LOCATION	TENDER	LIQUID	°API	DATE	AMBIENT TEMP.	REPORT NO.

METER DATA

SERIAL NO.	METER NO.	PULSES/bbl	TEMP. COMPENSATED	MANUFACTURER	SIZE	MODEL

FLOW RATE	NON RESET COUNTER

PREVIOUS REPORT NO. ____________

FLOW RATE	FACTOR	DATE
bbl/hr.		

MASTER METER DATA MAKE: ____________ SIZE ________ MODEL ________ SERIAL NO. ________

1	CLOSING READING, bbls/gals					
2	OPENING READING, bbls/gals					
3	INDICATED VOLUME (LINE 1 − LINE 2)					
4	TEMPERATURE AT METER, °F					
5	PRESSURE AT METER, psig					
6	MASTER METER FACTOR					
7	C_{tl}					
8	C_{pl}					
9	*CCF* (LINE 6 × LINE 7 × LINE 8)					
10	CORRECTED PROVER VOLUME (LINE 3 × LINE 9)					

PROVED METER DATA

11	CLOSING METER READING, bbls/gals					
12	OPENING METER READING, bbls/gals					
13	INDICATED VOLUME (LINE 11 − LINE 12)					
14	TEMPERATURE AT METER, °F					
15	PRESSURE AT METER, psig					
16	C_{tl}					
17	C_{pl}					
18	CCF (LINE 16 × LINE 17)					
19	CORRECTED METER VOLUME (LINE 13 × LINE 18)					
20	METER FACTOR (LINE 10 ÷ LINE 19)					

METER FACTOR (AVERAGE VALUE)	×	C_{pl} LIQUID CORRECTION FOR PRESSURE AT METERING CONDITIONS	=	COMPOSITE FACTOR USE FOR CONSTANT PRESSURE APPLICATION

SIGNATURE	DATE	COMPANY REPRESENTATIVE

APPENDIX D

CHAPTERS 22 AND 23 FROM NBS HANDBOOK 91[1]

CHAPTER 22—NOTES ON STATISTICAL COMPUTATIONS

22-1 Coding in Statistical Computations

Coding is the term used when arithmetical operations are applied to the original data in order to make the numbers easier to handle in computation. The possible coding operations are:

(a) Multiplication (or its inverse, division) to change the order of magnitude of the recorded numbers for computing purposes.

(b) Addition (or its inverse, subtraction) of a constant—applied to recorded numbers which are nearly equal, to reduce the number of figures which need be carried in computation.

When the recorded results contain non-significant zeros, (e.g., numbers like .000121 or like 11,100), coding is clearly desirable. There obviously is no point in copying these zeros a large number of times, or in adding additional useless zeros when squaring, etc. Of course, these results could have been given as 121×10^{-4} or 11.1×10^{3}, in which case coding for order of magnitude would not be necessary.

The purpose of coding is to save labor in computation. On the other hand, the process of coding and decoding the results introduces more opportunities for error in computation. The decision of whether to code or not must be considered carefully, weighing the advantage of saved labor against the disadvantage of more likely mistakes. With this in mind, the following five rules are given for coding and decoding.

1. The whole set of observed results must be treated alike.
2. The possible coding operations are the two general types of arithmetic operations:
   (a) addition (or subtraction); and,
   (b) multiplication (or division). Either (a) or (b), or both together, may be used as necessary to make the original numbers more tractable.
3. Careful note must be kept of how the data have been coded.
4. The desired computation is performed on the coded data.
5. The process of decoding a computed result depends on the computation that has been performed, and is indicated separately for several common computations, in the following Paragraphs (a) through (d).

(a) *The mean* is affected by every coding operation. Therefore, we must apply the inverse operation and reverse the order of operations used in coding, to put the coded mean back into original units. For example, if the data have been coded by first multiplying by 10,000 and then subtracting 120, decode the mean by adding 120 and then dividing by 10,000.

	Observed Results	Coded Results	
	.0121		1
	.0130		10
	.0125		5
Mean	.0125	Coded mean	5

Decoding: $$\text{Mean} = \frac{\text{Coded mean} + 120}{10{,}000} = \frac{25}{10{,}000} = .0125$$

(b) *A standard deviation* computed on coded data is affected by multiplication or division only. The standard deviation is a measure of dispersion, like the range, and is not affected by adding or subtracting a constant to the whole set of data. Therefore, if the data have been coded by addition or subtraction only, no adjustment is needed in the computed standard deviation. If the coding has involved multiplication (or division), the inverse operation must be applied to the computed standard deviation to bring it back to original units.

(c) *A variance* computed on coded data must be: multiplied by the square of the coding factor, if division has been used in coding; or divided by the square of the coding factor, if multiplication was used in coding.

(d) *Coding which involves loss of significant figures:* The kind of coding thus far discussed has involved no loss in significant figures. There is another method of handling data, however, that involves both *coding* and *rounding*, and is also called "coding". This operation is sometimes used when the original data are considered to be too finely-recorded for the purpose.

[1] Extracted from National Bureau of Standards Handbook 91, Natrella, M. G., *Experimental Statics*, U.S. Government Printing Office, Washington, D.C. 1963.

For example, suppose that the data consist of weights (in pounds) of shipments of some bulk material. If average weight is the characteristic of interest, and if the range of the data is large, we might decide to work with weights coded to the nearest hundred pounds, as follows:

Observed Weights Units: lbs.	Coded Data Units: 100 lbs.
7,123	71
10,056	101
100,310	1003
5,097	51
543	5
.	.
.	.
.	.
etc.	etc.

Whether or not the resulting average of the coded data gives us sufficient information will depend on the range of the data and the intended use of the result. It should be noted that this "coding" requires a higher order of judgment than the strictly arithmetical coding discussed in previous examples, because some loss of information does occur. The decision to "code" in this way should be made by someone who understands the source of the data and the intended use of the computations. The grouping of data in a frequency distribution is coding of this kind.

22-2 Rounding in Statistical Computations

22-2.1 ROUNDING OF NUMBERS

Rounded numbers are inherent in the process of reading and recording data. The readings of an experimenter are rounded numbers to start with, because all measuring equipment is of limited accuracy. Often he records results to even less accuracy than is attainable with the available equipment, simply because such results are completely adequate for his immediate purpose. Computers often are required to round numbers—either to simplify the arithmetic calculations, or because it cannot be avoided, as when 3.1416 is used for π or 1.414 is used for $\sqrt{2}$.

When a number is to be rounded to a specific number of significant figures, the rounding procedure should be carried out in accordance with the following three rules.

1. When the figure next beyond the last place to be retained is less than 5, the figure in the last place retained should be kept unchanged.

For example, .044 is rounded to .04.

2. When the figure next beyond the last figure or place to be retained is greater than 5, the figure in the last place retained should be increased by 1.

For example, .046 is rounded to .05.

3. When the figure next beyond the last figure to be retained is 5, and,

(a) there are no figures or are only zeros beyond this 5, an odd figure in the last place to be retained should be increased by 1, an even figure should be kept unchanged.

For example, .045 or .0450 is rounded to .04; .055 or .0550 is rounded to .06.

(b) if the 5 is followed by any figures other than zero, the figure in the last place to be retained should be increased by 1, whether odd or even.

For example, in rounding to two decimals, .0451 is rounded to .05.

A number should always be rounded off in one step to the number of figures that are to be recorded, and should not be rounded in two or more steps of successive roundings.

22-2.2 ROUNDING THE RESULTS OF SINGLE ARITHMETIC OPERATIONS

Nearly all numerical calculations arising in the problems of everyday life are in some way approximate. The aim of the computer should be to obtain results consistent with the data, with a minimum of labor. We can be guided in the various arithmetical operations by some basic rules regarding significant figures and the rounding of data:

1. *Addition.* When several approximate numbers are to be added, the sum should be rounded to the number of decimal places (not significant figures) no greater than in the addend which has the smallest number of decimal places.

Although the result is determined by the least accurate of the numbers entering the operation, one more decimal place in the more-accurate numbers should be retained, thus eliminating inherent errors in the numbers.

For example:

$$\begin{array}{r} 4.01 \\ .002 \\ \underline{.623} \\ 4.635 \end{array}$$

The sum should be rounded to and recorded as 4.64.

2. *Subtraction.* When one approximate number is to be subtracted from another, they must both be rounded off to the same place before subtracting.

Errors arising from the subtraction of nearly-equal approximate numbers are frequent and troublesome, often making the computation practically worthless. Such errors can be avoided when the two nearly-equal numbers can be approximated to more significant digits.

3. *Multiplication.* If the less-accurate of two approximate numbers contains n significant digits, their product can be relied upon for n digits at most, and should not be written with more.

As a practical working plan, carry intermediate computations out in full, and round off the final result in accordance with this rule.

4. *Division*. If the less-accurate of either the dividend or the divisor contains n significant digits, their quotient can be relied upon for n digits at most, and should not be written with more.

Carry intermediate computations out in full, and round off the final result in accordance with this rule.

5. *Powers and Roots*. If an approximate number contains n significant digits, its power can be relied upon for n digits at most; its root can be relied upon for at least n digits.

6. *Logarithms*. If the mantissa of the logarithm in an n-place log table is not in error by more than two units in the last significant figure, the antilog is correct to $n - 1$ sigificant figures.

The foregoing statements are working rules only. More complete explanations of the rules, together with procedures for determining explicit bounds to the accuracy of particular computations, are given in Scarborough[1], and the effects of rounding on statistical analyses of large numbers of observations are discussed in Eisenhart[2].

22-2.3 ROUNDING THE RESULTS OF A SERIES OF ARITHMETIC OPERATIONS

Most engineers and physical scientists are well acquainted with the rules for reporting a result to the proper number of significant figures. From a computational point of view, they know these rules too well. It is perfectly true, for example, that a product of two numbers should be reported to the same number of significant figures as the least-accurate of the two numbers. It is not so true that the two numbers should be rounded to the same numbers of significant figures before multiplication. A better rule is to round the more-accurate number to one more figure than the less-accurate number, and then to round the product to the same number of figures as the less-accurate one. The great emphasis against reporting more figures than are reliable has led to a prejudice against carrying enough figures in computation.

Assuming that the reader is familiar with the rules of the preceding Paragraph 22-2.2, regarding significant figures in a single arithmetical operation, the following paragraphs will stress the less well-known difficulties which arise in a computation consisting of a long series of different arithmetic operations. In such a computation, strict adherence to the rules at each stage can wipe out all meaning from the final results.

For example, in computing the slope of a straight line fitted to observations containing three significant figures, we would not report the slope to seven significant figures; but, if we round to three significant figures after each necessary step in the computation, we might end up with no significant figures in the value of the slope.

It is easily demonstrated by carrying out a few computations of this nature that there is real danger of losing all significance by too-strict adherence to rules devised for use at the final stage. The greatest trouble of this kind comes where we must subtract two nearly-equal numbers, and many statistical computations involve such subtractions.

The rules generally given for rounding-off were given in a period when the average was the only property of interest in a set of data. Reasonable rounding does little damage to the average. Now, however, we almost always calculate the standard deviation, and this statistic does suffer from too-strict rounding. Suppose we have a set of numbers:

$$\begin{array}{r} 3.1 \\ 3.2 \\ \underline{3.3} \\ \text{Avg.} = 3.2 \end{array}$$

If the three numbers are rounded off to one significant figure, they are all identical. The average of the rounded figures is the same as the rounded average of the original figures, but all information about the variation in the original number is lost by such rounding.

The generally recommended procedure is to carry two or three extra figures thorughout the computation, and then to round off the final reported answer (e.g., standard deviation, slope of a line, etc.) to a number of significant figures consistent with the original data. However, in some special computations such as the fitting of equations by least squares methods given in ORDP 20-110, Chapters 5 and 6, one should carry extra decimals in the intermediate steps—decimals sufficiently in excess of the number considered significant to insure that the computational errors in the final solutions are negligible in relation to their statistical imprecision as measured by their standard errors. For example, on a hand-operated computing machine, use its total capacity and trim the figures off as required in the final results. (See Chapter 23.)

REFERENCES

1. J. B. Scarborough, *Numerical Mathematical Analysis*, Chapter 1, (3d edition), The Johns Hopkins Press, Baltimore, Md., 1955.

2. C. Eisenhart, *Techniques of Statistical Analysis*, Chapter 4, McGraw-Hill Book Co., New York, N.Y., 1947.

CHAPTER 23—EXPRESSION OF THE UNCERTAINTIES OF FINAL RESULTS

23-1 Introduction

Measurement of some property of a thing in practice always takes the form of a sequence of steps or operations that yield as an end result a number that serves to represent the amount or quantity of some particular property of a thing—a number that indicates how much of this property the thing has, for someone to use for a specific purpose. The end result may be the outcome of a single reading of an instrument, with or without corrections for departures from prescribed conditions. More often, it is some kind of average; e.g., the arithmetic mean of a number of independent determinations of the same magnitude, or the final result of a least squares "reduction" of measurements of a number of different magnitudes that bear known relations with each other in accordance with a definite experimental plan. In general, the purpose for which the answer is needed determines the precision or accuracy of measurement required, and ordinarily also determines the method of measurement employed.

Although the accuracy required of a reported value depends primarily on the use, or uses, for which it is intended, we should not ignore the requirements of other uses to which the reported value is likely to be put. A certified or reported value whose accuracy is entirely unknown is worthless.

Strictly speaking, the actual *error* of a reported value, that is, the magnitude and sign of its deviation from the truth, is usually unknowable. Limits to this error, however, can usually be inferred—with some risk of being incorrect—from the *precision* of the measurement process by which the reported value was obtained, and from reasonable limits to the possible *bias* of the measurement process. The *bias*, or *systematic error*, of a measurement process is the magnitude and direction of its tendency to measure something other than what was intended; its *precision* refers to the typical *closeness together* of successive independent measurements of a single magnitude generated by repeated applications of the process under specified conditions; and, its *accuracy* is determined by the *closeness of the true value* characteristic of such measurements.

Precision and *accuracy* are inherent characteristics of the measurement process employed, and not of the particular end result obtained. From experience with a particular measurement process and knowledge of its sensitivity to uncontrolled factors, we can often place reasonable bounds on its likely systematic error (bias). It also is necessary to know how well the particular value in hand is likely to agree with other values that the same measurement process might have provided in this instance, or might yield on remeasurement of the same magnitude on another occasion. Such information is provided by the *standard error* of the reported value, which measures the characteristic disagreement of repeated determinations of the same quantity by the same method, and thus serves to indicate the precision (strictly, the *imprecision*) of the reported value.

The uncertainty of a reported value is indicated by giving credible limits to its likely inaccuracy. No single form of expression for these limits is universally satisfactory. In fact, different forms of expression are recommended, the choice of which will depend on the relative magnitudes of the impression and likely bias; and on their relative importance in relation to the intended use of the reported value, as well as to other possible uses to which it may be put.

Four distinct cases need to be recognized:

1. *Both systematic error and imprecision negligible* in relation to the requirements of the intended and likely uses of the result.

2. *Systematic error not negligible*, but *imprecision negligible*, in relation to the requirements.

3. *Neither systematic error nor imprecision negligible* in relation to the requirements.

4. *Systematic error negligible*, but *imprecision not negligible* in relation to the requirements.

Specific recommendations are made below with respect to each of these four cases, supplemented by further discussion of each case in Paragraphs 23-2 through 23-5. These recommendations may be summarized as follows:

(a) Two numerics, respectively expressing the imprecision and bounds to the systematic error of the result, should be used whenever: (1) the margin is narrow between ability to measure and the accuracy or precision requirements of the situation; or, (2) the imprecision and the bounds to the systematic error are nearly equal in indicating possible differences from the *true value*. Such instances come under Case 3.

(b) A quasi-absolute type of statement with one numeric, placing bounds on the inaccuracy of the result, should be used whenever: (1) a wide or adequate margin exists between ability to measure and the accuracy requirements of the situation (Case 1); (2) the imprecision is negligibly small in comparison with the bounds placed on the systematic error (Case 2); or, (3) the control is so satisfactory that the extent of error is known.

(c) A single numeric expressing the imprecision of the result should be used whenever the systematic error is either zero by definition or negligibly small in comparison with the imprecision (Case 4).

(d) Expressions of uncertainty should be given in sentence form whenever feasible.

(e) The form "$a \pm b$" should be avoided as much as possible; and never used without explicit explanation of its connotation.

23-2 Systematic Error and Imprecision Both Negligible (Case 1)

In this case, the certified or reported result should be given correct to the number of significant figures consistent with the accuracy requirements of the situation, together with an explicit statement of its accuracy or correctness.

For example:

. . . the wavelengths of the principal visible lines of mercury 198 have been measured relative to the 6057.802106 A (Angstrom units) line of krypton 98, and their values in vacuum are certified to be

5792.2685 A
5771.1984 A
5462.2706 A
4359.5625 A
4047.7146 A

correct to eight significant figures.

It must be emphasized that when no statement of accuracy or precision accompanies a certified or reported number, then, in accordance with the usual conventions governing rounding, this number will be interpreted as being accurate within $\pm\frac{1}{2}$ unit in the last significant figure given; i.e., it will be understood that its inaccuracy before rounding was less than ± 5 units in the next place.

23-3 Systematic Error Not Negligible, Imprecision Negligible (Case 2)

In such cases:

(a) Qualification of a certified or reported result should be limited to a single quasi-absolute type of statement that places bounds on its inaccuracy;

(b) These bounds should be stated to no more than two significant figures;

(c) The certified or reported result itself should be given (i.e., rounded) to the last place affected by the stated bounds, unless it is desired to indicate and preserve such relative accuracy or precision of a higher order that the result may possess for certain particular uses;

(d) Accuracy statements should be given in sentence form in all cases, except when a number of results of different accuracies are presented, e.g., in tabular arrangement. If it is necessary or desirable to indicate the respective accuracies of a number of results, the results should be given in the form $a \pm b$ (or $a {+b \atop -c}$, if necessary) with an appropriate explanatory remark (as a footnote to the table, or incorporated in the accompanying text) to the effect that the $\pm b$, or ${+b \atop -c}$, signify bounds to the errors to which the a's may be subject.

The particular form of the quasi-absolute type of statement employed in a given instance ordinarily will depend upon personal taste, experience, current and past practice in the field of activity concerned, and so forth. Some examples of good practice are:

. . . is(are) not in error by more than 1 part in (x).
. . . is(are) accurate within $\pm$ (x units) (or $\pm$ (x)%).
. . . is(are) believed accurate within (. . .)

Positive wording, as in the first two of these quasi-absolute statements, is appropriate only when the stated bounds to the possible inaccuracy of the certified or reported value are themselves reliably established. On the other hand, when the indicated bounds are somewhat conjectural, it is desirable to signify this fact (and thus put the reader on guard) by inclusion of some modifying expression such as "believed", "considered", "estimated to be", "thought to be", and so forth, as exemplified by the third of the foregoing examples.

Results should never be presented in the form "$a \pm b$", without explanation. If no explanation is given, many persons will automatically take $\pm b$ to signify bounds to the inaccuracy of a. Others may assume that b is the *standard error* or the *probable error* of a, and hence that the uncertainty of a is at least $\pm 3b$, or $\pm 4b$, respectively. Still others may take b to be an indication merely of the imprecision of the individual measurements; that is, to be the *standard deviation, the average deviation, or the probable error of a SINGLE observation*. Each of these interpretations reflects a practice of which instances can be found in current scientific literature. As a step in the direction of reducing this current confusion, we urge that the use of "$a \pm b$" in presenting results in official documents be limited to that sanctioned under (d) above.

The term *uncertainty*, with the quantitative connotation of limits to the likely departure from the truth, and not simply connotating vague lack of certainty, may sometimes be used effectively to achieve a conciseness of expression otherwise difficult or impossible to attain. Thus, we might make a statement such as:

The uncertainties in the above values are not more than ± 0.5 degree in the range 0° to 1100°C, and then increase to ± 2 degrees at 1450°C;

or,

The uncertainty in this values does not exceed . . . excluding (or, including) the uncertainty of . . . in the value . . . adopted for the reference standard involved.

Finally, the following forms of quasi-absolute statements are considered poor practice, and should be avoided:

The accuracy of . . . is 5 percent.

The accuracy of . . . is ± 2 percent.

These statements are presumably intended to mean that the result concerned is not inaccurate, i.e., not in error, by more than 5 percent or 2 percent, respectively; but they explicitly state the opposite.

23-4 Neither Systematic Error Nor Imprecision Negligible (Case 3)

In such cases:

(a) A certified or reported result should be qualified by: (1) a quasi-absolute type of statement that places bounds on its systematic error; and, (2) a separate statement of its standard error or its probable error, explicitly identified, as a measure of its imprecision;

(b) The bounds to its systematic error and the measure of its imprecision should be stated to no more than two significant figures;

(c) The certified or reported result itself should be stated, at most, to the last place affected by the finer of the two qualifying statements, unless it is desired to indicate and preserve such relative accuracy or precision of a higher order that the result may possess for certain particular uses;

(d) The qualification of a certified or reported result, with respect to its imprecision and systematic error, should be given in sentence form, except when results of different precision or with different bounds to their systematic errors are presented in tabular arrangement. If it is necessary or desirable to indicate their respective imprecisions or bounds to their respective systematic errors, such information may be given in a parallel column or columns, with appropriate identification.

Here, and in Paragraph 23-5, the term *standard error* is to be understood as signifying *the standard deviation of the reported value itself,* not as signifying *the standard deviation* of a single determination (unless, of course, the reported value is the result of a single determination only).

The above recommendations should not be construed to exclude the presentation of a quasi-absolute type of statement placing bounds on the inaccuracy, i.e., on the overall uncertainty, of a certified or reported value, provided that separate statements of its imprecision and its possible systematic error are included also. Bounds indicating the overall uncertainty of a reported value should not be numerically less than the corresponding bounds placed on the systematic error outwardly increased by at least two times the standard error. The fourth of the following examples of good practice is an instance at point:

> The standard errors of these values do not exceed 0.000004 inch, and their systematic errors are not in excess of 0.00002 inch.
>
> The standard errors of these values are less than (x units), and their systematic errors are thought to be less than $\pm$ (y units).
>
> . . . with a standard error of (x units), and a systematic error of not more than $\pm$(y units).
>
> . . . with an overall uncertainty of ± 3 percent based on a standard error of 0.5 percent and an allowance of ± 1.5 percent for systematic error.

When a reliably established value for the relevant standard error is available, based on considerable recent experience with the measurement process or processes involved, and the dispersion of the present measurements is in keeping with this experience, then this established value of the standard error should be used. When experience indicates that the relevant standard error is subject to fluctuations greater than the intrinsic variation of such a measure, then an appropriate upper bound should be given, e.g., as in the first two of the above examples, or by changing "a standard error . . ." in the third and fourth examples to "an upper bound to the standard error . . .".

When there is insufficient recent experience with the measurement processes involved, an estimate of the standard error must of necessity be computed, by recognized statistical procedures, from the same measurements as the certified or reported value itself. It is essential that such computations be carried out according to an agreed-upon standard procedure, and that the results thereof be presented in sufficient detail to enable the reader to form his own judgment and make his own allowances for their inherent uncertainties. To avoid possible misunderstanding in such cases:

(a) the term *computed standard error* should be used;

(b) the estimate of the standard error employed should be that obtained from the relation

$$\begin{matrix}\text{estimate of}\\ \text{standard error}\end{matrix} = \sqrt{\frac{\text{sum of squared residuals,}}{n\nu}}$$

where n is the (effective) number of completely independent determinations of which a is the arithmetic mean (or, other appropriate least squares adjusted value) and ν is the number of degrees of freedom involved in the sum of squared residuals (i.e., the number of residuals minus the number of fitted constants and/or other independent constraints); and,

(c) the number of degrees of freedom ν should be explicitly stated.

If the reported value a is the arithmetic mean, then:

$$\text{estimate of standard error} = \sqrt{\frac{s^2}{n}}$$

where s^2 is computed as shown in ORDP 20-110, Chapter 2, Paragraph 2-2.2, and n is the number of completely independent determinations of which a is the arithmetic mean.

For example:

> The computed probable error (or, standard error) of these values is (x units), based on (ν) degrees of freedom, and

the systematic error is estimated to be less than ± (y units).

. . . which is the arithmetic mean of (n) independent determinations and has a computed standard error of . . . .

. . . with an overall uncertainty of ±5.2 km sec based on a standard error of 1.5 km sec and bounds of ±0.7 km sec on the systematic error. (The figure 5.2 equals 0.7 plus 3 times 1.5).

Or, if based on a computed standard error:

. . . with an overall uncertainty of ±7 km/sec derived from bounds of ±0.7 km/sec on the systematic error and a computed standard error of 1.5 km/sec based on 9 degrees of freedom. (The figure 7 is approximately equal to 0.7 + 4.3 (1.5), where 4.3 is the two-tail 0.002 probability value of Student's t for 9 degrees of freedom. As $\nu \rightarrow \infty$, $t_{.002}(\nu) \rightarrow 3.090$.)

23-5 Systematic Error Negligible, Imprecision Not Negligible (Case 4)

In such cases:

(a) Qualification of a certified or reported value should be limited to a statement of its standard error or of an upper bound thereto, whenever a reliable determination of such value or bound is available. Otherwise, a computed value of the standard error so designated should be given, together with a statement of the number of degrees of freedom on which it is based;

(b) The standard error or upper bound thereto, should be stated to not more than two significant figures;

(c) The certified or reported result itself should be stated, at most, to the last place affected by the stated value or bound to its imprecision, unless it is desired to indicate and preserve such relative precision of a higher order that the result may possess for certain particular uses;

(d) The qualification of a certified or reported result with respect to its imprecision should be given in sentence form, except when results of different precision are presented in tabular arrangement and it is necessary or desirable to indicate their respective imprecisions, in which event such information may be given in a parallel column or columns, with appropriate identification.

The above recommendations should not be construed to exclude the presentation of a quasi-absolute type of statement placing bounds on its possible inaccuracy, provided that a separate statement of its imprecision is included also. Such bounds to its inaccuracy should be numerically equal to at least two times the stated standard error. The fourth of the following examples of good practice is an instance at point:

The standard errors of these values are less than (x units).

. . . with a standard error of (x units).

. . . with a computed standard error of (x units) based on (ν) degrees of freedom.

. . . with an overall uncertainty of ±4.5 km/sec derived from a standard error of 1.5 km/sec. (The figure 4.5 equals 3 times 1.5).

Or, if based on a computed standard error:

. . . with an overall uncertainty of ±6.5 km/sec derived from a computed standard error of 1.5 km/sec (based on 9 degrees of freedom). (The figure 6.5 equals 4.3 times 1.5, where 4.3 is the two-tail 0.002 probability value of Student's t for 9 degrees of freedom. As $\nu \rightarrow \infty$, $t_{.002}(\nu) \rightarrow 3.090$.

The remarks with regard to a computed standard error in Paragraph 23-4 apply with equal force to the last two of the above examples.

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Manual of Petroleum Measurement Standards Chapter 12—Calculation of Petroleum Quantities

Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors

Part 1—Introduction

Measurement Coordination

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Chapter 12—Calculation of Petroleum Quantities

Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors

PART 1—INTRODUCTION

1.1 Purpose

When most of the older standards were written, mechanical desk calculators were widely used for calculating measurement documentation. and tabulated values were used more widely than is the case today. Rules for rounding and the choice of how many figures to enter in each calculation step were often made on the spot. As a result, different operators obtained different results from the same data.

This five-part publication consolidates and standardizes calculations pertaining to metering petroleum liquids using turbine or displacement meters and clarifies terms and expressions by eliminating local variations of such terms. The purpose of standardizing calculations is to produce the same unbiased answer from the given data. So that different operators can obtain identical results from the same data, the rules for sequence, rounding, and discrimination of figures (or decimal places) have been defined.

1.2 Scope

This document provides standardized calculation methods for the quantification of liquids and the determination of base prover volumes under defined conditions, regardless of the point of origin or destination or the units of measure required by governmental customs or statute. The criteria contained in this document allow different entities using various computer languages on different computer hardware (or manual calculations) to arrive at identical results using the same standardized input data.

The publication rigorously specifies the equations for computing correction factors, rules for rounding, calculational sequence, and discrimination levels to be employed in the calculations. No deviations from these specifications are permitted since the intent of this document is to serve as a rigorous standard.

1.3 Organization of Standard

This standard is organized into five separate parts. Part 1 contains a general introduction for dynamic calculations. Part 2 focuses on the calculation of metered quantities for fiscal purposes or measurement tickets. Part 3 applies to meter proving calculations for field operations or proving reports. Parts 4 and 5 apply to the determination of base prover volumes (BPVs).

1.3.1 PART 1—INTRODUCTION

The base (reference or standard) volumetric determination of metered quantities is discussed along with the general terms required for solution of the various equations.

General rules for rounding of numbers, including field data, intermediate calculational numbers, and discrimination levels, are specified within the context of this standard.

For the proper use of this standard, a discussion is presented on the prediction of the liquid's density at flowing and base conditions.

An explanation of the principal correction factors associated with dynamic measurement are presented in a clear, concise manner.

1.3.2 PART 2—MEASUREMENT TICKETS

The application of this standard to the calculation of metered quantities is presented for base volumetric calculations in conformance with North American industry practices.

Recording of field data, rules for rounding, calculational sequence, and discrimination levels are specified, along with a set of example calculations. The examples are designed to aid in checkout procedures for any routines that are developed using the requirements stated in this part.

1.3.3 PART 3—PROVING REPORTS

The application of this standard to the calculation of proving reports is presented for base volumetric calculations in conformance with North American industry practices. Proving reports are utilized to calculate the following meter correction and performance indicators: meter factors (MF), composite meter factors (CMF), K-factors (KF), composite K-factors (CKF), and meter accuracy factor (MA). The determination of the appropriate term is based on both the hardware and the user's preference.

Recording of field data, rules for rounding, calculational sequence, and discrimination levels are specified, along with a set of example calculations. The examples are designed to aid in checkout procedures for any routines that are developed using the requirements stated in this part.

1.3.4 PART 4—CALCULATION OF BASE PROVER VOLUMES BY WATERDRAW METHOD

The BPV may be determined by one of two methods—waterdraw or master meter. The waterdraw method involves the displacing (or drawing) of water from the prover into certified volumetric field measures. Alternatively, for open tank provers, the waterdraw method may involve the displacing (or drawing) of water from the certified volumetric test measures into the open tank prover. Certification of the field measures are traceable to the appropriate national weights and measures organization (i.e., National Institute of Standards and Technology).

Recording of field data, rules for rounding, calculational sequence, and discrimination levels are specified, along with a set of example calculations. The examples are designed to aid in checkout procedures for any routines that are developed using the requirements stated in this part.

1.3.5 PART 5—CALCULATION OF BASE PROVER VOLUMES BY MASTER METER METHOD

The BPV may be determined by one of two methods—waterdraw or master meter. The master meter method employs the use of a master meter (or transfer standard). The master meter is proved under actual operating conditions by a master prover that has been calibrated by the waterdraw method. The master prover, master meter, and field prover are piped in series allowing fluid to pass through the three devices simultaneously.

Recording of field data, rules for rounding, calculational sequence, and discrimination levels are specified, along with a set of example calculations. The examples are designed to aid in checkout procedures for any routines that are developed using the requirements stated in this part.

1.4 Referenced Publications

Several documents served as references for the revisions of this standard. In particular, previous editions of Chapter 12.2 (ANSI/API 12.2) provided a wealth of information. The following are other publications that served as a resource of information for this revision:

API

Manual of Petroleum Measurement Standards (MPMS)

- Chapter 4, "Proving Systems"
- Chapter 5, "Metering"
- Chapter 6, "Metering Assemblies"
- Chapter 7, "Temperature Determination"
- Chapter 9, "Density Determination"
- Chapter 10, "Sediment and Water"
- Chapter 11, "Physical Properties Data"

ASTM[1]

- D1250 (Historical Edition—1952), "Petroleum Measurement Tables"
- D1550 "ASTM Butadiene Measurement Tables"
- D1555 "Calculation of Volume and Weight of Industrial Aromatic Hydrocarbons"

NIST[2]

- Handbook 105-3, "Specifications and Tolerances for Reference Standards and Field Standards"
- Monograph 62, "Testing of Metal Volumetric Standards"

1.5 Field of Application

1.5.1 APPLICABLE LIQUIDS

This standard applies to liquids that, for all practical purposes, are considered to be clean, single-phase, homogeneous, and Newtonian at metering conditions. Most liquids and dense phase liquids associated with the petroleum and petrochemical industries are usually considered to be Newtonian.

The application of this standard is limited to liquids that utilize tables and/or implementation procedures to correct metered volumes at flowing temperatures and pressures to corresponding volumes at base (reference or standard) conditions. To accomplish this, the liquid's density shall be determined by appropriate technical standards, or if necessary, proper correlations or equations of state. If multiple parties are involved in the measurement, the method selected for determining the liquid's densities shall be mutually agreed upon.

1.5.2 BASE CONDITIONS

Historically, the measurement of some liquids for custody transfer and process control have been stated in volume units at base (reference or standard) conditions.

The base conditions for the measurement of liquids, such as crude petroleum and its liquid products, having a vapor pressure equal to or less than atmospheric at base temperature are as follows:

United States Customary (USC) Units:
Pressure—14.696 psia (101.325 kPa_a)
Temperature—60.0°F (15.56°C)

International System (SI) Units:
Pressure—14.696 psia (101.325 kPa_a)
Temperature—59.00°F (15.00°C)

For liquids, such as liquid hydrocarbons, having a vapor pressure greater than atmospheric pressure at base temperature, the base pressure shall be the equilibrium vapor pressure at base temperature.

For liquid applications, base conditions may change from one country to the next due to governmental regulations. Therefore, it is necessary that the base conditions be identified and specified for standardized volumetric flow measurement by all parties involved in the measurement.

[1]American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pennsylvania 19103
[2]U.S. Department of Commerce, National Institute of Standards and Technology, Washington, D.C. 20234 (formerly National Bureau of Standards)

1.6 Uncertainty

1.6.1 GENERAL

The user of this standard needs to consider the custody transfer facility from a holistic viewpoint. The user must have defined the desired uncertainty to the designer in order to build, operate, and maintain the facility properly.

At a single metering facility, there are two types of uncertainty. The average of the many readings may be offset from the true value (bias error), and/or the readings may be randomly scattered about the offset (random error).

The uncertainty of the metered quantities depends on a combination of the following:

a. The traceability chain associated with the field standards.
b. The calculation procedure and means of computation (chart integration, flow computer, mainframe, personal computer, and so forth).
c. The uncertainty associated with the liquid density predictions.
d. The sensitivity of the liquid prediction correlation to errors in pressure, temperature, and base density determinations.
e. The design, installation, and operation of the metering facility.
f. The choice of measurement equipment (charts, transmitters, A/D converters, data loggers, and so forth)
g. The data transmission means (analog, pneumatic, digital, manual).
h The operating/calibration equipment's effects due to ambient temperature, liquid temperature, liquid pressure, response time, local gravitational forces, atmospheric pressure, and so forth.

The uncertainty is dependent not just on the hardware or equipment, but also on the hardware's performance, the software's performance, the method of calculation, the method of calibration, the calibration equipment, the calibration procedures, and the human factor.

1.6.2 HIERARCHY OF ACCURACIES

There is an inevitable or natural hierarchy of accuracies in petroleum measurement. The natural hierarchy of accuracies, often referred to as a traceability chain, is comprised of both bias and random uncertainty components.

The concept of traceability describes how an instrument can be related to a national standard by calibrating it against another device that is closer to the national standard in the traceability chain. For example, the waterdraw method for calibrating provers consists of displacing the contents between detectors into a certified volumetric field standard test measure, which itself has been calibrated using repeated fillings from a secondary standard laboratory measure. This laboratory measure will have been owned and calibrated by the national weights and measures authority, which in turn has been calibrated by comparison with the country's national primary volumetric and/or mass standard.

To expect equal or lower uncertainty in a lower level of the traceability chain than that which exists in a higher level is physically impossible, given the bias uncertainty component associated with the respective level of the chain. The random uncertainty is minimized by taking a large number of determinations with high precision devices and then finding their mean value.

In summary, the simplified traceability chain associated with a BPV contains both bias and random components. The random component can be reduced during calibration by a large number of repeated measurements. However, no amount of repeated measurement can reduce the bias component; it is a fixed systematic contribution to the uncertainty in any subsequent measurements.

1.7 Precision, Rounding, and Discrimination Levels

The minimum precision of the computing hardware must be equal to or greater than a ten-digit calculator to obtain the same answer in all calculations. For tickets calculated manually in the field utilizing printed CTL and CPL tables and not requiring the same precision, a less precise calculator (eight digit) may be used if agreed to by all parties.

The general rounding rules and discrimination levels are described in the following subsections.

1.7.1 ROUNDING OF NUMBERS

When a number is to be rounded to a specific number of decimals, it shall always be rounded off in one step to the number of figures that are to be recorded and shall not be rounded in two or more steps of successive rounding. The rounding procedure shall be in accordance with the following:

a. When the figure to the right of the last place to be retained is 5 or greater, the figure in the last place to be retained should be increased by 1.
b. If the figure to the right of the last place to be retained is less than 5, the figure in the last place retained should be unchanged.

1.7.2 DISCRIMINATION LEVELS

For field measurements of temperature and pressure, the levels specified in the various tables are maximum discrimination levels.

For example, if the parties agree to use a thermometer graduated in whole °F increments, then the device is normally read to levels of 0.5°F resolution. Likewise, if the parties agree to use a "smart" temperature transmitter, which can indicate to 0.01°F or 0.005°C, then the reading shall be rounded to the nearest 0.1°F or 0.05°C value prior to recording for calculation purposes.

1.8 Definitions, Symbols, and Abbreviations

The definitions and symbols described below are a compilation of this five-part publication.

1.8.1 DEFINITIONS

1.8.1.1 barrel (bbl): a unit volume equal to 9,702.0 cubic inches, or 42.0 U.S. gallons.

1.8.1.2 base prover volume (BPV): the volume of the prover at base conditions as shown on the calibration certificate and obtained by arithmetically averaging three consecutive successful CPV determinations.

1.8.1.3 calibrated prover volume (CPV): the volume at base conditions between the detectors in a pipe prover or the volume of a proving tank between specified "empty" and "full" levels. The calibrated volume of a bidirectional prover is the sum of the two volumes swept out between detectors during a roundtrip.

1.8.1.4 composite meter factor (CMF): a meter factor corrected from normal operating pressure to base pressure. A CMF may be used for meter applications where the relative density, temperature, and pressure are considered constant during the measurement ticket period.

1.8.1.5 cubic meter (M^3): a unit of volume equal to 1,000,000.0 milliliters (ml), or 1,000.0 liters.

1.8.1.6 gross standard volume (GSV): the volume at base conditions corrected also for the meter's performance (MF, MMF, or CMF).

1.8.1.7 indicated standard volume (ISV): the IV corrected to base conditions. It **does not** contain any correction for the meter's performance (MF, MMF, or CMF).

1.8.1.8 indicated volume (IV): the change in meter reading that occurs during a receipt or delivery. The word *registration*, though not preferred, often has the same meaning.

1.8.1.9 liter (l): a unit of volume equal to 1,000.0 milliliters (ml).

1.8.1.10 master meter: a meter proved using a certified prover and then utilized to calibrate other provers or prove other meters.

1.8.1.11 master meter factor (MMF): a dimensionless term obtained by dividing the gross standard volume of the liquid passed through the master prover (during the proving of the master meter) by the indicated standard volume (ISV_m) as registered by the master meter during proving.

1.8.1.12 master prover: refers to a volumetric standard (conventional pipe prover, SVP, or open tank prover), which was calibrated by the waterdraw method, and is used to calibrate a *master meter*.

1.8.1.13 measurement ticket: the generalized term used in this publication to embrace and supersede longstanding expressions such as "run ticket," "meter ticket," and "receipt and delivery ticket."

1.8.1.14 meter factor (MF): a dimensionless term obtained by dividing the volume of the liquid passed through the prover corrected to standard conditions during proving by the indicated standard volume (ISV_m) as registered by the meter.

1.8.1.15 meter reading (MR_o, MR_c, MMR_o, MMR_c): the instantaneous display on a meter head. When the difference between a closing and an opening reading is being discussed, such a difference should be called an IV.

1.8.1.16 net standard volume (NSV): the gross standard volume corrected for nonmerchantable quantities such as sediment and water (CSW).

1.8.1.17 pass: a single movement of the displacer in a prover that activates the start-stop detectors.

1.8.1.18 prover calibration certificate: a document stating the BPV and other physical data required when proving flowmeters (E, Gc, Ga, Gl). The calibration certificate is a written acknowledgment of a proper calibration of a prover between the authorized representatives of the interested parties.

1.8.1.19 proving report: an organized collection of all information (meter, prover, and other), used during meter proving, meter performance verification, and meter factor determination.

1.8.1.20 round trip: the forward (out) and reverse (back) consecutive passes in a bidirectional prover.

1.8.1.21 run, meter proving: one or more consecutive passes, the results of which, when totalized, are deemed sufficient to provide a single value of the meter factor (MF, CMF, MMF) or K-factor (KF, CKF).

1.8.1.22 run, prover calibration: one or more consecutive passes, the results of which, when totalized, are deemed sufficient to provide a single value of the calibrated prover volume (CPV).

1.8.1.23 U.S. gallon (gal): a unit volume equal to 231.0 cubic inches.

1.8.1.24 weighted average pressure (PWA): the average liquid pressure at the meter for the ticket period.

For volumetric methods, the weighted average pressure is the average of the pressure values sampled at uniform flow intervals and is representative of the entire measurement ticket period.

$$PWA = [SUM_i \cdot (Pi)]/n$$

Where:

n = the number of uniform intervals

For time-based methods, the weighted average pressure is the sum of the pressure values sampled during the time interval, multiplied by the volume or mass determined during the same time interval, and divided by the entire volume measured.

$$PWA = [SUM\ (Pi \times Vi)]/Vt$$

1.8.1.25 weighted average temperature (TWA): the average liquid temperature at the meter for the ticket period.

For volumetric based methods, the weighted average temperature is the average of the temperature values sampled at uniform flow intervals during the entire measurement ticket period.

$$TWA = [SUM_1^n\ (Ti)]/n$$

Where:

n = the number of uniform intervals

For time-based methods, the weighted average temperature is the sum of the temperature values sampled during the time interval, multiplied by the volume or mass determined during the same time interval, and divided by the entire volume measured.

$$TWA = [SUM\ (Ti \times Vi)]/Vt$$

1.8.2 SYMBOLS AND ABBREVIATIONS

While a combination of uppercase, lowercase, and subscripted notation is used in this publication, the uppercase notation may be used for computer programming and other documents as deemed appropriate..

Additional letters may be added to the symbolic notations below for clarity and specificity.

Units

- SI International system of units (pascal, cubic meter, kilogram, metric system).
- USC U.S. customary units (inch, pound, cubic inch, traditional system).

Pipe Dimensions

- ID Inside diameter of prover pipe.
- OD Outside diameter of prover pipe.
- WT Wall thickness of prover pipe.

Liquid Density

- API Density of liquid in degrees API gravity units.
- API_b Base liquid density in degrees API gravity units.
- API_{obs} Observed liquid density at base pressure in degrees API gravity units.
- DEN Density of liquid in kilogram per cubic meter (kg/M3) units.
- DEN_b Base liquid density in kilogram per cubic meter (kg/M3) units.
- DEN_{obs} Observed liquid density at base pressure in kilogram per cubic meter (kg/M3) units.
- RD Density of liquid in relative density.
- RD_b Base liquid density in relative density.
- RD_{obs} Observed liquid density at base pressure in relative density.
- RHO Density of liquid in mass per unit volume.
- RHO_b Base density.
- RHO_{obs} Observed liquid density at base pressure.
- RHO_p Density of liquid in prover (for prover calibrations).
- RHO_{tm} Density of liquid in test measure (for prover calibrations).
- RHO_{tp} Density of liquid at operating temperature and pressure.

Temperature

- °C Celsius temperature scale.
- °F Fahrenheit temperature scale.
- T Temperature.
- T_b Base temperature in °F or °C.
- T_d Temperature of detector mounting shaft or displacer shaft on SVP with external detectors.
- T_{obs} Observed temperature to determine RHO_b (i.e., hydrometer temperature) in °F or °C.
- T_m Temperature of meter in °F or °C.
- T_{tm} Temperature of test measure in °F or °C.
- T_{mm} Temperature of master meter in °F or °C.
- T_p Temperature of prover in °F or °C.
- T_{mp} Temperature of master prover in °F or °C.
- TWA Weighted average temperature of liquid for measurement ticket calculations in °F or °C.

Pressure

- kPa Kilopascals (SI) pressure units.
- kPa_a Kilopascals in absolute pressure units.
- kPa_g Kilopascals in gauge pressure units.
- psi Pounds per square inch (USC) pressure units.
- psia Pounds per square inch in absolute pressure units.
- psig Pounds per square inch in gauge pressure units.
- P Pressure.
- Pb Base pressure in psi or kPa pressure units.
- Pb_a Base pressure in absolute pressure units.
- Pb_g Base pressure in gauge pressure units.
- P_m Pressure of liquid in meter in gauge pressure units.
- P_{mm} Pressure of liquid in master meter in gauge pressure units.
- P_{mp} Pressure of liquid in master prover in gauge pressure units.
- P_p Pressure of liquid in prover in gauge pressure units.

PWA Weighted average pressure of liquid for measurement ticket calculations in gauge pressure units.

Pe Equilibrium vapor pressure of liquid at normal operating conditions in absolute pressure units.

Pe_b Equilibrium vapor pressure of liquid at base temperature in absolute pressure units.

Pe_m Equilibrium vapor pressure of liquid in meter at proving conditions in absolute pressure units.

Pe_{mm} Equilibrium vapor pressure of liquid in master meter in absolute pressure units.

Pe_p Equilibrium vapor pressure of liquid in prover at proving conditions in absolute pressure units.

Correction Factors

CCF Combined correction factor.

CCF_m Combined correction factor for meter at proving conditions.

CCF_{mm} Combined correction factor for master meter at proving conditions.

CCF_{mp} Combined correction factor for master prover at proving conditions.

CCF_p Combined correction factor for prover at proving conditions.

CPL Correction for compressibility of liquid at normal operating conditions (for CMF and ticket calculations).

CPL_m Correction for compressibility of liquid in meter at proving conditions.

CPL_{mm} Correction for compressibility of liquid in master meter at proving conditions.

CPL_{mp} Correction for compressibility of liquid in paster prover at proving conditions.

CPL_p Correction for compressibility of liquid in prover at proving conditions.

CPS Correction for the effect of pressure on steel (see Appendix A).

CPS_m Correction for the effect of pressure on steel test measure.

CPS_{mp} Correction for the effect of pressure on steel master prover.

CPS_p Correction for the effect of pressure on steel prover.

CSW Fiscal correction for sediment and water.

$CTDW_p$ Correction for the effect of temperature difference of water for prover calibrations.

CTL Correction for the effect of temperature on liquid at normal operating conditions (for ticket calculations).

CTL_m Correction for the effect of temperature on liquid in meter at proving conditions.

CTL_{mm} Correction for the effect of temperature on liquid when using a master meter for proving operations.

CTL_{mp} Correction for the effect of temperature on liquid in master prover.

CTL_p Correction for the effect of temperature on liquid in prover.

CTS Correction for the effect of temperature on steel (see Appendix A).

CTS_m Correction for the effect of temperature on steel test measure.

CTS_{mp} Correction for the effect of temperature on steel master prover.

CTS_p Correction for the effect of temperature on steel prover.

CCTS Combined correction for the effect of temperature on steel prover and steel test measure.

E Modulus of elasticity of steel prover.

F Compressibility factor of liquid in meter at normal operating conditions (for CMF and ticket calculations).

F_m Compressibility factor of liquid in meter at proving conditions.

F_{mm} Compressibility factor of liquid in master meter at proving conditions.

F_{mp} Compressibility factor of liquid in master prover.

F_p Compressibility factor of liquid in prover.

Gl Linear coefficient of thermal expansion on displacer shaft or detector mounting.

Ga Area coefficient of thermal expansion of prover chamber.

Gc Cubical coefficient of thermal expansion of prover.

Gcm Cubical coefficient of thermal expansion of test measure or master prover.

MA Meter accuracy factor.

MF Meter factor.

CMF Composite meter factor.

MMF Master meter factor.

MMF_{start} Master meter factor at start of each master meter calibration run.

MMF_{stop} Master meter factor at stop of each master meter calibration run.

MMF_{avg} Average master meter factor for each master meter calibration run.

NKF Nominal K-factor, pulses per unit volume.

KF K-factor, pulses per unit volume.

CKF Composite K-factor, pulses per unit volume.

Volumes

BMV Base test measure volume.

BMVa Base test measure volume adjusted for scale reading.

BPV	Base prover volume for prover.
BPV_{mp}	Base prover volume for master prover.
CPV	Calibrated prover volume.
GV	Gross volume.
GSV	Gross standard volume (for ticket calculations).
GSV_m	Gross standard volume of meter for proving operations.
GSV_{mm}	Gross standard volume when using a master meter for proving operations.
GSV_{mp}	Gross standard volume of master prover for proving operations.
GSV_p	Gross standard volume of prover for proving operations.
IV	Indicated volume (for ticket calculations).
IV_m	Indicated volume of meter for proving operations.
IV_{mm}	Indicated volume of master meter for proving operations.
ISV	Indicated standard volume.
ISV_m	Indicated standard volume of meter for proving operations.
ISV_{mm}	Indicated standard volume of master meter for proving operations.
MR_o	Opening meter reading.
MR_c	Closing meter reading.
MMR_o	Opening master meter reading.
MMR_c	Closing master meter reading.
N	Number of whole pulses for a single proving roundtrip.
Ni	Number of interpolated pulses for a single proving roundtrip
N_{avg}	Average number of pulses for the proving roundtrips that satisfy the repeatability requirements.
NSV	Net standard volume (for ticket calculations).
SR	Scale reading of test measure.
SRu	Upper scale reading of open tank prover.
SRl	Lower scale reading of open tank prover.
SWV	Sediment and water volume (for ticket calculations).
V	Volume
V_b	Volume of container at base conditions.
V_{tp}	Volume of container at operating temperature and pressure conditions.
WD	Waterdraw's test measure volume adjusted for scale reading and corrected for CTDW and CCTS.
WDz	Sum of all test measures' WD values for a single pass.
WDzb	Sum of all test measures' WDz values for a single pass corrected to Pb.

1.9 Liquid Density

The density of the liquid shall be determined by appropriate technical standards or, if necessary, by either proper correlations or equations of state. If multiple parties are involved in the measurement, the method selected for determining the liquid's densities shall be mutually agreed upon.

The density of the liquid at both flowing and base conditions can be obtained by using one of three methods:

a. Empirical density correlation.
b. An equation of state.
c. An appropriate technical expression.

The liquid's flowing density (RHO_{tp}) is determined from the following expression:

$$RHO_{tp} = RHO_b \times CTL \times CPL$$

and

$$RHO_{tp}/RHO_b = CTL \times CPL$$

It is important to note that RHO_b must be known to accurately calculate RHO_{tp}. Appendix B—Liquid Density Correlation contains a list of recommended liquid versus API correlations in accordance with API's position paper dated 1981. Where an API correlation does not currently exist, the appropriate ASTM standard has been provided to assist the user community.

1.10 Derivation of Liquid Base Volume Equations

The volume correction factors for the liquid utilized by the petroleum industry are based on the following fundamental expressions.

1.10.1 DETERMINATION OF INDICATED VOLUME

The IV is the change in meter reading that occurs during a receipt or delivery. The word *registration*, though not preferred, often has the same meaning. The IV is obtained by subtracting the Opening Meter Reading (MR_o) from the Closing Meter Reading (MR_c).

$$IV = MR_c - MR_o$$

1.10.2 DETERMINATION OF GROSS STANDARD VOLUME

The GSV is correlated by the following physical expression:

$$GSV = Mass/RHO_b$$

and the mass of the metered quantities by

$$Mass = IV \times MF \times RHO_{tp}$$

As a result, the GSV can be calculated by substituting the various terms to arrive at the following traditional expression:

$$GSV = IV \times CTL \times CPL \times MF$$

or

$$GSV = IV \times CTL \times CMF$$

Note: When using temperature compensated meter readings (MR_o, MR_c, IV), the CTL value shall be set to 1.0000.

1.10.3 DETERMINATION OF NET STANDARD VOLUME

The NSV is the equivalent volume of a liquid at its base conditions that does not include nonmerchantable items such as sediment and water. The formula for calculating NSV is as follows:

$$NSV = GSV \times CSW$$

The correction for sediment and water content (CSW) is explained in the subsequent section.

1.10.4 DETERMINATION OF S&W VOLUME

The sediment & water volume (SWV) is a calculated quantity based upon the percent sediment and water (%S&W) determined by a representative sample of the quantity of liquid being measured. It represents the nonhydrocarbon portion of the liquid and is calculated as follows:

$$SWV = GSV - [GSV \times (1 - [\%S\&W/100])]$$

1.11 Principal Correction Factors

Calculations in this publication are based on correcting the measured volume of the petroleum liquid to its volume at base conditions. Correction factors are provided to adjust the metered volume and the volume of prover or test measures to base conditions.

1.11.1 LIQUID DENSITY CORRECTION FACTORS

Liquid density correction factors are employed to account for changes in density due to the effects of temperature and pressure upon the liquid. These correction factors are as follows:

CTL corrects for the effect of temperature on the liquid density.

CPL corrects for the effect of compressibility on the liquid density.

1.11.1.1 Correction for Effect of Temperature on Liquid (CTL)

If a petroleum liquid is subjected to a change in temperature, its density will decrease as the temperature rises or increase as the temperature falls. This density change is proportional to the thermal coefficient of expansion of the liquid, which varies with base density (RHO_b) and the liquid temperature.

The correction factor for the effect of temperature on the liquid's density is called CTL. The appropriate standards for the thermal expansion factor for a liquid (CTL) may be found in Appendix B—Liquid Density Correlation.

1.11.1.2 Correction for Compressibility on Liquid (CPL)

If a petroleum liquid is subjected to a change in pressure, its density will increase as the pressure increases and decrease as the pressure decreases. This density change is proportional to the liquid's compressibility factor (F), which depends upon both its base density (RHO_b) and the liquid temperature. The appropriate standards for the compressibility factor (F) may be found in Appendix B—Liquid Density Correlation.

The correction factor for the effect of pressure on the liquid's density (CPL) can be calculated using the following expression:

$$CPL = 1/(1 - [P - (Pe_a - Pb_a)] \times [F])$$

and

$$(Pe_a - Pb_a) \geq 0$$

Where:

Pb_a = base pressure, in absolute pressure units.
Pe_a = equilibrium vapor pressure at the temperature of the liquid being measured, in absolute pressure units.
P = operating pressure, in gauge pressure units.
F = compressibility factor for liquid.

The liquid equilibrium vapor pressure (Pe_a) is considered to be equal to base pressure (Pb_a) for liquids that have an equilibrium vapor pressure less than or equal to atmospheric pressure at flowing temperature.

1.11.2 PROVER AND FIELD MEASURE STEEL CORRECTION FACTORS

Prover correction factors are employed to account for changes in the prover volume due to the effects of temperature and pressure upon the steel. These correction factors are as follows:

CTS corrects for thermal expansion and/or contraction of the steel in the prover shell due to the average prover liquid temperature.

CPS corrects for pressure expansion and/or contraction of the steel in the prover shell due to the average prover liquid pressure.

When the volume of the container at base conditions (V_b) is known, the volume at any other temperature and pressure (V_{tp}) can be calculated from the following equation:

$$V_{tp} = V_b \times CTS \times CPS$$

Conversely, when the volume of the container at any temperature and pressure (V_{tp}) is known, the volume at base conditions (V_b) can be calculated by

$$V_b = V_{tp}/(CTS \times CPS)$$

1.11.2.1 Correction for the Effect of Temperature on Steel (CTS)

Any metal container, be it a pipe prover, a tank prover, or a portable test measure, when subjected to a change in temperature, will change its volume accordingly. The volume change, regardless of prover shape, is proportional to the cubical coefficient of thermal expansion of the material. The cubical coefficient of thermal expansion is valid when the calibrated section and its detector switch mountings are constructed of a single material (pipe provers, tank provers, and field measures).

Corrections for Single-Walled Container or Prover

The CTS for pipe provers, open tank provers, and portable test measures assumes a singular construction material and may be calculated from the following:

$$CTS = 1 + [(T - T_b) \times Gc]$$

Where:

Gc = Mean coefficient of cubical expansion per degree temperature of the material of which the container is made between T_b and T.

T_b = Base temperature.

T = Mean liquid temperature in the container.

The cubical coefficient of expansion (Gc) for a pipe prover or open tank prover shall be the one for the materials used in the construction of the calibrated section. However, the Gc values contained in Table 1 shall be used if the coefficient of cubical expansion is unknown.

The cubical coefficient of expansion (Gc) on the Report of Calibration furnished by the calibrating agency is the one to be used for that individual field measure.

Corrections for Small Volume Provers With External Detectors

While the cubical coefficient of expansion is used in calculating CTS for pipe provers, tank provers, and field measures, a modified approach is needed for some of the small volume provers due to their design. The detector(s) are mounted externally, rather than on the prover barrel itself. Thus the volume changes that occur due to temperature are defined in terms of the area change in the prover barrel and the change in distance between the detector positions. While occasionally these detector positions may be on a carbon or stainless steel mounting, it is much more likely that they will be on a mounting of a special alloy that has a very small linear coefficient of expansion.

For small volume provers that utilize detectors not mounted in the calibrated section of the pipe, the correction factor for the effect of temperature (CTS) may be calculated from the following:

Table 1—Coefficients of Thermal Expansion for Steel (Gc,Ga,G1)

Type of Steel	Thermal Expansion Coefficient	
	(per °F)	(per °C)
A. Cubical Coefficient, Gc		
Mild Carbon	1.86E-05	3.35E-05
304 Stainless	2.88E-05	5.18E-05
316 Stainless	2.65E-05	4.77E-05
17-4PH Stainless	1.80E-05	3.24E-05
B. Area Coefficient, Ga		
Mild Carbon	1.24E-05	2.23E-05
304 Stainless	1.92E-05	3.46E-05
316 Stainless	1.77E-05	3.18E-05
17-4PH Stainless	1.20E-05	2.16E-05
C. Linear Coefficient, Gl		
Mild Carbon	6.20E-06	1.12E-05
304 Stainless	9.60E-06	1.73E-05
316 Stainless	8.83E-06	1.59E-05
17-4PH Stainless	6.00E-06	1.08E-05

$$CTS = (1 + [(T_p - T_b) \times (Ga)]) \times (1 + [(T_d - T_b) \times (G1)]$$

Where:

Ga = Area thermal coefficient of expansion for prover chamber.

$G1$ = Linear thermal coefficient of expansion on displacer shaft.

T_b = Base temperature.

T_d = Temperature of the detector mounting shaft or displacer shaft on SVP with external detectors.

T_p = Temperature of the prover chamber.

The linear and area thermal coefficients of expansion used shall be the ones for the materials used in the construction of the prover. However, the values contained in Table 1 shall be used if the coefficients are unknown.

1.11.2.2 Correction for the Effect of Pressure on Steel (CPS)

If a metal container such as a conventional pipe prover, a tank prover, or a test measure is subjected to an internal pressure, the walls of the container will stretch elastically and the volume of the container will change accordingly

Corrections for Single-Walled Container or Prover

While it is recognized that simplifying assumptions enter the equations below, for practical purposes, the correction factor for the effect of internal pressure on the volume of a cylindrical container, called CPS, may be calculated from

$$CPS = 1 + ([(P - P_b) \times (ID)]/(E \times WT))$$

Assuming P_b is 0 gauge pressure, the equation simplifies to

$$CPS = 1 + [(P \times ID)/(E \times WT)]$$

and

$$ID = OD - (2 \times WT)$$

Where:

- P = internal operating pressure of prover, in gauge pressure units.
- P_b = base pressure, in gauge pressure units.
- ID = internal diameter of container.
- E = modulus of elasticity for container material.
- OD = outside diameter of container.
- WT = wall thickness of container.

The modulus of elasticity (E) for a pipe prover or open tank prover shall be the one for the materials used in the construction of the calibrated section. However, the values contained in Table 2 shall be used if the modulus of elasticity (E) is unknown.

The modulus of elasticity (E) on the Report of Calibration furnished by the calibrating agency is the one to be used for that individual field measure. However, the values contained in Table 2 shall be used if the modulus of elasticity (E) is unknown.

Corrections for Double-Walled Container or Prover

Some provers are designed with a double wall to equalize the pressure inside and outside the calibrated chamber. In this case, the inner measuring section of the prover is not subjected to a net internal pressure, and the walls of this inner chamber do not stretch elastically. Therefore, in this special case,

$$CPS = 1.0000$$

1.11.3 METER FACTORS AND COMPOSITE METER FACTORS (MFs, CMFs)

Meter factors (MFs) and composite meter factors (CMFs) are terms to adjust for inaccuracies associated with the meter's performance as determined at the time of proving. Unless the meter is equipped with an adjustment that alters its registration to account for the MF, an MF must be applied to the indicated volume of the meter.

The MF is determined at the time of proving by the following expression:

$$MF = GSV_p / ISV_m$$

The CMF may be used in applications where the gravity, temperature, and pressure are considered constant throughout the measurement ticket period, or anticipated changes in these parameters result in uncertainties unacceptable to the parties or as agreed by the parties as a convenience. The CMF is determined at the time of proving by the following expression:

$$CMF = CPL_m \times MF$$

1.11.4 METER ACCURACY FACTOR (MA)

Meter accuracy factor (MA) is a term utilized specifically for loading rack meters for refined products. In most truck rack applications, the meter is mechanically or electronically adjusted at the time of proving to ensure that the meter factor is approximately unity. This simplifies the bill of lading and accounting issues associated with truck applications in refined product service.

The MA is determined at the time of proving by the following expression:

$$MA = ISV_m / GSV_p$$

or the reciprocal of the MF

$$MA = 1/MF$$

1.11.5 K-FACTORS AND COMPOSITE K-FACTORS (KFs, CKFs)

For some applications, K-factors (KFs) and composite K-factors (CKFs) are utilized to eliminate the need for applying meter correction factors to the IV. By changing the K-factor or CKF at the time of proving, the meter is electronically adjusted at the time of proving to ensure that the meter factor is approximately unity.

A new K-factor is determined at the time of proving by the following expression:

New KF = (Old KF)/MF

The CKF may be used in applications where the gravity, temperature, and pressure are approximately constant throughout the measurement ticket period. The new CKF is determined at the time of proving by the following expression:

New CKF = (Old CKF)/CMF

1.11.6 COMBINED CORRECTION FACTORS (CCF, CCF_p, CCF_m)

When multiplying a large number (for example, an IV) by a small number (for example, a correction factor) over and over again, a lowering of the precision may occur in the calculations. In addition, errors can occur in mathematical calculations due to sequencing and rounding between different machines or programs. To minimize these errors, the industry selected a method that combines correction

Table 2—Modulus of Elasticity for Steel Containers (E)

Type of Steel	Modulus of Elasticity		
	(per psi)	(per bar)	(per kPa)
Mild Carbon	3.00E+07	2.07E+06	2.07E+08
304 Stainless	2.80E+07	1.93E+06	1.93E+08
316 Stainless	2.80E+07	1.93E+06	1.93E+08
17-4PH Stainless	2.85E+07	1.97E+06	1.97E+08

factors in a specified sequence and maximum discrimination levels. The method for combining two or more correction factors is to first obtain a CCF by serial multiplication of the individual correction factors and rounding the CCF to a required number of decimal places.

Three CCFs have been adopted to minimize errors in calculations:

a. For measurement ticket calculations to determine GSV,

$$CCF = CTL \times CPL \times MF$$

or

$$CCF = CTL \times CPL \times CMF$$

Note: When using temperature compensated meter readings (MR_o, MR_c, IV), the CTL value shall be set to 1.0000 for CCF measurement ticket calculations.

Note: When using a CMF, the CPL value shall be set to 1.0000 for CCF measurement ticket calculations.

b. For proving calculations to determine GSV_p,

$$CCF_p = CTS_p \times CPS_p \times CTL_p \times CPL_p$$

c. For proving calculations to determine ISV_m.

$$CCF_m = CTL_m \times CPL_m$$

Note: When using temperature compensated meter readings (MR_c, MR_c, ISV_m), the CTL value shall be set to 1.0000 for CCF_m proving report calculations.

1.11.7 CORRECTION FOR SEDIMENT AND WATER (CSW)

Sediment and water are not considered merchantable components of certain hydrocarbon liquids, such as crude oil and certain refined products. The correction to adjust the GSV of the liquid for these nonmerchantable quantities is defined by the following expression:

$$CSW = [1 - (\%S\&W/100)]$$

APPENDIX A—CORRECTION FACTORS FOR STEEL

The abbreviated tables contained in this appendix are designed to assist the user in validating computer calculations.

Table A-1—Temperature Correction Factors for Mild Carbon Steel

	USC (°F)	SI (°C)	
T_b[a]	60.0	15.0	Degree
Gc[b]	1.86E-05	3.35E-05	per Degree

USC Units

Observed Temperature (°F)	CTS	Observed Temperature (°F)	CTS
0.0	0.998884	100.0	1.000744
1.0	0.998903	101.0	1.000763
2.0	0.998921	102.0	1.000781
3.0	0.998940	103.0	1.000800
4.0	0.998958	104.0	1.000818
5.0	0.998977	105.0	1.000837
6.0	0.998996	106.0	1.000856
7.0	0.999014	107.0	1.000874
8.0	0.999033	108.0	1.000893
9.0	0.999051	109.0	1.000911
10.0	0.999070	110.0	1.000930
50.0	0.999814	150.0	1.001674
51.0	0.999833	151.0	1.001693
52.0	0.999851	152.0	1.001711
53.0	0.999870	153.0	1.001730
54.0	0.999888	154.0	1.001748
55.0	0.999907	155.0	1.001767
56.0	0.999926	156.0	1.001786
57.0	0.999944	157.0	1.001804
58.0	0.999963	158.0	1.001823
59.0	0.999981	159.0	1.001841
60.0	1.000000	160.0	1.001860

SI Units

Observed Temperature (°C)	CTS	Observed Temperature (°C)	CTS
-5.00	0.999330	40.00	1.000838
-4.00	0.999364	41.00	1.000871
-3.00	0.999397	42.00	1.000905
-2.00	0.999431	43.00	1.000938
-1.00	0.999464	44.00	1.000972
0.00	0.999498	45.00	1.001005
1.00	0.999531	46.00	1.001039
2.00	0.999565	47.00	1.001072
3.00	0.999598	48.00	1.001106
4.00	0.999632	49.00	1.001139
5.00	0.999665	50.00	1.001173
15.00	1.000000	60.00	1.001508
16.00	1.000034	61.00	1.001541
17.00	1.000067	62.00	1.001575
18.00	1.000101	63.00	1.001608
19.00	1.000134	64.00	1.001642
20.00	1.000168	65.00	1.001675
21.00	1.000201	66.00	1.001709
22.00	1.000235	67.00	1.001742
23.00	1.000268	68.00	1.001776
24.00	1.000302	69.00	1.001809
25.00	1.000335	70.00	1.001843

Note: The correction for the effect of temperature on steel values are shown to six decimal places in conformance with the requirements for prover calibrations and to assist the user in validating computer calculations. The table shown was calculated using the following equation applicable to conventional pipe and open tank provers: $CTS = 1 + [(T - T_b) \times Gc]$

[a]T_b = Base temperature in °F or °C.

[b]Gc = Cubical coefficient of thermal expansion of prover.

Table A-2—Temperature Correction Factors for 304 Stainless Steel

	USC (°F)	SI (°C)	
T_b[a]	60.0	15.0	Degree
Gc[b]	2.88E-05	5.18E-05	per Degree

USC Units

Observed Temperature (°F)	CTS	Observed Temperature (°F)	CTS
0.0	0.998272	100.0	1.001152
1.0	0.998301	101.0	1.001181
2.0	0.998330	102.0	1.001210
3.0	0.998358	103.0	1.001238
4.0	0.998387	104.0	1.001267
5.0	0.998416	105.0	1.001296
6.0	0.998445	106.0	1.001325
7.0	0.998474	107.0	1.001354
8.0	0.998502	108.0	1.001382
9.0	0.998531	109.0	1.001411
10.0	0.998560	110.0	1.001440
50.0	0.999712	150.0	1.002592
51.0	0.999741	151.0	1.002621
52.0	0.999770	152.0	1.002650
53.0	0.999798	153.0	1.002678
54.0	0.999827	154.0	1.002707
55.0	0.999856	155.0	1.002736
56.0	0.999885	156.0	1.002765
57.0	0.999914	157.0	1.002794
58.0	0.999942	158.0	1.002822
59.0	0.999971	159.0	1.002851
60.0	1.000000	160.0	1.002880

SI Units

Observed Temperature (°C)	CTS	Observed Temperature (°C)	CTS
-5.00	0.998964	40.00	1.001295
-4.00	0.999016	41.00	1.001347
-3.00	0.999068	42.00	1.001399
-2.00	0.999119	43.00	1.001450
-1.00	0.999171	44.00	1.001502
0.00	0.999223	45.00	1.001554
1.00	0.999275	46.00	1.001606
2.00	0.999327	47.00	1.001658
3.00	0.999378	48.00	1.001709
4.00	0.999430	49.00	1.001761
5.00	0.999482	50.00	1.001813
15.00	1.000000	60.00	1.002331
16.00	1.000052	61.00	1.002383
17.00	1.000104	62.00	1.002435
18.00	1.000155	63.00	1.002486
19.00	1.000207	64.00	1.002538
20.00	1.000259	65.00	1.002590
21.00	1.000311	66.00	1.002642
22.00	1.000363	67.00	1.002694
23.00	1.000414	68.00	1.002745
24.00	1.000466	69.00	1.002797
25.00	1.000518	70.00	1.002849

Note: The correction for the effect of temperature on steel values are shown to six decimal places in conformance with the requirements for prover calibrations and to assist the user in validating computer calculations. The table shown was calculated using the following equation applicable to conventional pipe and open tank provers:
$CTS = 1 + [(T - T_b) \times Gc]$

[a]T_b = Base temperature in °F or °C.

[b]Gc = Cubical coefficient of thermal expansion of prover.

Table A-3—Temperature Correction Factors for 316 Stainless Steel

	USC (°F)	SI (°C)	
T_b[a]	60.0	15.0	Degree
Gc[b]	2.65E-05	4.77E-05	per Degree

USC Units

Observed Temperature (°F)	CTS	Observed Temperature (°F)	CTS
0.0	0.998410	100.0	1.001060
1.0	0.998437	101.0	1.001087
2.0	0.998463	102.0	1.001113
3.0	0.998490	103.0	1.001140
4 0	0.998516	104.0	1.001166
5.0	0.998543	105.0	1.001193
6 0	0.998569	106.0	1.001219
7 0	0.998596	107 0	1.001246
8.0	0.998622	108.0	1.001272
9.0	0.998649	109.0	1.001299
10.0	0.998675	110 0	1.001325
50.0	0.999735	150 0	1.002385
51 0	0.999762	151.0	1.002412
52.0	0.999788	152.0	1.002438
53.0	0.999815	153.0	1.002465
54.0	0.999841	154 0	1.002491
55 0	0.999868	155.0	1.002518
56.0	0.999894	156.0	1.002544
57.0	0.999921	157.0	1.002571
58.0	0.999947	158.0	1.002597
59.0	0.999974	159.0	1.002624
60.0	1.000000	160.0	1.002650

SI Units

Observed Temperature (°C)	CTS	Observed Temperature (°C)	CTS
-5.00	0.999046	40.00	1.001193
-4 00	0.999094	41.00	1 001240
-3.00	0.999141	42.00	1.001288
-2.00	0.999189	43.00	1.001336
-1.00	0.999237	44 00	1.001383
0.00	0.999285	45.00	1.001431
1.00	0.999332	46 00	1.001479
2 00	0.999380	47.00	1.001526
3.00	0.999428	48.00	1.001574
4.00	0 999475	49 00	1.001622
5 00	0.999523	50.00	1.001670
15.00	1.000000	60.00	1.002147
16.00	1.000048	61.00	1.002194
17 00	1.000095	62.00	1.002242
18.00	1.000143	63.00	1.002290
19 00	1.000191	64 00	1.002337
20 00	1.000239	65.00	1.002385
21.00	1.000286	66.00	1.002433
22 00	1 000334	67 00	1.002480
23.00	1.000382	68.00	1.002528
24.00	1.000429	69.00	1.002576
25 00	1.000477	70 00	1.002624

Note: The correction for the effect of temperature on steel values are shown to six decimal places in conformance with the requirements for prover calibrations and to assist the user in validating computer calculations. The table shown was calculated using the following equation applicable to conventional pipe and open tank provers: $CTS = 1 + [(T - T_b) \times Gc]$

[a]T_b = Base temperature in °F or °C.

[b]Gc = Cubical coefficient of thermal expansion of prover.

Table A-4—Temperature Correction Factors for 17-4PH Stainless Steel

	USC (°F)	SI (°C)	
T_b[a]	60.0	15.0	Degree
Gc[b]	1.80E-05	3.24E-05	per Degree

USC Units

Observed Temperature (°F)	CTS	Observed Temperature (°F)	CTS
0.0	0.998920	100.0	1.000720
1.0	0.998938	101.0	1.000738
2.0	0.998956	102.0	1.000756
3.0	0.998974	103.0	1.000774
4.0	0.998992	104.0	1.000792
5.0	0.999010	105.0	1.000810
6.0	0.999028	106.0	1.000828
7.0	0.999046	107.0	1.000846
8.0	0.999064	108.0	1.000864
9.0	0.999082	109.0	1.000882
10.0	0.999100	110.0	1.000900
50.0	0.999820	150.0	1.001620
51.0	0.999838	151.0	1.001638
52.0	0.999856	152.0	1.001656
53.0	0.999874	153.0	1.001674
54.0	0.999892	154.0	1.001692
55.0	0.999910	155.0	1.001710
56.0	0.999928	156.0	1.001728
57.0	0.999946	157.0	1.001746
58.0	0.999964	158.0	1.001764
59.0	0.999982	159.0	1.001782
60.0	1.000000	160.0	1.001800

SI Units

Observed Temperature (°C)	CTS	Observed Temperature (°C)	CTS
-5.00	0.999352	40.00	1.000810
-4.00	0.999384	41.00	1.000842
-3.00	0.999417	42.00	1.000875
-2.00	0.999449	43.00	1.000907
-1.00	0.999482	44.00	1.000940
0.00	0.999514	45.00	1.000972
1.00	0.999546	46.00	1.001004
2.00	0.999579	47.00	1.001037
3.00	0.999611	48.00	1.001069
4.00	0.999644	49.00	1.001102
5.00	0.999676	50.00	1.001134
15.00	1.000000	60.00	1.001458
16.00	1.000032	61.00	1.001490
17.00	1.000065	62.00	1.001523
18.00	1.000097	63.00	1.001555
19.00	1.000130	64.00	1.001588
20.00	1.000162	65.00	1.001620
21.00	1.000194	66.00	1.001652
22.00	1.000227	67.00	1.001685
23.00	1.000259	68.00	1.001717
24.00	1.000292	69.00	1.001750
25.00	1.000324	70.00	1.001782

Note: The correction for the effect of temperature on steel values are shown to six decimal places in conformance with the requirements for prover calibrations and to assist the user in validating computer calculations. The table shown was calculated using the following equation applicable to conventional pipe and open tank provers: $CTS = 1 + [(T - T_b) \times Gc]$

[a]T_b = Base temperature in °F or °C.
[b]Gc = Cubical coefficient of thermal expansion of prover

Table A-5—Pressure Correction Factors for Mild Carbon Steel

	USC (psi)	SI (bar)		USC (in)	SI (mm)
T_b[a]	14.7	15.0	OD[c]	10.750	273.05
Gc[b]	3.00E+07	2.07E+06	WT[d]	0.375	9.53
			ID[e]	10.000	254.00

USC Units

Observed Pressure (psig)	CPS	Observed Pressure (psig)	CPS
0.0	1.000000	500.0	1.000444
5.0	1.000004	505.0	1.000449
10.0	1.000009	510.0	1.000453
15.0	1.000013	515.0	1.000458
20.0	1.000018	520.0	1.000462
25.0	1.000022	525.0	1.000467
30.0	1.000027	530.0	1.000471
35.0	1.000031	535.0	1.000476
40.0	1.000036	540.0	1.000480
45.0	1.000040	545.0	1.000484
50.0	1.000044	550.0	1.000489
50.0	1.000044	800.0	1.000711
55.0	1.000049	805.0	1.000716
60.0	1.000053	810.0	1.000720
65.0	1.000058	815.0	1.000724
70.0	1.000062	820.0	1.000729
75.0	1.000067	825.0	1.000733
80.0	1.000071	830.0	1.000738
85.0	1.000076	835.0	1.000742
90.0	1.000080	840.0	1.000747
95.0	1.000084	845.0	1.000751
100.0	1.000089	850.0	1.000756

SI Units

Observed Pressure (bar-g)	CPS	Observed Pressure (bar-g)	CPS
0.00	1.000000	40.00	1.000515
1.00	1.000013	41.00	1.000528
2.00	1.000026	42.00	1.000541
3.00	1.000039	43.00	1.000554
4.00	1.000052	44.00	1.000567
5.00	1.000064	45.00	1.000580
6.00	1.000077	46.00	1.000593
7.00	1.000090	47.00	1.000605
8.00	1.000103	48.00	1.000618
9.00	1.000116	49.00	1.000631
10.00	1.000129	50.00	1.000644
20.00	1.000258	60.00	1.000773
21.00	1.000271	61.00	1.000786
22.00	1.000283	62.00	1.000799
23.00	1.000296	63.00	1.000812
24.00	1.000309	64.00	1.000824
25.00	1.000322	65.00	1.000837
26.00	1.000335	66.00	1.000850
27.00	1.000348	67.00	1.000863
28.00	1.000361	68.00	1.000876
29.00	1.000374	69.00	1.000889
30.00	1.000386	70.00	1.000902

Note: The correction for the effect of pressure on steel values are shown to six decimal places in conformance with the requirements for prover calibrations and to assist the user in validating computer calculations. The tables shown were calculated using the following equation applicable to single-walled containers or provers:
$CPS = 1 + [(P \times ID)/(E \times WT)]$

[a]T_b = Base temperature in °F or °C
[b]Gc = Cubical coefficient of thermal expansion of prover.
[c]OD= Outside diameter of prover pipe.
[d]WT= Wall thickness of prover pipe.
[e]ID= Inside diameter of prover pipe.

Table A-6—Pressure Correction Factors for 304 and 316 Stainless Steel

	USC (psi)	SI (bar)		USC (in)	SI (mm)
T_b[a]	14.7	15.0	OD[c]	10 750	273.05
Gc[b]	2.80E+07	1 93E+06	WT[d]	0 375	9.53
			ID[e]	10.000	254.00

USC Units

Observed Pressure (psig)	CPS	Observed Pressure (psig)	CPS
0.0	1 000000	500.0	1.000476
5.0	1.000005	505.0	1.000481
10.0	1.000010	510.0	1.000486
15.0	1.000014	515.0	1.000490
20 0	1.000019	520.0	1.000495
25.0	1.000024	525.0	1.000500
30.0	1.000029	530.0	1.000505
35.0	1.000033	535.0	1.000510
40.0	1.000038	540.0	1.000514
45.0	1.000043	545.0	1.000519
50.0	1.000048	550.0	1.000524
50.0	1.000048	800.0	1.000762
55.0	1.000052	805.0	1.000767
60.0	1.000057	810.0	1.000771
65.0	1.000062	815.0	1.000776
70.0	1.000067	820 0	1.000781
75.0	1.000071	825.0	1.000786
80.0	1.000076	830.0	1.000790
85.0	1.000081	835 0	1.000795
90.0	1.000086	840.0	1.000800
95.0	1.000090	845.0	1.000805
100.0	1.000095	850 0	1.000810

SI Units

Observed Pressure (bar-g)	CPS	Observed Pressure (bar-g)	CPS
0.00	1 000000	40 00	1.000553
1.00	1.000014	41.00	1.000566
2.00	1.000028	42.00	1.000580
3 00	1 000041	43 00	1.000594
4.00	1.000055	44.00	1.000608
5.00	1.000069	45.00	1.000622
6.00	1.000083	46 00	1.000636
7.00	1.000097	47.00	1.000649
8.00	1.000111	48 00	1.000663
9.00	1.000124	49 00	1.000677
10 00	1.000138	50.00	1.000691
20.00	1.000276	60 00	1.000829
21.00	1.000290	61.00	1.000843
22.00	1.000304	62.00	1.000857
23.00	1.000318	63 00	1.000870
24.00	1.000332	64 00	1.000884
25.00	1.000345	65.00	1.000898
26.00	1.000359	66.00	1.000912
27.00	1.000373	67.00	1.000926
28.00	1.000387	68.00	1.000940
29.00	1.000401	69.00	1.000953
30.00	1.000415	70.00	1.000967

Note: The correction for the effect of pressure on steel values are shown to six decimal places in conformance with the requirements for prover calibrations and to assist the user in validating computer calculations. The tables shown were calculated using the following equation applicable to single-walled containers or provers:
$CPS = 1 + [(P \times ID)/(E \times WT)]$

[a]T_b = Base temperature in °F or °C
[b]Gc = Cubical coefficient of thermal expansion of prover.
[c]OD= Outside diameter of prover pipe.
[d]WT= Wall thickness of prover pipe.
[e]ID= Inside diameter of prover pipe.

Table A-7—Pressure Correction Factors for 17-4PH Stainless Steel

	USC (psi)	SI (bar)		USC (in)	SI (mm)
T_b[a]	14.7	15.0	OD[c]	10.750	273.05
Gc[b]	2.85E+07	1.97E+06	WT[d]	0.375	9.53
			ID[e]	10.000	254.00

USC Units

Observed Pressure (psig)	CPS	Observed Pressure (psig)	CPS
0.0	1.000000	500.0	1.000468
5.0	1.000005	505.0	1.000473
10.0	1.000009	510.0	1.000477
15.0	1.000014	515.0	1.000482
20.0	1.000019	520.0	1.000487
25.0	1.000023	525.0	1.000491
30.0	1.000028	530.0	1.000496
35.0	1.000033	535.0	1.000501
40.0	1.000037	540.0	1.000505
45.0	1.000042	545.0	1.000510
50.0	1.000047	550.0	1.000515
50.0	1.000047	800 0	1.000749
55.0	1.000051	805.0	1.000753
60.0	1.000056	810.0	1.000758
65.0	1.000061	815 0	1.000763
70.0	1.000065	820.0	1.000767
75.0	1.000070	825 0	1.000772
80.0	1.000075	830.0	1.000777
85.0	1.000080	835.0	1.000781
90.0	1.000084	840.0	1.000786
95.0	1.000089	845.0	1.000791
100.0	1.000094	850.0	1.000795

SI Units

Observed Pressure (bar-g)	CPS	Observed Pressure (bar-g)	CPS
0.00	1.000000	40.00	1.000541
1 00	1 000014	41.00	1.000555
2.00	1.000027	42.00	1.000569
3.00	1.000041	43.00	1.000582
4.00	1 000054	44.00	1.000596
5.00	1.000068	45.00	1.000609
6.00	1.000081	46.00	1.000623
7.00	1 000095	47.00	1.000636
8.00	1.000108	48.00	1.000650
9.00	1.000122	49.00	1.000663
10.00	1.000135	50 00	1.000677
20.00	1.000271	60.00	1.000812
21.00	1.000284	61.00	1.000826
22.00	1.000298	62.00	1.000839
23.00	1.000311	63 00	1.000853
24.00	1.000325	64.00	1.000866
25.00	1.000338	65.00	1.000880
26 00	1.000352	66 00	1.000893
27.00	1.000365	67 00	1.000907
28.00	1.000379	68.00	1.000920
29 00	1.000393	69 00	1.000934
30 00	1.000406	70.00	1.000948

Note: The correction for the effect of pressure on steel values are shown to six decimal places in conformance with the requirements for prover calibrations and to assist the user in validating computer calculations. The tables shown were calculated using the following equation applicable to single-walled containers or provers: $CPS = 1 + [(P \times ID)/(E \times WT)]$

[a]T_b = Base temperature in °F or °C.
[b]Gc = Cubical coefficient of thermal expansion of prover.
[c]OD= Outside diameter of prover pipe.
[d]WT= Wall thickness of prover pipe.
[e]ID= Inside diameter of prover pipe.

APPENDIX B—LIQUID DENSITY CORRELATION

B.1 General Information

The liquid table, found in Table B-1, provides a guide to the appropriate reference for most of the liquids associated with the petroleum and petrochemical industry (RHO_b, CTL, F).

The text following the table describes the recommended references. The expertise of a physical properties specialist should be consulted before adopting the recommendations contained in the table.

For some older references, tabular values for RHO_b and CTL cannot be curve fit. Therefore, it is recommended that linear interpolation of these tables (between columns and values within a column) be utilized for intermediate calculations.

Density Meter Calculations

When using an online density meter, the liquid's base density (RHO_b) is determined by the following expression:

$$RHO_b = RHO_{tp}/(CTL \times CPL)$$

It is important to note that RHO_{tp} must be known to accurately calculate RHO_b. Also, for low pressure applications, CPL may be assumed to be 1.0000 if a sensitivity analysis indicates an acceptable level of uncertainty.

For some liquids, computer subroutines exist to correct to base density using API MPMS Chapter 11.1 implementation procedures. **However, for elevated pressures, an iterative procedure to solve for base density is required for fiscal purposes.** The manufacturer should be contacted for consultation on elevated pressures.

The computation for correcting from density at flowing conditions (RHO_{tp}) to density at base conditions (RHO_b) may be carried out continuously if mutually agreed between the parties.

B.2 RHO_b Determination

The standards to convert liquid density at observed conditions (RHO_{obs}) to base density (RHO_b) are as follows:

R1. API MPMS Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 5A, 53A, and 23A cover generalized crude oils and JP4. The document specifies the implementation procedures and the rounding and truncating procedures to determine the Base Density (RHO_b) from the Observed Density (RHO_{obs}) and Observed Temperature (T_{obs}) at Base Pressure (P_b).

a. Table 5A, used for base temperature of 60°F, covers generalized crude oils and JP4 over an API@60 gravity range of 0 to 100. For natural or drip gasolines with API@60 gravities greater than 100, use Table 23 of ASTM D1250 (Historical Edition - 1952).

b. Table 53A, used for base temperature of 15°C, covers generalized crude oils and JP4 over a DEN_b@15 range of 610 to 1075 kg/m3.

c. Table 23A, used for base temperature of 60°F, covers generalized crude oils and JP4 over a RD@60 range of 0.6110 to 1.0760.

R2. API MPMS Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 5B, 53B, and 23B cover generalized products. The document specifies the implementation procedures and the rounding and truncating procedures to determine the Base Density (RHO_b) from the Observed Density (RHO_{obs}) and Observed Temperature (T_{obs}) at Base Pressure (P_b).

a. Table 5B, used for base temperature of 60°F, covers generalized products (excluding JP4) over an API@60 gravity range of 0 to 85.

b. Table 53B, used for base temperature of 15°C, covers generalized products over a DEN_b@15 range of 653 to 1075 kg/m3.

c. Table 23B, used for base temperature of 60°F, covers generalized products over a RD@60 range of 0.6535 to 1.0760.

R3. API MPMS Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 5D and 53D cover lubricating oils. The document specifies the implementation procedures and the rounding and truncating procedures to determine the Base Density (RHO_b) from the Observed Density (RHO_{obs}) and Observed Temperature (T_{obs}) at Base Pressure (P_b).

a. Table 5D, used for base temperature of 60°F, covers lubricating oils over an API@60 gravity range of -10 to 40.

b. Table 53D, used for base temperature of 15°C, covers lubricating oils over a DEN_b@15 range of 825 to 1164 kg/m3.

R4. ASTM D1250 (Historical Edition - 1952) covers a relative density at 60°F (RD@60) range of 0.500 to 1.100. Table 23 converts the observed relative density at the observed temperature and equilibrium pressure to the RD@60.

R5. ASTM D1550, used for base temperature of 60°F, is applicable to both butadiene and butadiene concentrates that contain at least 60 percent butadiene.

B.3 CTL Determination

The standards that have been developed to determine the CTL values for various liquids are as follows:

C1. API MPMS Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 6A, 54A, and 24A cover generalized crude oils and JP4 The document specifies the implementation procedures and the rounding and truncating procedures to determine the CTL from Base Density (RHO_b) and Flowing Temperature (T).

a. Table 6A, used for base temperature of 60°F, covers generalized crude oils and JP4 over an API@60 gravity range of 0 to 100. For natural or drip gasolines with API@60 gravities greater than 100, use Table 24 of ASTM D1250 (Historical Edition - 1952).
b. Table 54A, used for base temperature of 15°C, covers generalized crude oils and JP4 over a DEN_b@15 range of 610.5 to 1075.0 kg/m3.
c. Table 24A, used for base temperature of 60°F, covers generalized crude oils and JP4 over a RD@60 range of 0.6110 to 1.0760.

C2. API MPMS Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 6B, 54B, and 24B cover generalized products. The document specifies the implementation procedures and the rounding and truncating procedures to determine the CTL from Base Density (RHO_b) and Flowing Temperature (T).

a. Table 6B, used for base temperature of 60°F, covers generalized products (excluding JP4) over an API@60 gravity range of 0-100.
b. Table 54B, used for base temperature of 15°C, covers generalized products (excluding JP4) over a DEN_b@15 range of 653.0 to 1075.0 kg/m3.
c. Table 24B, used for base temperature of 60°F, covers generalized products over a RD@60 range of 0.6535 to 1.0760.

C3. API MPMS Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 6D and 54D cover lubricating oils. The document specifies the implementation procedures and the rounding and truncating procedures to determine the CTL from the Base Density (RHO_b) and Flowing Temperature (T).

a. Table 6D, used for base temperature of 60°F, covers lubricating oils over an API@60 gravity range of -10 to 40.
b Table 54D, used for base temperature of 15°C, covers lubricating oils over a DEN_b@15 range of 825 to 1164 kg/m3.

C4. ASTM D1250 (Historical Edition - 1952) covers a relative density at 60°F (RD@60) range of 0.500 to 1.100 for LPGs. Table 24 calculates the CTL from the flowing temperature (T) and the RD@60.

C5. ASTM D1250 (Historical Edition - 1952) Table 6, used for base temperature of 60°F, covers a gravity range for asphalt. Table 6 is recommended by the API and Asphalt Institute for CTL determinations.

C6. ASTM D1555, used for base temperature of 60°F, is the industry reference for CTL values associated with certain aromatic hydrocarbons.

C7. ASTM D1550, used for base temperature of 60°F, is the industry reference for CTL values associated with butadiene and butadiene concentrates that contain at least 60 percent butadiene.

C8. API MPMS Chapters 11.2.3 and 11.2.3M cover CTDW values utilized in water calibration of volumetric provers.

a. Chapter 11.2.3, used for base temperature of 60°F, calculates the CTDW for water from the Prover's Flowing Temperature (T_p) and Test Measure's Flowing Temperature (T_m).
b. Chapter 11.2.3M, used for base temperature of 15°C, calculates the CTDW for water from the Prover's Flowing Temperature (T_p) and Test Measure's Flowing Temperature (T_m).

Fixed or Small-Variant Liquid Composition

Numerous specification solvents, resins, and chemicals used or manufactured by companies are not compatible with existing industry CTL tables. For these materials, the parties may wish to utilize proprietary liquid property tables that have been used for years and that remain in use for most applications. In applications where Table 6C of API MPMS, Chapter 11.1 is used to maintain industry compatibility, the fluid property tables can be used to calculate the desired alpha value. These values can be used where existing commercial requirements permit.

Table 6C of API MPMS, Chapter 11.1 calculates the CTL for a liquid with a composition that is fixed or does not vary significantly.

Since RHO_b is constant, no correction or determination of observed gravity is necessary. The API MPMS standard is commonly used for specialized products with coefficients of thermal expansion that do not follow Tables 6A, 6B, or 6D of API MPMS, Chapter 11.1.

Use of Table 6C requires an equation of state and/or extensive data on the metered liquid.

B.4 Compressibility Factor Determination (F)

The density of the liquid shall be determined by appropriate technical standards, or if necessary, by either proper correlations or equations of state. To assist in selecting which methods to utilize, the following information has been assembled for clarity.

F1. API MPMS Chapters 11.2.1, 11.2.1M, 11.2.2, and 11.2.2M provide values for compressibility factors (F) for hydrocarbon liquids. The documents specify the implementation procedures and the rounding and truncating procedures to determine the F from base density (RHO_b), flowing temperature (T), and flowing pressure (P).

a. Chapter 11.2.1, used for base temperature of 60°F, covers hydrocarbon liquids over an API@60 range of 0 to 90.

b. Chapter 11.2.1M, used for base temperature of 15°C, covers hydrocarbon liquids over a DEN@15 range of 638 to 1074 kg/m³.
c. Chapter 11.2.2, used for base temperature of 60°F, covers hydrocarbon liquids over a RD@60 range of 0.350 to 0.637.
d. Chapter 11.2.2M, used for base temperature of 15°C, covers hydrocarbon liquids over a DEN@15 range of 350 to 637 kg/m³.

F2. The compressibility factor (F) for water utilized in the calibration of volumetric provers is defined as follows:

a. For USC units, a constant F value 3.2E+06 per psi for water shall be utilized in the calculations.
b. For SI units, a constant F value 4.6E+07 per kPa or 4.641E+05 per bar for water shall be utilized in the calculations.

Table B-1—Liquid Density

Liquid Type	RHO_b	CTL	F
CRUDE OILS			
Crude Oils	(R1)	(C1)	(F1)
Natural Gasolines	(R1)	(C1)	(F1)
Drip Gasolines	(R1)	(C1)	(F1)
REFINED PRODUCTS			
JP4	(R1)	(C1)	(F1)
Gasoline	(R2)	(C2)	(F1)
Naphthenes	(R2)	(C2)	(F1)
Jet Fuels	(R2)	(C2)	(F1)
Aviation Fuels	(R2)	(C2)	(F1)
Kerosine	(R2)	(C2)	(F1)
Diesel	(R2)	(C2)	(F1)
Heating Oils	(R2)	(C2)	(F1)
Fuel Oils	(R2)	(C2)	(F1)
Furnace Oils	(R2)	(C2)	(F1)
Lube Oils	(R3)	(C3)	(F1)
Propane	(R4)	(C4)	(F1)
Butane	(R4)	(C4)	(F1)
Propane Mixes	(R4)	(C4)	(F1)
Butane Mixes	(R4)	(C4)	(F1)
Isopentane	(R4)	(C4)	(F1)
Asphalt	NA	(C5)	(F1)
SOLVENTS			
Benzene	NA	(C6)	(F1)
Toluene	NA	(C6)	(F1)
Stoddard Solvent	NA	(C6)	(F1)
Xylene	NA	(C6)	(F1)
Styrene	NA	(C6)	(F1)
Orthoxylene	NA	(C6)	(F1)
Metaxylene	NA	(C6)	(F1)
Paraxylene	NA	(C6)	(F1)
Cyclohexane	NA	(C6)	(F1)
Acetone	NA	(C6)	(F1)
BUTADIENE			
Butadiene	(R5)	(C7)	(F1)
Butadiene Mixtures	(R5)	(C7)	(F1)
WATER			
For Volumetric Provers	NA	(C8)	(F2)

Manual of Petroleum Measurement Standards Chapter 12—Calculation of Petroleum Quantities

Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors

Part 3—Proving Reports

Measurement Coordination

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American Petroleum Institute

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Chapter 12—Calculation of Petroleum Quantities

Section 2—Calculation of Petroleum Quantities Using Dynamic Measurement Methods and Volumetric Correction Factors

Part 3—Proving Reports

0 Introduction

When most of the older standards for the calculation of petroleum quantities were written, mechanical desk calculators were widely used for calculating the measurement documents. Tabulated values were used more widely than is the case today. Rules for rounding and the choice of how many figures to enter in each calculation step were often made by individual operators at the time of the calculation. As a result, different operators obtained different results from the same data.

This multi-part publication consolidates and standardizes the calculations pertaining to metering petroleum liquids using turbine or displacement meters and clarifies terms and expressions by eliminating local variations of such terms. The purpose of standardizing the calculations is to produce identical answers from given data. For different operators to obtain identical results from the same data, the rules for sequence, rounding, and discrimination of figures (or decimal places) must be defined.

1 Scope

This part provides standardized calculation methods for the determination of meter factors under defined conditions, regardless of the point of origin or destination or units of measure required by governmental customs or statute. The criteria contained here will allow different entities using various computer languages on different computer hardware (or by manual calculations) to arrive at identical results using the same standardized input data.

This document also specifies the equations for computing correction factors, including the calculation sequence, discrimination levels, and rules for rounding to be employed in the calculations. No deviations from these specified equations are permitted, since the intent of this document is to establish a rigorous standard.

2 Organization of Standard

The calculation standard is presently organized into five parts as follows: Part 1 contains a general introduction to dynamic calculations. Part 2 focuses on the calculation of metered quantities. Part 3 applies to meter proving calculations. Parts 4 and 5 apply to the calculation of base prover volumes by two different methods. A brief description of each of these parts follows.

2.1 PART 1—INTRODUCTION

2.1.1 The base (reference or standard) volumetric determination of metered quantities is discussed, along with the general terms required for solution of equations.

2.1.2 General rules for the rounding of numbers, including field data, intermediate calculation numbers, and discrimination levels, are specified.

2.1.3 For the proper use of this standard, prediction of the density of the liquid in both flowing and base conditions is discussed.

2.1.4 An explanation of the principal correction factors associated with dynamic measurement is presented.

2.2 PART 2—CALCULATION OF METERED QUANTITIES

2.2.1 The application of this standard to the calculation of metered quantities is presented, for base volumetric calculations in conformance with North American industry practices.

2.2.2 Recording of field data, rules for rounding, discrimination levels, calculation sequences, along with a detailed explanation of the calculation steps, are all specified, together with appropriate flow charts and a set of example calculations. These examples can be used to aid in checking out the procedures for any computer calculation routines that are developed on the basis of the requirements stated in this standard.

2.3 PART 3—PROVING REPORTS

2.3.1 The application of this standard to the calculation of meter factors is presented for base volumetric calculations in conformance with North American industry practices. Proving reports are utilized to calculate meter correction factors and/or performance indicators. The determination of the appropriate terms is based on both the hardware and the preferences of users.

2.3.2 Recording of field data, rules for rounding, calculation sequence, and discrimination levels are specified, along with a set of example calculations. The examples are designed to aid in checkout procedures for any computer routines that are developed using the requirements stated in this part.

2.4 PART 4—CALCULATION OF BASE PROVER VOLUMES BY WATERDRAW METHOD

2.4.1 The waterdraw method uses the displacement (or drawing) of water from a prover into certified volumetric field standard test measures. Alternatively, for open tank provers, the waterdraw method may also use the displacement (or drawing) of water from field standard test measures into the open tank prover. Certification of the field standard test measures must be traceable to an appropriate national weights and measures organization.

2.4.2 Recording of field data, rules for rounding, calculation sequence, and discrimination levels are specified, along with a set of example calculations. The examples are designed to aid in checkout procedures for any routines that are developed using the requirements stated in this part.

2.5 PART 5—CALCULATION OF BASE PROVER VOLUMES BY MASTER METER METHOD

2.5.1 The master meter method uses a transfer meter (or transfer standard). This transfer meter is proved under actual operating conditions, by a prover that has previously been calibrated by the waterdraw method, and is designated the master meter. This master meter is then used to determine the base volume of a field operating prover.

2.5.2 Recording of field data, rules for rounding, calculation sequences, and discrimination levels are specified, along with a set of example calculations. The examples are designed to aid in the checkout procedures for any routines that are developed using the requirements stated in this part.

3 References

Several documents served as references for the revisions of this standard. In particular, past editions of *API MPMS* Chapter 12.2 provided a wealth of information. Other publications that were a resource for information are:

API

Manual of Petroleum Measurement Standards (*MPMS*)

Chapter 4—*Proving Systems*
Chapter 5—*Metering*
Chapter 6—*Metering Assemblies*
Chapter 7—*Temperature Determination*
Chapter 9—*Density Determination*
Chapter 10—*Sediment and Water*
Chapter 11—*Physical Properties Data*
Chapter 13—*Statistical Analysis*

ASTM[1]

D1250 *Petroleum Measurement Tables*, Current Edition
D1250 *Petroleum Measurement Tables*, Historical Edition, 1952
D1550 *ASTM Butadiene Measurement Tables*
D1555 *Calculation of Volume and Weight of Industrial Aromatic Hydrocarbons*

NIST[2]

Handbook 105-3 *Specifications and Tolerances for Reference Standards and Field Standards*
Handbook 105-7 *Small Volume Provers*

4 Terms and Symbols

Terms and symbols described below are acceptable and in common use for the calibration of flow meters.

4.1 DEFINITIONS OF TERMS

4.1.1 barrel (Bbl): A unit volume equal to 9,702.0 cubic inches or 42.0 U.S. gallons.

4.1.2 base prove volume (*BPV*): The volume of the prover at base conditions as shown on the calibration certificate and obtained by arithmetically averaging an acceptable number of consecutive calibrated prover volume (*CPV*) determinations.

4.1.3 calibration certificate: A document stating the base prover volume (*BPV*) and other physical data required for the calibration of flow meters (i.e., *E*, *Gc*, *Ga*, and *Gl*).

4.1.4 composite K-factor (*CKF*): A K-factor adjusted from normal operating pressure (*CPL*) to standard pressure and used to correct the indicated volume where the gravity, temperature, and pressure are considered constant throughout the delivery.

4.1.5 composite meter factor (*CMF*): A meter factor corrected from normal operating pressure (*CPL*) to base pressure. This term is used for meter applications where the gravity, temperature, and pressure are considered constant during the ticket period.

4.1.6 cubic meter (m^3): A unit of volume equal to 1,000,000.0 milliliters (ml) or 1,000.0 liters. One cubic meter equals 6.28981 barrels.

4.1.7 gross standard volume (*GSV*): The metered volume corrected to base conditions and also corrected for the performance of the meter (*MF*, *MMF*, or *CMF*).

4.1.8 indicated standard volume (*ISV*): The indicated meter volume (*IV*) corrected to base conditions. It does not contain any correction for the meter's performance (*MF*, *MMF*, or *CMF*).

[1]American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428.

[2]U.S. Department of Commerce, National Institute of Standards and Technology, Washington, D.C. 20234 (formerly National Bureau of Standards).

4.1.9 indicated volume (*IV*): The change in the meter register head volume that occurs during a proving run (*MRo* – *MRc*). The word registration, though not preferred, often has the same meaning. Alternatively, indicated volume (*IV*) may also be determined by dividing the meter pulse output, *N* or *Ni*, during a proving pass, by the nominal K-factor (*NKF*).

4.1.10 K-factor (*KF*): The number of pulses generated by the meter per unit volume. A new K-factor may be determined during each proving to correct the indicated volume to gross volume. If a new K-factor is not used, then a nominal K-factor may be utilized to generate a new meter factor, which will then correct the indicated volume of the meter to gross volume.

4.1.11 liter (L): A unit of volume equal to 1,000.0 milliliters (ml) or 0.001 cubic meters. One liter equals 0.264172 U.S. gallons.

4.1.12 master meter: A transfer device (meter) that is proved using a certified prover (called the master prover) and is then used to calibrate other meter provers or to prove other flow meters.

4.1.13 master meter factor (*MMF*): A dimensionless term obtained by dividing the gross standard volume of the liquid passed through the master prover during proving by the indicated standard volume as registered by the master meter.

4.1.14 master prover: A volumetric standard (displacement prover or open tank prover), that was calibrated by the waterdraw method, with test measures traceable to a national standards organization, and is then used to calibrate a master meter.

4.1.15 meter accuracy (*MA*): Defined as the reciprocal of the meter factor. It is a term specifically utilized for loading rack meters where the meter is mechanically or electronically adjusted at the time of proving to ensure that the meter factor is approximately unity.

4.1.16 meter factor (*MF*): Used to correct the indicated volume of a meter to its actual metered volume. It is a dimensionless term obtained by dividing the gross standard volume of the liquid passed through the prover (*GSVp*) when compared to the indicated standard volume (*ISVm*) as registered by the meter being proved.

4.1.17 meter reading (*MRo, MRc, MMRo, MMRc*): The instantaneous display of the register on a meter head. When the difference between a closing and an opening meter reading is being discussed, such difference shall be called an indicated volume.

4.1.18 nominal K-factor (*NKF*): The number of pulses per indicated unit volume which is used to determine the meter factor. It is a K-factor generated by the manufacturer, retained as a fixed value, and used to convert meter pulses, *N* or *Ni*, into an indicated volume (*IV*) during meter proving. Many installations use a nominal K-factor throughout the operating life of the meter to provide an audit trail for meter proving.

4.1.19 pass: A single movement of the displacer between detectors which define the calibrated volume of a prover.

4.1.20 pressure weighted average (*PWA*): The average liquid pressure at the meter for the ticket period.

For volumetric methods, the pressure weighted average is the average of the pressure values sampled at uniform flow intervals and is representative of the entire measurement ticket period.

$$PWA = \frac{\sum_{1}^{n}(Pi)}{n}$$

where

n = the number of uniform intervals.

For time-based methods, the pressure weighted average is the sum of the pressure values sampled during the time interval multiplied by the volume or mass determined during the same time interval and divided by the entire volume measured.

$$PWA = \frac{\sum(Pi \times Vi)}{Vt}$$

4.1.21 proving report: A document showing all the meter and prover data, together with all the other parameters used to calculate the reported meter factor.

4.1.22 round-trip: The combined forward (out) and reverse (back) passes of the displacer in a bidirectional meter prover.

4.1.23 run, meter proving: One pass of a unidirectional prover, one round-trip of a bidirectional prover, or one filling/emptying of a tank prover, the results of which are deemed sufficient to provide a single value of the meter factor (*MF, CMF, MMF*) or K-factor (*KF, CKF*) when using the average meter factor method of calculation.

4.1.24 temperature weighted average (*TWA*): The average liquid temperature at the meter for the ticket period.

For volumetric methods, the temperature weighted average is the average of the temperature values sampled at uniform flow intervals and representative of the entire measurement ticket period.

$$TWA = \frac{\sum_{1}^{n}(Ti)}{n}$$

where

n = the number of uniform intervals.

For time-based methods, the temperature weighted average is the sum of the temperature values sampled during the time interval multiplied by the volume or mass determined during the same time interval and divided by the entire volume measured.

$$TWA = \frac{\sum(Ti \times Vi)}{Vt}$$

4.1.25 U.S. gallon (gal): A unit volume equal to 231.0 cubic inches or 3.7854 l liters.

4.2 DEFINITIONS OF SYMBOLS

A combination of upper and lower case notation is used for symbols and formulas in this publication. Subscripted notation is often difficult to use in word-processed documents and therefore has not been used in this publication, but may be employed if the parties wish. Upper case notation is usually preferred for computer programming and other documents as deemed appropriate.

Symbols have been defined to aid in clarity and specificity of the mathematical treatments. Some examples of the symbol notation are as follows: *CTL* = Correction for Temperature on the Liquid; *GSV* = Gross Standard Volume; *MMF* = Master Meter Factor; *CPS* = Correction for Pressure on Steel. In many cases the symbols have additional letters added at the end to help clarify their meaning and application. Some of these additional letters are defined as follows: "m" throughout this document always refers to the meter (as in *CTLm*), "p" always applies to the meter prover (as in *GSVp*), "b" means base conditions (as in *DENb*), "obs" is observed conditions (as in *RHOobs*), "avg" defines the average (mean) of the readings [as in *Tp(avg)*], "mm" denotes master meter (as in *Pmm*), and "mp" the master prover (as in *CCFmp*). Where, occasionally, other additional letters have been used they should be just as easy to interpret.

4.2.1 Units

SI	International System of Units (e.g., bars, cubic meters, kilograms, °C).
USC	US Customary Units (e.g., psig, cubic feet, pounds, °F).

4.2.2 Pipe Dimensions

ID	Inside diameter of the prover pipe.
OD	Outside diameter of the prover pipe.
WT	Wall thickness of the prover pipe.

4.2.3 Liquid Density

API	Density of liquid in degree API gravity units.
APIb	Base density in degree API gravity units.
APIobs	Observed density at base pressure in degree API gravity units.
DEN	Density of liquid in kilogram/cubic meter (kg/m^3) units.
DENb	Base density of liquid in kilogram/cubic meter (kg/m^3) units.
DENobs	Observed density of liquid at base pressure in kilogram/cubic meter (kg/m^3).
RD	Relative density of the liquid.
RDb	Base relative density of the liquid.
RDobs	Observed relative density of the liquid at base pressure.
RHO	Density of liquid (SI or US Customary) in mass per unit volume.
RHOb	Liquid density at base conditions in mass per unit volume.
RHOobs	Observed density of liquid at base pressure in mass per unit volume.
RHOtp	Liquid density at flowing temperature and pressure in mass per unit volume.

4.2.4 Temperature

T	Temperature in °F or °C.
Tb	Base temperature in °F or °C units.
Tobs	Observed temperature to determine base density in °F or °C units.
Td	Temperature of detector mounting shaft on small volume prover with external detectors.
Td(avg)	Average temperature of the detector mounting shaft for proving runs, in °F or °C.
Tm	Temperature of meter in °F or °C units.
Tm(avg)	Average temperature of meter for selected runs in °F or °C.
Tmm	Temperature of master meter in °F or °C.
Tmm(avg)	Average temperature of master meter for selected proving runs in °F or °C.
Tp	Temperature of prover in °F or °C.
Tp(avg)	Average temperature of prover for selected proving runs in °F or °C.
Tmp	Temperature of master prover in °F or °C.
Tmp(avg)	Average temperature of master prover for selected proving runs in °F or °C.

TWA Temperature weighted average—the average liquid temperature at the meter determined over the whole delivery period.

4.2.5 Pressure

kPa Kilopascals (SI) in absolute pressure units.

kPag Kilopascals (SI) in gauge pressure units.

psi Pounds per square inch (US Customary) pressure units.

psia Pounds per square inch (US Customary) in absolute pressure units.

psig Pounds per square inch (US Customary) in gauge pressure units.

P Operating pressure in psi or kPa pressure units.

Pa Operating pressure in absolute pressure units

Pb Base pressure in psi or kPa pressure units.

Pba Base pressure in absolute pressure units.

Pbg Base pressure in gauge pressure units.

Pg Operating pressure in gauge pressure units.

Pm Pressure of liquid in meter, in gauge pressure units.

Pm(avg) Average pressure of meter for selected proving runs in gauge pressure units.

Pmm Pressure of liquid in master meter in gauge pressure units.

Pmm(avg) Average pressure of master meter for selected proving runs in gauge pressure units.

Pp Pressure of liquid in prover, in gauge pressure units.

Pp(avg) Average Pressure of prover for selected proving runs in gauge pressure.

Pmp Pressure of liquid in master prover in gauge pressure units.

Pmp(avg) Average pressure of master prover for selected proving runs gauge pressure.

Pe Equilibrium vapor pressure at operating conditions, in absolute pressure.

Peb Equilibrium vapor pressure of liquid at base temperature, in absolute pressure.

Pem Equilibrium vapor pressure of liquid in meter, in absolute pressure units.

Pep Equilibrium vapor pressure of liquid in prover, in absolute pressure units.

Pemm Equilibrium vapor pressure of liquid in master meter, in absolute pressure

Pemp Equilibrium vapor pressure of liquid in master prover, in absolute pressure

PWA Pressure weighted average—the average liquid pressure at the meter determined over the whole delivery period.

4.2.6 Correction Factors

CCF Combined correction factor.

CCFm Combined correction factor for meter at proving conditions.

CCFp Combined correction factor for prover at proving conditions.

CCFmm Combined correction factor for master meter at proving conditions.

CCFmp Combined correction factor for master prover at proving conditions.

CPL Basic correction for the compressibility of a liquid.

CPLm Correction for compressibility of liquid in meter at proving conditions.

CPLp Correction for compressibility of liquid in prover at proving conditions.

CPLmm Correction for compressibility of liquid in master meter at proving conditions.

CPLmp Correction for compressibility of liquid in master prover at proving conditions.

CPS Basic correction for the pressure effects on steel.

CPSm Correction for the effect of pressure on steel meter.

CPSp Correction for the effect of pressure on steel prover.

CPSmp Correction for the effect of pressure on steel in a master prover.

CTL Basic correction for the effect of temperature on a liquid.

CTLm Correction for the effect of temperature on a liquid in a meter at proving conditions.

CTLp Correction for the effect of temperature on a liquid in a prover at proving conditions.

CTLmm Correction for the effect of temperature on a liquid in a master meter.

CTLmp Correction for the effect of temperature on a liquid in a master prover.

CTS Basic correction for the effect of temperature on steel.

CTSm Correction for the effect of temperature on steel meter.

CTSp Correction for the effect of temperature on steel in a prover.

CTSmp Correction for the effect of temperature on steel in a master prover.

E Modulus of elasticity of a steel prover.

F Compressibility factor of liquid in meter (for *CMF* and ticket calculations).

Fm Compressibility factor of liquid in meter at proving conditions.

Fp Compressibility factor of liquid in prover at proving conditions.

Fmm	Compressibility factor of liquid in master meter at proving conditions.
Fmp	Compressibility factor of liquid in master prover at proving conditions.
Gl	Linear coefficient of thermal expansion on the displacer shaft or the detector mounting for a small volume prover.
Ga	Area coefficient of thermal expansion of the prover.
Gc	Cubical coefficient of thermal expansion of the prover.
Gmp	Cubical coefficient of thermal expansion of the master prover.
MA	Meter accuracy factor.
MF	Meter factor.
CMF	Composite meter factor.
IMF	Intermediate meter factor as determined by the average meter factor method.
MMF	Master meter factor.
NKF	Nominal K-Factor, pulses per indicated unit volume.
IKF	Intermediate K-Factor as determined by the average meter factor method.
KF	K-Factor, pulses per unit volume.
CKF	Composite K-Factor, pulses per unit volume.
q	One pulse volume, determined as a volume per unit pulse.

4.2.7 Volumes

BPV	Base prover volume of a displacement prover.
BPVa	Adjusted tank prover volume, defined as the difference between the upper and lower scale readings during a proving run.
BPVmp	Base prover volume of a master prover.
BPVamp	Adjusted base prover volume of a tank prover when used as a master prover.
MRo	Opening meter reading.
MRc	Closing meter reading.
MMRo	Opening master meter reading.
MMRc	Closing master meter reading.
GSV	Gross standard volume.
GSVmm	Gross standard volume of master meter for proving operations.
GSVmp	Gross standard volume of master prover for proving operations.
GSVp	Gross standard volume of prover for proving operations.
IV	Indicated volume.
IVm	Indicated volume of meter for proving operations.
IVmm	Indicated volume of master meter for proving operations.
ISV	Indicated standard volume.
ISVm	Indicated standard volume of meter for proving operations.
ISVmm	Indicated standard volume of master meter for proving operations.
N	Number of whole meter pulses for a single proving run.
Ni	Number of interpolated meter pulses for a single proving run.
Nb	Number of whole pulses or interpolated pulses under base or standard conditions.
N(avg)	Average number of pulses or interpolated pulses for proving runs that satisfy the repeatability requirements.
SRu	Upper scale reading of atmospheric tank prover.
SRl	Lower scale reading of atmospheric tank prover.

5 Application of Chapter 12.2, Part 3

5.1 For fiscal and custody transfer applications, proving reports are written statements of the calibration of the meter. In addition, they serve as an agreement between the authorized representatives of the parties concerned as to the calibration assigned to a meter. Proper accounting practices require that a proving report contains all the field data required to calculate the meter factor or composite meter factor.

5.2 The purpose of standardizing all the terms and arithmetical procedures employed in calculating the meter factor shown in a proving report is to avoid disagreement between the parties involved. Chapter 12.2, Part 3—Proving Reports will obtain the same unbiased answer from the same measurement data, regardless of who or what does the computing.

5.3 Some custody transfers of liquid petroleum, measured by meter, are sufficiently small in volume or value, or are performed at essentially uniform conditions, that the meter can be mechanically and/or electronically adjusted to read within a predetermined accuracy. The purpose of determining a meter factor is to ensure the accuracy of measurements, regardless of how the operating conditions change with respect to density, viscosity, flow rate, temperature or pressure, *by always proving the meter under the specific operating conditions encountered.*

5.4 Therefore, it must be noted that the meter factor as calculated by this standard is the *meter factor at the operating conditions at the time of proving*. **It is *not*,** as is often mistakenly assumed, the meter factor at base (standard) conditions. Although both the prover volume and the meter volume in the calculations are adjusted by correction factors derived from the base temperature and base pressure, this is just the most convenient method of correcting for the temperature and pressure differences of the liquid when passing through the meter and the prover. *The ratio between the prover volume* *and the meter volume (GSVp and ISVm) establishes the meter factor at the applicable conditions (viscosity, temperature, flow rate, density, pressure, etc.) at the time of proving.* Obtaining a meter factor at base conditions requires that the meter factor be multiplied by both the liquid temperature and pressure correction factors (*CTL* and *CPL*), which must be derived from the weighted average temperature, weighted average pressure, and weighted average density of the whole ticketed volume of the delivery.

5.5 The recording of field data, the calculation sequence, the discrimination levels, and the rules for rounding, are all specified, along with a set of example calculations. The examples may be used to aid in checking out procedures for any computer routines that are developed using the requirements stated.

5.6 *Care must be taken to ensure that all copies of a proving report are correct and legible. Standard procedure does not allow making corrections or erasures on a proving report. It shall be voided and a new meter proving report prepared.*

6 Field of Application

6.1 APPLICABLE LIQUIDS

6.1.1 This standard applies to liquids that, for all practical purposes, are considered to be Newtonian, single-phase, and homogeneous at metering conditions. Most liquids and dense phase fluids associated with the petroleum and petrochemical industries are considered to be Newtonian.

6.1.2 The application of this standard is limited to liquids which utilize tables and/or implementation procedures to correct metered volumes at flowing temperatures and pressures to corresponding volumes at base (reference or standard) conditions. To accomplish this, the density of a liquid shall be determined by the appropriate technical standards, or, alternatively, by use of the proper density correlations, or, if necessary, by the use of the correct equations of state. If multiple parties are involved in the measurement, the method for determining the density of the liquid shall be mutually agreed upon by all concerned.

6.2 BASE CONDITIONS

6.2.1 Historically, the measurement of all petroleum liquids, for both custody transfer and process control, is stated in volume units at base (reference or standard) conditions.

6.2.2 The base conditions for the measurement of liquids, such as crude petroleum and its liquid products, having a vapor pressure equal to or less than atmospheric pressure at base temperature, are:

US Customary Units:

Pressure	14.696 psia	(101.325 kPa)
Temperature	60.0°F	(15.56°C)

International System (SI) Units:

Pressure	101.325 kPa	(14.696 psia)
Temperature	15.00°C	(59.00°F)

6.2.3 For fluids, such as gas/liquid hydrocarbons, having a vapor pressure that is greater than atmospheric pressure at base temperature, the base pressure shall be the equilibrium vapor pressure at base temperature.

6.2.4 For liquid applications, base conditions may change from one country to the next due to governmental regulations or to different national standards requirements. Therefore, it is necessary that the base conditions shall be identified and specified for standardized volumetric flow measurement by all parties involved in the measurement.

6.3 CLASSIFICATION OF PROVERS

Provers are generally classified according to their type and design. However, present-day practice also requires that the method of pulse detection and the measurement technology utilized by the prover be specified.

There are generally three main classes of liquid provers—displacement provers, tank provers, and master meters.

6.3.1 Displacement Provers

6.3.1.1 Within the classification of displacement provers is the common type generally known as the pipe prover. It is usually constructed of precisely rounded, coated sections of pipe, utilizing either a piston or sphere as the method of sweeping out the calibrated volume during a proving run. The pipe prover is defined as a prover whose volume is sufficient to generate a *minimum* of 10,000 whole, unaltered pulses as generated by the primary measurement device between the detector switches for each pass of the displacer. This results in a proving pulse resolution of at least one part in ten thousand (0.0001).

6.3.1.2 Also within this group of displacement provers is another prover type called the small volume prover (*SVP*). A small volume prover may be a pipe prover or a precision-built small volume proving device, utilizing either a machined metal piston or an elastomer sphere moving between precision detectors. It is defined as a prover whose volume *is not* sufficiently large enough to generate 10,000 whole unaltered pulses as generated by the primary measurement device between the detector switches for each pass of the displacer. As a result, a measurement technique called pulse interpolation must be used. This has the capability to detect and interpolate to fractions of a whole pulse, producing a pulse resolution of one part in ten thousand (0.0001) without having to generate 10,000 or more pulses per proving pass.

6.3.1.3 Displacement provers are further divided into two subgroups, consisting of either the unidirectional or bidirectional type of flow design. The primary difference between these two types is that the unidirectional prover requires only one proving pass (always in the same direction) of the displacer, between the detectors, to complete a proving run. The bidirectional prover requires two passes of the displacer between the detectors, one in a forward direction and another in the reverse (back) direction, the sum of these two passes constituting a proving round-trip.

6.3.2 Atmospheric (Open) Tank Provers

Atmospheric tank provers can be classified as either top-filling or bottom-filling proving devices. Both types have a smaller diameter upper neck attached to the top of the main body of the tank prover which contains a sight glass together with a graduated scale. Measurement of the liquid in the bottom of the tank prover before filling, or after draining, is done by one of three different types of bottom design. These types are defined as follows:

a. An open tank prover with a top and bottom neck design—that is, having sight glasses and graduated scales on both upper and lower necks. This enables upper and lower liquid levels to be read and recorded.
b. An open tank prover with a sight glass and graduated scale on the upper neck. This type has no measurement device at the bottom; it simply has a tapered bottom, drain line, and block valve, and is "drained" for a prescribed time to an empty condition that is repeatable.
c. An open tank prover with a top neck having a sight glass and graduated scale. This type has a lower neck design that always reads zero due to a built-in weir in the bottom of the prover. This allows the liquid to flow until the U-bend in the weir is reached, breaking the siphon and stopping the flow at the same zero mark each time the tank prover is emptied.

6.3.3 Master Meters

The master meter is an indirect meter-proving device which utilizes the concept of transfer proving. A flow meter with good linearity and repeatability is selected to serve as a transfer standard between a meter operating in the field and a meter prover. The meter prover and the operating meter are often in different geographic locations, although sometimes the master meter and master prover are both in series with the meter to be proved. Two separate stages are necessary in master meter proving: first, the master meter must be proved using a meter prover (master prover) that has been calibrated by the waterdraw method. After proving, this master meter is used to determine a new meter factor for the field meter. *Of all the different meter proving procedures, the master meter technique has a higher uncertainty, and particular care must be taken when using this meter-proving practice to obtain accurate results.*

7 Precision, Rounding, and Discrimination Levels

The minimum precision of the computing hardware must be equal to or greater than a ten-digit calculator to obtain the same answer in all calculations.

The general rounding rules and discrimination levels are described in the following subsections.

7.1 ROUNDING OF NUMBERS

When a number is rounded to a specific number of decimals, it shall always be rounded off in one step to the number of figures that are to be recorded, and shall not be rounded in two or more steps of successive rounding. The rounding procedure shall be in accordance with the following:

a. When the figure to the right of the last place to be retained is 5 or greater, the figure in the last place to be retained should be increased by 1.
b. If the figure to the right of the last place to be retained is less than 5, the figure in the last place to be retained should be unchanged.

7.2 DISCRIMINATION LEVELS

7.2.1 For field measurements of temperature and pressure, the levels specified in the various tables are maximum discrimination levels.

7.2.2 For example, if the parties agree to use a thermometer graduated in whole °F or $^1/_2$°C increments, then the device is normally read to levels of 0.5°F, or 0.25°C resolution.

7.2.3 Likewise, if the parties agree to use a "smart" temperature transmitter which can indicate to 0.01°F or 0.005°C, then the reading shall be rounded to the nearest 0.1°F, or 0.05°C, prior to recording for calculation purposes.

8 Repeatability Requirements

8.1 The meter proving is considered acceptable when the following criterion has been satisfied:

- Proving repeatability shall be within a range not to exceed 0.050 percent (except in the case of proving a master meter with a master prover, when the repeatability shall be within a range not to exceed 0.020 percent).

8.2 As a measure of repeatability, the following equation shall be utilized to calculate the range (repeatability):

$$R\% = \left(\frac{Max - Min}{Min}\right) \times 100$$

8.3 A minimum of two proving runs are required to use the above formula and determine if the repeatability criterion has been satisfied.

8.4 Two different meter factor calculation methods are in common use and are described in this text. The two methods have been designated the ***Average Meter Factor Method and the Average Data Method.*** The *average meter factor method* uses a range of intermediate meter factors calculated for selected runs, with a repeatability criterion, *not to exceed 0.050 percent.* The repeatability criterion for the *average data method* uses the range of meter generated pulses for selected runs, which *shall not exceed 0.050 percent.*

8.5 In the case of proving a master meter with a master prover, then the acceptable range for repeatability by both the average meter factor method and the average data method *shall not exceed 0.020 percent.*

8.6 *Each operating facility shall select a preferred method of calculation* at the time of start-up. If a user should wish to change to the other method of meter factor calculation at a later date, all of the interested parties involved in meter proving operations should concur prior to any such change being implemented.

9 Meter Proving Report Calculation Methods

9.1 The method of determining the number of proving runs to be made for an acceptable meter proving calibration shall be an operator-based (company policy) decision. Examples of calibration proving run sequences currently in use are 5 consecutive runs out of a total of 6 consecutive runs, any 5 runs out of 6 consecutive runs, 5 consecutive runs out of 10 consecutive runs, 3 sets of 5 runs, any 5 consecutive runs, 3 consecutive runs, 2 sets of 10 runs. However, there are many other proving run sequences that are also regularly used. Some guidelines on selecting proving run sequences are provided in the *API MPMS* Chapter 4.8—*Guide to Proving Operations*. The choice of the number of proving runs to be made is usually established on the basis of many factors, some of which are: manpower availability, installed equipment, prover design, automation, customer requirements, corporate measurement policy, pipeline tariffs, contracts, etc. No matter what sequence of acceptable meter proving runs are used, at least two proving runs are required to test that the repeatability requirement has been achieved.

9.2 As stated previously, there are two usual and acceptable meter factor calculation methods, both of which are in normal use and are described in this standard—the Average Meter Factor Method and the Average Data Method.

9.3 The average meter factor method calculates an intermediate meter factor (*IMF*) or intermediate K-factor (*IKF*) for each selected proving run based on individual *Tp, Tm, Pp, Pm,* and *Ni* or *N* values. The average (mean) of these separately calculated intermediate meter factors (*IMF*) or intermediate K-factors (*IKF*) is used as the *final meter factor or final K-factor* for the proving report.

$$Repeatability\% = \left(\frac{Highest\ IMF - Lowest\ IMF}{Lowest\ IMF}\right) \times 100$$

9.4 The range of the intermediate meter factors for the selected proving runs is used to determine that the required repeatability requirement (≤0.050 percent) has been satisfied.

9.5 The average data method calculates the meter factor (*MF*) or K-factor (*KF*) using *Tp(avg), Tm(avg), Pp(avg), Pm(avg),* and *N(avg)* values from all the selected runs which satisfy the repeatability requirement (≤0.050%).

$$Repeatability\% = \left(\frac{Highest\ N - Lowest\ N}{Lowest\ N}\right) \times 100$$

9.6 The range of the pulses (*N*) or interpolated pulses (*Ni*) for the selected runs is used to determine that the required repeatability requirement (≤0.050 percent) has been satisfied.

9.7 Problems are sometimes encountered when proving a meter that is temperature compensated using the average data method of calculation. Should the liquid temperature in the meter change during a proving pass, then the temperature compensator will make corrections to the shaft output of a mechanical compensator or change the pulse output of an electronic compensator. The amount of this pulse change is a function of two factors:

a. The coefficient of expansion of the liquid in the meter.
b. The total number of pulses generated during the meter proving pass.

For example:

If 40,000 pulses are generated during each meter proving pass and the coefficient of expansion per degree Fahrenheit of the fluid is 0.0005/°F, then:

Pulse Change = 40,000 x 0.0005 = 20 pulses per °F

In the above example, if the liquid temperature rises one degree Fahrenheit, then the total number of pulses generated during the proving pass will decrease by 20 pulses. Similarly, if the liquid temperature decreases one degree Fahrenheit, then the total number of pulses generated will increase by 20 pulses. This phenomenon should be considered when evaluating the repeatability of the meter pulse data and the advisability of using the average data method in this operation.

10 Correction Factors

Calculations in this publication are based on correcting the measured volume of the petroleum liquid for the difference between the temperature and pressure of the liquid in the prover and the meter. Correction factors are provided to adjust the metered volume and the volume of prover to base conditions so that they may be compared on the same basis.

10.1 LIQUID DENSITY CORRECTION FACTORS

10.1.1 General

10.1.1.1 The density of the liquid shall be determined by the appropriate technical standards, or, alternatively, by use of the proper density correlations, or, if necessary, by the use of the correct equations of state. If multiple parties are involved in the measurement, the method selected for determining the density of the liquid shall be mutually agreed upon by all concerned.

10.1.1.2 Appendix A contains a list of recommended liquids versus API correlations in accordance with the position paper issued by API in 1981. Where an API correlation does not currently exist, an appropriate ASTM standard has been provided to assist the user community.

10.1.1.3 Liquid density correction factors are employed to account for changes in density due to the effects of temperature and pressure upon the liquid. These correction factors are:

a. *CTL*—corrects for the effect of temperature on the liquid density.

b. *CPL*—corrects for the effect of pressure on the liquid density.

10.1.2 Correction for Effect of Temperature on Liquid Density (*CTL*)

10.1.2.1 If a volume of petroleum liquid is subjected to a change in temperature, its density will decrease as the temperature rises and increase as the temperature falls. This density change is proportional to the thermal coefficient of expansion of the liquid and the temperature.

10.1.2.2 The correction factor used for the effect of temperature on the density of a liquid is called *CTL*. This *CTL* factor is a function of the base density (*RHOb*) of the liquid and its temperature (*T*).

10.1.2.3 *API MPMS* Chapter 11.1—*Volume Correction Factors, Volume X, Background, Development, and Program Documentation*, provides the source documentation for computer programs to determine *CTL* for crude oils and petroleum products. *CTL* correction factors can also be determined by use of various standards (ASTM, API, IP, ISO, etc.) and also from industry accepted tables. Appendix A contains assistance in determining an appropriate reference to enable the correct *CTL* to be determined for the liquid involved.

10.1.3 Equilibrium Vapor Pressure

10.1.3.1 Equilibrium vapor pressure (*Pe*) can be defined as the pressure required to maintain the liquid state at a given temperature. Liquefied gases and other volatile liquids have an equilibrium vapor pressure higher than atmospheric pressure at their proving temperature. When proving a meter containing these types of fluids, the value of the equilibrium vapor pressure at the proving conditions is required. To calculate a meter factor for these fluids currently requires the use of *API MPMS* Chapter 11.2.2 for the *CPL* factor and API historical Table 24 for the *CTL* factor, until such time that they are superseded by new API standards.

10.1.3.2 The equilibrium vapor pressure of a fluid can be determined by appropriate technical standards, alternatively, by the use of vapor pressure correlations, or, by the use of the correct equations of state. If multiple parties are involved in the meter proving, then the method selected for determining the equilibrium vapor pressure of the fluid shall be mutually agreed on by all concerned.

10.1.3.3 A field method, sometimes used to determine the equilibrium vapor pressure at proving conditions, is to isolate the meter prover after proving and immediately vent off a small amount of fluid. The pressure in the prover will quickly drop until it reaches a constant reading. The constant reading is considered the equilibrium vapor pressure at the proving conditions. At this point, the venting should be stopped, the pressure gauge read, and the reading recorded as either "gauge" or "absolute" as appropriate. Venting too aggressively can cause the temperature to be lowered, which would compromise the accuracy of the equilibrium vapor pressure determination since proving conditions (temperature) would not be maintained.

10.1.4 Correction for Effect of Compressibility on Liquid Density (*CPL*)

If a petroleum liquid is subjected to a change in pressure, the liquid density will increase as the pressure increases and decrease as the pressure decreases. This density change is proportional to the compressibility factor (*F*) of the liquid, which depends upon both its base density and the liquid temperature. The correction factor used for the effect of compressibility on liquid density is called *CPL*. References to the appropriate standards for the compressibility factor (*F*) may be found in *API MPMS* Chapter 11.2.1, *API MPMS* Chapter 11.2.2, or their metric equivalents, and Appendix A of this standard. *CPL* can be expressed as:

$$CPL = \frac{Ve}{Vo} = \frac{1}{1-[(P-Pe)\times F]},$$

where

Ve = volume at equilibrium pressure (Pe) at operating temperature,

Vo = volume at operating pressure (P) at operating temperature.

a. *Where the operating pressure is in gauge pressure units:*

$$CPL = \frac{1}{1 - [(Pg + Pba - Pe) \times F]},$$

where

Pg = operating pressure of the liquid in gauge pressure units,

Pba = base pressure in absolute pressure units,

Pe = equilibrium vapor pressure at the temperature of the liquid being measured, in absolute pressure units,

F = compressibility factor for the liquid.

b. *Where the operating pressure is in absolute pressure units:*

$$CPL = \frac{1}{1 - [(Pa - Pe) \times F]},$$

where

Pa = $Pg + Pba$,

Pa = operating pressure of the liquid in absolute pressure units,

Pe = equilibrium vapor pressure at the temperature of the liquid being measured, in absolute pressure units,

F = compressibility factor for the liquid.

The liquid equilibrium vapor pressure (Pe) is considered to be equal to the base pressure (Pba) for liquids that have an equilibrium vapor pressure less than, or equal to, atmospheric pressure at the flowing temperature.

10.2 PROVER CORRECTION FACTORS

10.2.1 General

Correction factors are employed to account for changes in the prover volume due to the effects of temperature and pressure upon the steel. These correction factors are:

a. *CTS*, which corrects for thermal expansion and/or contraction of the steel in the prover shell due to the average prover liquid temperature.

b. *CPS*, which corrects for pressure expansion and/or contraction of the steel in the prover shell due to the average prover liquid pressure.

10.2.2 Correction for the Effect of Temperature on Steel (*CTS*)

Any metal container, be it a pipe prover, small volume prover, tank prover, etc., when subjected to a change in temperature, will change its volume accordingly. This volume change, regardless of shape of the prover, is proportional to the cubical coefficient of thermal expansion of the material. The cubical coefficient of thermal expansion is valid when the calibrated section of the prover and its detector switch mountings are constructed of a single material.

10.2.3 Corrections for Single-Walled Prover

The *CTS* for pipe provers and open tank provers assumes a singular construction material and may be calculated from:

$$CTS = 1 + [(T - Tb) \times Gc],$$

where

Gc = mean coefficient of cubical expansion per degree temperature of the material of which the container is made between Tb and T,

Tb = base temperature,

T = average liquid temperature in the container.

The cubical coefficient of expansion (Gc), for a displacement prover or open tank prover shall be the one for the materials used in the construction of its calibrated section. Should the coefficient of expansion be unknown, then the Gc values contained in Table 6 shall be used.

The cubical coefficient of expansion (Gc) on the report of calibration furnished by the calibrating agency is to be used for that prover.

10.2.4 Corrections for Displacement Pipe Provers with External Detectors

The cubical coefficient of expansion used to calculate *CTS* for some displacement pipe provers must sometimes be modified because of their design. In a special case, where the detector(s) are mounted externally and are not on the prover barrel itself, the volume changes that occur due to temperature are defined in terms of the area change in the prover barrel, and a distance change between the detector positions. While occasionally these detector positions may be on a carbon or stainless steel mounting shaft, it is much more likely that they will be on a mounting made of a special alloy (e.g., Invar) that has a very small linear coefficient of expansion.

For displacement pipe provers, which utilize detectors not mounted on the calibrated section of the pipe but are attached to a separate shaft (e.g., small volume provers), the correction factor for the effect of temperature (*CTS*) shall be modified and calculated as follows:

$$CTS = \{1 + [(Tp - Tb) \times Ga]\} \times \{1 + [(Td - Tb) \times Gl]\},$$

where

Ga = area thermal coefficient of expansion for the prover chamber,

Gl = linear thermal coefficient of expansion of the displacer shaft,

Tb = base temperature,

Td = temperature of the detector mounting shaft or the displacer shaft with external detectors,

Tp = temperature of the liquid in the prover chamber.

The linear and area thermal coefficients of expansion shall be the ones for the materials used in the construction of the prover. The values contained in Table 6 shall be used if the coefficients are unknown.

10.2.5 Correction for the Effect of Pressure on Steel (*CPS*)

If a metal container such as a pipe prover or a tank prover is subjected to an internal pressure, the walls of the container will stretch elastically and the volume of the container will change accordingly.

10.2.6 Correction for Single-Walled Prover

While it is recognized that simplifying assumptions enter into the equations below, for all practical purposes the correction factor for the effect of the internal pressure on the volume of a cylindrical container, called *CPS*, may be calculated from:

$$CPS = 1 + \frac{(Pg - Pbg) \times ID}{E \times WT},$$

Since *Pbg* is 0 psi gauge pressure, the equation simplifies to.

$$CPS = 1 + \frac{Pg \times ID}{E \times WT},$$

where

ID = $OD - (2 \times WT)$,

Pg = internal operating pressure of the prover, in gauge pressure units,

Pbg = base pressure, in gauge pressure units,

ID = internal diameter of the prover,

E = modulus of elasticity for the prover material,

OD = outside diameter of the prover,

WT = wall thickness of the prover.

The modulus of elasticity (E) for a pipe prover or open tank prover shall be the one for the materials used in the construction of the calibrated section. The values contained in Table 7 shall be used if E is unknown.

10.2.7 Correction for Double-Walled Prover

Some provers are designed with a double wall to equalize the pressure inside and outside the calibrated chamber. In this case, the inner measuring section of the prover is not subjected to a net internal pressure, and the walls of this inner chamber do not stretch elastically. Therefore, in this special case:

$$CPS = 1.0000$$

10.3 COMBINED CORRECTION FACTORS (*CCF, CCFp, CCFm, CCFmm, CCFmp*)

When multiplying a large number, for example, an indicated volume (*IV*), by a small correction factor, such as, *CTS, CPS, CTL*, or *CPL*, over and over again, a lowering of the precision may occur. In addition, errors can occur in mathematical calculations due to sequence order and the rounding differences between computers and/or programs. To minimize these errors, a method was selected by the industry which combines all the required correction factors in a specified sequence and at maximum discrimination levels. The accepted method of combining two or more correction factors is to obtain a combined correction factor (*CCF*) by serial multiplication of the individual correction factors and then rounding the CCF to the required number of decimal places.

Five combined correction factors have been adopted and are used in meter proving calculations to minimize errors:

a. For calculation of the *GSVp* of a meter prover:

$$CCFp = [CTSp \times CPSp \times CTLp \times CPLp].$$

b. For calculation of the GSVmp of a master prover:

$$CCFmp = [CTSmp \times CPSmp \times CTLmp \times CPLmp].$$

c. For calculation of the ISVm for a meter being proved:

$$CCFm = [CTLm \times CPLm].$$

d. For calculation of a master meter volume (*GSVmm*) when proving a field meter.

$$CCFmm = [CTLmm \times CPLmm \times MMF].$$

e. For calculation of a master meter volume (*ISVmm*) using a master prover:

$$CCFmm = [CTLmm \times CPLmm].$$

10.4 METER FACTOR (*MF*) AND COMPOSITE METER FACTOR (*CMF*)

10.4.1 General

Meter factor (*MF*) and composite meter factor (*CMF*) are nondimensional values which correct errors of the meter due to such factors as temperature, pressure, viscosity, gravity, together with the mechanical condition of the meter (slippage).

10.4.2 Meter Factor

The meter factor (MF) is determined at the time of proving by the following expression:

$$MF = \frac{GSVp}{ISVm}$$

10.4.3 Composite Meter Factor

A composite meter factor (CMF) may be used in the following applications:

a. Where the density, temperature, and pressure are considered constant throughout the measurement ticket period.
b. Where anticipated changes in these parameters result in uncertainties unacceptable to the parties.
c. When agreed to by all the interested parties as a convenience.

The composite meter factor is determined at the time of proving by the following expression:

$$CMF = MF \times CPL$$

When calculating the CMF, use a CPL value that is based on normal metering pressure that occurs when the hydrocarbon liquid flow *is not* passing through the prover.

10.5 METER ACCURACY FACTOR (*MA*)

The meter accuracy factor (MA) is a term utilized specifically for loading rack meters. In most truck rack applications, the meter is mechanically or electronically adjusted at the time of proving to ensure that the meter factor is approximately unity. This simplifies the bill of lading and accounting issues associated with truck applications in refined product service.

The meter accuracy factor (MA) is determined at the time of proving from the reciprocal of the meter factor (MF) as follows:

$$MA = \frac{1}{MF}$$

10.6 NOMINAL K-FACTOR (*NKF*)

A nominal K-factor (NKF) is utilized to determine the meter factor (MF), master meter factor (MMF), composite meter factor (CMF), and meter accuracy (MA). The original nominal K-factor (NKF) is a fixed value for a specific meter, determined by the manufacturer of the device and supplied with the new meter. This original nominal K-factor is established at the time of installation of the flow meter and, if unchanged, can be used to calculate the meter factor. Using a constant unchanging nominal K-factor provides an audit trail through the meter proving system, establishes meter factor control charts, and allows meter factor control of the system.

However, an alternative method is to change the nominal K-factor every time the meter is proved to an actual K-factor. Changing the Nominal K-factor at each proving allows the resulting meter factor to approach unity. In this type of operation, it is necessary to track K-factors as an audit trail requirement and to generate K-factor control charts to maintain a history on the meter.

10.7 K-FACTOR (*KF*) AND COMPOSITE K-FACTOR (*CKF*)

10.7.1 General

For some applications, K-factors (KF), and composite K-factors (CKF) are used to eliminate the need for applying meter factors to the indicated volume (IV). As discussed above, by changing the KF or CKF at the time of proving, the meter is electronically adjusted at the time of proving to ensure that the meter factor is approximately unity.

10.7.2 K-factor (*KF*)

The actual meter K-factor (KF) as differentiated from the nominal K-factor, is described by the following formula:

$$KF = \frac{Nb}{GSVp}$$

When the number of pulses (N) or interpolated pulses (Ni) per proving run are reduced to base or standard conditions by the use of $CTLm$ and $CPLm$, the resulting pulses at base conditions (Nb) are given by one of these expressions:

$$Nb = N \times CTLm \times CPLm,$$

or

$$Nb = Ni \times CTLm \times CPLm$$

However, we know that:

$$CCFm = CTLm \times CPLm$$

Therefore,

$$Nb = N \times CCFm \text{ or } Nb = Ni \times CCFm.$$

We also know that the $GSVp$ of the prover—that is, the "true" volume of liquid passing through the prover during a proving run, is calculated from the following equation:

$$GSVp = BPV \times CCFp,$$

and also that

$$CCFp = CTSp \times CPSp \times CTLp \times CPLp.$$

Therefore, application of the above formula enables an actual K-factor to be calculated.

Alternatively, a new K-factor can also be determined at the time of proving by use of the following formula:

$$actual.KF = \frac{KF}{MF},$$

where

$actual.KF$ = the actual K-factor to be calculated from the present meter proving,

KF = the K-factor used in the meter proving to calculate the meter factor,

MF = the new meter factor calculated from the meter proving.

10.7.3 Composite K-Factor (*CKF*)

The composite K-factor (*CKF*) may be used in applications where the gravity, temperature and pressure are approximately constant throughout the measurement ticket period. A new composite K-factor can be determined at the time of proving by the following expression:

$$new.CKF = \frac{actual.KF}{CPL}$$

The *CPL* shall be calculated using the average pressure during the delivery (see explanatory notes at the bottom of Table 8).

10.8 ONE PULSE VOLUME (*q*)

When repeated calculations are being processed manually, the reciprocal of the K-factor may sometimes be a more useful quantity for field use than the K-factor itself. This reciprocal is called the one pulse volume (q) because it indicates the volume delivered by the meter (on average) while one pulse is being emitted. It is defined by the following equation:

$$q = \frac{1}{KF}$$

Thus, q has the dimensions of volume; when it is multiplied by the number of pulses emitted by the meter, the result is the volume delivered through the meter.

11 Recording of Field Data

All required field data shall be recorded and rounded in accordance with the discrimination levels specified in this section. In addition, see 7.2 which also discusses discrimination levels.

Discrimination levels of field data *less than* those specified *may be permitted* in the meter factor calculation procedures if their use is mutually agreeable to all the parties having an interest in the custody transaction.

Discrimination levels of field data *greater than* those specified *are not in agreement* with the intent of this standard and *shall not be used* in the meter factor calculation procedures. Field devices (e.g., smart temperature and pressure sensors), which are capable of measuring to discrimination levels beyond those specified in the following tables, must have their values rounded prior to their use in any calculations.

Rather than stating a minimum level of instrument discrimination for all metering applications, the user is restricted to a maximum level for recording field data.

11.1 SPECIFIED DISCRIMINATION LEVELS FOR FIELD DATA

Specified discrimination levels for field data are listed in the tables indicated below:

11.1.1 Liquid Data

RHO, DEN, API, RD	Table 1
RHOb, DENb, APIb, RDb	Table 1
RHOobs, DENobs, APIobs, RDobs	Table 1
Tobs, Tb	Table 3

11.1.2 Prover Data

OD, ID, WT	Table 2
Tp, Tmp, Td	Table 3
Pp, Pmp, Pb	Table 4
Pep, Pemp	Table 4
Fp, Fmp	Table 5
Gc, Gmp, Ga, Gl	Table 6
E	Table 7
SRu, SRl	Table 9
BPV, BPVa	Table 9
BPVmp, BPVamp	Table 9

11.1.3 Meter Data

Tm, Tmm	Table 3
Pm, Pmm	Table 4
Pem, Pemm	Table 4
Fm, Fmm	Table 5
NKF, KF, CKF	Table 8
N, Ni, N(avg), Nb	Table 10

11.2 DISCRIMINATION TABLES

In the tables that follow, the number of digits shown as (X) *in front of the decimal point* are for illustrative purposes only, and may have a value more or less than the number of (X) illustrated.

The number of digits shown as (**x**) after the decimal point are very specific, as they define the required discrimination level for each value described.

Tables 8 and 9 have letters, such as ABCD.**xx**, to the left of the decimal point, in this case the letters do give the actual size of the value before the decimal and are intended to be specific, not illustrative.

In cases where a value is shown with the number **5** in the last decimal place, such as XX.**x5**, this is intended to signify that the last decimal place in the value must be rounded to either 0 or 5, no other value is permitted.

Table 1—Liquid Density Discrimination Levels

	API	DEN (kg/M^3)	RD
Observed Density (*RHOobs*)	XXX.x	XXXX.5	X.xxx5
Base Density (*RHOb*)	XXX.x	XXXX.x	X.xxxx
Flowing Density (*RHOtp*)	XXX.x	XXXX.x	X.xxxx

Table 2—Dimensional Discrimination Levels

	US Customary (inches)	SI Units (mm)
Outside Diameter of Prover Pipe (*OD*)	XX.xxx	XXX.xx
Wall Thickness of Prover Pipe (*WT*)	X.xxx	XX.xx
Inside Diameter of Prover Pipe (*ID*)	XX.xxx	XXX.xx

Table 3—Temperature Discrimination Levels

	US Customary (°F)	SI Units (°C)
Base Temperature (*Tb*)	60.0	15.00
Observed Temperature (*Tobs*)	XX.x	XX.x5
Prover Temperatures [*Tp, Tp(avg), Tmp, Tmp(avg)*]	XX.x	XX.x5
Meter Temperatures [*Tm, Tm(avg), Tmm, Tmm(avg)*]	XX.x	XX.x5
Detector Mounting Shaft Temperatures [*Td, Td(avg)*]	XX.x	XX.x5
Weighted Average Temperature (*TWA*)	XX.x	XX.x5

Table 4—Pressure Discrimination Levels

	US Customary		SI Units	
	(psia)	(psig)	(bar)	(kPa)
Base Pressure (*Pb, Pba, Pbg*)	14.696	0.0	1.01325	101.325
Prover Pressures [*Pp, Pp(avg), Pmp, Pmp(avg)*]	XX.x	XX.0	XX.x	XX.0
Meter Pressures [*Pm, Pm(avg), Pmm, Pmm(avg)*]	XX.x	XX.0	XX.x	XX.0
Weighted Average Pressure (*PWA*)	XX.x	XX.0	XX.x	XX.0
Equilibrium Vapor Pressures [*Pe, Peb, Pep, Pep(avg), Pem, Pem(avg), Pemm, Pemm(avg), Pemp, Pemp(avg)*]	XX.x	XX.0	XX.x	XX.0

Table 5—Compressibility Factor Discrimination Levels (*F, Fp, Fm, Fmp, Fmm*)

US Customary Units	SI Units	
(psi)	(bar)	(kPa)
0.00000xxx	0.0000xxx	0.000000xxx
0.0000xxxx	0.000xxxx	0.00000xxxx
0.000xxxxx	0.00xxxxx	0.0000xxxxx

Table 6—Discrimination Levels of Coefficients of Thermal Expansion

	Thermal Expansion Coefficients	
Type of Steel	(per °F)	(per °C)
Cubical Coefficient (*Gc, Gmp*)		
Mild Carbon	0.0000186	0.0000335
304 Stainless	0.0000288	0.0000518
316 Stainless	0.0000265	0.0000477
17-4PH Stainless	0.0000180	0.0000324
Area Coefficient (*Ga*)		
Mild Carbon	0.0000124	0.0000223
304 Stainless	0.0000192	0.0000346
316 Stainless	0.0000177	0.0000318
17-4PH Stainless	0.0000120	0.0000216
Linear Coefficient (*Gl*)		
Mild Carbon	0.00000620	0.0000112
304 Stainless	0.00000960	0.0000173
316 Stainless	0.00000883	0.0000159
17-4PH Stainless	0.00000600	0.0000108
Invar Rod	0.00000080	0.0000014

Table 7—Modulus of Elasticity Discrimination Levels (*E*)

	US Customary Units	SI Units	
	(psi)	(bar)	(kPa)
Mild Steel	30,000,000	2,068,000	206,800,000
304 Stainless Steel	28,000,000	1,931,000	193,100,000
316 Stainless Steel	28,000,000	1,931,000	193,100,000

Table 8—Correction Factor Discrimination Levels

CTSp	X.xxxxx
CTSmp	X.xxxxx
CPSp	X.xxxxx
CPSmp	X.xxxxx
CTLp	X.xxxxx
CTLmp	X.xxxxx
CPLp	X.xxxxx
CPLmp	X.xxxxx
CCFp	X.xxxxx
CCFmp	X.xxxxx
CTLm	X.xxxxx
CTLmm	X.xxxxx
CPLm	X.xxxxx
CPLmm	X.xxxxx
CCFm	X.xxxxx
CCFmm	X.xxxxx
IKF	AB.xxxx or ABC.xxx or ABCD.xx or ABCDE.x
NKF	Value recorded as determined by manufacturer.
KF	AB.xxx or ABC.xx or ABCD.x or ABCDE.0
CKF	AB.xxx or ABC.xx or ABCD.x or ABCDE.0
IMF	X.xxxxx
MF	X.xxxx
IMMF	X.xxxxx
MMF	X.xxxx
CPL	X.xxxx[1,2]
CTL	X.xxxx[1]
CMF	X.xxxx
MA	X.xxxx

Notes on specific uses of *CPL* and *CTL*:
[1] *CPL* and *CTL* are calculated using *PWA*, *TWA*, and the average density [*RHO(avg)*], as determined for the whole metered delivery of the liquid, when used to calculate the *CCF* for a measurement ticket. *CCF* is derived from *CTL* x *CPL* x *MF*, which can also be defined as the meter factor at base conditions.
[2] *CPL* is required to calculate a *CMF* or *CKF*, and is calculated using an assumed average pressure, average temperature, and average density, for the whole delivery at the time of proving.

Table 9—Volume Discrimination Levels

	US Customary Units		SI Units	
	(Bbl)	(gal)	(M^3)	(L)
Meter Readings (*MMRo, MRo, MMRc, MRc*)	XX.xx	XX.x	XX.xxx	XX.xx
Scale Readings (*SRu, SRl*)	X.xxxx	X.xx	—	X.xx
Volume Discrimination Levels (*BPV, BPVa, BPVmp, BPVamp, IVm, IVmm, ISVm, ISVmm, GSVp, GSVmp, GSVm, GSVmm*)	ABC.xxxx	ABCDE.x	AB.xxxxx	ABCDE.x
	AB.xxxx	ABCD.xx	A.xxxxx	ABCD.xx
	A.xxxxx	ABC.xxx	0.xxxxxx	ABC.xxx
	0.xxxxxx	AB.xxxx	0.0xxxxxx	AB.xxxx

Table 10—Pulse Discrimination Levels

	N	*Ni*	*Nb, N(avg)*
Whole Pulse Applications	XX.0	–	XX.x
Pulse Interpolation Applications	–	XX.xxx	XX.xxxx

12 Calculation Sequence, Discrimination Levels, and Rules For Rounding

The following section describes the steps required to obtain a calculated value for a meter factor, based on standardized input data and exact calculation procedures. This will ensure that all interested parties will arrive at the same answer. Note that after the first five steps, which are common to both the average meter factor method and the average data method in determining the meter factor value, the two methods diverge. They are described separately following Step 5, 12.1.

12.1 DISPLACEMENT PROVERS

This section rigorously specifies the rounding, calculation sequence, and discrimination levels required for meter proving report calculations using pipe provers and small volume provers.

The procedures outlined below do not include the requirements for the calculations associated with *RHOb*, *CTL*, and *F*. The rounding, calculation sequence, and discrimination levels for these terms are, for the most part, contained in the references listed in Appendix A. When a reference does not contain an implementation procedure, Appendix A contains a suggested method of implementation.

a. Step 1—Enter Initial Prover Data.

Enter all the following prover information, taken from the prover calibration certificate into the meter proving report form:

- Manufacturer and serial number.
- Type of prover.
- Base prover volume (*BPV*).
- Inside diameter (*ID*).
- Wall thickness (*WT*).
- Coefficient of cubical expansion (*Gc*).
- Modulus of elasticity (*E*).
- Coefficients of linear and area expansion (*Gl*, *Ga*) (If using a small volume prover with externally mounted detectors).

b. Step 2—Enter Initial Meter Data.

Enter the following information on the meter being proved and record on the meter proving report form:

- Nominal K-factor (*NKF*) or actual K-factor (*KF*).
- Whether the meter is temperature compensated.
- What the proving report should calculate (*MF*, *CMF*, *KF*, *CKF*, or *MA*).
- Calculation method used (average data method or average meter factor method).
- Company assigned meter number.
- Meter manufacturer, size, and type.
- Meter model number and serial number.
- Flow rate.
- Proving report number and date of proving.
- Nonresetable totalizer reading.

c. Step 3—Enter Fluid Data.

1. Enter the following information on the hydrocarbon liquid being metered:

- Type of liquid on which meter is being proved.
- Batch number of the receipt or delivery.
- Observed liquid density (*APIobs*, *DENobs*, *RDobs*, *RHOobs*).
- Observed liquid temperature for density (*Tobs*).
- The selected implementation procedure required (Tables 5A/6A, 5B/6B, etc.).
- Viscosity (if needed).

2. *If using an atmospherically unstable liquid—that is, the equilibrium vapor pressure is higher than the atmospheric pressure—enter the following additional information:*

- The liquid proving temperature in °F or °C.
- The equilibrium vapor pressure of the fluid at the proving temperature, in appropriate pressure units.

3. *If the proving report requires the calculation of CMF or CKF terms, then enter the following additional information.*

- The normal operating pressure of the liquid in gauge pressure units, which is assumed to be constant throughout the delivery.
- The liquid temperature of the meter while proving, which is assumed to be the normal operating temperature and also assumed to be constant throughout the delivery.

d. Step 4—Record Run Data.

For every proving run, record the following data:

	Discrimination Levels
Prover Data	
Tp	Table 3
Pp	Table 4
Meter Data	
Tm	Table 3
Pm	Table 4
N or *Ni*	Table 10

e. Step 5—Determine Base Density.

Using the observed density (*RHOobs*, *DENobs*, *APIobs*, or *RDobs*) and observed temperature (*Tobs*), calculate the base density (*RHOb*, *DENb*, *APIb*, *RDb*). This liquid density shall be determined by the appropriate technical standards, or, alternatively, by use of the proper density correlations, or, if necessary, by the use of the correct equations of state. Round the density value in accordance with specifications given in Table 1.

For some liquids (pure hydrocarbons, chemicals, solvents, etc.), the base density is a constant value as a result of stringent manufacturing specifications. This density value must be stated in accordance with the requirements specified in Table 1.

At some metering facilities, online density meters (densitometers) are installed to continuously monitor and determine density in real time. In these cases, users should refer to Appendix A for information and references on special calculation requirements.

12.1.1 Determination of the Meter Factor Using the Average Meter Factor Method

a. Step 6A—Calculate *GSVp*.

The gross standard volume (*GSVp*) of the prover—that is, the "true" volume of liquid passing through the prover during the proving run—is calculated by the following equation:

$$GSVp = BPV \times CCFp$$

The base prover volume (*BPV*) is obtained from the initial prover data in Step 1, 12.1.a.

To calculate the Combined Correction Factor (*CCFp*) requires that all four individual correction factor values, *CTSp* x *CPSp* x *CTLp* x *CPLp*, are calculated. They are then sequentially multiplied together, in the order specified, for each selected proving run, to obtain the combined correction factor (*CCFp*). Round result as shown in Table 8.

1. Determine *CTSp*:

The *CTSp* value corrects for the thermal expansion of the steel in the prover calibrated section, using the prover liquid temperature (*Tp*), and is calculated for each selected proving run.

For displacement provers with detectors mounted in the calibrated section, the following formula shall be used:

$$CTSp = 1 + [(Tp - Tb) \times Gc]$$

For displacement provers, usually small volume provers, that utilize detectors mounted on an external shaft, the modified formula shall be used:

$$CTSp = \{1 + [(Tp - Tb) \times Ga]\} \times \{1 + [(Td - Tb) \times Gl]\}$$

The *CTSp* value shall be rounded in accordance with Table 8 discrimination level requirements.

2. To Determine *CPSp*:

The *CPSp* value corrects for the expansion of the steel in the prover calibrated section, using the prover liquid pressure (*Pp*), and is calculated for each selected proving run.

The *CPSp* for a single wall pipe prover shall be calculated using the following formula:

$$CPSp = 1 + \frac{(Pp - Pbg) \times ID}{E \times WT},$$

where

$$ID = OD - (2 \times WT),$$

$$Pbg = 0 \text{ psig}.$$

For a double wall displacement prover, the value of $CPSp = 1.00000$.

The *CPSp* value shall be rounded in accordance with Table 8 discrimination level requirements.

3. Determine *CTLp*:

The *CTLp* value corrects for thermal expansion of the liquid in the prover calibrated section and is calculated for each selected proving run.

Using the base density (*RHOb*, *APIb*, *RDb*, and *DENb*) and the temperature of the liquid (*Tp*), together with the appropriate standards or computer routines, a value for *CTLp* can be obtained. Round the value according to the discrimination level requirements specified in Table 8.

4. Determine *CPLp*:

The *CPLp* value corrects for the compressibility of the liquid in the prover calibrated section for each of the selected proving runs.

Using a density value (*RHOb*, *APIb*, *RDb*, *DENb*), the prover pressure (*Pp*), and the prover temperature (*Tp*), calculate the value of *Fp* using the appropriate technical standards. Round this value according to the discrimination level requirements specified in Table 5.

Using the compressibility factor (*Fp*) together with the pressure in the prover calibrated section (*Pp*), the equilibrium vapor pressure of the liquid in the prover (*Pep*), and the base pressure (*Pba*), calculate the *CPLp* value using the following expression:

$$CPLp = \frac{1}{1 - [(Pp + Pba - Pep) \times Fp]}$$

Round this value according to the requirements specified in Table 8.

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then *Pep* is considered to be zero psig.

5. Determine $CCFp$:

The Combined Correction Factor of prover ($CCFp$) is calculated by serial multiplication of the above correction factors in the order specified, using the equation shown below. This value shall be rounded according to the requirements specified in Table 8:

$$CCFp = CTSp \times CPSp \times CTLp \times CPLp$$

Calculate $GSVp$ by use of the formula defined at beginning of Step 6A.

Make sure that the BPV, the nominal K-factor (NKF) or K-factor (KF), and the register head volume are all in the same units.

b. Step 7A—Calculate $ISVm$.

The indicated standard volume ($ISVm$) of meter is the volume of the liquid passing through the meter for the selected runs with *no correction* for meter inaccuracies, calculated by the following equation:

$$ISVm = IVm \times CCFm$$

1. Determine IVm:

Using a digital pulse train, calculate the indicated volume (IVm) of liquid passing through the meter by dividing the pulses (N) or the interpolated pulses (Ni), for each selected proving run, by the nominal K-factor (NKF), as shown below. Round and record the value of IVm in accordance with the discrimination levels specified in Table 9

$$IVm = \frac{N}{NKF} \quad \text{or} \quad IVm = \frac{Ni}{NKF}$$

2. Determine $CCFm$:

To calculate the combined correction factor ($CCFm$), two correction factor values, $CTLm$ and $CPLm$, are calculated and then sequentially multiplied in the order specified.

The correction factors $CTSm$ and $CPSm$ are not used in meter proving applications. Since the effects of temperature and pressure on steel within the much smaller meter cavity or volume is relatively insignificant, they can be ignored in most cases. The effects are reflected in the meter factor calculated at the time of proving.

3. Determine $CTLm$:

The $CTLm$ value corrects for the thermal expansion of the liquid in the meter. Using a base density ($RHOb$, $APIb$, RDb, $DENb$) and the temperature (Tm) of the liquid in the meter, together with the relevant standards or computer routines, a value for $CTLm$ is obtained for each of the selected proving runs. Round this value according to the discrimination level requirements specified in Table 8.

4. Determine $CPLm$:

The $CPLm$ value corrects for the compressibility of the liquid in the meter. Using the density value ($RHOb$, $APIb$, RDb, $DENb$), the meter pressure (Pm), and the meter temperature (Tm), for each of the selected proving runs, calculate the value of the compressibility factor (Fm) using the appropriate technical standards. Round this value according to the discrimination level requirements specified in Table 5.

Using the compressibility factor (Fm) together with the pressure in the meter (Pm), the equilibrium vapor pressure of the liquid in the meter (Pem), and the base pressure (Pba), for each of the selected proving runs, calculate the $CPLm$ value using the following expression.

$$CPLm = \frac{1}{1 - [(Pm + Pba - Pem) \times Fm]}$$

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then Pem is considered to be zero psig.

Having determined the two required correction factors, calculate the combined correction factor of the meter ($CCFm$) by serial multiplication of the correction factors using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFm = CTLm \times CPLm$$

The $ISVm$ is then calculated by the equation shown below:

$$ISVm = IVm \times CCFm$$

c. Step 8A—Calculate IMF.

Intermediate meter factors (IMF) are determined for each of the selected proving runs by the formula:

$$IMF = \frac{GSVp}{ISVm}$$

Record and round the values of the IMF according to the discrimination level requirements specified in Table 8.

d. Step 9A—Calculate Repeatability.

To judge the acceptability of the selected run data, the repeatability (range) using the average meter factor method must be calculated by the following method.

Intermediate meter factors are calculated for each selected pass or round trip of the prover. The range of these intermediate meter factors for all the acceptable proving runs is now calculated and used as the measure of acceptability for the meter proving. In this method, the complete calculation steps needed to determine an intermediate meter factor have to be performed for every selected pass or round trip, and then these intermediate meter factors must be compared to assess their acceptable repeatability.

An example of this repeatability check is shown in the table at the bottom of this page.

$$R\% = \frac{Max - Min}{Min} \times 100$$

$$\text{Range }\% = \frac{0.99343 - 0.99319}{0.99319} \times 100 = 0.024\%$$

e. Step 10A—Calculate Final *MF*.

Meter Factor (*MF*) is a value used to adjust for any small inaccuracies associated with the performance of the meter as determined at the time of proving. Having established that the range (repeatability) of the intermediate meter factors (*IMF*) meets the acceptability criteria, a final meter factor shall be calculated as follows:

$$MF = \frac{\sum IMF}{n},$$

where

n = the number of *IMF* from the selected proving runs.

Round the meter factor as specified in Table 8.

Unless the meter is equipped with an adjustment that alters its registration to account for the meter factor, a meter factor must be applied to correct the indicated volume of the meter.

f. Step 11A—Calculate Composite Meter Factor (*CMF*).

Composite meter factor (*CMF*) also is used to adjust meter performance. The composite meter factor must be used in applications where the density, temperature, and pressure are considered constant throughout the measurement ticket period, or as agreed by all the parties concerned as a convenience. The composite meter factor is determined at the time of proving by correcting the meter factor from normal operating pressure to base pressure (*CPL*), using the following expression:

$$CMF = MF \times CPLm$$

When calculating the *CMF*, use a *CPLm* value that is based on the normal meter operating pressure that occurs when the flow is not going through the prover. Record and round this value to the requirements specified in Table 8.

12.1.2 Determination of the Meter Factor Using the Average Data Method

a. Step 6B—Calculate Repeatability.

Having made the selected number of proving runs as described in Step 4, 12.1.d, record the results of the data for *Tm*, *Tp*, *Pm*, *Pp*, and *N* or *Ni*.

Use of the average data method requires that the range of the pulses generated for each selected pass or round trip be calculated and used to measure acceptable repeatability. To determine the repeatability, examine the pulses generated for each of the selected proving runs, as follows:

Run	Prover Temp.	Meter Temp.	Prover Pressure	Meter Pressure	Total Pulses
1	72.5	73	23	23	12,234
2	72	73	23	23	12,232
3	72	72.5	22	23	12,237
4	72	72.5	23	22	12,237
5	72.5	73	23	23	12,233
Avg.	72.2	72.8	22.8	22.8	12,233.6

$$R\% = \frac{\textit{Highest Pulse} - \textit{Lowest Pulse}}{\textit{Lowest Pulse}} \times 100$$

$$\text{Range }\% = \frac{12{,}237 - 12{,}232}{12{,}232} \times 100 = 0.041\%$$

Example of Repeatability Check (Average Meter Factor Method)

Run	Total Pulses	Prover Temperature	Meter Temperature	Prover Pressure	Meter Pressure	*GSVp*	*ISVm*	*IMF*
1	12,234	72.5	73	23	23	22.3356	22.4883	0.99321
2	12,232	72	73	23	23	22.3348	22.4855	0.99330
3	12,237	72	72.5	22	23	22.3363	22.4854	0.99337
4	12,237	72	72.5	23	22	22.3360	22.4892	0.99343
5	12,233	72.5	73	23	23	22.3340	22.4856	0.99319
							Average Meter Factor (*MF*)	0.9933

Once the range of pulses for the selected proving runs satisfies the repeatability requirement by not exceeding 0.050 percent, the following data should be calculated:

	Discrimination Levels
Prover Data	
Tp(avg)	Table 3
Pp(avg)	Table 4
Pep(avg)	Table 4
Meter Data	
Tm(avg)	Table 3
Pm(avg)	Table 4
Pem(avg)	Table 4
N(avg)	Table 10

b. Step 7B—Calculate *GSVp*.

The gross standard volume (*GSVp*) of the prover—that is, the "true" volume of liquid passing through the prover during the proving run, is calculated by the following equation, and rounded to the discrimination requirements shown in Table 9.

$$GSVp = BPV \times CCFp$$

The base prover volume (*BPV*) is obtained from the prover calibration certificate as shown in Step 1, 12.1.a.

To calculate the combined correction factor (*CCFp*) requires calculating all four correction factor values—*CTSp*, *CPSp*, *CTLp*, and *CPLp*. These values are then sequentially multiplied in the order specified, rounding at the end of the multiplication.

1. Determine *CTSp*:

The *CTSp* value corrects for the thermal expansion of the steel in the prover calibrated section, using the average prover liquid temperature [*Tp(avg)*] from all of the selected proving runs.

For displacement provers with detectors mounted internally in the calibrated section, the following formula shall be used:

$$CTSp = \{1 + [(Tp(avg) - Tb) \times Gc]\}$$

For displacement provers using detectors that are mounted externally on a shaft (e.g. small volume provers), then this modified formula shall be used:

$$CTSp = \{1 + [(Tp(avg) - Tb) \times Ga]\} \times \{1 + [(Td(avg) - Tb) \times Gl]\}$$

This *CTSp* value shall be rounded in accordance with the requirements in Table 8.

2. Determine *CPSp*:

The *CPSp* value corrects for the expansion of the steel in the prover calibrated section, using the average liquid pressure of the prover [*Pp(avg)*] from all of the selected proving runs.

The *CPSp* for a single wall pipe prover shall be calculated using the following formula:

$$CPSp = 1 + \frac{[Pp(avg) - Pbg] \times ID}{E \times WT},$$

where

$ID = OD - (2 \times WT)$,

$Pbg = 0$ psig.

For double wall displacement pipe provers, $CPSp = 1.00000$.

This *CPSp* value shall be rounded in accordance with the requirements in Table 8.

3. Determine *CTLp*:

The *CTLp* value corrects for the thermal expansion of the liquid in the prover calibrated section. By using an average base density (*RHOb*, *APIb*, *RDb*, and *DENb*) and the average temperature of the liquid [*Tp(avg)*] together with the relevant standards or computer routines, a value for *CTLp* can be obtained. Round this value according to the discrimination level requirements specified in Table 8.

4. Determine *CPLp*:

The *CPLp* corrects for the compressibility of the liquid in the prover calibrated section. Using an average density value (*RHOb*, *APIb*, *RDb*, *DENb*), the average prover pressure Pp(avg), and the average prover temperature [*Tp(avg)*], calculate the value of *Fp* using the appropriate technical standards. Round this value according to the requirements specified in Table 5.

Using the compressibility factor (*Fp*) determined in the preceding step, together with the average pressure in the prover calibrated section [*Pp(avg)*], the equilibrium vapor pressure of the liquid in the prover [*Pep(avg)*], and the base pressure (*Pba*), calculate the *CPLp* value using the following expression:

$$CPLp = \frac{1}{1 - \{[Pp(avg) + Pba - Pep(avg)] \times Fp\}}$$

Round this value according to the discrimination level requirements specified in Table 8.

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then *Pep(avg)* is considered to be zero psig.

5. Determine *CCFp*:

Having determined the four correction factors, the combined correction factor of prover (*CCFp*) can be calculated by serial multiplication of the correction factors in the exact order specified, using the equation shown below and rounding at the end of the multiplication. Round this value according to the discrimination level requirements specified in Table 8.

$$CCFp = CTSp \times CPSp \times CTLp \times CPLp$$

When the preceding calculations are done, calculate *GSVp* by the following formula:

$$GSVp = BPV \times CCFp$$

Ensure that *BPV*, nominal K-Factor (*NKF*), K-Factor (*KF*), and Register Head volume *are all in the same units*.

c. Step 8B—Calculate *ISVm*

The indicated standard volume (*ISVm*) of meter is the volume of the liquid passing through the meter for the selected proving runs with *no correction* for meter inaccuracies, and is calculated by the following equation:

$$ISVm = IVm \times CCFm$$

1. Determine *IVm*:

Using a digital pulse train allows the indicated volume (*IVm*) through the meter to be calculated by dividing the average of all the pulses [*N(avg)*] for all of the selected proving runs by the nominal K-factor (*NKF*), as shown below. Round and record the value of *IVm* in accordance with the discrimination levels specified in Table 9.

$$IVm = \frac{N(avg)}{NKF}$$

Calculating the combined correction factor (*CCFm*) requires the calculating of two individual correction factor values, *CTLm* and *CPLm*, which are then sequentially multiplied in the order specified.

The correction factors *CTSm* and *CPSm* are not used or calculated in metering applications, since the effects of temperature and pressure within the meter cavity are often insignificant and in most cases can be ignored. The effects are reflected in the meter factor calculated at the time of proving.

2. Determine *CTLm*:

The *CTLm* value corrects for the thermal expansion of the liquid in the meter. By using an average base density (*RHOb, APIb, RDb, DENb*), and the average temperature [*Tm(avg)*] of the liquid, together with the relevant standards or computer routines, a value for *CTLm* can be obtained. Round this value according to the discrimination level requirements specified in Table 8.

3. Determine *CPLm*:

The *CPLm* value corrects for the compressibility of the liquid in the meter. Using an average density value (*RHOb, APIb, RDb, DENb*), the average meter pressure [*Pm(avg)*], and average meter temperature [*Tm(avg)*], from all of the selected proving runs, calculate the value of the compressibility factor (*Fm*) using the appropriate technical standards. Round this value according to the requirements specified in Table 5.

Using the value of *Fm* determined in the preceding step, together with the average pressure in the meter [*Pm(avg)*], the equilibrium vapor pressure of the liquid in the meter [*Pem(avg)*], and the base pressure (*Pba*), calculate the *CPLm* value using the following expression:

$$CPLm = \frac{1}{1 - \{[Pm(avg) + Pba - Pem(avg)] \times Fm\}}$$

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then *Pem* is considered to be zero psig.

4. Determine *CCFm*:

When the two correction factors *CTLm* and *CPLm* have been determined, the combined correction factor of prover (*CCFm*) shall be calculated by serial multiplication of the correction factors in the exact order specified, rounding at the end of the multiplication, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFm = CTLm \times CPLm$$

The *ISVm* can then be calculated by the equation shown above.

d. Step 9B—Calculate Final *MF*

Meter factor (*MF*) is a dimensionless value used to adjust for any small inaccuracies associated with the performance of the meter as determined at the time of proving. Unless the meter is equipped with an adjustment that alters its registration to account for the meter factor, a meter factor must be applied to the indicated volume of the meter. The meter factor is determined at the time of proving by the formula:

$$MF = \frac{GSVp}{ISVm}$$

Record and round this value to the requirements specified in Table 8.

e. Step 10B—Calculate Composite Meter Factor (*CMF*).

The composite meter factor (*CMF*), as determined at the time of proving, is also a value used to adjust the meter performance. The composite meter factor is normally used in applications where the density, temperature, and pressure are considered constant throughout the measurement ticket period, or as agreed by all the parties concerned as a measurement convenience. The composite meter factor (*CMF*) is determined at the time of proving by correcting the meter factor from normal operating pressure to base pressure (*CPL*), using the following expression:

$$CMF = MF \times CPLm$$

When calculating the *CMF*, use a *CPLm* value that is based on the normal meter operating pressure that occurs when the liquid is not going through the prover.

Record and round this value to the requirements specified in Table 8.

12.2 ATMOSPHERIC TANK PROVERS

This section rigorously specifies the rounding, calculation sequence, and discrimination levels required for meter proving report calculations when atmospheric tank provers are used.

The procedures described below do not include the requirements for calculations associated with *RHOb*, *CTL*, or *F*. The rounding, calculation sequence, and discrimination levels for these terms are, for the most part, contained in the references listed in Appendix A. When a reference does not contain an implementation procedure, Appendix A contains a suggested method of solution.

In normal industry practice, the average meter factor method is used to calculate meter factors when proving meters with tank provers. Normal accepted proving technique requires the flow to be put through the meter being proved into the empty tank prover until it is filled. This constitutes a proving run.

a. Step 1—Enter Initial Prover Data.

Enter the following tank prover information, which is taken from the prover calibration certificate, and record it on the meter proving report form:

- Coefficient of cubical expansion (*Gc*).
- Manufacturer and serial number.
- Nominal capacity.

b. Step 2—Enter Initial Meter Data.

Enter the following information about the meter being proved on the meter proving report form:

- Nominal K-factor (*NKF*) or actual K-factor (*KF*).
- Whether the meter is temperature compensated.
- What the proving report should calculate (*MF*, *CMF*, *KF*, *CKF*, or *MA*).
- Company assigned meter number.
- Manufacturer, meter type, and size.
- Meter model number and serial number.
- Flow rate.
- Proving report number and date of proving.
- Nonresetable totalizer reading.

c. Step 3—Enter Fluid Data.

1. Enter the following information about the fluid being metered on the meter proving report form:
   - Type of fluid on which meter is being proved.
   - Batch number of the receipt or delivery.
   - Observed liquid density (*APIobs*, *DENobs*, *RDobs*, *RHOobs*).
   - Observed liquid temperature for density determination (*Tobs*).
   - The selected implementation procedure required (Tables 5A/6A, 5B/6B, 53A/54A, 53B/54B, etc.).
   - Viscosity (if needed).
2. *If the report form requires the calculation of CMF or CKF, the following additional information must be entered:*
   - The normal operating pressure of the liquid in gauge pressure units, which is assumed to be constant throughout the delivery. The temperature of the liquid in the meter while proving, is assumed to be the normal operating temperature, and assumed to be constant throughout the delivery.

d. Step 4—Record Run Data.

For each run of the tank prover, record the following data:

	Discrimination Levels
Prover Data	
Tp(avg)	Table 3
SRu	Table 9
SRl	Table 9
Meter Data	
Tm	Table 3
Pm	Table 4
MRo	Table 9
MRc	Table 9
N	Table 10

e. Step 5—Calculate Base Density.

Using the observed density (*RHOobs*, *DENobs*, *APIobs*, or *RDobs*) and observed temperature (*Tobs*), calculate the base density (*RHOb*, *DENb*, *APIb*, *RDb*). The base density of the liquid shall be determined by the appropriate technical standards, or, alternatively, by use of the proper density correlations, or, if necessary, by the use of the correct equations of state. Round the density value in accordance with specifications given in Table 1.

For some liquids (pure hydrocarbons, chemicals, solvents, etc.), the base density is a constant value as a result of stringent manufacturing specifications. This density value must be stated in accordance with the requirements specified in Table 1.

At some metering facilities, online density meters (densitometers) are installed to continuously monitor and determine density in real time. The user should refer to Appendix A for information on the special calculation requirements when using this equipment.

f. Step 6—Calculate *GSVp*.

The gross standard volume (*GSVp*) of the tank prover is the "true" volume of the liquid contained in the prover between the nominal "empty" and "full" levels. The *GSVp* is calculated from the following equation:

$$GSVp = BPVa \times CCFp,$$

where

$$BPVa = SRu - SRl.$$

The adjusted base prover volume (*BPVa*) for the tank prover is determined by the difference between the upper and lower scale readings during each proving run. To determine the lower (*SRl*) scale reading of the open tank prover, the tank prover should first be filled with liquid, then drained to empty for the prescribed draining time, refilled up to the lower scale and the lower scale reading taken prior to commencing the proving run. If the tank prover has no lower scale, the zero mark is established depending on the type of tank prover. The proving run is then initiated. When the tank prover is filled to the upper scale the flow is shut off, and the upper (*SRu*) scale reading is taken. The scale readings should be recorded as indicated in the discrimination levels in Table 9.

To calculate the combined correction factor for the open tank prover (*CCFp*) (as discussed in the previous section on pipe and small volume provers), it is necessary to determine the *CTSp*, *CPSp*, *CTLp*, and *CPLp* values.

1. Determine *CTSp*:

The *CTSp* corrects for thermal expansion of the steel in the tank prover, using the temperature of the liquid in the prover from the selected runs. The *CTSp* for an open tank prover may be calculated from the formula:

$$CTSp = 1 + [(Tp - Tb) \times Gc]$$

This value shall be rounded in accordance with the discrimination requirements of Table 8.

2. Determine *CPSp*:

The *CPSp* corrects for expansion of the steel in the tank prover due to pressure on the liquid.

Since an open tank prover is under atmospheric conditions, the *CPSp* value is set to equal unity.

$$CPSp = 1.00000$$

3. Determine *CTLp*:

The *CTLp* corrects for thermal expansion of the liquid in the tank prover. By using a base density (*RHOb*, *APIb*, *RDb*, or *DENb*), and the temperature (*Tp*) of the liquid, together with the appropriate standards or computer routines, a value for *CTLp* can be determined. Round this value according to the requirements specified in Table 8.

4. Determine *CPLp*:

The *CPLp* corrects for the effect of compressibility on the density of the liquid in the open tank prover. Since the open tank prover is under atmospheric conditions, the *CPLp* value is set equal to unity.

$$CPLp = 1.00000$$

5. Determine *CCFp*:

When the four correction factors have been determined, the combined correction factor for the tank prover (*CCFp*) can be calculated, by serial multiplication of the correction factors in the exact order specified, using the equations shown below. Round this value according to the requirements specified in Table 8.

$$CCFp = CTSp \times CPSp \times CTLp \times CPLp$$

$$CCFp = CTSp \times 1.00000 \times CTLp \times 1.00000$$

$$CCFp = CTSp \times CTLp$$

When these calculations are completed, calculate *GSVp* using formula at the beginning of Step 6, 12.2.f.

g. Step 7—Calculate *ISVm*.

The indicated standard volume (*ISVm*) of the meter is the volume of the liquid passing through the meter for selected runs *without correction* for meter inaccuracies. It is calculated by the following equation:

$$ISVm = IVm \times CCFm$$

1. Determine *IVm*:

The indicated volume (*IVm*) passing through the meter is determined in one of two ways:

If a digital pulse train is used, the *IVm* is calculated by dividing the pulses (*N*) from each run by the nominal K-factor (*NKF*), as shown below. Round and record the value of *IVm* in accordance with Table 9.

$$IVm = \frac{N}{NKF}$$

If a meter register head is used, the *IVm* is calculated using the opening and closing meter readings (*MRo, MRc*) for each run, as shown below. Round and record the value of *IVm* in accordance with Table 9.

$$IVm = MRc - MRo$$

To calculate the combined correction factor (*CCFm*) for the meter, the correction factor values *CTLm* and *CPLm* are calculated and then sequentially multiplied together, in the order specified. The correction factors *CTSm* and *CPSm* are not calculated, since the effects of temperature and pressure on the steel within the meter is insignificant and can be ignored in most cases. The effects are reflected in the meter factor calculated at the time of proving.

2. Determine *CTLm*:

The *CTLm* corrects for thermal expansion of the liquid in the meter. By using a base density (*RHOb, APIb, RDb,* or *DENb*). and the temperature (*Tm*) of the liquid in the meter, together with the appropriate standards or computer routines, a value for *CTLm* can be obtained. Round this value according to the requirements specified in Table 8.

3. Determine *CPLm*:

The *CPLm* corrects for the compressibility of the liquid in the meter. Using a density value (*RHOb, APIb, RDb,* or *DENb*), the meter pressure (*Pm*), and the meter temperature (*Tm*), calculate the value of the compressibility factor (*Fm*), using the appropriate technical standards. Record and round this value according to the requirements specified in Table 5.

Using the *Fm* determined in the preceding step, together with the pressure in the meter (*Pm*), the equilibrium vapor pressure of the liquid in the meter (*Pem*), and the base pressure (*Pba*), calculate the *CPLm* value using the following expression:

$$CPLm = \frac{1}{1 - [(Pm + Pba - Pem) \times Fm]}$$

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, *Pem* is considered to be zero psig.

4. To Determine *CCFm*.

When the two correction factors have been determined, the *CCFm* can be calculated by serial multiplication of the correction factors in the exact order specified, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFm = CTLm \times CPLm$$

The *ISVm* is then calculated by the equation:

$$ISVm = IVm \times CCFm$$

h. Step 8—Calculate *IMF*.

Intermediate Meter Factors (*IMF*) are determined at the time of proving for each of the selected proving runs by the formula:

$$IMF = \frac{GSVp}{ISVm}$$

Record and round the values of the *IMF* according to the discrimination level requirements specified in Table 8.

i. Step 9—Calculate Repeatability.

To judge the acceptability of each of the selected run data, the repeatability for the average meter factor method is calculated as follows:

Intermediate meter factors (*IMF*) have been calculated for each filling of the tank prover. The range of these intermediate meter factors for all the acceptable proving runs is now calculated and used as the measure of acceptability for the meter proving. In this method, the complete calculation steps to determine an intermediate meter factor have to be performed for every prover filling, and then these intermediate meter factors must be compared to assess acceptable repeatability.

An example of this repeatability check is shown in the table at the top of the following page:

$$R\% = \frac{maxIMF - minIMF}{minIMF} \times 100$$

$$\text{Range }\% = \frac{0.99343 - 0.99319}{0.99319} \times 100 = 0.024\%$$

j. Step 10—Calculate Final *MF*.

Meter factor (*MF*) is a value used to adjust for any small inaccuracies associated with the performance of the meter. Having established that the range (repeatability) of the intermediate meter factors (*IMF*) meets the acceptability criteria, a final meter factor shall be calculated as follows:

$$MF = \frac{\sum IMF}{n},$$

where

n = the number of intermediate meter factors from the selected proving runs.

Round the final meter factor as specified in Table 8.

Unless the meter is equipped with an adjustment that alters its registration to account for the meter factor, a meter factor must be applied to correct the indicated volume of the meter.

Example of Repeatability Check (Average Meter Factor Method)

Run	Total Pulses	Prover Temperature	Meter Temperature	Prover Pressure	Meter Pressure	*GSVp*	*ISVm*	*IMF*
1	12,234	72.5	73	23	23	22.3356	22.4883	0.99321
2	12,232	72	73	23	23	22.3348	22.4855	0.99330
3	12,237	72	72.5	22	23	22.3363	22.4854	0.99337
4	12,237	72	72.5	23	22	22.3360	22.4892	0.99343
5	12,233	72.5	73	23	23	22.3340	22.4856	0.99319
						Average Meter Factor (*MF*)		0.9933

k. Step 11—Composite Meter Factor (*CMF*).

Composite meter factor (*CMF*) also adjusts the meter performance as determined at the time of proving. The composite meter factor must be used in applications where the density, temperature, and pressure are considered constant throughout the measurement ticket period, or as agreed by all the parties concerned as a convenience. The composite meter factor is determined by correcting the meter factor from normal operating pressure to base pressure (*CPL*) by using the following expression:

$$CMF = MF \times CPL$$

When calculating the *CMF*, use a *CPL* value that is based on the normal meter operating pressure when the flow is not going through the prover. Record and round this value to the requirements specified in Table 8.

l. Step 12—Determine Meter Accuracy (*MA*).

For many field applications, a mechanical or electronic calibrator is often used to adjust the meter factor to unity to correct meter readings associated with truck loading racks and LACT/ACT meter skids. To ascertain that the proving report and the required calibrator adjustments have been made without error, determine the meter accuracy for each proving run, using the following equation:

$$MA = \frac{1}{MF}$$

12.3 MASTER METER PROVING

The following section rigorously specifies the rounding, calculation sequence, and discrimination levels required for meter proving report calculations, using a master meter. In the case of proving with master meters, two separate actions are necessary. First, the master meter must be proved using a master prover. Second, this master meter is then used to determine the meter factor for the operational (field) meter by acting as the prover.

Three different calculation procedures are possible, depending on whether the master prover is a displacement prover or a tank prover. These three procedures are described below, following Steps 1–5, 12.3.1.a—d, which are common to all the calculation methods.

12.3.1 Proving a Master Meter with a Master Prover

As indicated above, it is first necessary to prove the master meter against a master prover. A master prover is defined as a prover (a displacement or tank prover is normally used) that has been calibrated by the water-draw method.

The procedures outlined below do not include the requirements for the calculations associated with *RHOb*, *CTL*, or *F*. The rounding, calculation sequence, and discrimination levels for these terms are, for the most part, contained in the references listed in Appendix A. When a reference does not contain an implementation procedure, Appendix A contains a suggested implementation method.

a. Step 1—Enter Initial Prover Data.

Enter all the prover information taken from the prover calibration certificate. The required information is the same as that described in 12.1.a, Step 1, for displacement provers, and 12.2.a, Step 1, for tank provers.

b. Step 2—Enter Initial Meter Data.

Enter all the required information on the meter being proved and record on the meter proving report form. The required information is the same as that described in 12.1.b, Step 2.

c. Step 3—Enter Fluid Data.

Enter all the information on the hydrocarbon liquid being metered. This required information is the same as described in 12.1.c, Step 3.

d. Step 4—Record Run Data.

For every proving run, record the following data:

	Discrimination Levels
Master Prover Data	
Td (for small volume provers)	Table 3
Tmp (for displacement and tank provers)	Table 3
Pmp (for displacement provers)	Table 4
BPVmp (for displacement provers)	Table 9
BPVamp (for tank provers)	Table 9
SRu (for tank provers)	Table 9
SRl (for tank provers)	Table 9
Master Meter Data	
Tmm	Table 3
Pmm	Table 4
MMRc	Table 9
MMRo	Table 9
Ni	Table 10
N	Table 10

e. Step 5—Determine Base Density.

Using the observed density (*RHOobs, DENobs, APIobs* or *RDobs*) and observed temperature (*Tobs*), calculate the base density (*RHOb, DENb, APIb, RDb*) by either the appropriate technical standards, the proper density correlations, or the relevant equations of state. Round the density value in accordance with specifications given in Table 1.

At some metering facilities, an online density meter (densitometer) is installed to continuously monitor and determine density in real time. In these cases, users should refer to Appendix A for information on calculation requirements.

12.3.1.1 To Determine a Master Meter Factor Using a Displacement Prover as the Master Prover and Using the Average Meter Factor Method of Calculation

a. Step 6A—Calculate *GSVmp*.

The gross standard volume (*GSVmp*) of the master prover—that is, the "true" volume of liquid passing through the prover during the proving run—is calculated by the following equation:

$$GSVmp = BPVmp \times CCFmp$$

The base prover volume (*BPVmp*) is obtained from the prover calibration certificate.

Calculating the combined correction factor (*CCFmp*) requires the calculation and serial multiplication, in the order given, of the four correction factors, *CTSmp, CPSmp, CTLmp*, and *CPLmp*. for each selected proving run.

1. Determine *CTSmp*:

For displacement master provers with detectors mounted in the calibrated section, the following formula shall be used:

$$CTSmp = 1 + [(Tmp - Tb) \times Gmp]$$

For displacement master provers (usually small volume provers) with detectors mounted on an external shaft, a modified formula shall be used:

$$CTSmp = \{1 + [(Tmp - Tb) \times Ga]\} \times \{1 + [(Td - Tb) \times Gl]\}$$

The *CTSmp* value shall be rounded in accordance with the discrimination level requirements specified in Table 8.

2. Determine *CPSmp*:

The *CPSmp* for a single wall pipe master prover shall be calculated using the following formula:

$$CPSmp = 1 + \frac{(Pmp - Pbg) \times ID}{E \times WT},$$

where

$ID = OD - (2 \times WT)$,

$Pbg = 0$ psig.

The *CPSmp* value shall be rounded in accordance with the discrimination level requirements specified in Table 8.

For a double wall displacement master prover,

$$CPSmp = 1.00000.$$

3. Determine *CTLmp*:

The *CTLmp* corrects for the thermal expansion of the liquid in the master prover. Using the base density (*RHOb, APIb, RDb*, and *DENb*) and the temperature of the liquid (*Tmp*) in the master prover, together with the appropriate standards or computer routines, a value for *CTLmp* can be obtained for each of the selected proving runs. Round the value according to the discrimination level requirements specified in Table 8.

4. Determine *CPLmp*:

Using a density value (*RHOb, APIb, RDb, DENb*), the master prover pressure (*Pmp*), and the master prover temperature (*Tmp*), calculate the compressibility value of *Fmp* using the appropriate technical standards for each of the selected proving runs. Round this value according to the discrimination level requirements specified in Table 5.

Using *Fmp*, together with the pressure in the master prover calibrated section (*Pmp*), the equilibrium vapor pressure of the liquid in the master prover (*Pemp*), and the base pressure (*Pba*), calculate the *CPLmp* value using the following expression.

$$CPLmp = \frac{1}{1 - [(Pmp + Pba - Pemp) \times Fmp]}$$

Round this value according to the requirements specified in Table 8.

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then *Pemp* is considered to be zero psig.

5. Determine *CCFmp*:

The combined correction factor of the master prover (*CCFmp*) is calculated by serial multiplication of the correction factors in the order specified, using the equation shown below. This value shall be rounded according to the requirements specified in Table 8:

$$CCFmp = CTSmp \times CPSmp \times CTLmp \times CPLmp$$

As stated above, *GSVmp* is now calculated for each of the selected master proving runs by the following equation, and rounded according to the requirements contained in Table 9:

$$GSVmp = BPVmp \times CCFmp$$

b. Step 7A—Calculate *ISVmm*.

The indicated standard volume (*ISVmm*) of the master meter is the volume of the liquid passing through the meter for the selected runs *with no correction for meter inaccuracies*, calculated by the following equation:

$$ISVmm = IVmm \times CCFmm$$

1. Determine *IVmm*:

Using a digital pulse train, calculate the indicated volume (*IVmm*) of liquid passing through the master meter by dividing the pulses (*N*) or the interpolated pulses (*Ni*) for each selected proving run by the nominal K-factor (*NKF*), as shown below. Round and record the value of *IVmm* in accordance with the discrimination levels specified in Table 9.

$$IVmm = \frac{N}{NKF} \quad \text{or} \quad IVmm = \frac{Ni}{NKF}$$

To calculate the combined correction factor (*CCFmm*), two correction factor values, *CTLmm* and *CPLmm*, are calculated and then sequentially multiplied in the order specified. *See note under 12.1.1.b, Step 7A, regarding other correction factors.*

2. Determine *CTLmm*:

By using a base density (*RHOb, APIb, RDb, DENb*) and the temperature (*Tmm*) of the liquid in the master meter, together with the relevant standards or computer routines, a value for *CTLmm* can be obtained for each of the selected proving runs. Round this value according to the discrimination level requirements specified in Table 8.

3. Determine *CPLmm*:

Using a density value (*RHOb, APIb, RDb, DENb*), the master meter pressure (*Pmm*), and the master meter temperature (*Tmm*) for each of the selected proving runs, calculate the value of *Fmm* using the appropriate technical standards. Round this value according to the discrimination level requirements specified in Table 5.

Using the compressibility factor (*Fmm*), together with the pressure in the master meter (*Pmm*), the equilibrium vapor pressure of the liquid in the master meter (*Pemm*), and the base pressure (*Pba*) for each of the selected proving runs, calculate the *CPLmm* value using the following expression:

$$CPLmm = \frac{1}{1 - [(Pmm + Pba - Pemm) \times Fmm]}$$

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then *Pemm* is considered to be zero psig.

4. Determine *CCFmm*:

Having determined the above two correction factors, calculate the combined correction factor of prover by serial multiplication of the correction factors, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFmm = CTLmm \times CPLmm$$

The ISVmm is then calculated by the equation shown below:

$$ISVmm = IVmm \times CCFmm$$

c. Step 8A—Calculate *IMMF*.

Intermediate master meter factors (*IMMF*) are determined for each of the selected proving runs by the formula:

$$IMMF = \frac{GSVmp}{ISVmm}$$

Record and round the values of the *IMMF* according to the discrimination level requirements specified in Table 8.

d. Step 9A—Calculate Repeatability.

To judge the acceptability of each of *IMMF* from the selected run data, the repeatability for the average meter factor method is calculated as follows;

Intermediate master meter factors (*IMMF*) are calculated for each selected pass or round trip of the prover. The range of these intermediate meter factors for all the acceptable proving runs is now calculated and used as the measure of acceptability for the master meter proving. In this method, the complete calculation steps needed to determine an intermediate master meter factor have to be performed for every selected pass or round trip, and then all these intermediate master meter factors must be compared to assess acceptable repeatability.

For a master meter proving using a displacement master prover, the range (*%R*) of the selected intermediate meter factors (*IMMF*) *shall not exceed 0.020%*. This range is calculated using the following formula:

$$R\% = \frac{maxIMMF - minIMMF}{minIMMF} \times 100$$

e. Step 10A—Calculate Final *MMF*.

After it has been established that the range (repeatability) of the intermediate master meter factors (*IMMF*) meets the acceptability criteria, a final master meter factor shall be calculated as follows:

$$MMF = \frac{\sum IMMF}{n},$$

where

n = the number of *IMMF* from the selected proving runs.

Record and round this value to the discrimination level requirements as specified in Table 8.

12.3.1.2 To Determine a Master Meter Factor Using a Displacement Prover as the Master Prover and Using the Average Data Method of Calculation

a. Step 6B—Calculate Repeatability.

Having made the selected number of proving runs as described in Step 4, 12.3.1.d, record the results of the data for *Tmm, Tmp, Pmm, Pmp,* and *N* or *Ni*

Use of the average data method requires that the range of the pulses generated for each selected pass or round trip be calculated and used to measure acceptable repeatability. Acceptable repeatability (*%R*) for a master meter proving with a master prover *shall not exceed a range of 0.020%*. To determine the range, examine the pulses generated for each of the selected proving runs, and use the following formula to calculate the repeatability:

$$R\% = \frac{Highest\ Pulse - Lowest\ Pulse}{Lowest\ Pulse} \times 100$$

Once it is established that the selected proving runs satisfy the repeatability requirement by not exceeding 0.020 percent, the following data should be calculated:

	Discrimination Levels
Prover Data	
(for *SVP* only) *Td(avg)*	Table 3
Tmp(avg)	Table 3
Pmp(avg)	Table 4
Pemp(avg)	Table 4
Meter Data	
Tmm(avg)	Table 3
Pmm(avg)	Table 4
Pemm(avg)	Table 4
N(avg)	Table 10

b. Step 7B—Calculate *GSVmp*.

The gross standard volume (*GSVmp*) of the master prover—that is, the "true" volume of liquid passing through the prover during the proving run, is calculated by the following equation:

$$GSVmp = BPVmp \times CCFmp$$

The base prover volume (*BPVmp*) is obtained from the master prover calibration certificate.

To calculate the combined correction factor (*CCFmp*) requires calculating all four correction factor values—*CTSmp, CPSmp, CTLmp,* and *CPLmp*. These values are then sequentially multiplied in the order specified, rounding at the end of the multiplication.

1. Determine *CTSmp*:

The *CTSmp* value corrects for the thermal expansion of the steel in the prover calibrated section, using the average prover liquid temperature [*Tmp(avg)*] from all of the selected proving runs.

For displacement master provers with detectors mounted internally in the calibrated section, the following formula shall be used:

$$CTSmp = 1 + [(Tmp(avg) - Tb) \times Gmp]$$

For displacement master provers using detectors that are mounted externally on a shaft (e.g., small volume provers), this modified formula shall be used:

$$CTSmp = \{1 + [(Tmp(avg) - Tb) \times Ga]\} \times \{1+[(Td(avg) - Tb) \times Gl]\}$$

This *CTSmp* value shall be rounded in accordance with the requirements of Table 8.

2. Determine *CPSmp*:

The *CPSmp* value corrects for the expansion of the steel in the prover calibrated section, using the average liquid pressure of the master prover [*Pmp(avg)*] from all of the selected proving runs.

The *CPSmp* for a single wall displacement master prover shall be calculated using the following formula:

$$CPSmp = 1 + \frac{[Pmp(avg) - Pbg] \times ID}{E \times WT},$$

where

$ID = OD - (2 \times WT)$,

$Pbg = 0$ psig.

This *CPSmp* value shall be rounded in accordance with the requirements of Table 8.

For a double wall displacement master prover,

$$CPSmp = 1.00000.$$

3. Determine *CTLmp*:

By using an average base density (*RHOb, APIb, RDb,* and *DENb*), and the average temperature of the liquid [*Tmp(avg)*] in the master prover, together with the relevant standards or computer routines, a value for *CTLmp* can be obtained. Round this value according to the discrimination level requirements specified in Table 8.

4. Determine *CPLmp*:

Using an average density value (*RHOb, APIb, RDb, DENb*), the average master prover pressure [*Pmp(avg)*] and the average master prover temperature [*Tmp(avg)*], calculate the value of *Fmp* using the appropriate technical standards. Round this value according to the requirements specified in Table 5.

Using the compressibility factor (*Fmp*) determined in the preceding step, together with the average pressure in the prover calibrated section [*Pmp(avg)*], the equilibrium vapor pressure of the liquid in the prover [*Pemp(avg)*], and the base pressure (*Pba*), calculate the *CPLmp* value using the following expression:

$$CPLmp = \frac{1}{1 - [(Pmp(avg) + Pba - Pemp(avg)) \times Fmp]}$$

Round this value according to the discrimination level requirements specified in Table 8.

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then *Pemp(avg)* is considered to be zero psig.

5. Determine *CCFmp*:

Having determined the four correction factors, the combined correction factor of the master prover (*CCFmp*) can be calculated by serial multiplication of the correction factors in the exact order specified, using the equation shown below and rounding at the end of the multiplication. Round this value according to the discrimination level requirements specified in Table 8.

$$CCFmp = CTSmp \times CPSmp \times CTLmp \times CPLmp$$

Following this calculation, calculate *GSVmp* using the formula:

$$GSVmp = BPVmp \times CCFmp$$

c. Step 8B—Calculate *ISVmm*.

The indicated standard volume (*ISVmm*) of the master meter is the volume of the liquid passing through the meter for the selected proving runs, *with no correction for meter inaccuracies*, and is calculated by the following equation:

$$ISVmm = IVmm \times CCFmm$$

1. Determine *IVmm*:

Using a digital pulse train allows the indicated volume (*IVmm*) through the master meter to be calculated by dividing the average of all the pulses [*N(avg)*] for all of the selected proving runs, by the nominal K-factor (*NKF*), as shown below. Round and record the value of *IVmm* in accordance with the discrimination levels specified in Table 9.

$$IVmm = \frac{N(avg)}{NKF}$$

Calculating the combined correction factor (*CCFmm*) for the master meter requires the calculating of two correction factor values, *CTLmm* and *CPLmm*, which are then sequentially multiplied in the order specified.

2. Determine *CTLmm*:

By using an average base density (*RHOb, APIb, RDb, DENb*), and the average temperature [*Tmm(avg)*] of the liquid in the master meter, together with the relevant standards or computer routines, a value for *CTLmm* can be obtained. Round this value according to the discrimination level requirements specified in Table 8.

3. Determine *CPLmm*:

Using an average density value (*RHOb, APIb, RDb, DENb*), the average master meter pressure [*Pmm(avg)*], and average master meter temperature [*Tmm(avg)*], from all of the selected proving runs, calculate the value of *Fmm* using the appropriate technical standards. Round this value according to the requirements specified in Table 5.

Using the value of *Fmm* determined in the preceding step, together with the average pressure in the master meter [*Pmm(avg)*], the equilibrium vapor pressure of the liquid in the master meter [*Pem(avg)*], and the base pressure (*Pba*), calculate the *CPLmm* value using the following expression:

$$CPLmm = \frac{1}{1-[(Pmm(avg)+Pba-Pemm(avg))\times Fmm]}$$

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, then *Pemm(avg)* is considered to be zero psig.

4. Determine *CCFmm*:

When the two correction factors have been determined, the combined correction factor of the master meter (*CCFmm*) is calculated by serial multiplication of the correction factors in the exact order specified and rounding at the end of the multiplication, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFmm = CTLmm \times CPLmm$$

After these calculations, calculate *ISVmm* using the formula at beginning of Step 8B.

d. Step 9B—Final *MMF*.

The master meter factor (*MMF*) is determined by the formula:

$$MMF = \frac{GSVmp}{ISVmm}$$

Round this value to the requirements specified in Table 8.

12.3.1.3 To Determine a Master Meter Factor with an Open Tank Prover as the Master Prover and Using the Average Meter Factor Method of Calculation

Normal industry practice uses the average meter factor method to calculate master meter factors when proving a master meter with a tank prover as the master prover. Normal proving technique allows flow through the master meter into the empty master tank prover until filled. This constitutes a proving run.

Complete Steps 1 through 5 as shown in 12.3.1.a—d.

a. Step 6C—Calculate *GSVmp*.

The gross standard volume (*GSVmp*) of the tank prover is the "true" volume of the liquid contained in the prover between the nominal "empty" and "full" levels. The *GSVmp* is calculated from the following equation:

$$GSVmp = BPVamp \times CCFmp$$

where

$$BPVamp = SRu - SRl$$

The adjusted base prover volume (*BPVamp*) for the master tank prover is determined by the difference between the upper and lower scale readings during each proving run. To determine the lower (*SRl*) scale reading, the open master tank prover should first be filled with liquid, then drained to empty for the prescribed draining time, then refilled up to the lower scale. The lower scale reading is taken prior to the proving run. If the tank prover has no lower scale, then the zero mark is established depending on the bottom arrangement of the tank prover. The proving run is then initiated. The master tank prover is filled to the upper scale, the flow is shut off, and the upper (*SRu*) scale reading is taken. The scale readings should be recorded as indicated in the discrimination levels in Table 9.

To calculate the combined correction factor for the master tank prover (*CCFmp*), it is necessary to obtain the *CTSmp*, *CPSmp*, *CTLmp*, and *CPLmp* values, as discussed in the previous section on displacement provers.

1. Determine *CTSmp*:

The *CTSmp* for a master tank prover may be calculated from the formula:

$$CTSmp = 1 + [(Tmp - Tb) \times Gmp]$$

This *CTSmp* value shall be rounded in accordance with the discrimination requirements specified in Table 8.

2. Determine *CPSmp*:

Since an open tank prover is under atmospheric conditions, the *CPSmp* value is set to unity.

$$CPSmp = 1.00000$$

3. Determine *CTLmp*:

By using a base density (*RHOb, APIb, RDb*, and *DENb*) and the temperature (*Tmp*) of the liquid in the master tank prover, together with the appropriate standards or computer routines, a value for *CTLmp* can be determined. Round this value according to the requirements specified in Table 8.

4. Determine *CPLmp*:

Since the open tank prover is under atmospheric conditions, the *CPLmp* value is set to unity.

$$CPLmp = 1.00000$$

5. Determine *CCFmp*:

When the four required correction factors have been determined, the combined correction factor of tank prover (*CCFmp*) can be calculated by serial multiplication of the correction factors in the exact order specified, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFmp = CTSmp \times CPSmp \times CTLmp \times CPLmp$$

$$CCFmp = CTSmp \times 1.00000 \times CTLmp \times 1.00000$$

$$CCFmp = CTSmp \times CTLmp$$

When these calculations are done, calculate *GSVmp* using the formula:

$$GSVmp = (SRu - SRl) \times CCFmp$$

b. Step 7C—Calculate *ISVmm*.

The indicated standard volume (*ISVmm*) of the master meter is the volume of the liquid passing through the meter for selected runs, *without correction* for meter inaccuracies. It is calculated by the following equation:

$$ISVmm = IVmm \times CCFmm$$

1. Determine *IVmm*:

If a digital pulse train is used, then the indicated volume passed through the master meter is calculated by dividing the pulses (*N*) from each run by the nominal K-factor (*NKF*), as shown below. Round and record the value of *IVmm* in accordance with the discrimination levels specified in Table 9.

$$IVmm = \frac{N}{NKF}$$

If a master meter register head is used, the *IVmm* is calculated using the opening and closing master meter readings (*MMRo*, *MMRc*) for each run, as shown below. Round and record the value of *IVmm* in accordance with the discrimination levels specified in Table 9.

$$IVmm = MMRc - MMRo$$

To calculate the combined correction factor (*CCFmm*) for the master meter requires calculation of the correction factor values *CTLmm* and *CPLmm*, which are sequentially multiplied together in the order specified.

2. Determine *CTLmm*:

By using a base density (*RHOb*, *APIb*, *RDb*, and *DENb*) and the temperature (*Tmm*) of the liquid in the master meter, together with the appropriate standards or computer routines, a value for *CTLmm* can be obtained. Round this value according to the requirements specified in Table 8.

3. Determine *CPLmm*:

Using a density value (*RHOb*, *APIb*, *RDb*, *DENb*), the master meter pressure (*Pmm*), and the master meter temperature (*Tmm*), calculate the value of *Fmm* using the appropriate technical standards. Record and round this value according to the requirements specified in Table 5.

Using the *Fmm* determined in the preceding step, together with the pressure in the master meter (*Pmm*), the equilibrium vapor pressure of the liquid in the master meter (*Pemm*), and the base pressure (*Pba*), calculate the *CPLmm* value using the following expression:

$$CPLmm = \frac{1}{1 - [(Pmm + Pba - Pemm) \times Fmm]}$$

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, *Pemm* is considered to be zero psig.

4. Determine *CCFmm*:

When the two correction factors have been determined, the combined correction factor for the master meter (*CCFmm*) can be calculated by serial multiplication of the correction factors in the exact order specified, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFmm = CTLmm \times CPLmm$$

The *ISVmm* is then calculated by the equation:

$$ISVmm = IVmm \times CCFmm$$

c. Step 8C—Calculate *IMMF*.

Intermediate master meter factors (*IMMF*) are determined for each of the selected proving runs by the formula:

$$IMMF = \frac{GSVmp}{ISVmm}$$

Record and round the values of *IMMF* according to the discrimination level requirements specified in Table 8.

d. Step 9C—Calculate Repeatability.

To judge the acceptability of each of the selected run data, the repeatability for the average meter factor method is calculated as follows:

Intermediate master meter factors (*IMMF*) have been calculated for each filling of the master tank prover. The range of these intermediate master meter factors for all the acceptable master proving runs is now calculated and used as the measure of acceptability for the master meter proving. In this method, the complete calculation steps to determine an intermediate meter factor have to be performed for every master prover filling and then these intermediate master meter factors must be compared to assess acceptable repeatability. Acceptable repeatability (*%R*) is defined as all the intermediate master meter factors within a range of 0.020%.

This repeatability check is made using the following formula:

$$R\% = \frac{maxIMMF - minIMMF}{minIMMF} \times 100$$

e. Step 10C—Final *MF*.

The master meter factor (*MMF*) is a value used to adjust for any small inaccuracies associated with the performance of the master meter. Having established that the range (repeatability) of the intermediate master meter factors (*IMMF*) meets the acceptability criteria, a final master meter factor shall be calculated as follows:

$$MMF = \frac{\sum IMMF}{n},$$

where

n = the total number of acceptable *IMMF* from the selected proving runs.

Round the master meter factor as specified in Table 8.

12.3.2 Proving an Operational Meter Using a Master Meter

After the master meter has been proved against a master prover, this master meter can then be used to prove operational meters that are in custody transfer service. Since differences will almost certainly occur between the proving conditions of the master meter using a master prover and the proving conditions of the master meter with an operational meter, an increased degree of uncertainty in the final meter factor may result.

The calculation procedures for proving operational meters with a master meter do not include the calculations associated with *RHOb*, *CTL*, or *F*. The rounding, calculation sequence, and discrimination levels for these terms are, for the most part, contained in the references listed in Appendix A. When a reference does not contain an implementation procedure, Appendix A contains a suggested implementation method. The calculation procedure to be used when proving a field meter with a master meter is the average meter factor method.

a. Step 1—Enter Initial Master Meter Data (Prover).

Enter the initial master meter information on the meter calibration certificate on the meter proving report form. See 12.1.a, Step 1.

b. Step 2—Enter Initial Field Meter Data.

Enter the required information on the operational meter being proved on the meter proving report form. See 12.1.b, Step 2.

c. Step 3—Enter Fluid Data

Enter all the required information on the hydrocarbon liquid being metered. See 12.1.c, Step 3.

d. Step 4—Record Run Data.

For each proving run, record the following data:

	Discrimination Levels
Master Meter Data	
Tmm	Table 3
Pmm	Table 4
MMF	Table 8
Meter Data	
Tm	Table 3
Pm	Table 4
N	Table 10

e. Step 5—Calculate Base Density.

Using the observed density (*RHOobs*, *DENobs*, *APIobs*, or *RDobs*) and observed temperature (*Tobs*), calculate the base density (*RHOb*, *DENb*, *APIb*, *RDb*) by either the appropriate technical standards, the proper density correlations, or the relevant equations of state. Round the density value in accordance with specifications given in Table 1.

f. Step 6—Calculate *GSVmm*.

The gross standard volume (*GSVmm*) for liquid passing through the master meter— that is, the "true" volume of liquid passing through the master meter during the proving run—is calculated by the following equation:

$$GSVmm = IVmm \times CCFmm$$

To calculate the combined correction factor (*CCFmm*), the correction factor values *CTLmm* and *CPLmm* are calculated and then sequentially multiplied together in the order specified.

The master meter factor (*MMF*) was calculated by the procedures shown previously.

1. Determine *IVmm*:

If a digital pulse train is used, the *IVmm* is calculated by dividing the pulses (*N*) from each run by the nominal K-factor (*NKF*) as shown below. Round and record the value of *IVmm* in accordance with the discrimination levels specified in Table 9.

$$IVmm = \frac{N}{NKF}$$

If a meter register head is used, the *IVmm* is calculated by using the opening and closing meter readings (*MMRo*, *MMRc*) for each run. Round and record the value of *IVmm* in accordance with Table 9.

$$IVmm = MMRc - MMRo$$

2. Determine *CTLmm*:

By using a base density (*RHOb, APIb, RDb, DENb*), and the temperature (*Tmm*) of the liquid in the master meter, together with the appropriate standards or computer routines, a value for *CTLmm* can be obtained. Round this value according to the requirements specified in Table 8.

3. Determine *CPLmm*:

Using a density value (*RHOb, APIb, RDb, DENb*), the master meter pressure (*Pmm*), and the master meter temperature (*Tmm*), calculate the value of *Fmm* using the appropriate technical standards. Round this value according to the requirements specified in Table 5.

Using the *Fmm* determined in the preceding step, together with the liquid pressure in the master meter (*Pmm*), the equilibrium vapor pressure of the liquid in the master meter (*Pemm*), and the base pressure (*Pba*), calculate the *CPLmm* value using the following expression:

$$CPLmm = \frac{1}{1-[(Pmm + Pba - Pemm) \times Fmm]}$$

Round this value according to the requirements specified in Table 8.

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, *Pemm* is considered to be zero psig.

4. Determine *CCFmm*:

When the two correction factors have been determined, the *CCFmm* can be calculated by serial multiplication of the correction factors and the master meter factor in the order specified, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFmm = CTLmm \times CPLmm \times MMF$$

5. Determine *GSVmm*:

The gross standard volume of the master meter (*GSVmm*) is the "true" volume of the liquid passing through the master meter during the proving pass. The *GSVmm* is calculated by the following equation and rounded to the discrimination requirements contained in Table 9:

$$GSVmm = IVmm \times CCFmm$$

g. Step 7—Calculate *ISVm*.

The indicated standard volume (*ISVm*) of the liquid passing through the operational meter that is being proved by the master meter, is calculated by the following equation:

$$ISVm = IVm \times CCFm$$

The indicated volume of the operational meter (*IVm*) is calculated in one of two ways:

If a digital pulse train is used, the *IVm* through the operational meter is calculated by dividing the pulses (*N*) from each run by the nominal K-factor (*NKF*), as shown below. Round and record the value of *IVm* in accordance with the discrimination levels specified in Table 9.

$$IVm = \frac{N}{NKF}$$

If a meter register head is used, the *IVm* is calculated using the opening and closing meter readings (*MRo, MRc*) for each run as shown below. Round and record the value of *IVm* in accordance with Table 9.

$$IVm = MRc - MRo$$

To calculate the combined correction factor (*CCFm*), the correction factor values *CTLm* and *CPLm* are calculated and then sequentially multiplied together, in the order specified.

1. Determine *CTLm*:

By using a base density (*RHOb, APIb, RDb, DENb*) and the temperature (*Tm*) of the liquid in the operational meter, together with the appropriate standards or computer routines, a value for *CTLm* can be obtained. Round this value according to the requirements specified in Table 8.

2. To Determine *CPLm*:

Using a density value (*RHOb, APIb, RDb, DENb*), the pressure in the operational meter (*Pm*) and the temperature of the liquid in the operational meter (*Tm*), calculate the value of *Fm* using the appropriate technical standards. Round this value according to the requirements specified in Table 5.

Using the factor (*Fm*) determined in the preceding step, together with the liquid pressure in the operational meter (*Pm*), the equilibrium vapor pressure of the liquid in the operational meter (*Pem*), and the base pressure (*Pba*), calculate the *CPLm* value using the following expression:

$$CPLm = \frac{1}{1-[(Pm + Pba - Pem) \times Fm]}$$

Round this value according to the requirements specified in Table 8.

Note: If the vapor pressure of the liquid is less than atmospheric pressure at normal temperature, *Pem* is considered to be zero psig.

3. Determine *CCFm*:

When the two correction factors have been determined, the combined correction factor of the operational meter (*CCFm*) can be calculated by serial multiplication of the correction factors in the order specified, using the equation shown below. Round this value according to the requirements specified in Table 8.

$$CCFm = CTLm \times CPLm$$

4. Determine $ISVm$:

The indicated standard volume ($ISVm$) of the operational meter is the volume of the liquid passing through the meter during the equivalent proving pass and is calculated by the following equation:

$$ISVm = IVm \times CCFm$$

Round this value according to the requirements specified in Table 8.

h. Step 8—Calculate *IMF*.

Intermediate meter factors are determined for every selected proving run by the formula:

$$IMF = \frac{GSVmm}{ISVm}$$

Record and round this value to the requirements specified in Table 8.

i. Step 9—Calculate Repeatability.

To judge the acceptability of each of the selected runs, the repeatability for the average meter factor method is calculated as follows;

Intermediate meter factors (*IMF*) shall be calculated for each proving run. The range of these intermediate master meter factors, for all the acceptable proving runs is now calculated, and used as the measure of acceptability for the meter proving. In this method, the complete calculation steps to determine an intermediate meter factor have to be performed for every selected prover run and then comparing all these intermediate meter factors for acceptable repeatability. Acceptable repeatability ($\%R$) is defined as all the intermediate meter factors within a range of 0.050%.

This repeatability check is made using the following formula:

$$R\% = \frac{maxIMF - minIMF}{minIMF} \times 100$$

j. Step 10—Calculate Final *MF*.

Having established that the range (repeatability) of the intermediate meter factors (*IMF*) meets the acceptability criteria, then a final meter factor shall be calculated as follows:

$$MF = \frac{\sum IMF}{n}$$

where

n = the number of acceptable *IMF* from the selected proving runs.

Record and round this value to the discrimination level requirements as specified in Table 8.

k. Step 11—Composite Meter Factor (*CMF*).

The composite meter factor is determined at the time of proving by the following expression:

$$CMF = MF \times CPL$$

When calculating the *CMF*, use a *CPL* value that is based on the normal metering pressure that occurs when the hydrocarbon liquid flow ***is not*** passing through the prover.

l. Step 12—Calculate Meter Accuracy (*MA*)

For many field applications, a mechanical or electronic calibrator is often used to adjust the meter factor to unity to correct meter readings associated with truck loading racks and LACT/ACT meter skids. To ascertain that the proving report and the required calibrator adjustments have been made without error, determine the meter accuracy for each proving run using the following equation:

$$MA = \frac{1}{MF}$$

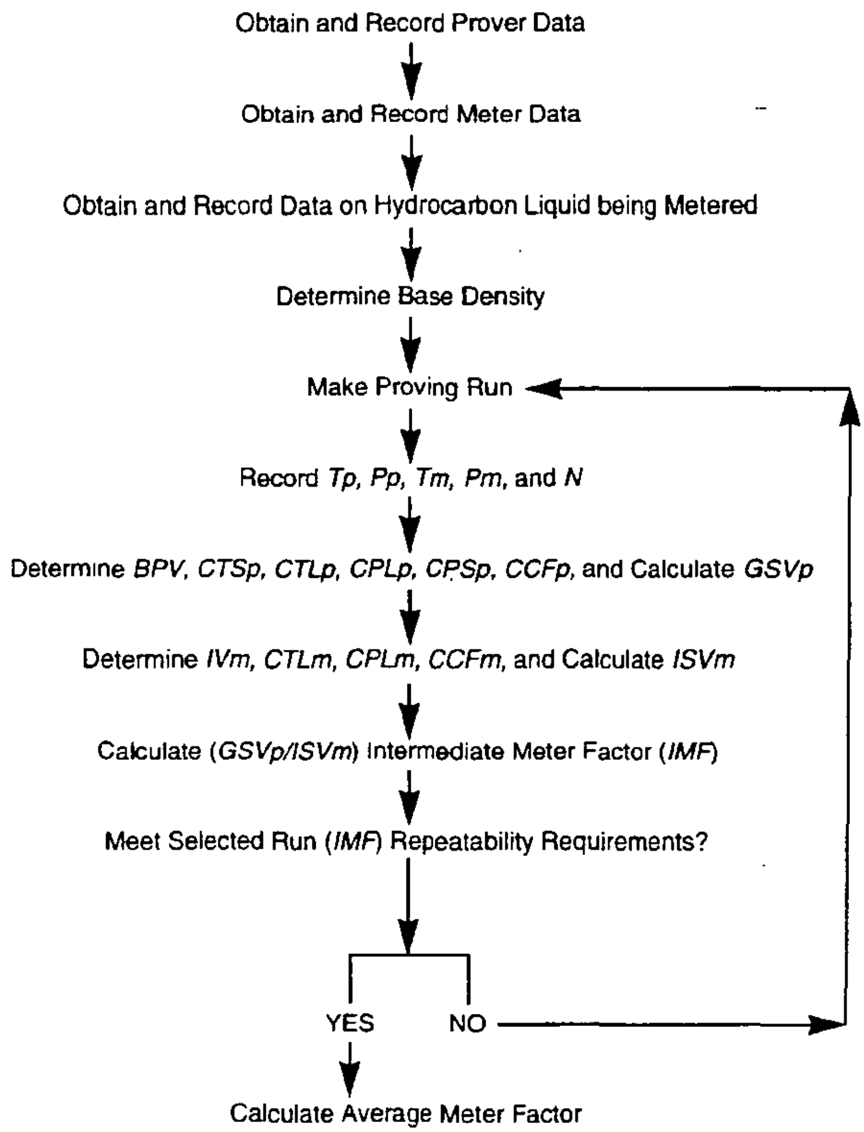

Figure 1—Proving Report Flow Chart
Displacement Pipe Prover Using Average Meter Factor Method

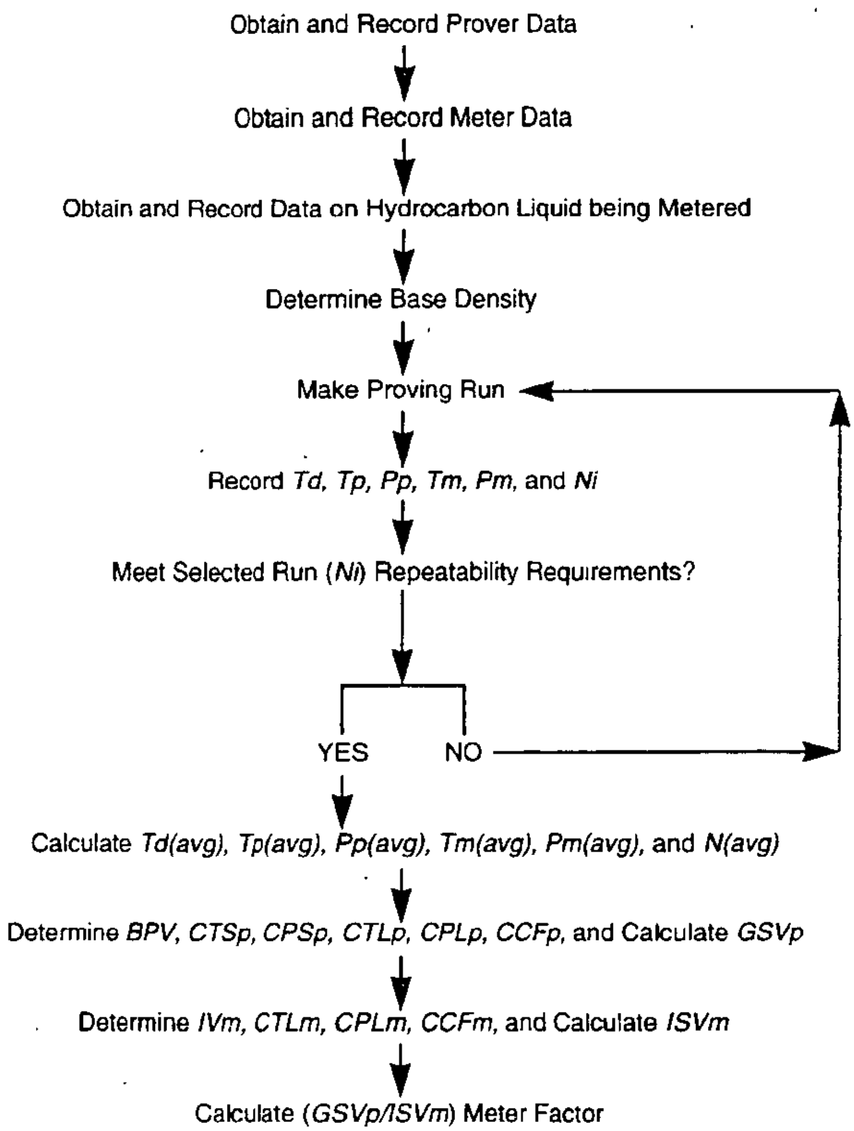

Figure 2—Proving Report Flow Chart
Small Volume Prover (with Externally Mounted Detectors) Using Average Data Method

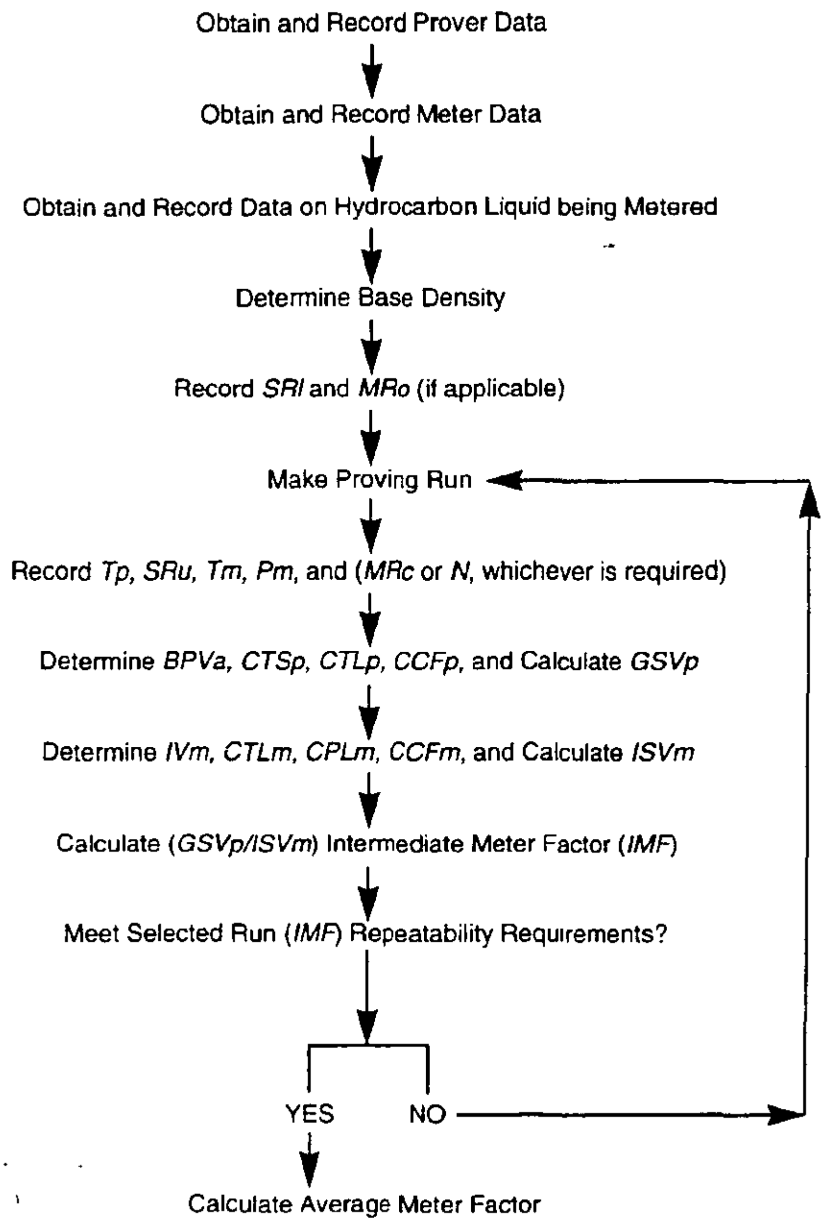

Figure 3—Proving Report Flow Chart
Volumetric Tank Prover Using Average Meter Factor Method

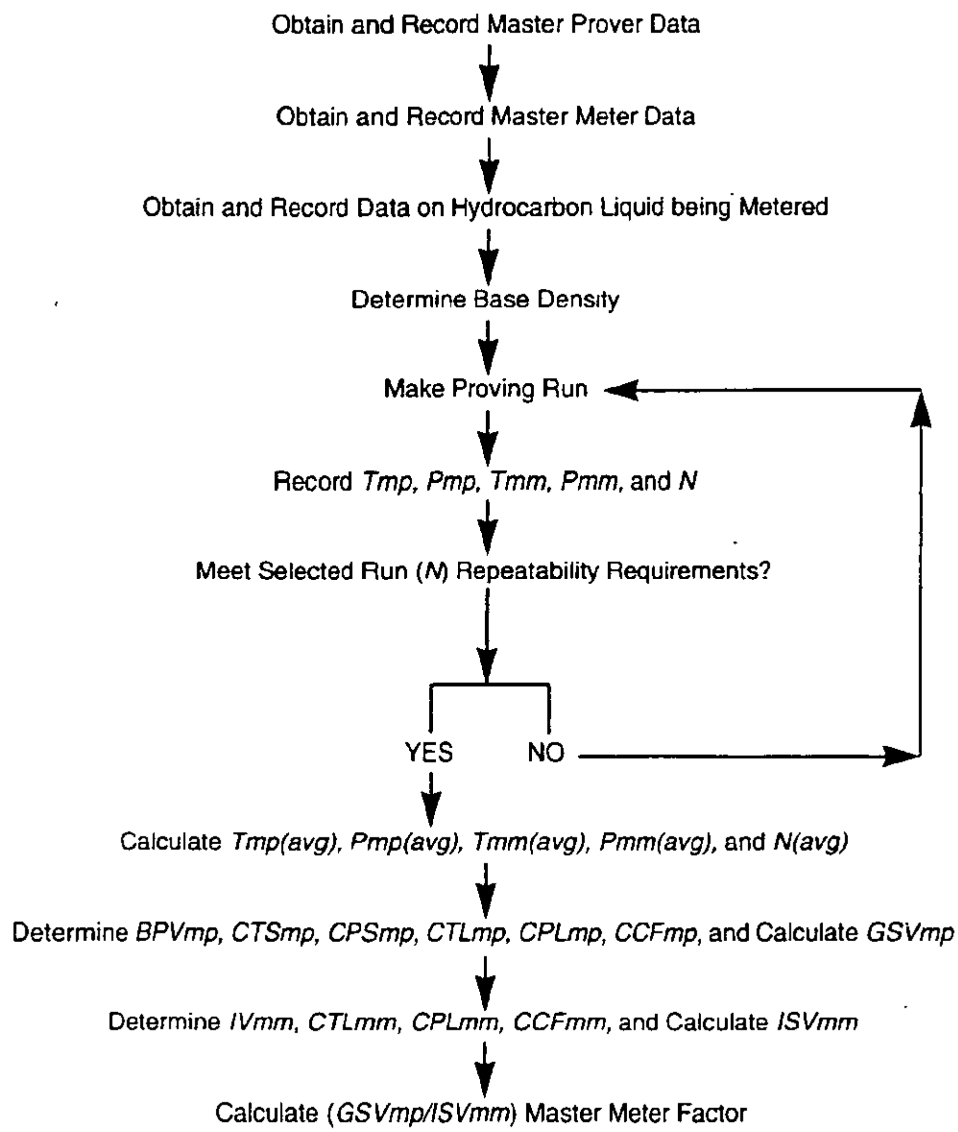

Figure 4—Proving Report Flow Chart
Proving a Master Meter with a Displacement Master Prover Using the Average Data Method

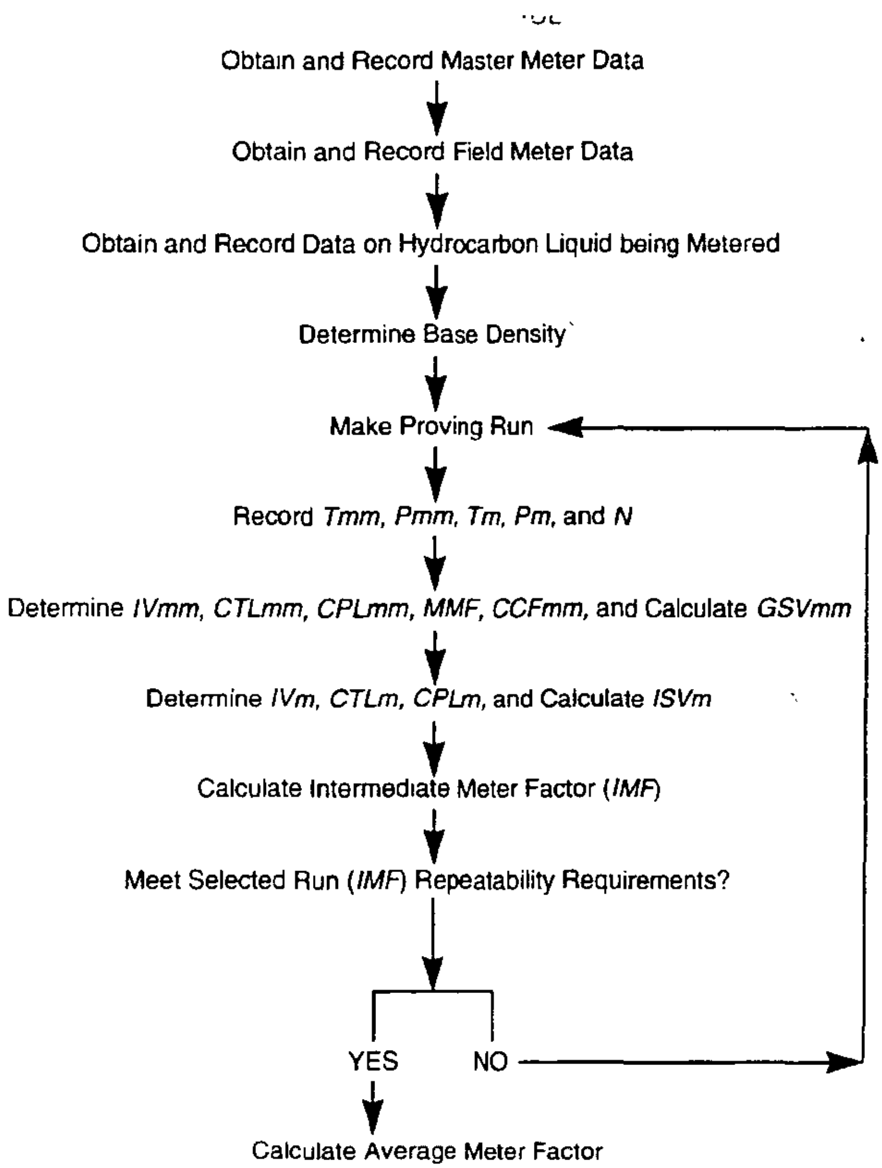

Figure 5—Proving Report Flow Chart
Proving a Field Meter with a Master Meter Using the Average Meter Factor Method

13 Proving Report Examples

The following examples are shown for illustrative purposes only. However, they can be used to verify computer routines and calculation procedures. *The number of selected proving runs is an operator (company policy) decision, and the number of proving runs shown in the following examples are intended to be illustrative only.* Many other equally valid numbers of proving runs could have been selected.

13.1 EXAMPLES OF METER PROVING CALCULATIONS FOR PIPE PROVERS AND SMALL VOLUME PROVERS

13.1.1 Example 1—Displacement Prover Report

a. Temperature Compensated Displacement Meter.

b. Unidirectional Meter Prover.

c. Low Vapor Pressure Crude Oil.

d. Calculate: Composite Meter Factor Using the Average Data Method.

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Example 1—DISPLACEMENT PROVER REPORT

OPERATOR : API MPMS Chapter 12.2 Part 3 - Example 1 November, 1997
LOCATION : Washington, D C. USA

METER DATA

Factor	CMF	
T.Comp. Pulses	Yes	
NKF	1,000 000	P/Bbl
Meter No.	006	
Manufacturer	PD	
Size	10	inches
Serial No.	PD-97-101	
Model No.	101-ABC	

FLUID DATA

Type	Crude	
Batch No	NA	
Obs API	44 5	API
Obs Temp	86.5	degF
Liquid Tables	1	
API@60	42.2	API
Viscosity 100degF	5.00	cP

1 - Tables 5A/6A
2 - Tables 5B/6B
<<< (Select 1 or 2)

REPORT DATA

	Previous	Current
Date	5-Aug 97	30-Jul-98
Fluid Type	Crude	Crude
Report No	20	21
Flowrate	2,457	2,542
Totalizer	4,878 329	5 423 873
API @ 60	41.8	42 2
Viscosity (cP)	4 8	5 00
Prover Temp	84.5	78 6
R(%)	0 042	0 025
Factor (CMF)	0 9968	0 9956
Factor Variation	—	-0 0011

PROVER DATA

BPV	11.9048	Bbls
O.D.	20	inches
W.T.	0.5	inches
Pipe Gl	6 20E-06	per degF
E	3.00E+07	per psi
Type	Unidirectional	
Single-Walled	1	(1-Y 2-N)
Internal Detectors	1	(1 Y, 2 N)
External Shaft. Gl	NA	per degF
Serial No	U-101	
Manufacturer	Prover Maker	

Liquid Properties at Metering Conditions For CMF

Pressure	25	psig
Temperature	78 0	degF
Eq. Vapor Pressure	0	psig
CPL	1 0002	

API 5A/6A - Crude Oil and JP-4
API MPMS Chapter 11.1 Vol X
API MPMS Chapter 11.2.1

Report Method	2	Avg DATA Method	
Run Criteria	5 out of 6 consecutive runs within 0.050%		
Repeatability (R)	0 025	(%)	

RUN	TEMPERATURE To and/or Td (degF)	Tm (degF)	PRESSURE Pp (psig)	Pm (psig)	PULSES N	RUN		RUN IMF
1	78 6	78.6	45	30	11 852,000	1	<>	NA
2	78.2	78 5	44	28	11,851.000	2	<>	NA
3	78 5	78 5	43	25	11,868.000	3	-	NA
4	78 5	78 8	44	28	11,850.000	4	<>	NA
5	78.8	78 9	42	25	11,852.000	5	<>	NA
6	78.8	78 9	42	25	11,849 000	6	<>	NA
7	0 0	0 0	0	0	0.000	7	-	NA
8	0 0	0 0	0	0	0.000	8	-	NA
9	0 0	0 0	0	0	0.000	9	-	NA
10	0 0	0 0	0	0	0.000	10	-	NA
Average	78 60	78.70	43 0	27.0	11 850 8000	<> Selected Runs		NA **Average**

(1) Determination of GSVp CCFp = 0 99104

BPV		Ctsp		Cpsp		Ctlp		Cplp		GSVp
((11 90480	)*((	1.00035	)*(	1 00005	)*(	0 99039	)*(	1 00026	)) =	11 798100

Security Seals

Seals Off

xxxxx	xxxxx
xxxxx	xxxxx

Seals On

xxxxx	xxxxx
xxxxx	xxxxx

(2) Determination of ISVm CCFm = 1 00016

Average Pulses		Pulses/BBL		Gross Mtr Vol		Ctlm		Cplm		ISVm
((11 850 800	)/(	1 000 000	))=((	11 850800	)*((	1 00000	)*(	1 00016	)) =	11 85270

(3) Determination of Proving Factors

(1)	(GSVp)/(ISVm) =	0 9954	MF	
(2)	(MF)*(CPL) =	0 9956	CMF	<<<<<
(3)	1 / MF =	1 0046	MA	
(4)	(NKF)/(MF) =	1 004 621	KF	
(5)	(KF)/(CPL) =	996 650	CKF	

Electronic Temperature Device

Found			
	Certified	77 5	degF
	Device	78.0	degF
Left			
	Certified	78 1	degF
	Device	78 2	degF

SIGNATURE DATE COMPANY

13.1.2 Example 2—Displacement Prover Report

a. Nontemperature Compensated Turbine Meter.

b. Bidirectional Meter Prover.

c. Low Vapor Pressure Petroleum Product.

d. Calculate: Meter Factor Using the Average Meter Factor Method.

Example 2—DISPLACEMENT PROVER REPORT

OPERATOR : API MPMS Chapter 12.2 Part 3 - Example 2
LOCATION : Washington, D C, USA

November, 1997

METER DATA		
Factor	MF	
T.Comp. Pulses	No	
NKF	1,000.000	P/Bbl
Meter No	006	
Manufacturer	Conventional Turbine	
Size	10	inches
Serial No.	PD-97-207	
Model No	102-ABC	

FLUID DATA		
Type	SU	
Batch No.	NA	
Obs API	62.5	API
Obs Temp	86.5	degF
Liquid Tables	2	
API@60	59 1	API
Viscosity 100degF	0.50	cP

1 - Tables 5A/6A
2 - Tables 5B/6B
<<< (Select 1 or 2)

REPORT DATA	Previous	Current
Date	3-Aug-97	30-Jul-98
Fluid Type	RU	SU
Report No.	20	21
Flowrate	2,457	2,542
Totalizer	4,678,329	5 423,873
API @ 60	54 5	59.1
Viscosity (cP)	0 56	0 50
Prover Temp	84.5	78 8
R(%)	0 042	0.027
Factor (MF)	0 9986	0 9996
Factor Variation	—	0.0010

PROVER DATA		
BPV	23.8105	Bbls
O D	16	inches
W T.	0.5	inches
Pipe GI	6.20E-06	per degF
E	3 00E+07	per psi
Type	Bidirectional	
Single-Walled	1	(1-Y, 2-N)
Internal Detectors	1	(1-Y, 2-N)
External Shaft, GI	NA	per degF
Serial No	B-202	
Manufacturer	Prover Maker	

Liquid Properties at Metering Conditions For CMF		
Pressure	25	psig
Temperature	78 0	degF
Eq Vapor Pressure	0	psig
CPL	NA	

API 5B/6B - Gasolines and Napthenes
API MPMS Chapter 11.1 Vol X
API MPMS Chapter 11.2.1

Report Method	1	Avg MF Method
Run Criteria	5 out of 6 consecutive runs within 0.050%	
Repeatability (R)	0.027	(%)

RUN	TEMPERATURE Tp and Td (degF)	Tm (degF)	PRESSURE Pp (psig)	Pm (psig)	PULSES N	RUN		RUN MF
1	78.6	78 6	45	30	23,835.000	1	<>	0 99950
2	78 2	78 5	44	28	23,839 000	2	<>	0 99952
3	78.5	78 5	43	25	23,849.000	3	-	
4	78.5	78.8	44	28	23,840.000	4	<>	0 99947
5	78.8	78 9	42	25	23,831.000	5	<>	0 99974
6	78.8	78 9	42	25	23,832.000	6	<>	0 99969
7	0 0	0 0	0	0	0.000	7	-	
8	0 0	0.0	0	0	0 000	8	-	
9	0.0	0 0	0	0	0.000	9	-	
10	0.0	0.0	0	0	0.000	10	-	
Average	78 60	78.70	43 0	27 0	23 835 4000		<> Selected Runs	0 99958 **Average**

(1) Determination of GSVp CCFp = NA

BPV		Ctsp		Cpsp		Ctlp		Cplp		GSVp
[(23 81050	)*(	1.00035	)*(	1 00004	)*(	0 98733	)*(	1 00035	)] =	NA

(2) Determination of ISVm CCFm = NA

Average Pulses		Pulses/BBL		Gross Mtr Vol		Ctlm		Cplm		ISVm
[(23,835.400	)/(	1,000 000	)]=[(	23 835400	)*(	0.98726	)*(	1 00022	)] =	NA

Security Seals		
Seals Off		
	xxxxx	xxxxx
	xxxxx	xxxxx
Seals On		
	xxxxx	xxxxx
	xxxxx	xxxxx

(3) Determination of Proving Factors

(1)	(GSVp)/(ISVm) =	0 9996	MF	<<<<<
(2)	(MF)*(CPL) =	NA	CMF	
(3)	1 / MF =	1 0004	MA	
(4)	(NKF)/(MF) =	1,000 400	KF	
(5)	(KF)/(CPL) =	NA	CKF	

Electronic Temperature Device		
Found		
Certified	77.5	degF
Device	78.0	degF
Left		
Certified	78 1	degF
Device	78.2	degF

SIGNATURE DATE COMPANY

13.1.3 Example 3—Small Volume Prover

a. Nontemperature Compensated Helical Turbine Meter.

b. Small Volume Unidirectional Prover with Externally Mounted Detectors.

c. High Vapor Pressure Liquid.

d. Calculate: Meter Factor Using the Average Meter Factor Method.

Example 3—SMALL VOLUME PROVER

OPERATOR : API MPMS Chapter 12.2 Part 3 - Example 3
LOCATION : Washington, D.C. USA

November, 1997

METER DATA

Factor	MF	
T.Comp. Pulses	No	
NKF	354.899	P/Bbl
Meter No.	006	
Manufacturer	Helical Turbine	
Size	4	inches
Serial No.	HT-97-198	
Model No	103-ABC	

FLUID DATA

Type	NAPTHA	
Batch No	NA	
Obs API	62 5	API
Obs Temp	86.5	degF
Liquid Tables	2	
API@60	59 1	API
Viscosity 100degF	0 50	cP

1 - Tables 5A/6A
2 - Tables 5B/6B
<<< (Select 1 or 2)

REPORT DATA

	Previous	Current
Date	3-Aug-97	30-Jul-98
Fluid Type	LPG	NAPTHA
Report No.	20	21
Flowrate	2,457	2 542
Totalizer	4 678 329	5,423,873
API @ 60	40 8	59 1
Viscosity (cP)	0 23	0 50
Prover Temp	84 5	78 6
R(%)	-0,042	0.037
Factor (MF)	0 9988	0 9997
Factor Variation	—	0.0009

PROVER DATA

BPV	5 24037	Bbls
O D	10.750	inches
W.T.	0.365	inches
Pipe Gl	6.20E-06	per degF
E	3.00E+07	per psi
Type	Sm.Vol.Prvr	
Single-Walled	1	(1-Y, 2-N)
Internal Detectors	2	(1-Y, 2-N)
External Shaft, Gl	6.00E-06	per degF
Serial No	U-303	
Manufacturer	Unidirectional	

Liquid Properties at Metering Conditions For CMF

Pressure	80	psig
Temperature	78.0	degF
Eq Vapor Pressure	15	psig
CPL	NA	

API 5B/6B - Gasolines and Napthenes
API MPMS Chapter 11.1 Vol X
API MPMS Chapter 11.2.1

Report Method	1	Avg MF Method
Run Criteria	5 out of 6 consecutive runs within 0.050%	
Repeatability (R)	0 037	(%)

RUN	TEMPERATURE Tp and Td (degF)	Tm (degF)	PRESSURE Pp (psig)	Pm (psig)	PULSES N	RUN		RUN IMF
1	78.6	78 6	81	77	1,861.541	1	<>	0 99952
2	78.2	78.5	82	77	1,861.244	2	<>	0.99989
3	78.5	78.5	81	78	1,860.998	3	-	
4	78.5	78.8	81	76	1,861.353	4	<>	0 99982
5	78.8	78.9	80	77	1,861.574	5	<>	0.99958
6	78.8	78 9	80	76	1,861 672	6	<>	0 99952
7	0.0	0 0	0	0	0 000	7	-	
8	0.0	0.0	0	0	0 000	8	-	
9	0.0	0 0	0	0	0 000	9	-	
10	0 0	0 0	0	0	0 000	10	-	
Average	78 60	78 70	81 0	77 0	1 861 4770		<> Selected Runs	0 99967 **Average**

(1) Determination of GSVp CCFp = NA

	BPV		Ctsp		Cpsp		Ctlp		Cplp		GSVp
[(	5.24037	)*[(	1 00034	)*(	1 00007	)*(	0 98733	)*(	1,00054	)]=	NA

(2) Determination of ISVm CCFm = NA

	Average Pulses		Pulses/BBL		Gross Mtr Vol		Ctlm		Cplm		ISVm
[(	1 861 477	)/(	354 899	)]=[	5 245090	]*[(	0 98726	)*(	1 00050	)]=	NA

Security Seals
Seals Off
xxxxx xxxxx
xxxxx xxxxx
Seals On
xxxxx xxxxx
xxxxx xxxxx

(3) Determination of Proving Factors

(1)	(GSVp)/(ISVm) =	0 9997	**MF** <<<<<
(2)	(MF)*(CPL) =	NA	**CMF**
(3)	(1 / MF =	1 0003	**MA**
(4)	(NKF)/(MF) =	355 006	**KF**
(5)	(KF)/(CPL) =	NA	**CKF**

Electronic Temperature Device

Found			
	Certified	77.5	degF
	Device	78.0	degF
Left			
	Certified	78 1	degF
	Device	78.2	degF

SIGNATURE DATE COMPANY

13.2 EXAMPLE OF A METER PROVING CALCULATION FOR AN ATMOSPHERIC (OPEN) TANK PROVER

13.2.1 Example 4—Atmospheric Tank Prover Report

a. Temperature Compensated Displacement Meter.

b. Atmospheric (Open) Tank Prover.

c. Low Vapor Pressure Petroleum Product.

d. Calculate: Meter Factor Using the Average Meter Factor Method.

Example 4—ATMOSPHERIC TANK PROVER REPORT

Operator: *API MPMS* Chapter 12.2 Part 3
Location: Washington, D.C. USA November 1997

METER DATA		FLUID DATA		REPORT DATA		
Factor type.	CMF	Fluid type:	Gasoline	History	Previous	As Found
Method:	Avg. Meter Factor	Obs. API	57.0 API	Date:	10/17/97	11/17/97
T.Comp. Pulses:	Yes	Obs Temp.	88.5 deg F	Report:	21	22
NKF.	200 pulses/gal.	API@60	53.6 API	Rate:	615 GPM	600 GPM
Meter No.	214	(Use Table 5B to get API@60)		Totalizer:	2000687	2004676
Meter type:	Displacement	(Use Table 6B for CTLp & CTLm)		APIb.	53.4	53.6
Meter size:	6 inches	(Use Table 11.2.1 for "F" factor)		Tp:	79.0°F	83.0°F
Meter Model:	60-ABC			R(%) Range	<0 050%	<0.050%
Serial Number:	PD-06-304			CMF	1.0005	1 0025

TANK PROVER DATA		COMPOSITE FACTOR:		METER PERFORMANCE:	
BPV:	1000.00 gallons	Assumed weighted		New CMF:	1 0004
Type:	Atmospheric tank	average temperature		Factor change:	0.200%
Mfg:	Prover Maker	and pressure for		(Avg. "as found" to previous CMF)	
Serial No.	AT-100	calculation of CMF:		Repeatability (R)	<0.050%
ID:	n/a (mild steel)	Pressure:	40 psig	Criteria: Range within	0.050%
WT:	n/a	Temperature:	82.5 deg F	Note: Minimum 2 Consecutive Runs	
Gc:	0.0000186 per deg F	Pe:	0 psig		
E:	30,000,000 per psi	CPL for CMF:	1.0003	(Compressibility (F) factor = 0.00000744)	

PROVER TANK DATA/CALCULATIONS		RUN 1	RUN 2	RUN 3	RUN 4
Upper Scale Reading (SRu), gallons		1000.10	1000.34	1000.29	1000.04
Lower Scale Reading (SRl), gallons		0.00	0.22	-0.17	-0.42
Base Measure Volume, Adjusted (BPVa)		1000.10	1000.12	1000.46	1000 46
Average Tank Prover Temperature – Tp(avg)		82.2	82.6	82.8	83.0
Tank Prover Pressure (Pp)		atmospheric	atmospheric	atmospheric	atmospheric
Compressibility Factor (Fp)		0.00000743	0.00000744	0.00000746	0.00000746
CTSp	(CTS for prover)	1.00041	1.00042	1.00042	1.00043
CPSp	(CPS for prover)...atmospheric	1.00000	1.00000	1.00000	1.00000
CTLp	(CTL for prover)	0.98553	0.98527	0.98513	0.98500
CPLp	(CPL for prover)...atmospheric	1.00000	1.00000	1.00000	1.00000
CCFp	(CTSp * CPSp * CTLp * CPLp)	0.98593	0.98568	0.98554	0.98542
GSVp =	(BPVa * CCFp)	986.029	985.798	985.993	985.873

FLOW METER DATA /CALCULATIONS		RUN 1	RUN 2	RUN 3	RUN 4
Flow Rate in Gallons per Minute (GPM)		600	600	600	600
Meter Closing Pulses		196688	196700	197139	197087
Meter Opening Pulses		zeroed counter	zeroed counter	zeroed counter	zeroed counter
Indicated Pulses from Meter (N)		196688	196700	197139	197087
Nominal K-Factor, Indic.P/Gal. (NKF)		200.000	200.000	200.000	200.000
Indicated Meter Volume (IVm) gallons		983.440	983 500	985.695	985.435
Meter Temperature in degrees F (Tm)		82.0	82.3	82.5	82.8
Meter Pressure in psig (Pm)		40	40	40	40
Compressibility Factor (Fm)		0.00000743	0.00000744	0.00000744	0.00000746
CTLm	(CTL for meter) Note: ATC	1.00000	1.00000	1 00000	1.00000
CPLm	(CPL for meter)	1.00030	1.00030	1.00030	1.00030
CCFm	(CTLm * CPLm)	1.00030	1.00030	1.00030	1.00030
ISVm =	(IVm * CCFm)	983.735	983 795	985.991	985.731

METER FACTOR CALCULATIONS		RUN 1	RUN 2		RUN 3	RUN 4	
IMF (Intermediate Meter Factor (GSVp / ISVm)		1.00233	1.00204		1 00000	1.00014	
MF	("As Found" & "As Left" MF)		Average MF	1.0022		Average MF	1.0001
CPL	(for assumed average conditions)			1.0003			1.0003
CMF	(MF) * (CPL)			1.0025			1.0004
MA	(1 / MF)			0.9978			0.9999
KF	(NKF) / (MF)			199.561			199.980
CKF	(NKF) / (CPL)			199.501			199.920

Signature Date Company

Remarks. Meter Calibrator adjusted after Run 2

Average Runs 1 & 2: "As Found" CMF (May be only one run if two consecutive made after recalibration).
Average Runs 3 & 4: "As Left" CMF. (May be only one run if two consecutive made before recalibration)

13.3 EXAMPLE OF A METER PROVING CALCULATION USING A MASTER METER

13.3.1 Example 5—Master Meter Proving Report

a. Nontemperature Compensated Master Meter.

b. Bidirectional Meter Prover.

c. Low Vapor Pressure Crude Oil.

d. Calculate: Master Meter Factor Using the Average Data Method.

Example 5—MASTER METER PROVING REPORT

OPERATOR : API MPMS Chapter 12.2 Part 3
LOCATION : Washington, D C USA

November, 1997

MASTER METER DATA		
Factor	MF	
T.Comp. Pulses	No	
NKF	1,000.000	pulses
Meter No.	MM-001	
Manufacturer	Displacement	
Size	6	inches
Serial No.	PD-222	
Model No	111-ACK	

FLUID DATA		
Type	Crude	
Batch No.	NA	
Obs API	44.5	API
Obs Temp	86 5	degF
Liquid Tables	1	
API @ 60	42 2	API
Viscosity 100degF	5.00	cP

1 - Tables 5A/6A
2 - Tables 5B/6B
<<< (Select 1 or 2)

MASTER METER REPORT DATA	Previous	Current
Date	3-Oct-97	30-Jul-98
Fluid Type	Crude	Crude
Report No.	20	21
Flowrate bph	1,134	1 203
Totalizer	5 398,229	5 423,873
API @ 60	43 0	42.2
Viscosity (cP)	4.76	5 00
Prover Temp	74 5	78 8
R(%)	0 014	0 017
Factor (MF)	1 0003	1 0002
Factor Variation	—	-0 0001

MASTER PROVER DATA		
BPV	23.829	Bbls
O D.	12	inches
W.T.	0.375	inches
Pipe Gl	6.20E-06	per degF
E	3 00E+07	per psi
Type	Bidirectional	
Single-Walled	1	(1-Y, 2-N)
Internal Detectors	1	(1-Y, 2-N)
External Shaft, Gl	NA	per degF
Serial No	Y-3979	
Manufacturer	Prover Maker	

Liquid Properties at Metering Conditions For CMF		
Pressure	25	psig
Temperature	86 0	degF
Eq. Vapor Pressure	0	psig
CPL	NA	

API 5A/6A - Crude Oil and JP-4
API MPMS Chapter 11.1 Vol X
API MPMS Chapter 11.2.1

Report Method	2	Avg DATA Method
Run Criteria	5 out of 6 consecutive runs within 0.020%	
Repeatability (R)	0.017	(%)

RUN	TEMPERATURE Tmp (degF)	Tmm (degF)	PRESSURE Pmp (psig)	Pmm (psig)	PULSES N	RUN		RUN MMF
1	78.6	78 6	45	30	23,849.000	1		NA
2	78.2	78 5	44	28	23,839.000	2	<>	NA
3	78.5	78 5	43	25	23,838.000	3	<>	NA
4	78.5	78 8	44	28	23,840.000	4	<>	NA
5	78.8	78 9	42	25	23,836.000	5	<>	NA
6	78 8	78 9	42	25	23,837.000	6	<>	NA
7	0.0	0 0	0	0	0 000	7	-	NA
8	0.0	0.0	0	0	0.000	8	-	NA
9	0 0	0 0	0	0	0.000	9	-	NA
10	0 0	0 0	0	0	0 000	10	-	NA
Average	78 60	78 70	43 0	26 0	23 838 0000	<> Selected Runs		NA **Average**

(1) Determination of GSVmp CCFmp = 0 99103

BPVmp		CTSmp		CPSmp		CTLmp		CPLmp		GSVmp
((23 82900	)*(	1 00035	)*(	1 00004	)*(	0 99039	)*(	1 00026	)) =	23 615300

(2) Determination of ISVmm CCFmm = 0 99050

Avg Pulses N(avg)		Pulses/BBL		Gross Mtr Vol IVmm		CTLmm		CPLmm		ISVmm
((23 838 000	)/(	1,000 000	))=(	23 838000	)*(	0 99034	)*(	1 00016	)) =	23 61150

Security Seals		
Seals Off		
	xxxxx	xxxxx
	xxxxx	xxxxx
Seals On		
	xxxxx	xxxxx
	xxxxx	xxxxx

(3) Determination of Master Meter Proving Factors

(1)	(GSVmp)/(ISVmm) =	1 0002	**MMF** <<<<<
(2)	(MMF)*(CPL) =	NA	**CMF**
(3)	1/ MMF =	0 9998	**MA**
(4)	(NKF)/(MMF) =	999 800	**KF**
(5)	(KF)/(CPL) =	NA	**CKF**

Electronic Temperature Device			
Found			
	Certified	77 5	degF
	Device	78 0	degF
Left			
	Certified	78 1	degF
	Device	78 2	degF

SIGNATURE DATE COMPANY

13.3.2 Example 6—Master Meter Proving Report (Proving Another Meter)

a. Temperature Compensated Displacement Meter

b. Master Meter used as the Proving Device

c. Low Vapor Pressure Crude Oil

d. Calculate: Composite Meter Factor Using the Average Meter Factor Method

Example 6—MASTER METER PROVING REPORT (PROVING ANOTHER METER)

Operator:	*API MPMS* Chapter 12.2 Part 3					
Location:	Washington, D.C. USA					November 1997
LINE METER DATA		**FLUID DATA**		**REPORT DATA**		
Meter No.	FM-4444	Fluid type:	Crude Oil	History	Previous	As Found
Meter Type:	Displacement	Obs. API	44.5 API	Date:	11/10/97	11/17/97
Meter Size:	6 inches	Obs Temp.	86 5 deg F	Report:	23	24
Meter Model:	AKC-600	API@60	42.2 API	Rate (BPH):	1210	1190
Meter Mfg.	Flow Meter Maker	Use Table 5B to get API@60)		Totalizer:	2000687	2004676
Meter Serial No.	PD-260	(Use Table 6B for CTLmm & CTLm)		APIb:	42.4	42.2
Temp. Comp.	Yes	(Use Table 11.2.1 for "F" factor)		Tp:	75 0°F	77.0°F
Gear Ratio:	1:1	Note: Viscosity 5.01 cP @ 100°F		R(%) Range	<0.050%	<0.050%
Factor type:	CMF			CMF	1.0020	1.0028

MASTER METER PROVER DATA		**COMPOSITE FACTOR:**		**LINE METER PERFORMANCE:**	
MM No	MM-004	Assumed weighted		New CMF:	1.0028
MM Type:	Displacement	average temperature		Factor change:	0.080%
MM Size:	6 inches	and pressure for		(Avg. "as found" to previous CMF)	
MM Model:	111-ACK	calculation of CMF:		Repeatability (R)	<0.050%
MM Mfg.	Flow Meter Maker	Pressure:	106 psig	Criteria: Range within	0.050%
MM Serial No.	PD-222	Temperature:	77.0 deg F	Note: *Minimum 2 Consecutive Runs*	
Temp. Comp?	No	Pe:	0 psig		
NKF:	1000 pulses/bbl.	CPL for CMF:	1.0006 (F factor = 0.00000597)		
Calculation:	Average Meter Factor Method				

DATA/CALCULATIONS, MASTER METER		**RUN 1**	**RUN 2**	**RUN 3**	**RUN 4**
Flow Rate in Barrels per Hour (BPH)		1190	1190		
Closing Master Meter Registration in Pulses		101530	101565		
Opening Master Meter Registration in Pulses		zeroed counter	zeroed counter		
Closing - Opening Pulses (N)		101530	101565		
Pulses per Indicated Barrel (NKF) on Master Meter		1000.00	1000.00		
Indicated Volume, Master Meter (IVmm = N/NKF)		101.530	101.565		
Temperature in degrees F (Tmm)		76.6	76.8		
Pressure in psig (Pmm)		104	104		
Compressibility Factor (Fmm)		0.00000596	0 00000597		
MMF	(Master Meter Factor)	1.00020	1 00020		
CTLmm	(CTL for master meter)	0.99143	0.99133		
CPLmm	(CPL for master meter)	1.00062	1.00062		
CCFmm	(CTLmm * CPLmm * MMF)	0.99224	0.99214		
GSVmm	(IVmm * CCFmm)	100.7421	100.7667		

DATA /CALCULATIONS, LINE METER		**RUN 1**	**RUN 2**	**RUN 3**	**RUN 4**
Closing Line Meter Registration (barrels)		100.4800	100.4600		
Opening Line Meter Registration (barrels)		zeroed counter	zeroed counter		
Closing - Opening Registration (IVm)		100.4800	100.4600		
Temperature in degrees F (Tm)		76.8	77.0		
Pressure in psig (Pm)		110	110		
Compressibility Factor (Fm)		0.00000597	00000597		
CTLm	(CTL for meter) Note: ATC	1.00000	1.00000		
CPLm	(CPL for meter)	1.00066	1.00066		
CCFm	(CTLm * CPLm)	1.00066	1.00066		
ISVm	(IVm * CCFm)	100 5463	100.5263		

METER FACTOR CALCULATIONS		**RUN 1**	**RUN 2**	**RUN 3**	**RUN 4**
IMF	(Meter Factor = GSVmm / ISVm)	1.00195	1.00239		
MF	(Average of Runs 1 & 2)			1.0022	
CPL	(for assumed average conditions)			1.0006	
CMF	(MF * CPL)			1.0028	
MA	(1 / MF)			0.9978	
KF	(NKF / MF)			n/a	
CKF	(KF / CPL)			n/a	

Signature Date Company

Remarks: Average Runs 1 & 2. "As Found" (same as "As Left") CMF.

APPENDIX A—FLUID DENSITIES, VOLUMES, AND COMPRESSIBILITY CORRELATIONS

A.1 General Information

Table A-1, provides a guide to the appropriate references for *RHOb*, *CTL*, and *F* for most of the liquids associated with the petroleum and petrochemical industry.

The following text, which is applicable to the Table A-1, describes these recommended references. The expertise of a physical properties specialist should be consulted before adopting the recommendations contained in the table.

For some of the older references, the table values for *RHOb* and *CTL* cannot be curve fit. Therefore, it is recommended that linear interpolation of these tables (between columns and values within a column) be utilized for intermediate calculations.

Density Meter (Densitometer) Calculations

When using an on-line density meter (densitometer), the base density of a liquid (*RHOb*) is determined by the following expression:

$$RHOb = \frac{RHOtp}{CTL \times CPL}$$

It is important to note that the density under flowing conditions (*RHOtp*), must be known to accurately calculate the base density (*RHOb*). Also, for low pressure applications, *CPL* may be assumed to be 1.0000, if a sensitivity analysis indicates an acceptable level of uncertainty.

For some liquids, computer subroutines exist to correct the observed density to base density, using the *API MPMS* Chapter 11.1, Volume X, implementation procedures. *However, for elevated pressures, an iterative procedure to solve for base density is required for custody transfer purposes.* The manufacturer of the densitometer should be contacted for consultation on the density calculation requirements at elevated pressures.

The computation for correcting from density at flowing conditions (*RHOtp*) to density at base conditions (*RHOb*) may be carried out continuously, if mutually agreed between all the parties concerned with the transaction.

A.2 Base Density (*RHOb*) Determination

The standards to convert liquid density at observed conditions (*RHOobs*) to base density (*RHOb*) are as follows:

R1. *API MPMS* Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 5A, 53A, and 23A cover generalized crude oils and jet fuel (JP4). The document specifies the implementation procedures, together with rounding and trun-

Table A-1—Appropriate References for *RHOb*, *CTL*, and *F* for Most Liquids

Liquid Type	*RHOb*	*CTL*	*F*
Crude Oils			
Crude Oils	(R1)	(C1)	(F1)
Natural Gasolines	(R1)	(C1)	(F1)
Drip Gasolines	(R1)	(C1)	(F1)
Refined Products			
JP4	(R1)	(C1)	(F1)
Gasoline	(R2)	(C2)	(F1)
Naphthenes	(R2)	(C2)	(F1)
Jet Fuels	(R2)	(C2)	(F1)
Aviation Fuels	(R2)	(C2)	(F1)
Kerosine	(R2)	(C2)	(F1)
Diesel	(R2)	(C2)	(F1)
Heating Oils	(R2)	(C2)	(F1)
Fuel Oils	(R2)	(C2)	(F1)
Furnace Oils	(R2)	(C2)	(F1)
Lube Oils	(R3)	(C3)	(F1)
Propane	(R4)	(C4)	(F1)
Butane	(R4)	(C4)	(F1)
Propane Mixes	(R4)	(C4)	(F1)
Butane Mixes	(R4)	(C4)	(F1)
Isopentane	(R4)	(C4)	(F1)
Asphalt	NA	(C5)	(F1)
Solvents			
Benzene	NA	(C6)	(F1)
Toluene	NA	(C6)	(F1)
Stoddard Solvent	NA	(C6)	(F1)
Xylene	NA	(C6)	(F1)
Styrene	NA	(C6)	(F1)
Orthoxylene	NA	(C6)	(F1)
Metaxylene	NA	(C6)	(F1)
Paraxylene	NA	(C6)	(F1)
Cyclohexane	NA	(C6)	(F1)
Acetone	NA	(C6)	(F1)
Butadiene			
Butadiene	(R5)	(C7)	(F1)
Butadiene Mixtures	(R5)	(C7)	(F1)
Water			
For Volumetric Provers	NA	(C8)	(F2)

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cating, to determine the base density (*RHOb*) from the observed density (*RHOobs*) and observed temperature (*Tobs*) at base pressure (*Pb*).

a. Table 5A, used for a base temperature of 60°F, covers generalized crude oils and jet fuel (JP4) over an API@60°F gravity range of 0 to 100°API. For natural or drip gasolines with API@60°F gravity greater than 100°API, use Table 23 of ASTM D1250 (Historical Edition, 1952).
b. Table 53A, used for base temperature of 15°C, covers generalized crude oils and jet fuel (JP4) over a DENb@15°C range of 610 to 1075 kg/m³.
c. Table 23A, used for base temperature of 60°F, covers generalized crude oils and jet fuel (JP4) over a RD@60°F range of 0.6110 to 1.0760.

R2. *API MPMS* Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 5B, 53B, and 23B cover generalized products. The document specifies the implementation procedures, together with rounding and truncating, to determine the base density (*RHOb*) from the observed density (*RHOobs*) and observed temperature (*Tobs*) at base pressure (*Pb*).

a. Table 5B, used for base temperature of 60°F, covers generalized products (excluding JP4) over an API@60°F gravity range of 0 to 85°API.
b. Table 53B, used for base temperature of 15°C, covers generalized products over a DENb@15°C range of 653 to 1075 kg/m³.
c. Table 23B, used for base temperature of 60°F, covers generalized products over a RD@60°F range of 0.6535 to 1.0760.

R3. *API MPMS* Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 5D and 53D cover lubricating oils. The document specifies the implementation procedures, together with rounding and truncating, to determine the base density (*RHOb*) from the observed density (*RHOobs*) and observed temperature (*Tobs*) at base pressure (*Pb*).

a. Table 5D, used for base temperature of 60°F, covers lubricating oils over an API@60°F gravity range of –10 to 40°API.
b. Table 53D, used for base temperature of 15°C, covers lubricating oils over a DENb@15°C range of 825 to 1164 kg/m³.

R4. ASTM D1250 (Table 23—Historical Edition, 1952) covers a relative density at 60°F (RD@60°F) range of 0.500 to 1.100. Table 23 converts the observed relative density at the observed temperature and equilibrium vapor pressure to the RD@60°F.

R5. ASTM D1550, used for base temperature of 60°F, is applicable to both butadiene and butadiene concentrates that contain at least 60 percent butadiene.

A.3 CTL Determination

The standards that have been developed to determine the *CTL* values for various liquids are as follows:

C1. *API MPMS* Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 6A, 54A, and 24A cover generalized crude oils and jet fuel (JP4). The document specifies the implementation procedures, together with rounding and truncating, to determine the *CTL* from base density (*RHOb*) and flowing temperature (*T*).

a. Table 6A, used for base temperature of 60°F, covers generalized crude oils and jet fuel (JP4), over an API@60°F gravity range of 0 to 100°API. For natural or drip gasolines and condensates with API@60°F gravity greater than 100°API, use Table 24 of ASTM D1250 (Historical Edition—1952).
b. Table 54A, used for base temperature of 15°C, covers generalized crude oils and jet fuel (JP4) over a DENb@15°C range of 610.5 to 1075.0 kg/m³.
c. Table 24A, used for base temperature of 60°F, covers generalized crude oils and jet fuel (JP4) over a RD@60°F range of 0.6110 to 1.0760.

C2. *API MPMS* Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 6B, 54B, and 24B cover generalized products. The document specifies the implementation procedures and the rounding and truncating procedures to determine the *CTL* from base density (*RHOb*) and flowing temperature (*T*).

a. Table 6B, used for base temperature of 60°F, covers generalized products (excluding JP4) over an API@60°F gravity range of 0 to 85°API.
b. Table 54B, used for base temperature of 15°C, covers generalized products (excluding JP4) over a DENb@15°C range of 653.0 to 1075.0 kg/m³.
c. Table 24B, used for base temperature of 60°F, covers generalized products over a RD@60°F range of 0.6535 to 1.0760.

C3. *API MPMS* Chapter 11.1, Volume X (ANSI/ASTM D1250-1980), Tables 6D and 54D cover lubricating oils. The document specifies the implementation procedures and the rounding and truncating procedures to determine the *CTL* from the base density (*RHOb*) and flowing temperature (*T*).

a. Table 6D, used for base temperature of 60°F, covers lubricating oils over an API@60°F gravity range of –10 to 40°API.
b. Table 54D, used for base temperature of 15°C, covers lubricating oils over a DENb@15°C range of 825 to 1164 kg/m³.

C4. ASTM D1250 (Table 24—Historical Edition, 1952) covers a relative density at 60°F (RD@60°F) range of 0.500 to 1.100 for liquefied petroleum gases (*LPG*). Table 24 calculates the *CTL* from the relative density @ 60°F and the flowing temperature (*T*).

C5. ASTM D1250 (Table 6—Historical Edition, 1952), used for base temperature of 60°F, covers the gravity range for asphalt. Table 6 is recommended by the API and Asphalt Institute for *CTL* determinations on asphalt and asphalt products.

C6. ASTM D1555, used for base temperature of 60°F, is the industry reference for *CTL* values associated with certain liquid aromatic hydrocarbons.

C7. ASTM D1550, used for base temperature of 60°F, is the industry reference for *CTL* values associated with butadiene and butadiene concentrates that contain at least 60 percent butadiene.

C8. *API MPMS* Chapters 11.2.3 and 11.2.3M cover *CTDW* values utilized in water calibration of volumetric provers.

a. Chapter 11.2.3, used for a base temperature of 60°F, calculates the *CTDW* for the temperature of the water flowing from the prover (*Tp*) and the temperature of the water in the test measure (*Ttm*).
b. Chapter 11.2.3M, used for a base temperature of 15°C, calculates the *CTDW* for the temperature of the water flowing from the prover (*Tp*) and the temperature of the water in the test measure (*Ttm*).

Fixed or Small-Variant Liquid Composition

There are numerous specification solvents, resins, chemicals, and specialty hydrocarbons that are used or manufactured by companies are not compatible with existing industry *CTL* tables. For these materials, interested parties may wish to utilize proprietary liquid property tables, that have been used for years, and that remain in use today for many applications. In applications where Table 6C of *API MPMS*, Chapter 11.1 is used, then laboratory testing or fluid property tables can be used to determine the desired alpha (coefficient of expansion) value. These alpha values can be used where existing commercial requirements permit.

Table 6C of *API MPMS*, Chapter 11.1 calculates the *CTL* for a liquid with a chemical composition that is fixed, or does not vary significantly, and whose coefficient of expansion may be easily determined.

Since *RHOb* is constant, no correction or determination of observed gravity is necessary. The *API MPMS* Chapter 11.1, Table 6C, is commonly used for specialized products with coefficients of thermal expansion that do not follow Tables 6A, 6B, or 6D of *API MPMS*, Chapter 11.1.

Use of Table 6C requires an equation of state and/or extensive data on the metered liquid.

A.4 Compressibility Factor Determination (*F*)

The density of the liquid shall be determined by the appropriate technical standards, or, alternatively, by the use of the proper density correlations, or, if necessary, by the use of the correct equations of state. If multiple parties are involved in the custody transfer measurement, the method selected for determining the density of the liquid shall be mutually agreed upon by all concerned. To assist in selecting which methods to utilize, the following information has been assembled for clarity.

F1. *API MPMS* Chapters 11.2.1, 11.2.1M, 11.2.2, and 11.2.2M provide values for compressibility factors (*F*) for hydrocarbon fluids. The documents specify the implementation procedures, together with rounding and truncating, to determine *F* from base density (*RHOb*), the flowing temperature (*T*), and the flowing pressure (*P*).

a. Chapter 11.2.1, used for base temperature of 60°F, covers hydrocarbon liquids over an API@60°F range of 0 to 90°API.
b. Chapter 11.2.1M, used for base temperature of 15°C, covers hydrocarbon liquids over a DEN@15°C range of 638 to 1074 kg/m^3.
c. Chapter 11.2.2, used for base temperature of 60°F, covers hydrocarbon liquids over a RD@60°F range of 0.350 to 0.637.
d. Chapter 11.2.2M, used for base temperature of 15°C, covers hydrocarbon liquids over a DEN@15°C range of 350 to 637 kg/m^3.

F2. The compressibility factor (*F*) for water utilized in the calibration of volumetric provers is defined as follows:

a. For US Customary units, a constant *F* value 0.00000320 (3.20E-06) per psi for water shall be utilized in the calculations.
b. For SI units, a constant *F* value 0.000000464 (4.64E-07) per kPa, or 0.0000464 (4.64E-05) per bar, for water shall be utilized in the calculations.