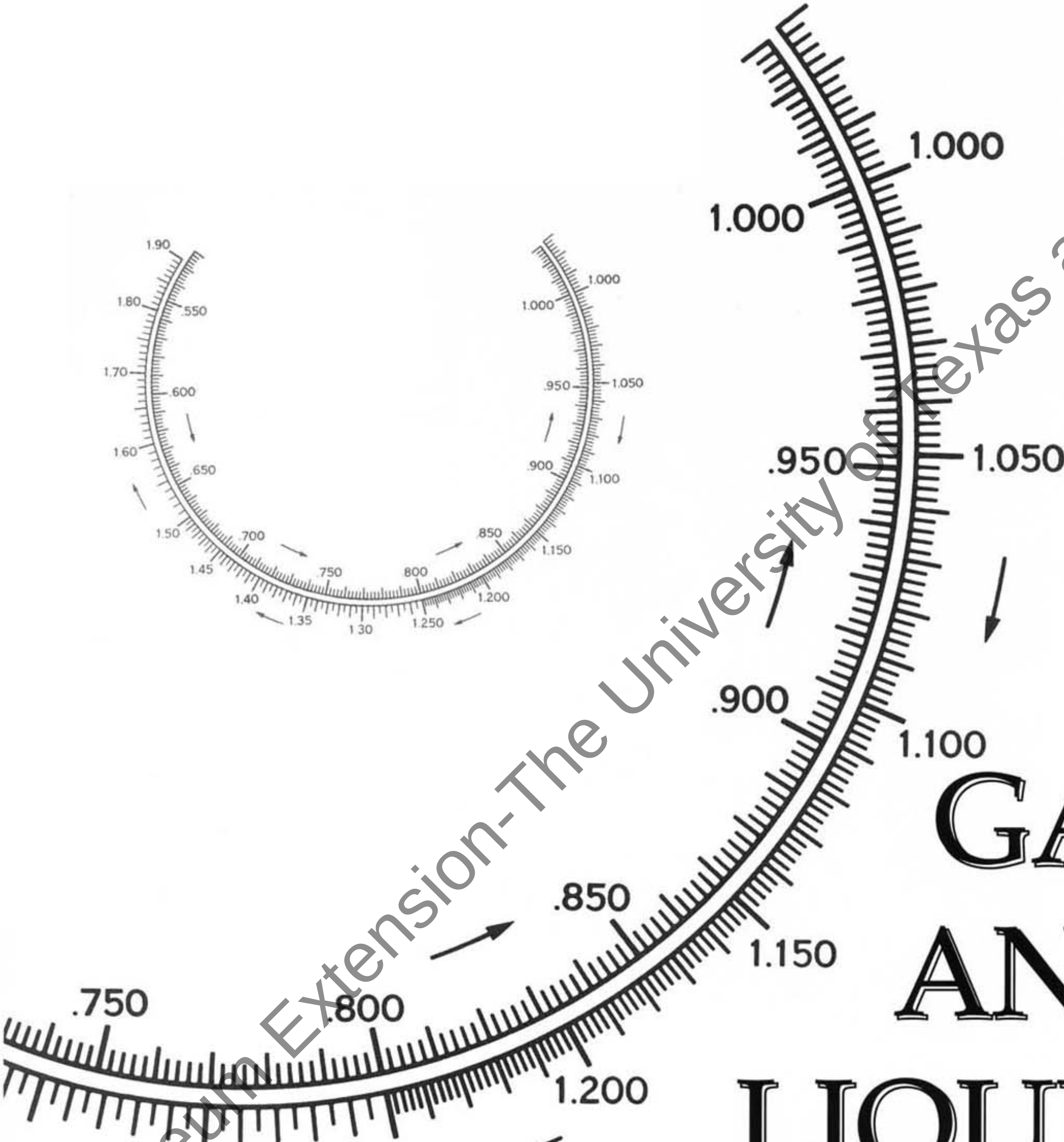

GAS AND LIQUID MEASUREMENT

PETROLEUM EXTENSION SERVICE DIVISION OF CONTINUING EDUCATION THE UNIVERSITY OF TEXAS AT AUSTIN

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Gas Measurement Fundamentals

INTRODUCTION

The importance of gas and gas liquids measurement has increased dramatically since World War II. The wellhead price of natural gas in the United States has risen from only a few cents to dollars per thousand cubic feet (MCf). In the not-too-distant future, it will probably go higher. Production has increased, and gas that used to be flared is now gathered and processed.

Domestic consumption of natural gas is almost 60 billion cubic feet per day (Bcf/d). About 96 percent of this gas is produced in the United States. About half is processed in over 800 liquid extraction plants. These plants recover about 70 million gallons (gal) of liquefied petroleum gas (LPG) per day. This 70 million gal represents about 30 percent of the domestic consumption of liquid hydrocarbons and about 98.5 percent of the demand for LPG as a fuel and petrochemical feedstock. Nearly 7 trillion cubic feet (Tcf) of gas is in underground storage.

Measurements of natural gas and natural gas liquids made at only a single point can represent hundreds of thousands of dollars per day. These measurements determine royalty, purchase, and sales contracts. They are also used for inventory accounting, process plant balances, loss prevention, and regulatory reporting. From the wellhead to the point of consumption, then, accurate measurement of gas and gas liquids is essential. Care and precision are mandatory. Measurement equipment must be installed and calibrated properly; it must be operated, inspected, and maintained carefully; and measurement results must be processed and accounted for accurately.

Natural gas provides warmth for our homes and offices, heat to cook with, and a great deal more. It is the raw material from which such items as toothpaste tubes, rubber tires, plastics, and panty hose are made. A considerable amount of natural gas is used as an energy source. In fact, almost everything produced by industry involves natural gas in one form or another.

What is natural gas? It cannot be seen, felt, heard, or, in its pure state, smelled. (For safety, companies that sell natural gas to consumers put odorants in it so that it can be smelled.) The people who extract gas from deep in the earth never see it, nor do those who purify, process, and transport it. Even though natural gas is essential to our way of life, it is dangerous. If it escapes its enclosure, it creeps along the ground and suffocates all life

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Head Meters

Several devices are available for measuring gas, but head meters are the most common. A head meter measures the differential pressure caused by a constriction in the pipe in which fluid is flowing. As the fluid passes through the constriction, its velocity increases. As the fluid's velocity increases, its pressure decreases. The pressure drop allows fluid volume, or rate of flow, to be calculated. Pressure in a line is often called pressure head. A constriction increases the velocity and causes a drop in the pressure head. Therefore, meters that measure a pressure drop are often called head meters.

Head meters are simple, inexpensive, easy to install and maintain, durable, and readily available. On the other hand, they have low rangeability, which means that they cannot accurately measure fluid flow rates if the maximum and minimum rates vary widely. A head meter operates best when the flow rate is fairly steady. Further, some head meters are not suitable for measuring dirty fluids because dirt clogs them.

PRIMARY ELEMENTS

A head meter installation consists of a primary element and a secondary element. The *primary element* is made up of the meter run, or tube, and the constriction. The *secondary element* measures the pressure drop caused by the primary element and other conditions, such as the flowing pressure of the fluid and its temperature. Several types of device or constriction are available as the primary element of a head meter installation; some are orifice plates, venturi tubes, flow tubes, flow nozzles, and Pitot tubes and annubars.

Orifice Meters

The most widely used head device in the gas industry is an orifice meter. Since they are so popular, they are covered in more detail in chapter 5; in this section, only a general description is given.

Figure 2.1 shows an orifice meter installation. The primary element is installed in the pipeline carrying the fluid and consists of a meter run, or tube, and an orifice plate inside an orifice fitting. The orifice that is bored through the plate creates the restriction.

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Turbine Meters

TURBINE METERS FOR GAS MEASUREMENT

An axial-flow turbine meter (fig. 3.1) is a velocity-measuring device in which gas flow is parallel to the rotor axis and the speed of rotation is proportional to the rate of flow. The volume of gas is determined by counting the revolutions of the rotor. Turbine meters are used in all phases of natural gas operations—production, transmission, and distribution.

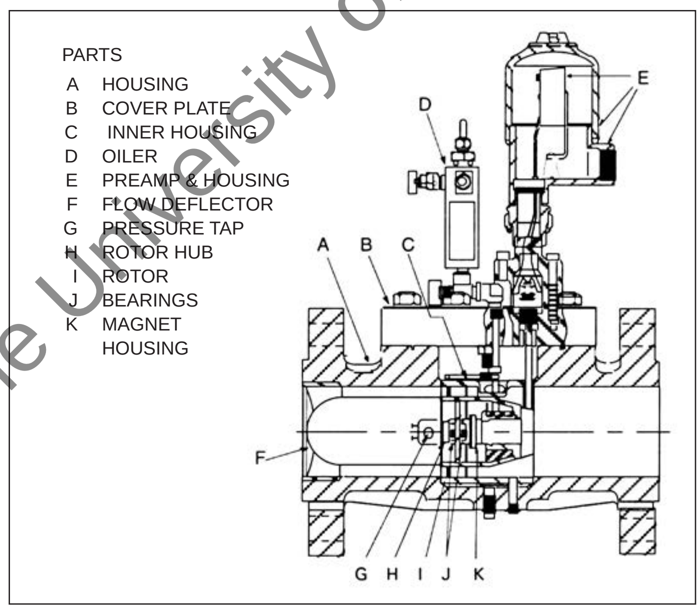

FIGURE 3.1. TURBINE METER

Fundamentals

Gas enters a turbine meter and is constricted, which increases the gas's velocity. The gas then passes through a free-turning rotor mounted coaxially on the pipe centerline and exits the meter. In passing through the meter, the gas imparts an angular velocity to the rotor proportional to the linear velocity of the gas in the meter. Since gas velocity is directly proportional to the volume flow rate, the rotor's rotating speed is also directly proportional to the volume flow rate. Therefore, by accurately measuring the rotor speed and applying a calibration constant, the volume flow rate can be obtained.

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Other Meters

In addition to head meters and turbine meters, many other meters are available for measuring gas and liquid. Some of these include diaphragm meters, rotary meters, vortex-shedding meters, swirl meters, variable-area meters, target meters, magnetic meters, and ultrasonic meters.

DIAPHRAGM METERS

Large-capacity diaphragm meters are the workhorses of the gas industry in commercial and light industrial applications. Other types of meter have made inroads, but because of their superior rangeability, diaphragm meters remain very popular.

Two types of diaphragm meter are currently manufactured in the United States. In the two-diaphragm, three-chamber, oscillating-valve meter, the diaphragms are flanged between two center castings and front and back cover castings to form the three measurement chambers. Two chambers are formed by the space between the front diaphragm and the front cover and between the back diaphragm and the back cover. The third chamber is the space between the two diaphragms. Motion from the diaphragms is transmitted by linkage to turn a center shaft, which in turn rotates a tangent crank. The tangent crank drives the valve cover and allows each chamber to fill and empty alternately while simultaneously transmitting motion to drive the index.

The two-diaphragm, four-chamber meter (fig. 4.1) uses D-shaped slide valves. The four chambers are formed by the space inside each diaphragm and the space in the case area around each diaphragm. Each valve seat contains three ports, or openings. The port nearest the center of the valve table communicates with the chamber inside the diaphragm; the port farthest from the center of the valve table communicates with the chamber in the case area; the center port communicates with the meter outlet. The valves are timed so that one chamber is always open to the meter inlet and one chamber is always open to the meter outlet. A slight drop in pressure at the meter outlet starts the diaphragms in motion.

Motion from the diaphragms is transferred to flag rods that extend above the valve table. Oscillating motion turns a tangent-and-crank assembly by means of flag arms, which are attached

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Orifice Meters

ORIFICE METER INSTALLATIONS

Orifice meters are the most widely used device for measuring gas flow. The primary element of an orifice meter installation contains the meter tube and the orifice fitting, which holds the orifice plate. The orifice, which causes the differential pressure drop that is necessary for measurement, is accurately bored into the plate. Taps are provided on or near the orifice fitting. Most taps are located on the flange of the orifice fitting, although in some installations, they are on the meter tube. If they are located on the orifice flange, they are called flange taps; if they are located on the meter tube, they are called pipe taps. Both the type and the location of the taps are important when calculating gas flow.

Gauge lines are attached to the taps. The gauge lines transmit static and differential pressures from each tap to the secondary element. The secondary element measures and records the static and differential pressure and sometimes other conditions, such as temperature of the flowing gas.

On some installations, the secondary element consists of sensing elements, a recorder, and a chart. The differential pressure is transferred through the pressure taps and gauge lines on each side of the orifice plate to a sensing element on the recorder. A pen records the pressure on a rotating chart. The chart rotates at a speed such that the pressure is recorded over a specific time period, such as 24 hours. The static pressure of the flowing gas, and sometimes the temperature of the gas, are also sensed and recorded on this chart. The temperature is sometimes recorded on a separate recorder and chart. Most secondary element installations today not only have the traditional chart recorder, but also feature an electronic flow measurement (EFM) system. EFM installations have transducers that electronically convert the differential pressure, the static pressure, and the temperature to electronic signals and feed them into a computer. In many cases, the chart recorder is eliminated.

Electronic Flow Measurement

Chart recorders cannot provide real-time measurement data. If a current reading of the differential pressure, the static pressure, the flowing temperature of the gas, or the gas flow is required, the chart must be retrieved and integrated before the data can

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Auxiliary Equipment

DEW POINT RECORDERS

According to Dalton's law, the total pressure of a mixture of gases equals the sum of the partial pressures of each of the gases in the mixture. The *partial pressure* of each gas is that which it would exert if it occupied the entire volume by itself. Assuming that water vapor is one of the components of natural gas, the pressure and temperature of the gas mixture determine the amount of water vapor that will be absorbed by that gas. In a state of dynamic equilibrium, the rate at which water vapor leaves a gas is exactly equal to the rate at which water vapor enters the gas.

The temperature at which dynamic equilibrium occurs at a given pressure is the *dew point temperature*. If the temperature decreases, the water vapor condenses. An increase in temperature of the gas allows the gas to hold more water vapor. The *dew point* is the temperature at which moisture begins to condense when a gas–water vapor mixture is cooled at constant pressure out of contact with liquid water.

Several dew point recorders are available for determining dew points or water content. Several of these use the ability of lithium chloride to absorb moisture from the surrounding atmosphere. As lithium chloride absorbs moisture, its conductance changes. By measuring the change in conductance of the chloride salt, the water content or the dew point can be determined. Lithium chloride devices require special cells that can measure 20°F of dew point. By changing the concentration of the lithium chloride, however, the dew point range can be set to cover a wide variety of temperatures.

Some dew point recorders use the change in capacitance between two plates to indicate a change in water content. Other units use a piezoelectric sorption unit that compares two hygroscopically coated quartz-crystal oscillators, which alternately sorb and desorb the water from the flowing stream. This action changes the mass of the coatings and hence the frequency of the oscillators. The change in frequency can be read in terms of moisture content.

One frequently used unit is the electrolytic moisture analyzer, which operates on the principle that moisture is absorbed on a phosphorus pentoxide (P_2O_5) film between two electrodes. A current is passed through the cell, and the absorbed water is

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Mass Flow Measurement

For many years, measuring fluids by volume was the standard for the petroleum industry. Now more than ever before, however, gas and liquids that rapidly change density at measuring conditions are being handled. Because of such density changes, volume measurement is no longer acceptable in many instances. Instead, measurement is based on the mass, or weight, of the fluid. In fact, in September 1990, API, AGA, and GPA issued a new standard for measuring gas with orifice meters. The *Manual of Petroleum Measurement Standards*, chapter 14, section 3 (AGA Report No. 3) now has four parts. Part 1 is entitled "General Equations and Uncertainty Guidelines" and gives an entirely new equation for determining mass flow through an orifice meter. As mentioned before, all four parts of the new standard have not yet been issued; also, those parts that have been issued are still awaiting industry acceptance. Because of the unsettled nature of the new standard at the time of this manual's publication, equations from other sources will be used.

When mass measurement is used, two types of contracts are usually written: one states that the fluid simply be measured in terms of mass, or weight, units; the other stipulates that mass measurement be used but that the mass units be converted to weight per unit of volume. Regardless of the type of contract, fluid mass is usually measured with true mass meters or inferential mass meters; or static measurement can be used, in which case, the fluid is weighed in a container.

TRUE MASS METERS

A true mass meter uses the physical law that states that force equals mass times acceleration. Several meters based on this principle are available for measuring the mass of both gas and liquid. Since the amount of force causing fluid to flow in a pipeline is known and since the flowing fluid is accelerated a known amount, the mass of the fluid can be determined. In effect, a true mass meter solves the force equation for mass—that is, since the force and the acceleration are known, and since the mass is unknown, the meter determines the mass from the two known factors.

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Sampling

GAS SAMPLING

To determine the quality of gas in the flowing stream, gas samples are obtained and analyzed. Since analysis of the sample can be no better than the sample itself, the sample must be obtained carefully so that it is representative of the gas flowing in the pipeline. Several devices and procedures are available to ensure that adequate samples are obtained.

Gas Sampling Equipment

To sample gas from the line, a probe is necessary. It should be made of rigid stainless steel tubing and should be installed so that it projects into the flowing stream. Its OD should be no larger than ¼-in. and it should be thick-walled for rigidity and strength.

All valves, fittings, and tubing with which the gas comes in contact should be of stainless steel. A minimum number of fittings should be used, and the sample lines should be as short as possible. In some cases, a sample line requires heating to maintain the temperature above the dew point. A heater should always be used to keep the gas and sample cylinder at temperatures high enough to prevent liquids from condensing.

Gas Sampling Techniques

Several techniques are used to collect a sample. Which technique is used depends on the composition of the gas, the purpose for which the samples are collected, the volume of the sample required, and the size, design, and material of connecting lines and cylinders. Regardless of the technique used, the connecting lines and containers should be cleaned thoroughly before use, particularly if they have previously been used on rich-gas streams. Samples should be taken under normal flowing conditions and in sufficient quantity for the tests to be run.

Two basic types of samples are the spot and the composite. Two procedures for collecting spot samples are available. The first is simply a series of fillings and blowdowns of a cylinder; it is often used in warm environments with dry gases. The second requires applying constant heat to replace the heat lost at the point of pressure reduction. (Gas cools when its pressure is reduced.) The

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Operation and Inspection of Measurement Equipment

TOLERANCES IN GAS MEASUREMENT

Need for Tolerances

Tolerances are necessary because no two orifice meters, no matter how well constructed, give continuously identical readings when the same amount of gas is flowing. Exact duplication of orifice plates is not commercially possible, so no two orifice plates of the same size manufactured by the same company have exactly the same coefficient of discharge when tested, even though the calculated value is the same.

Tolerances provide a practical solution to unavoidable differences between seemingly identical primary elements, although they do not provide for accidental errors in observation of secondary elements. In addition to allowances for tolerances in the commercial manufacture of primary elements, allowances must also be made for tolerances in the manufacture of secondary elements. Because of allowances for tolerances, overall measurement accuracy is sometimes less than that published in standards or calculated from equations for the orifice flow constant.

Effect of Tolerances

Calculations of coefficients from equations given in the 1985 edition of AGA Report No. 3 apply to orifices manufactured and installed in accordance with the report's instructions. (Bear in mind that a 1990 edition is available that may, upon industry acceptance, require an equation different from the one in this manual.) In any case, the 1985 report points out that the pipe must have an ID of not less than 1.6 in., and the ratio of the orifice bore to the pipe ID (the β ratio, or simply β) must be between 0.10 and 0.75. Under these conditions, coefficients calculated for flange taps are subject to a tolerance of ±0.5 percent when the β ratio is between 15 and 70 percent. When the ratio is less than 15 percent or greater than 70 percent, the tolerance is doubled to 1 percent. Table 9.1 is an example of the effect of tolerances used in the flow equation:

$$Q_h = F_b \times F_r \times Y \times F_{tf} \times F_{gr} \times F_{pv} \sqrt{h_w P_f} \qquad \text{(Eq. 9.1)}$$

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Gas Sales Contracts

MARKET PERIODS

A gas contract is a mutually negotiated set of rules governing conduct between the parties making the contract. Typically, a contract relates to all matters of common interest. Gas sales contracts can be made during one of two market periods: a seller's market, when demand exceeds supply, and a buyer's market, when supply exceeds demand.

FIXED-RATE CONTRACTS

A *fixed-rate contract* is a contract in which a known rate of gas is sold at so many dollars per million BTU ($/MMBtu) during every month of sale. It is called a fixed-rate contract because the volume or rate of gas is fixed over the period of the contract even though the rate may vary from month to month. If the gas is processed for the recovery of LPGs, a separate processing agreement must be drawn up.

Details of a Fixed-Rate Contract

Both the buyer and the seller attempt to put into the contract rules covering all conceivable situations, especially ones that have been problems in the past. All situations cannot possibly be covered, however, so the contract usually includes an agreement to arbitrate problem situations.

Preamble

The preamble contains the contract date, which serves to identify the contract. It also names the buyer(s) and seller(s) and gives a synopsis of the transaction. Following is an example preamble:

> This Agreement, made and entered into this 28th day of February, 19__, by and between LONG LINE PIPELINE COMPANY, hereinafter referred to as "Buyer," and LITTLE GUY OIL COMPANY, hereinafter referred to as "Seller"; whereas Seller has a supply of natural gas available for sale from the Glasscock area located in Dublin County, Texas, and whereas Buyer owns a natural gas transmission pipeline system; and whereas Seller desires to sell and Buyer desires to purchase and receive from Seller natural gas under the terms and conditions hereinafter set forth.

II

Unaccounted-for Gas

To a gas company, natural gas is an inventory of goods to be sold. Gas that is bought but not sold is money lost to the gas company. *Unaccounted-for gas* is a loss of inventory; it is the difference between the gas taken into the distribution system and the known quantities of gas taken out of the system.

Gas that is purchased, taken on exchange, or injected from storage constitutes *gas into the system*. Similarly, LPG, liquefied natural gas (LNG), and gas from other sources also constitute gas into the system. Sales, exchanges, company-used gas for fuel and construction, and known line losses from breaks and blowdowns are known quantities of gas out of the system. The difference in the quantities of gas in and gas out is gas that has not been accounted for, or unaccounted-for gas.

The difference between the amount of gas in and the gas out may be a loss or a gain—that is, less gas may go out than went in or more gas may go out than went in. A loss or a gain indicates a problem in the system that must be found and corrected. In general, unaccounted-for gas comes from leakage, incorrect measurement, theft, incorrect calculations and recordkeeping, or similar causes.

Preparing an unaccounted-for gas balance for a distribution system is not just a matter of totaling the accounting records of gas bought and sold. All phases of accounting, measurement, and operations must be considered continuously to make certain that the information used is accurate and complete.

INPUT-OUTPUT POINTS

All the points at which gas enters and leaves the distribution system must be metered. Without metering, preparing a correct gas balance is impossible. Estimates of unmetered taps cannot be relied on to produce a correct gas balance.

An accurate list must be made of all gas input meters and all gas output meters. Constant checking is necessary to be certain that no meters are missing and that no uninvolved meters are on the list. Keeping lists correct can be a time-consuming job, considering the turn-ons, turn-offs, and construction changes that go on in a distribution system.

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