NBSIR 86-3057

RAL GAS HANDBOOK

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U.S. Department of Commerce
Boulder, Colorado 80303

August 1986

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August 1986

Prepared for
U.S. Air Force
Engineering and Services Center
Tyndall Air Force Base, Florida 32404

U.S. DEPARTMENT OF COMMERCE, Malcolm Baldrige, Secretary

NATIONAL BUREAU OF STANDARDS, Ernest Ambler, Director

Foreword

This handbook was written for Base Civil Engineering (BCE) personnel and Real Property Management Agency personnel who have responsibility for checking the monthly gas utility bills and authorizing payment for natural gas purchased by the Air Force. Air Force Contracting Officers negotiating agreements with Gas Utility Companies should also find this handbook useful for background information. The purpose of the handbook is to promote a better understanding of gas metering principles and the computations involved in the sale of natural gas.

The handbook was prepared by the National Bureau of Standards, Center for Chemical Engineering, for the U.S. Air Force under project order No. F84-67.

Identification of Commercial Equipment

Identification of certain commercial equipment and instruments has been necessary in this report. Such identification does not imply recommendation or endorsement by the National Bureau of Standards, nor does it imply that the equipment identified is necessarily the best available for the purpose.

Use of Non-SI Units

It is necessary to write this report using units normally encountered on gas utility bills and used universally throughout the natural gas industry. The use of SI units or dual units would add unnecessary complication to this report and only serve to confuse the intended audience. The necessary use of non-SI units in this report departs from the usual NBS practice of using SI units.

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Definitions and Terminology

Abbreviations & Acronyms

AFB	=	Air Force Base
A.G.A.	=	American Gas Association
BCE	=	Base Civil Engineering
Btu	=	British thermal unit
CCF	=	one hundred cubic feet of gas.
MCF	=	one thousand cubic feet of gas.
MMCF	=	one million cubic feet of gas.
mole	=	one molecular weight of a compound.
n	=	the number of moles of a gas.
psia	=	pounds per square inch, absolute.
psig	=	pounds per square inch, gauge.
psid	=	pounds per square inch, differential.
ppm	=	parts per million (volume basis).
R	=	the universal gas constant (this constant has various units).
SCFH	=	standard cubic feet per hour (60°F & 14.73 psia)
SG	=	specific gravity = the mass of a unit volume of gas divided by the mass of the same unit volume of air, at a specified temperature.
SI	=	the International System of Units.
Z	=	compressibility factor.
J	=	joule = the unit of energy in the metric system; 1055 joules = 1 Btu (International).
MJ	=	megajoule = one million joules
Th	=	Therm = 100,000 Btu
daTh	=	dekaTherm = one million Btu

Definitions

- **Atmospheric Pressure** (P_a)

  The absolute pressure in the atmosphere at a given location. The average annual pressure at the nearest weather station to an Air Force Base will sometimes be used for contractual purposes.

- **Ideal Gas**

  A gas that obeys the ideal gas law of PV = nRT (Z=1).

- **One cubic foot of gas**

  The amount of gas that will occupy a volume of one cubic foot.

- **Boyle's Law**

  Boyle's law states that if the temperature of a given quantity of gas is held constant, the volume will vary inversely with the absolute pressure. The law may be expressed in equation form:

  $$\frac{P_1}{P_2} = \frac{V_2}{V_1} \text{ or } PV = \text{Constant} \Big]_T$$

- **Charles' Law**

  Charles' law states that if the pressure of a given quantity of gas is held constant, the volume will vary in direct proportion to the absolute temperature. Expressed in an equation:

  $$\frac{V_1}{V_2} = \frac{T_1}{T_2} \text{ or } \frac{T}{V} = \text{Constant} \Big]_P$$

- **Pressure and Temperature Base**

  When natural gas is purchased or sold on a volume basis, a pressure and a temperature have to be specified in order to completely define the amount of gas transferred. The most common pressure and temperature base in the gas utility industry is 14.73 psia and 60°F. 60°F is used almost universally, but other pressures such as 14.65 psia are quite common.

- Metered Volume of Gas

    This is the volume of gas that passes through the meter at the meter temperature and pressure.

- Base or Billing Volume of Gas

    This is the volume of gas that results when the metered volume of gas is converted to the billing pressure and temperature base (such as 14.73 psia and 60°F).

- Gross and Net Heating Value of Natural Gas

    There are two basic definitions for the heating value of a fuel gas; one is the gross or higher heating value (HHV), and the other is the net or lower heating value (LHV). The difference between the two depends on the state of the water product of combustion; i.e., whether the water is in the liquid or vapor state.

    The stoichiometric chemical reaction for the combustion of methane is

$$CH_4 + 2O_2 \rightarrow 2H_2O + CO_2 .$$

The products of combustion are water and carbon dioxide. When the reactants and the products are at the same initial conditions of pressure and temperature, the exothermic heat of combustion is dependent upon the state of the water in the combustion products. If the water is in the liquid state, the heat of combustion is called the gross or higher heating value. If the water is in the vapor state, the heat of combustion is called the net or lower heating value. The difference between the two values is of course the latent heat of vaporization of the water product.

- Compressibility Ratio (s)

    This is the ratio of the compressibility of the natural gas at base conditions (Z_b) to the compressibility at the metered or flowing conditions

(Z_f). The compressibility ratio is defined as Z_b/Z_f, and is properly designated by (s).

- Supercompressibility Factor (F_{pv})

  The supercompressibility factor is one of the correction factors in the A.G.A. orifice equation. This term accounts for the compressibility of the gas, and is defined as

$$F_{pv} = \left(\frac{Z_b}{Z_f}\right)^{1/2} .$$

- Dry Natural Gas

  Dry gas has negligible water vapor content; less than 7 lbs/MMCF ($<$ 147 ppm H_2O).

- Absolutely Dry Natural Gas

  By definition, gas that contains zero water vapor.

- Sour Gas

  Sour gas contains hydrogen sulfide and other sulfur compounds.

- Sweet Gas

  Sweet gas contains less than one grain of hydrogen sulfide per one hundred cubic feet of gas.

- Saturated Gas

  Saturated gas is completely saturated with water vapor.

- Certified Calibration Gas

  A hydrocarbon gas with certified mole fraction and heating value. Certified gas is necessary for gas chromatographs, combustion calorimeters, and flame titration instruments used for measuring heating value.

- Rangeability

A characteristic of gas meters; the rangeability is defined as the ratio of maximum to minimum flow rate that a meter can measure accurately, at a constant pressure.

- Relative Density

This is simply another term for specific gravity.

- Wobbe Index

This is an index used to characterize natural gas. It is

$$\frac{\text{Net or Gross Heating Value}}{(\text{Relative Density})^{1/2}} \quad [\text{Btu/ft}^3]$$

- Index

An index is a small unit that attaches to the top of a gas meter. The index is activated by the meter (once/revolution) and the index output is a dial or odometer type readout, in terms of cubic feet or liters of gas. The internal mechanism contains the necessary gears, wheels, and dials.

- Instrument

An instrument is similar to a meter index, but it is considerably more sophisticated. The instrument also attaches to the gas meter; it is driven by the meter output, but also has pressure and temperature sensors. The pressure and temperature values are used to correct the metered volumes to a specified billing volume. Usually the instrument will have two odometer type dials; one for the non-corrected volume, and another volume reading corrected to the specified pressure and temperature base. Often times a circular chart is part of the instrument package; the circular chart provides a permanent record of meter pressure and temperature, plus the meter revolutions. Instruments are available that will also correct for the compressibility ratio. Two typical temperature and pressure correcting instruments are shown in figures 6.1, 6.2

- Beta Ratio (β)

    A descriptive term for orifice meters; it is the ratio of the orifice bore diameter to the inside diameter of the pipe.

Abstract

A Natural Gas Handbook has been prepared to help Air Force BCE personnel better understand the principles of metering and selling natural gas on an energy content basis. The various aspects of natural gas such as heating value, moisture content, and hydrogen sulfide content are discussed. The characteristics of the various types of meters currently used for flow measurements are given. The correct procedures for calculating gas utility bills, including compressibility corrections, are presented. The responsibility of the gas utility to periodically check the gas meter and instrument accuracy is discussed. A list of information that should appear on the gas utility bill is given, and the various methods of selling natural gas are discussed.

Key words: compressibility; gas meters; heating value; natural gas

1.0 Introduction

During the initial survey phase of this study, fourteen different Air Force bases within the U.S. were visited. The purpose of the visits was to obtain a representative sampling of the way natural gas is purchased by the Air Force. The gas metering facilities at each base service entrance were inspected, and there were discussions with the BCE gas utility personnel about problem areas concerning gas metering and billing procedures. In addition, meetings were conducted with technical representatives from the gas utility serving the Base, with BCE personnel attending; various aspects of gas metering, heating value measurement, meter calibration, and billing procedures were discussed.

The information gathered during the survey and study phases was used to prepare this Natural Gas Handbook for the Air Force. The purpose of the handbook is as follows:

- to promote a better understanding of gas metering and measurement techniques, and the billing procedures for gas delivered,
- to promote a better understanding of temperature and pressure corrections to metered volumes, and also the correction factor for the deviation from Boyle's law.
- To accurately define the supercompressibility factor and the compressibility ratio, and point out the difference between the two.
- To promote a better understanding of the parameters which determine the heating value of natural gas, the various methods of measuring heating value, and the sale of gas on a heating value or energy content basis.
- To provide sample billing calculations showing all the steps in going from metered volume differences to dollars owed for gas delivered.

- To inform BCE personnel about new meter correcting instruments, and pulse transmitters which facilitate telemetering of meter output.

During the survey we found that there are definite trends taking place in the sale of natural gas to government bases and light industry. There is a definite movement toward the sale of natural gas on a heat content basis. Gas has become considerably more expensive. Thus there is more emphasis on measuring it accurately and selling it on a more equitable basis, and that basis is the heat content of the gas. Because of this, one complete section of this report is devoted to the various methods of measuring heat content, to new instruments to measure heat content, and to methods of calculating heat content from chromatographic mole fraction analysis.

Orifice meters are being used less at the Air Force base meter stations. The orifice meters are being replaced mostly with turbine meters, and some rotary displacement meters.

The use of newer, more sophisticated correcting instruments atop the gas meters is increasing. The older family of instruments provided pressure and temperature correction to a specified base, but the current instruments can also correct for the compressibility ratio and transmit the data by pulse senders to central data acquisition stations (telemetering).

The natural gas industry has its own set of units or nomenclature that is fairly consistent throughout the pipeline transmission and gas utility companies. However, these are not the recommended SI units. The units that the BCE and utilities management personnel will encounter on the gas utility bills are listed below, and for consistency these are also the units that will be used throughout this handbook.

CCF	=	One hundred cubic feet of gas
MCF	=	One thousand cubic feet of gas
MMCF	=	One million cubic feet of gas
Btu	=	British thermal unit
Therm	=	100,000 Btu
MJ	=	One million joules (megajoule)
psia	=	pounds per square inch absolute
psig	=	pounds per square inch gauge
°F	=	degrees Fahrenheit

Thus, we will use MCF for 1,000 cubic feet of gas and MMCF for 1,000,000 cubic feet of gas. This is not consistent with present Air Force terminology wherein 1,000 cubic feet of gas is denoted KCF, and 1,000,000 cubic feet of gas is denoted MCF.

The American Gas Association (A.G.A.) has set guidelines for the use of metric units [9] but the natural gas industry has not yet started toward metric conversion.

This study was limited to an evaluation of the various methods of purchasing, metering, and billing for natural gas sold to Air Force bases. Only the primary gas meters on the service lines entering the Base were considered. Additional submetering within the Base (except power plants) and the facility gas distribution systems were only peripherally included in this study.

2.0 Characterization of Natural Gas

Raw natural gas from oil and gas wells must be processed in order to obtain a marketable product; water vapor, inert and poisonous constituents, and condensable hydrocarbons are removed to tolerable levels. The processed (sweet) gas sold to industry and the public is mostly methane with small amounts of ethane, propane, butane, pentane, carbon dioxide, and nitrogen. A typical analysis would have constituents in the following ranges:

Methane	90 to 96	Mole	%
Ethane	0 to 8	"	"
Propane	<1.0	"	"
Butane	<0.5	"	"
Pentane	<0.5	"	"
Carbon Dioxide	0 to 2	"	"
Nitrogen	0.5 to 8	"	"
Hydrogen Sulfide	<1 grain/CCF		
Water	1 to 4 lbs/MMCF		

Natural gas is classified in several broad categories, as follows:

- Wet gas contains the heavier, condensable, hydrocarbons such as propane, butane, pentane, and above. This term shouldn't be confused with saturated gas; which means the gas is saturated with water.
- Lean gas denotes an absence of the above condensable hydrocarbons.
- Dry gas has negligible water vapor content; less than 7 lbs/MMCF.
- Sour gas contains hydrogen sulfide and other sulfur compounds.
- Sweet gas denotes an absence of hydrogen sulfide and other sulfur compounds, i.e. < 1 grain H_2S/CCF.

Natural gas sold to the public is characterized as lean, dry, and sweet.

The degree to which raw natural gas is processed is to some extent dictated by distribution and safety constraints. The water vapor must be removed because water will promote the formation of solid gas hydrates in the pipeline, as explained in section 3.0.

The heavier hydrocarbons such as propane, butane, pentane and above may condense to liquid in the pipeline; accumulation of condensed liquid is a safety hazard and will also restrict the gas flow. Thus the concentrations of the heavier hydrocarbons are usually very low.

Hydrogen sulfide (H_2S) must be removed since it is extremely toxic and dangerous. It is also corrosive in the presence of air and water. The hydrogen sulfide content of processed gas is usually limited by contract specification to less than one grain H_2S per 100 cubic feet of gas, or less than 1.44 lbs H_2S per MMCF gas (approximately 16ppm H_2S).

It is also common practice to limit the inert species (carbon dioxide and nitrogen) to approximately 3 Vol.% of total. With the above constraints, the heating value of the processed gas ranges from 950 to 1235 Btu/ft^3 [14.73 psia & 60°F].

Before final distribution, the utility companies add a commercial odorant to the gas; the odorant is a mixture of mercaptans, aliphatic sulfides, or cyclic sulfur compounds. The concentration ranges from 0.25 to 1.5 lbs odorant per MMCF gas.

The processed gas is normally particulate free, but will entrain pipeline scale and rust at high flow rates. The explosive and flammability limits of natural gas are very close to those for methane (5-15 Vol.%). Processed natural gas from different sources is sometimes blended in the field to adjust the heating value, or it may be blended with propane or vaporized LNG.

Moreover, there are some utilities that blend air with natural gas to decrease the heating value.

3.0 Water Content of Natural Gas

Processed natural gas contains only a negligible amount of water vapor (moisture). The water must be removed because solid gas hydrates will form at temperatures well above 0°C, at prevailing pipeline pressures of 400 to 800 psig. The buildup of these ice-like crystals can restrict or stop pipeline gas flow. Water is easily removed during processing by absorption using hygroscopic liquids or by adsorption on activated solid desicants such as molecular sieves. The usual process is to use diethylene or triethylene glycol in an absorbtion tower. Within the continental United States, the natural gas contract specifications almost always limit the water content to the range of five to seven pounds per million cubic feet of gas (5-7 lbs H_2O/MMCF). At 14.73 psia and 60°F, this is equivalent to 105 to 147 ppm water, respectively.

Various terms are used to characterize the amount of water vapor in natural gas, and one has to be very careful with this terminology. Most of the processed natural gas sold in the United States has only a negligible amount of water vapor as explained above. Throughout the Natural Gas Industry this is called processed gas, dry gas, and as-delivered gas. However, in the strict sense of the word, the gas is not absolutely dry. It still contains up to 147 ppm water.

Therefore, in order to keep in step with current terminology, natural gas with zero water vapor content will be called absolutely dry gas, and natural gas with less than 7 lbs H_2O/MMCF will be called dry, processed, or as-delivered natural gas.

At the other extreme we have saturated natural gas which is completely saturated with water; this definition is straightforward with no confusion.

At 60°F the vapor pressure of water is 0.25611 psia. Thus saturated natural gas at 14.73 psia and 60°F contains

$$\frac{0.25611}{14.73} \times 100 = \underline{1.7387 \text{ Vol.\% Water}} \;;$$

in parts per million this is 17,387 ppm. Thus saturated natural gas will hold a significant amount of water; water of course is inert and will decrease the heating value of dry gas. If a given source of absolutely dry gas had a heating value of 1000 Btu/ft³, the same gas saturated with water vapor would have a heating value of

$$\frac{100 - 1.7387}{100} \times 1000 \frac{\text{Btu}}{\text{ft}^3} = 982.6 \frac{\text{Btu}}{\text{ft}^3}$$

This is a significant decrease.

For comparison, the same gas with as-delivered water content of 7 lbs/MMCF (147ppm) would have a heating value of

$$\frac{10^6 - 147}{10^6} \times 1000 \frac{\text{Btu}}{\text{ft}^3} = \underline{999.85 \text{ Btu/ft}^3} \;.$$

Thus the as-delivered water content has negligible effect on the heating value of the gas.

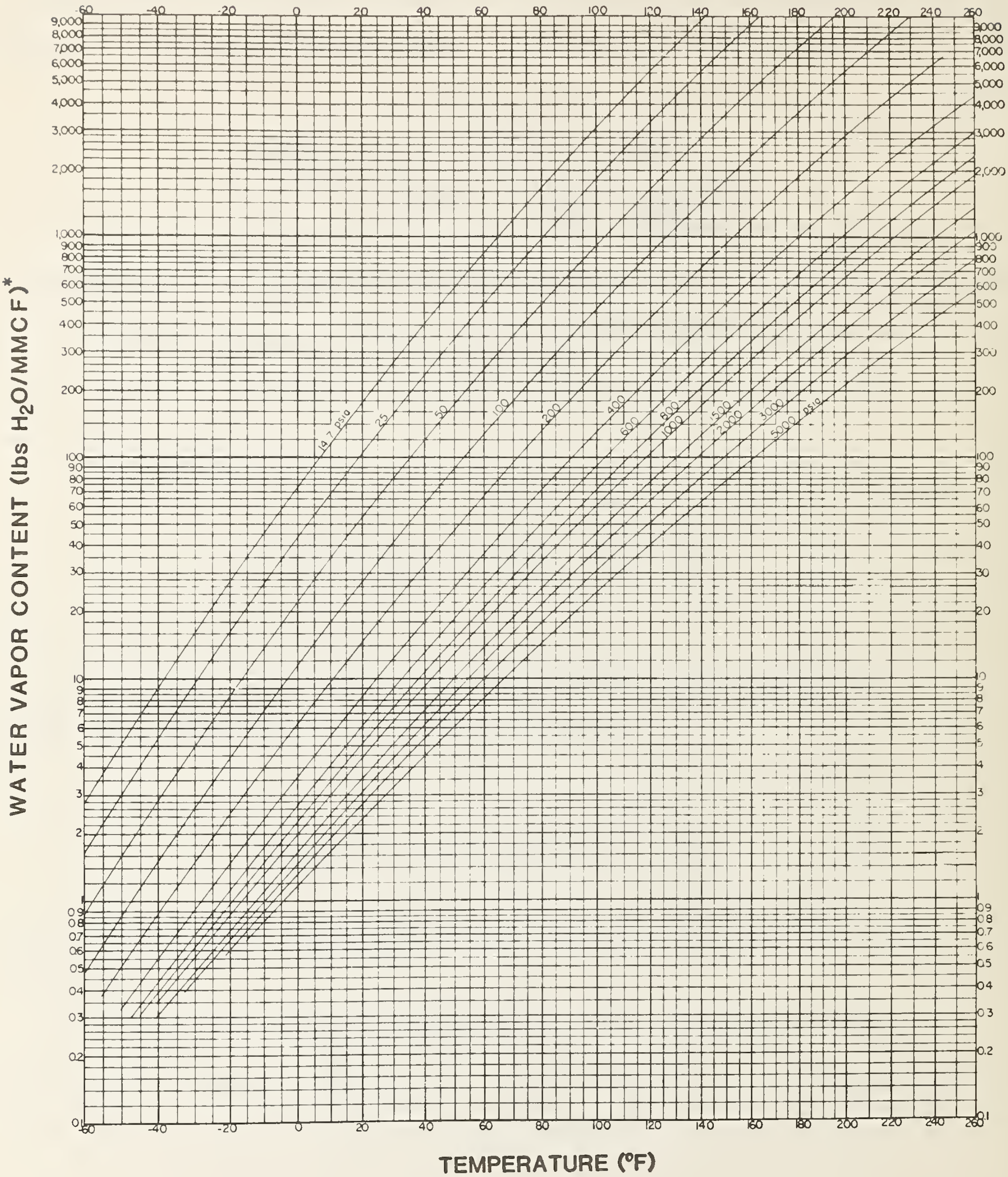
The one area where saturated natural gas is encountered is with combustion calorimetry. The gas is necessarily saturated as it passes through the calorimeter, and the heating value recorded is for saturated natural gas.

In order to determine the heat content of the same absolutely dry gas, one merely divides by 0.9826, as shown below. Using the saturated value of 1020 Btu/ft^3,

$$\frac{1020\ \text{Btu/ft}^3\ [\text{sat}]}{0.9826} = 1038\ \text{Btu/ft}^3\ [\text{dry}] \ .$$

Figure 3.1 shows the water vapor content of natural gas at 14.73 psia and 60°F for various dew-point (saturated) conditions of temperature and pressure.

Water Content of Saturated Natural Gas



*Cubic feet @ 14.73 psia & 60°F

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FIGURE 3.1

4.0 Heating Value of Natural Gas

There are two basic definitions for the heating value of a fuel gas: one is the gross or higher heating value (HHV), and the other is the net or lower heating value (LHV). The difference between the two depends on the state of the water product of combustion; i.e., whether the water is in the liquid or vapor state.

The stoichiometric chemical reaction for the combustion of methane is

$$CH_4 + 2O_2 \rightarrow 2H_2O + CO_2$$

The products of combustion are water and carbon dioxide. When the reactants and the products are at the same initial conditions of pressure and temperature, the exothermic heat of combustion is dependent upon the state of the water in the combustion products. If the water is in the liquid state, the heat of combustion is called the gross or higher heating value. If the water is in the vapor state, the heat of combustion is called the net or lower heating value. The difference between the two values is, of course, the latent heat of vaporization of the water product.

The gross or higher heating value is the term most widely used in the natural gas industry---probably because the widely used combustion calorimeters measure the gross heating value.

There are three basic methods or instruments for measuring the heating value of natural gas, and all three are currently used.

1) combustion calorimeters

2) flame titrators

3) gas chromatographs

The combustion calorimeters have been widely used for years and there are still many in service. The calorimeters must be located in a temperature controlled environment, and the response time is on the order of several minutes. The calorimeters have a water bath and measure the gross heating value of saturated gas. The specific gravity has to be measured with another independent instrument.

There are several types of flame titration instruments available. They all operate on the basic principle that the heating value of a gas or gas mixture is proportional to the flame temperature of a stoichiometric mixture. Several methods are being used to sense the optimum stoichiometric ratio: one method is to measure the flame temperature, and another is to sense the oxygen content of the combustion products. The flame titrators have a response time of approimately 20 seconds; a temperature controlled environment is not necessary; and some instruments are also capable of measuring the specific gravity of the gas.

The gas chromatographs are even more sophisticated and more expensive, but they also provide all the information necessary to calculate heating value, specific gravity, the compressibility factor, and mole percent of inert gases. The mole fraction of all species except water is routine output. Recently, there has been agreement on a standard method (ANSI/API-2530, second edition) [11] of calculating the heating value of natural gas from mole fraction analysis. Previously, there were several different methods of calculation, from several trade associations, with no complete agreement between methods.

It should be clearly pointed out that the heating value of a gas or gas mixture is for a cubic foot of gas at specified conditions of temperature, pressure, and moisture content; in addition one has to indicate whether it is gross or net heating value. Each of the above qualifiers must be clearly specified if the heating value (energy content) is to be meaningful. For example, if the gross heating value of as-delivered gas is 1020 Btu per cubic foot at base conditions, the heating value should be written as follows:

$$1020 \text{ Btu/ft}^3 \left] \begin{array}{l} \text{Gross} \\ 60\,^\circ\text{F \& 14.73 psia} \\ \text{as-delivered moisture} \end{array} \right.$$

The heating value normally encountered in the natural gas industry is the gross heating value for as-delivered gas, at some specified pressure and temperature base. The heat or energy content of natural gas is increasingly important, because the trend is definitely toward the more equitable method of selling gas on an energy content (Therm) basis.

5.0 Volume Measurement of Gas

There are three basic types of meters being used to meter natural gas delivered to government installations: these are orifice meters, turbine meters, and positive displacement meters (rotary and diaphragm types). The type of meter best suited for a given installation depends on the following parameters:

- The range of gas flow required during the winter and summer months,
- The service gas pressure at the meter (this varies from 10 to 150 psig),
- The temperature extremes the meter will incur,
- The physical size of the meter,
- The possible use of parallel meters--often meters are installed such that a parallel secondary meter cuts in at a predetermined high flow rate through the primary meter,
- The maintenance and service time the utility company is willing to devote to a meter station,
- The presence of dirt or scale at high flowrates,
- The presence of heavier hydrocarbons ($>C_4$) that would tend to condense at colder temperatures.

As an integral part of the meter, there are various types of indexes, instruments, and chart recorders that are used to record and indicate the accumulated volume of gas that has flowed through the meter. These are explained in detail in a later part of this section.

Natural gas entering government bases flows through the primary service meters at various temperatures and pressures. The metered temperature and pressure are dependent upon geographical location, the ambient temperature, the delivery pressure in the service line, and the amount of isenthalpic expansion (pressure reduction) just upstream of the meter. The metered gas pressure and temperature are usually continuously monitored and recorded, except for the small diaphragm meters.

However, it is necessary to buy, sell, bill, and measure heating value in terms of a cubic foot of gas at a certain pressure, temperature, and moisture content. This is usually referred to as a base or billing pressure and temperature. The prevalent and most popular base temperature and pressure in the natural gas industry is 14.73 psia and 60°F; however, some utility companies use other pressure bases such as 14.65 psia. The base temperature of 60°F is used almost universally.

So, after metering the incoming gas at the delivery pressure and temperature, it becomes necessary to convert the metered volume to a new volume, at the billing base temperature and pressure.

In order to convert the metered volume to the base billing volume, we use two gas laws, plus a correction to account for the deviation from one of the laws. Each of these laws and the correction will now be discussed separately.

- Charles' Law

Charles' law states that if the pressure of a given quantity of gas is held constant, the volume will vary in direct proportion to the absolute temperature. Expressed as an equation, we have,

$$\frac{V_1}{V_2} = \frac{T_1}{T_2} \quad \text{or} \quad \frac{T}{V} = \text{Constant}\,\Big]_P \quad . \tag{1}$$

This is a simple linear correction. For example, if the metered gas temperature was 20°F at some cold location, in order to correct that metered volume to a base temperature of 60°F, we would first convert the 20° and 60°F temperatures to the absolute Rankine temperature of 460 + 20 = 480°R, and 460 + 60 = 520°R. The new volume at the base temperature of 60°F would be:

$$\frac{V_{520}}{V_{480}} = \frac{T_{520}}{T_{480}}\ , \text{ or } V_{520} = V_{480} \times \frac{520\,°R}{480\,°R}$$

$$V_{520} = 1.0833 \times V_{480}$$

The above calculation assumes that the pressure is constant at both temperatures. Thus, Charles' Law is a simple linear temperature correction, however, one must be careful to use absolute temperature values.

- Boyle's Law

Boyle's law states that if the temperature of a given quantity of gas is held constant, the volume varies inversely with the absolute pressure. Expressed in equation form, we have

$$\frac{P_1}{P_2} = \frac{V_2}{V_1}\text{, or } P_1V_1 = P_2V_2\text{, or } PV = \text{Constant}\ \Big]_T \tag{2}$$

This is a straightforward linear correction provided the gas is an ideal gas. For example, if gas was flowing through a meter at 60°F and 60 psig, and the metered volume was to be converted to a billing base of 60°F and 14.73 psia, the correction procedure would be as follows.

First convert the pressures to absolute values:

60 psig + 14.4 psia (atmospheric pressure) = 74.4 psia

and 14.73 psia is already an absolute value.

Thus, the metered gas volumes converted to the billing base volume @ 60°F and 14.73 psia would be

$$\frac{V_{base}}{V_{meter}} = \frac{P_{meter}}{P_{base}}\text{, or}$$

$$V_{base} = \frac{74.4 \text{ psia}}{14.73 \text{ psia}} \times V_{meter}.$$

Charles' and Boyle's laws are often combined to give an "Ideal Gas Law" in the form,

$$\frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2} = \text{Constant} \tag{3}$$

However, natural gas does not behave as an ideal gas at pressures above ~ 60 psia. This non-ideal behavior is accounted for by a correction term called the compressibility factor, almost always designated as Z. A compressibility plot for the major constituent of natural gas (methane) is shown in figure 5.1.

The equation of state for an ideal gas (Z=1) is

$$PV = nRT^{*} \tag{4}$$

and the virial equation of state for a real gas (Z≠1) becomes

$$PV = nZRT. \tag{5}$$

The compressibility factor (Z) is a correction factor to compensate for the non-ideal nature of real gases at higher pressures. The compressibility factor is a function of pressure and temperature, and one should note from figure 5.1 that the compressibility factor for methane (and natural gas) can be significant at higher pressures and especially at lower temperatures.

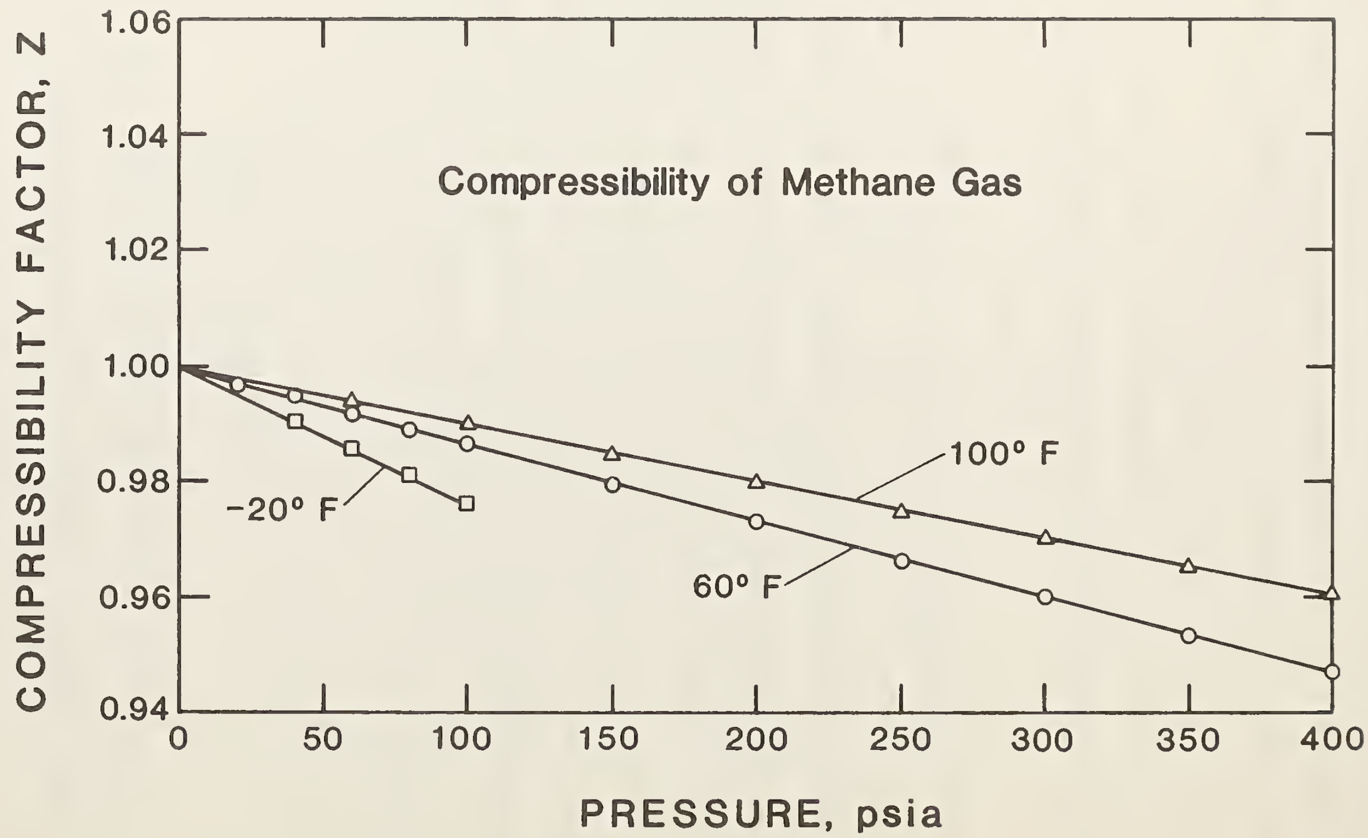
At the natural gas wholesale level, base pressures of 600 - 800 psig are common at orifice meter custody transfer stations, and the compressibility correction becomes significant. At the other extreme, the compressibility correction for gas at about one atmosphere flowing through a small diaphragm meter is negligible.

If we put equation 5 in a different form as shown below

$$V = \frac{nZRT}{P}$$

it is easier to see how the compressibility correction manifests itself for volume measurements that are different from those of an ideal gas.

*R = The universal gas constant
P & T are absolute pressure and temperature



NBS Technical Note 653 [8]

FIGURE 5.1

For instance, in a positive displacement metering application, we measure temperature, pressure, and volume through the meter. The temperature and pressure are correct values, and R is a constant. Thus if $Z \neq 1$, the volume has to vary proportional to Z. The bottom line is:

- If $Z = 1$, the volume measurement will be the same as for an ideal gas.
- If Z is less than 1, the volume measured is less than that of an ideal gas.
- If Z is more than 1, the volume measured is more than that of an ideal gas.

In summary, there are three factors that have to be applied to metered gas volumes (excluding orifices) in order to convert the volumes read on the meter to a volume at base or billing conditions.

- A linear temperature correction (Charles' Law)
- A linear pressure correction (Boyle's Law)
- A compressibility correction (deviation from ideal gas behavior)

These three adjustments to metered volumes for the various gas meters will be demonstrated in the following sections.

5.1 Turbine Meters

Turbine meters are becoming increasingly popular for natural gas measurement in the U.S. at the retail level. All of these meters will accommodate indexes and correcting instruments, thus making a compact, low maintenance metering unit. A cross-section of a typical turbine meter is shown in figure 5.2.

Turbine meters infer the volume flow through a pipe from the rotation of a turbine blade in the flow stream. The incoming gas is forced into an annular zone on the perimeter of the nose cone where the kinetic energy of the gas displaces the rotor blades to make the rotor spin with an angular velocity proportional to the velocity of the gas. A mechanical or electric readout is calibrated to give volume flow through the meter.

A typical accuracy curve for a turbine flowmeter is shown in figure 5.3. At flow rates less than 10% of rated capacity the turbine meter deviates sharply from the calibration curve. However, these meters typically have a nice flat calibration curve over the upper 90% of their rated capacity, as indicated in the figure.

The recommended installation configuration for an in-line gas turbine meter is shown in figure 5.4. A strainer or filter upstream of the meter is absolutely necessary to minimize contamination of the rotor bearings and to prevent damage to the rotor blades by larger particulates such as scale and rust. The use of straightening vanes upstream of the turbine meter is also recommended. Straightening vanes minimize cross-currents and swirl set up by upstream piping components. A typical straightening vane or "tube bundle" is shown in figure 5.5.

There are various types of straightening vane modules available: square, round, and hexagonal tubes. Whatever the shape, the cross-section geometry

Typical Turbine Meter

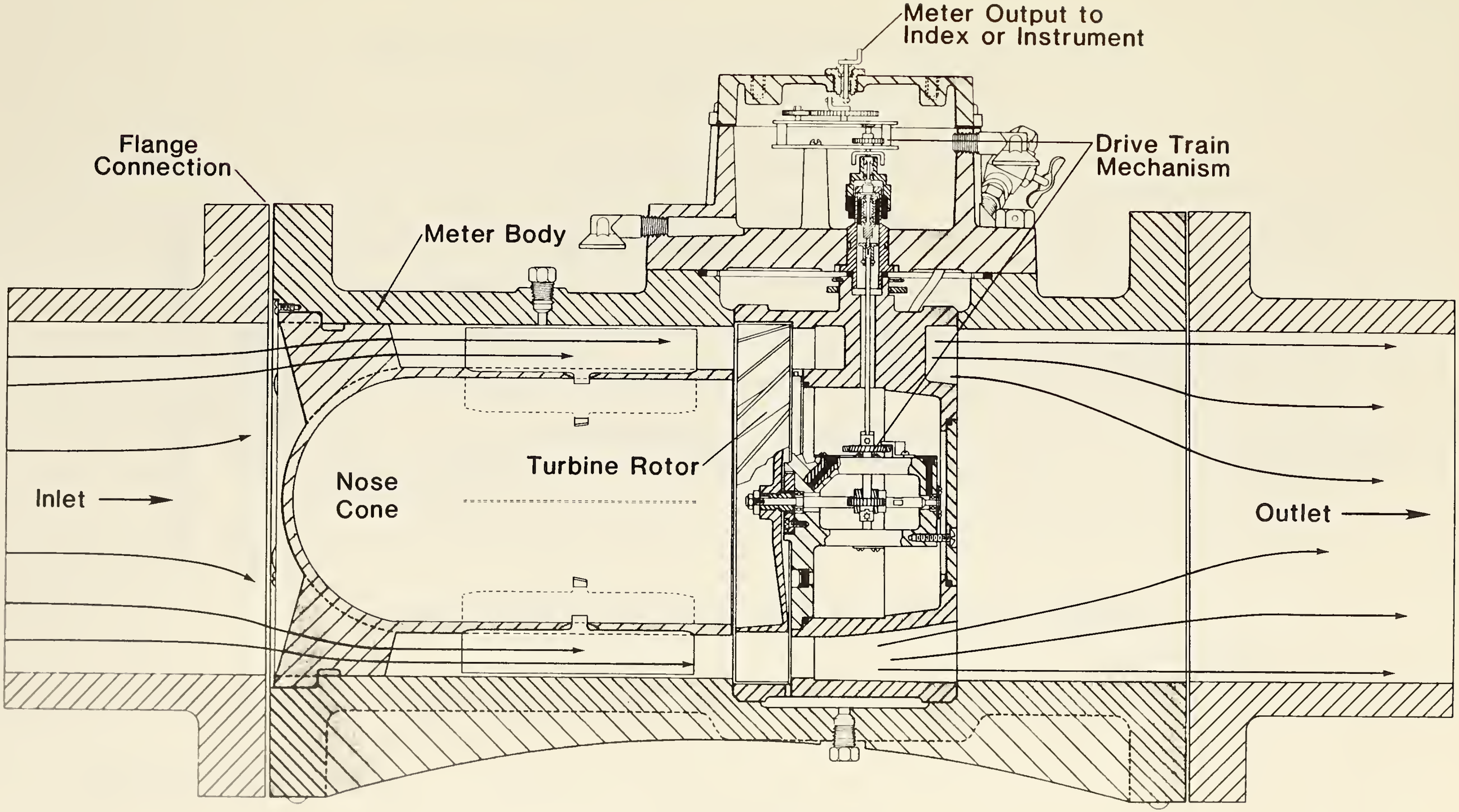
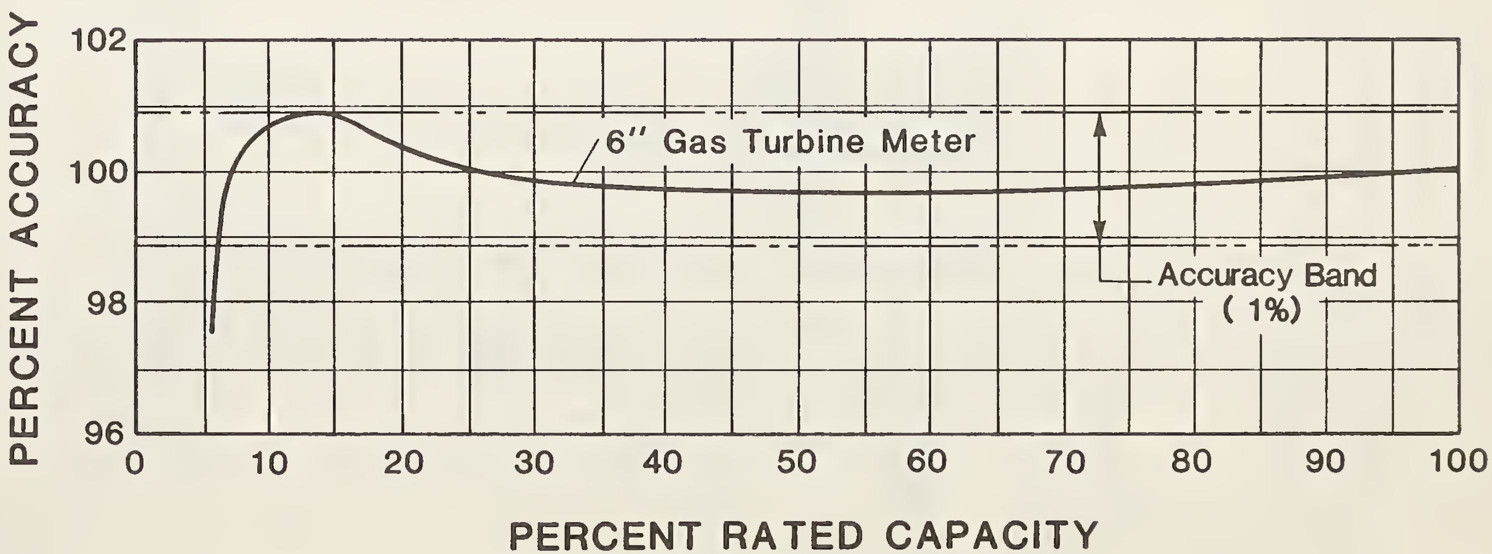


FIGURE 5.2

Courtesy of Rockwell International

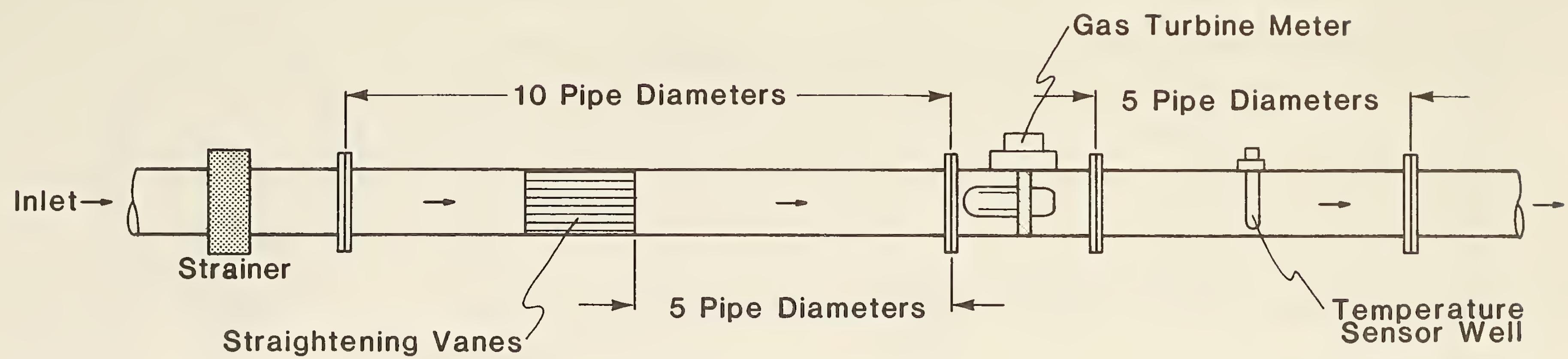
Accuracy Curve for a Turbine Meter



Courtesy of the American Meter Company

FIGURE 5.3

Recommended Installation Configuration for a Gas Turbine Meter



NOTE:

All lengths are minimum recommended.

FIGURE 5.4

Typical Straightening Vane Bundle

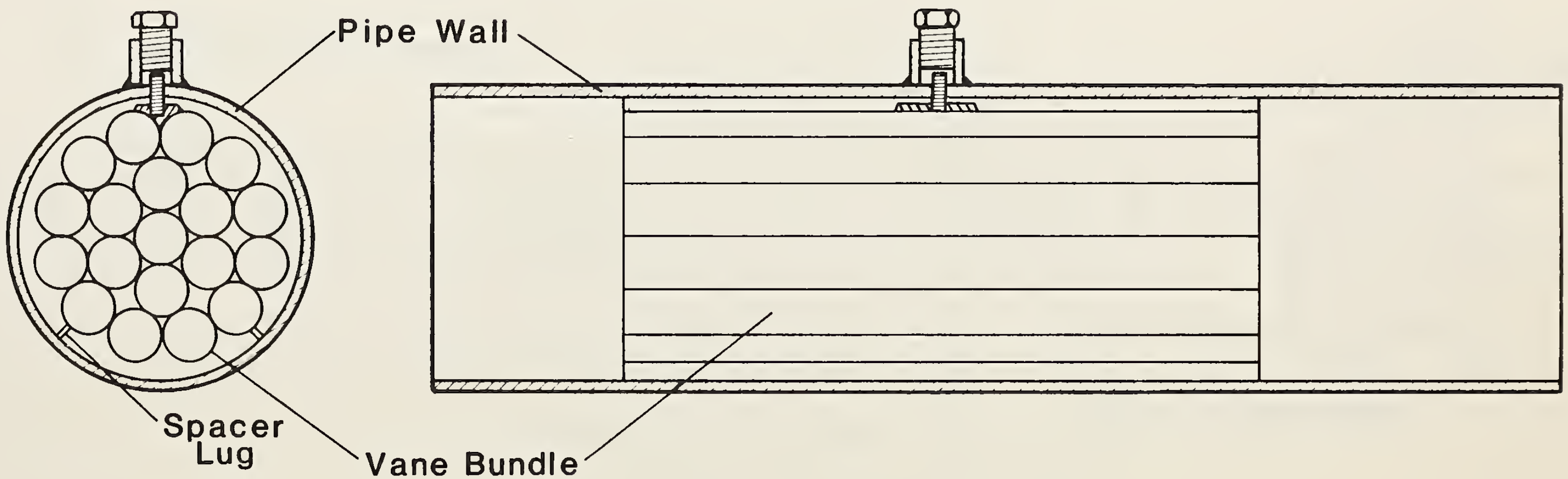


FIGURE 5.5

should be symmetrical. Straightening vanes are used to minimize swirl and cross currents in the flow stream that are caused by pipe fittings, valves, and regulators upstream of the meter. Additional design specifications for straightening vanes can be found in A.G.A. Report No. 7, Measurement of Gas by Turbine Meters [4].

Most utility companies will install a by-pass around the gas meter piping so that the meter can be serviced without interrupting gas service to the customer.

One disadvantage of turbine meters is their susceptibility to damage by overspeeding. They can be operated up to 150% of their rated capacity for short periods; beyond that, damage to the rotor or bearings will probably occur. There are two precautions to protect against overspeeding:

1) Pressure blow-down valves should be located downstream of the meter and be sized properly.
2) A critical flow orifice or sonic velocity nozzle may be installed downstream to limit the flow to 120% of the meters maximum rated capacity, provided adequate pressure is available. The sonic nozzle is more desirable since it has considerably less permanent pressure loss than the orifice.

In addition to the recommended installation configuration shown in figure 5.4, the A.G.A. also has short-coupled and close-coupled installation recommendations for in-line gas turbine meters. These are also given in the A.G.A. Report No. 7 [4]. A photo of a typical turbine meter installation with an upstream strainer and a correcting instrument with a chart recorder is shown in figure 5.6.

The advantages and disadvantages of gas turbine meters are listed below:

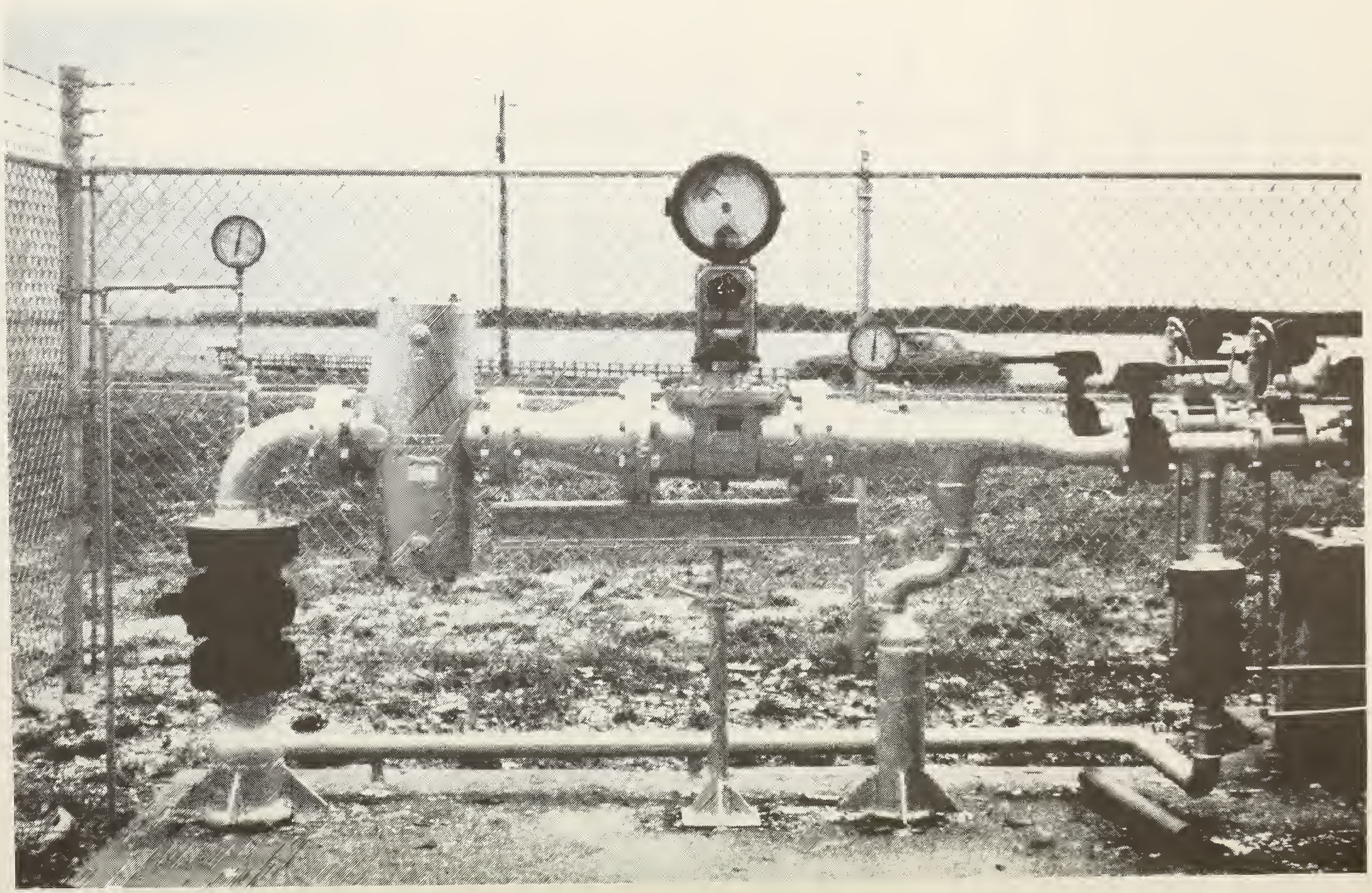


Photo of a turbine meter installation

FIGURE 5.6

Advantages

- Comparatively small in size,
- Maintenance on the meter and recording instrument is minimal,
- The meter inner works can be easily removed for a spin test, and may be easily interchanged with little down-time.
- A spin test to determine the mechanical friction in the meter mechanism is easily conducted.
- Variable rangeability, dependent on inlet pressure (18 @ 0.25 psig and 50 @ 100 psig).

Disadvantages

- Upstream strainers and possibly filters are necessary; particles of significant size can cause rotor blade damage or may wipe out the entire rotor.
- The rotor bearings are subject to contamination by dirt or debris in the gas stream. In past years bearing failure has been a problem area for process gas turbine meters.
- Gas turbine rotors are subject to overspeeding. Rotor speeds exceeding 150% of rated capacity can easily damage the rotor.

Any deterioration in the performance of a gas turbine meter due to increased mechanical friction or missing rotor blades will almost always decrease the rotor speed and thus record a lower flow rate than actual. This of course favors the buyer downstream rather than the upstream supplier.

5.1.1 Calculation of Base Volumes

A gas turbine meter may have an index output (dial or digital) that gives cumulative volume flow at the temperature and pressure of the gas flowing through the meter. Thus we have a cumulative volume at a flow temperature and pressure, but we need a billing volume at a base temperature and pressure.

The task is to convert the volume read on the meter to the billing or base volume.

The general equation for the gas at each set of conditions is:

For the meter,

$(P_f)(V_f) = (Z_f)(n_f)(R_f)(T_f)$ Flowing Conditions

For base conditions,

$(P_b)(V_b) = (Z_b)(n_b)(R_b)(T_b)$ Billing Conditions

where,

P = absolute pressure

V = volume

Z = compressibility factor

n = number of moles of gas

R = universal gas constant

T = absolute temperature

and the subscripts,

f = flow conditions

b = base or billing conditions

Now if we combine both of the equations above and solve for the base volume V_b, we have

$$\frac{P_b V_b = Z_b n_b R_b T_b}{P_f V_f = Z_f n_f R_f T_f} \text{ , or}$$

$$V_b = V_f \left(\frac{Z_b}{Z_f}\right)\left(\frac{n_b}{n_f}\right)\left(\frac{R_b}{R_f}\right)\left(\frac{T_b}{T_f}\right)\left(\frac{P_f}{P_b}\right) .$$

The number of moles of gas at each state is the same, so

$$\frac{n_b}{n_f} = 1$$

Similarly, the universal gas constant at both states is the same, so

$$\frac{R_b}{R_f} = 1$$

Thus, the equation for V_b reduces to

$$V_b = V_f \left(\frac{Z_b}{Z_f}\right) \left(\frac{T_b}{T_f}\right) \left(\frac{P_f}{P_b}\right)$$

Z_b and Z_f are the compressibility factors for the gas at each state (flow and base). The compressibility factors account for the compressibility of the gas at each state; this term is sometimes referred to as a correction for the deviation from Boyle's law.

The ratio Z_b/Z_f is properly called the compressibility ratio, and it is designated by (s). Thus,

$$\frac{Z_b}{Z_f} = s = \text{Compressibility Ratio.}$$

This ratio is often called various other incorrect names such as supercompressibility, supercompressibility factor, supercompressibility effect, etc., all of which are misnomers and incorrect. The supercompressibility factor is a similar compressibility correction term which applies only to the flow of gas through an orifice meter; this is fully explained in Section 5.3.

The compressibility ratio (s) can be easily found in table 10.5 of the <u>A.G.A. Report No. 7</u>, <u>Measurement of Gas by Turbine Meters</u> [4]. The table is for a hydrocarbon gas with a specific gravity of 0.6; the specific gravity of natural gas is not always 0.6, but it is usually very close. The table is for base conditions of 14.73 psia and 60°F, thus $Z_b \cong 1$. To use the table, one merely selects the proper value of (s) for the flow (meter) conditions of pressure and temperature. If the flow temperature were 20°F, and the flow pressure were 100 psig, $s = Z_b/Z_f = 1.0209$. The compressibility factor (Z_f) for natural gas at high pressures and low temperatures has values less than one, as indicated in figure 5.1. Thus in this case $Z_f \cong 0.9795$. With the compressibility ratio, we now have all the information necessary to correct the metered volume to a base billing volume. As an example, assume the following:

- The average monthly gas temperature at the meter = T_f = 20°F.
- The regulated gas pressure at the meter = P_f = 100 psig.
- The difference in meter readings for the monthly billing period = 644 MCF.

We first have to convert to absolute pressures and temperatures. Our base temperature = 60°F, we convert this to absolute Rankine temperature by adding 460. Thus,

T_b = 60°F + 460 = <u>520°R</u>. Similarly T_f = 20°F + 460 = <u>480°R</u>.

To convert to absolute pressure, the atmospheric pressure P_a must be known. This is usually specified in the gas contract. We will assume P_a = 14.4 psia. Our meter or flow pressure is gauge pressure (psig) plus the atmospheric pressure (P_a); ($P_f = P_g + P_a$). So our flow pressure (P_f) = 14.4 psia + 100 psig = <u>114.4 psia</u>. The billing base pressure is already given in absolute units of <u>14.73 psia</u>.

The expression becomes,

$$V_b = V_f \left(\frac{Z_b}{Z_f}\right) \left(\frac{T_b}{T_f}\right) \left(\frac{P_f}{P_b}\right)$$

$$V_b = 644\text{MCF} \times 1.0209 \times \frac{520\,°\text{R}}{480\,°\text{R}} \times \frac{114.4\text{ psia}}{14.73\text{ psia}}$$

$$V_b = 644\text{MCF} \times 1.0209 \times 1.0833 \times 7.766$$

$$\underline{V_b = 5532 \text{ MCF}} \quad [14.73 \text{ psia } \& \text{ } 60°\text{F}].$$

So the 644 MCF of gas that flowed through the meter @ 100 psig and 20°F would occupy a volume of 5532 MCF at a pressure of 14.73 psia and a temperature of 60°F.

With the delivered gas now converted to billing base conditions, the customer can be billed for the gas on either a volume basis (MCF) or on an energy basis (Therms).

If the gas were sold on a volume basis at a price of $4.75/MCF, the monthly bill would be

$$\frac{\$4.75}{\text{MCF}} \times \frac{5532 \text{ MCF}}{\text{month}} = \underline{\$26{,}277.00/\text{month}}$$

If the gas were sold on an energy basis, the calculation would be as follows. Assume:

- The average monthly heat content of the as-delivered natural gas is 1032 Btu/ft³ [60°F & 14.73 psia].
- The price of gas is 46 cents/Therm or $4.60/dekaTherm.

  (1 Therm = 100,000 Btu and 1 dekaTherm = 1,000,000 Btu)

The monthly gas bill would be,

<u>On a Therm basis</u>:

$$\frac{5532 \text{ MCF}}{\text{month}} \times \frac{1000 \text{ ft}^3}{\text{MCF}} \times \frac{1032 \text{ Btu}}{\text{ft}^3} \times \frac{\$0.46}{\text{Therm}} \times \frac{1 \text{ Therm}}{100{,}000 \text{ Btu}} = \underline{\$26{,}262/\text{month}}$$

<u>On a dekaTherm basis</u>:

$$\frac{5532 \text{ MCF}}{\text{month}} \times \frac{1000 \text{ ft}^3}{\text{MCF}} \times \frac{1032 \text{ Btu}}{\text{ft}^3} \times \frac{\$4.60}{\text{dekaTherm}} \times \frac{1 \text{ dekaTherm}}{1{,}000{,}000 \text{ Btu}} = \underline{\$26{,}262/\text{month}}$$

So, regardless of whether the gas is sold on a volume basis or an energy content basis, the gas flowing through the meter has to be converted to cubic feet of gas at base conditions. Once we have the volume at base conditions

(V_b), the gas can be sold on a volume basis @ $ per MCF, or it can be sold on an energy content basis @ $ per Therm. However, if the gas is to be sold on an energy content basis, we have to know the heat content of the delivered gas at the base conditions. This is another reason why it is so important to establish base conditions of temperature and pressure and to take measurements such as heat content with respect to that base.

5.2 Gas Displacement Meters

The gas flowing through this type of meter occupies a definite volume within the meter rather than spinning a rotor as with the turbine meter. There are two main types of displacement meters: rotary and diaphragm. Positive displacement meters have the desirable feature that upstream flow straighteners or conditioners are not required; thus installation configuration is not as critical as with some of the other type meters.

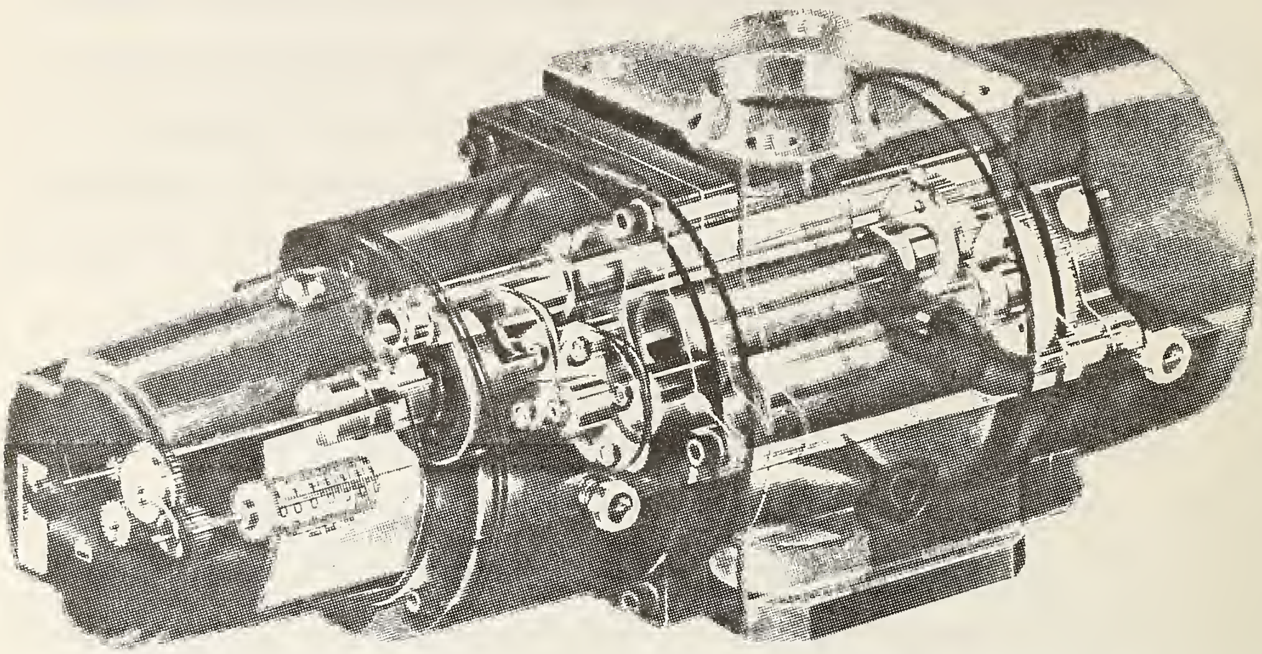
5.2.1 Rotary Displacement Meters

Rotary displacement meters operate on the principle of measuring gas (or liquid) that fills voids or chambers of given volume as the gas flows through the meter. The chambers are usually created by rotary lobes of figure-8 cross-section or rotary worm drives. Rotation results from the flow of gas through the meter. These meters have very close tolerances between the rotating lobes, between the lobes and the semi-cylindrical shells, and the lobe end plates; precision machining and assembly is necessary. A photo of a typical lobe-type rotary displacement meter is shown in figure 5.7. Rotary meters are normally used for large volume flow measurement applications such as a Base service entrance or a central power plant.

New compact designs are now available in the smaller range of meters; thus a wide range of sizes (flow capacities) are now available. The inherent design of these meters make them suitable for high pressure applications. Standard meters with working pressures of 300 and 600 psig are available and special meters with 1200 and 1400 psig working pressures can be purchased.

The capacity of rotary meters is limited by the permissible speed of the rotating parts, and overspeeding must be prevented by using an orifice or sonic nozzle downstream of the meter. Restricting orifice plates are usually sized to cause critical flow @ approximately 120% of rated meter capacity.

A typical lobe type rotary displacement meter



Permission granted by Dresser Industries Inc., Dresser Meter Division.

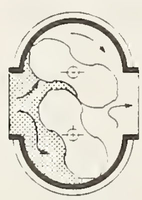
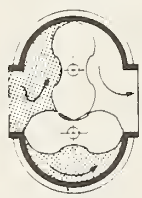
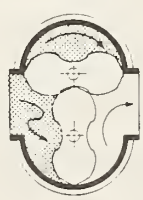
	**Position 1.** As bottom impeller rotates in counterclockwise direction toward horizontal position, gas enters space between impeller and cylinder.
	**Position 2.** In horizontal position, a definite volume of gas is contained in bottom compartment.
	**Position 3.** As impeller continues to turn, the volume of gas is discharged.
	**Position 4.** Concurrently, top impeller rotating in opposite direction has trapped a definite volume of gas in its horizontal position, confining another known and equal volume of gas. Process is repeated four times for each complete revolution of impeller shafts. Flow of gas creates the rotation of impellers.

FIGURE 5.7

The rotary meters are normally sized for maximum load @ 50 to 100% of their rated capacity. The rangeability of these meters is typically fifty to one.

A typical performance curve for rotary lobe meters is shown in figure 5.8. The accuracy suffers at low flow rates because a greater percentage of the total gas flow slips past the lobe clearance passages.

One desirable feature of these meters is the ease in which the condition of the meter may be checked. The pressure differential (ΔP) across the meter during operation gives a good indication of rotating friction as well as lobe clearance passages. Pressure taps are provided on most of the rotary meters so the pressure differential can be measured without altering the meter flow or taking the meter run out of service. A curve indicating the normal ΔP across the meter is usually provided by the manufacturer as shown in figure 5.8.

A complete line of indexes, correcting instruments, pulse transmitters, and telemetering equipment is available for rotary displacement meters.

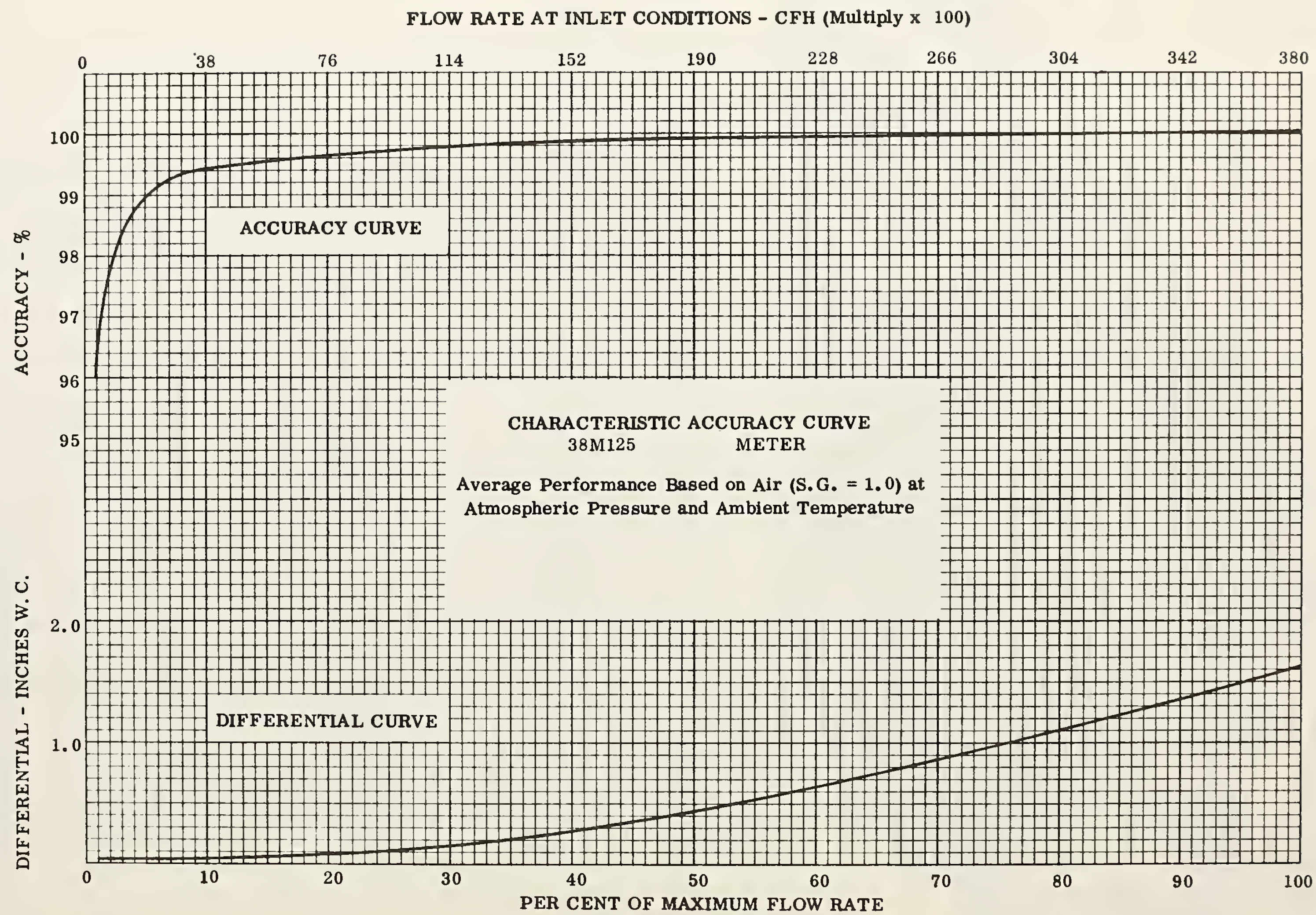
The advantages and disadvantages of the rotary displacement meters are given below:

Advantages

- High pressure capability,
- Simple, quick method of checking condition of meter,
- Reliable design -- proven low maintenance,
- Broad operating temperature range (-40°F to 140/250°F),
- Upstream flow straighteners are not necessary.

Disadvantages

- Close tolerance construction,
- Overspeeding must be prevented,
- The larger meters are noisy,



Performance curve for a lobe type rotary displacement meter

Permission granted by Dresser Industries Inc.,
Dresser Meter Division.

FIGURE 5.8

- Limited rangeability (22 to 77, dependent upon model).

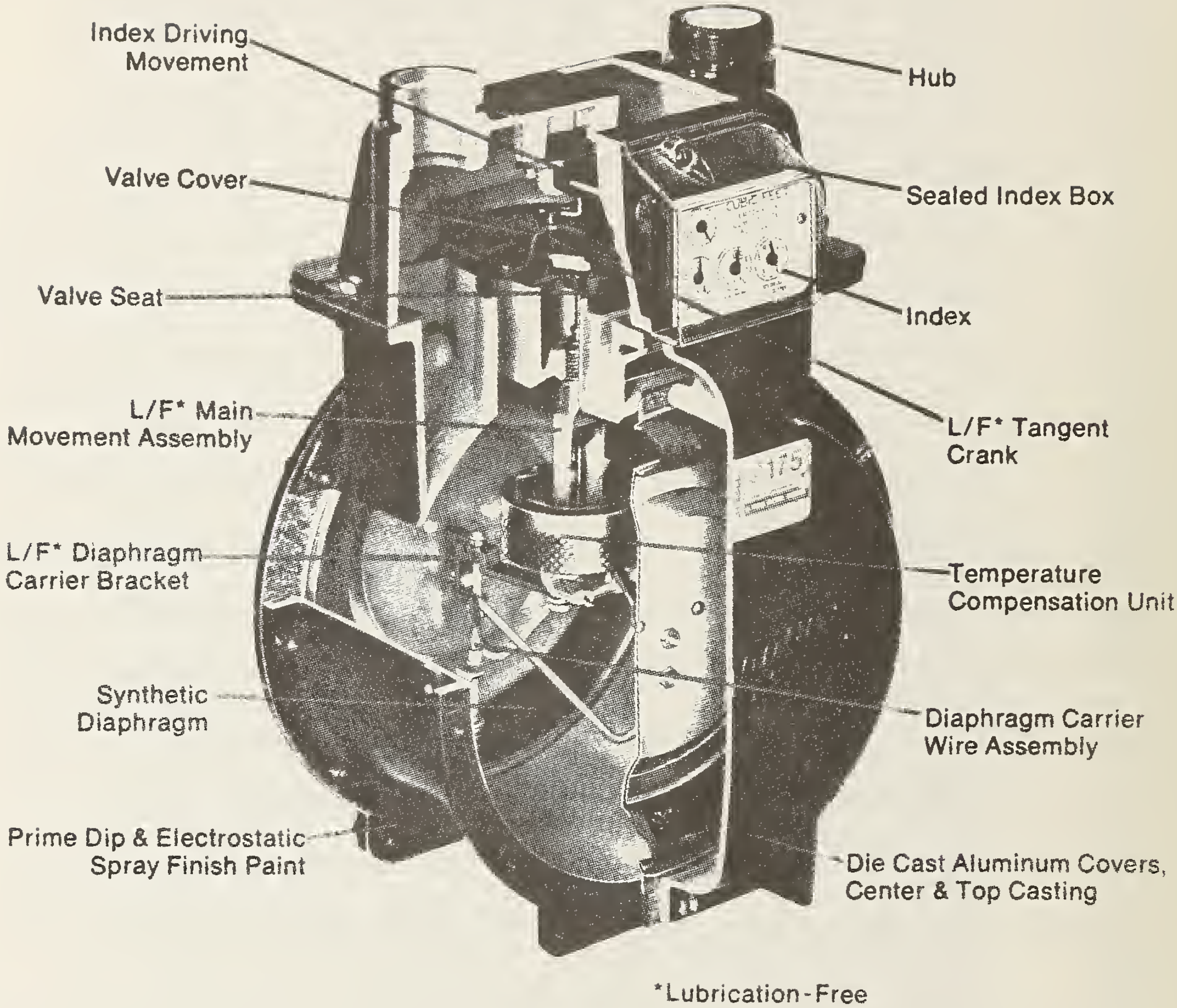
The procedure for calculating base billing volume from metered volumes is the same for the rotary and diaphragm meters; a sample calculation will be presented at the end of the next section on diaphragm type positive displacement meters.

5.2.2 Diaphragm Displacement Meters

Diaphragm type displacement meters also have chambers of a given volume that measure the gas as it flows through the meter. There is a wide range of sizes available ranging from 100 to 10,000 SCFH. A cross-section of a typical diaphragm meter is shown in figure 5.9. Diaphragm meters are excellent measuring devices from practically zero flow up to their maximum rated capacity. They have an excellent rangeability of 100:1, and are preferred for applications with cyclic loads. These meters also have the desirable feature that the measuring module can be easily replaced; most of these meters have a horizontal bolted flange which affords easy removal of the measuring module. One unique characteristic of these meters is that they must be set level.

Most of the newer diaphragm meters have an aluminum case and the operating pressure is 100 psig or less. However some of the meters can be purchased with a ductile iron body and cover with a pressure rating of 500 psig.

Another desirable feature available on most of the meters is temperature compensation (correction to a 60°F base) within the meter. The temperature compensated meters usually have a red badge or nameplate. For low pressure metering applications, this allows one to use a temperature corrected meter with a simple index, and get a temperature corrected volume reading without correcting instruments. Small diaphragm type gas meters are used for most



Typical diaphragm type positive displacement meter

FIGURE 5.9

Courtesy of Sprague Meter Division
of Sangamo Weston Inc.

residential housing throughout the U.S. Large diaphragm meters are used on many commercial buildings and for sub-metering at Government Bases.

A typical accuracy curve for diaphragm meters is shown in figure 5.10; the factory calibration accuracy is within ±1% over the meter operating range. A photograph of a large diaphragm meter with a pressure correcting instrument on top is shown in figure 5.11.

The advantages and disadvantages of diaphragm type displacement meters are shown below:

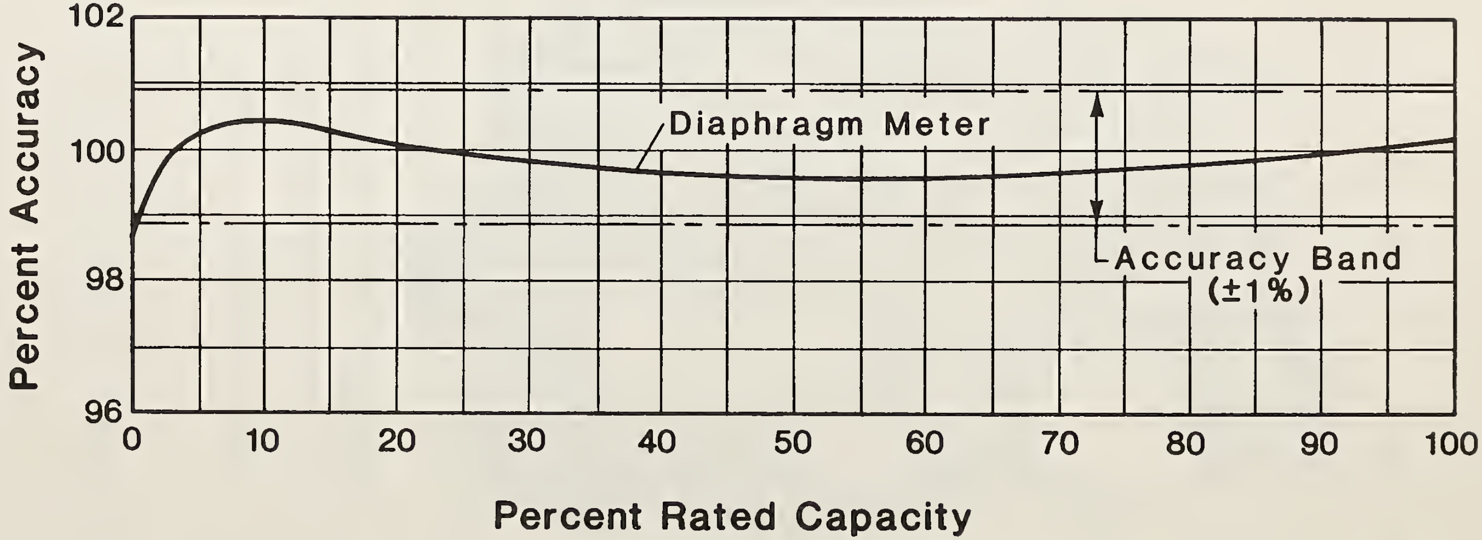
Advantages

- Good rangeability, (100 to 1)
- Temperature compensation available
- Measuring module is easily replaced.
- Large selection of sizes
- Negligible accuracy deterioration at low flow rates
- Flow straighteners are not necessary.

Disadvantages

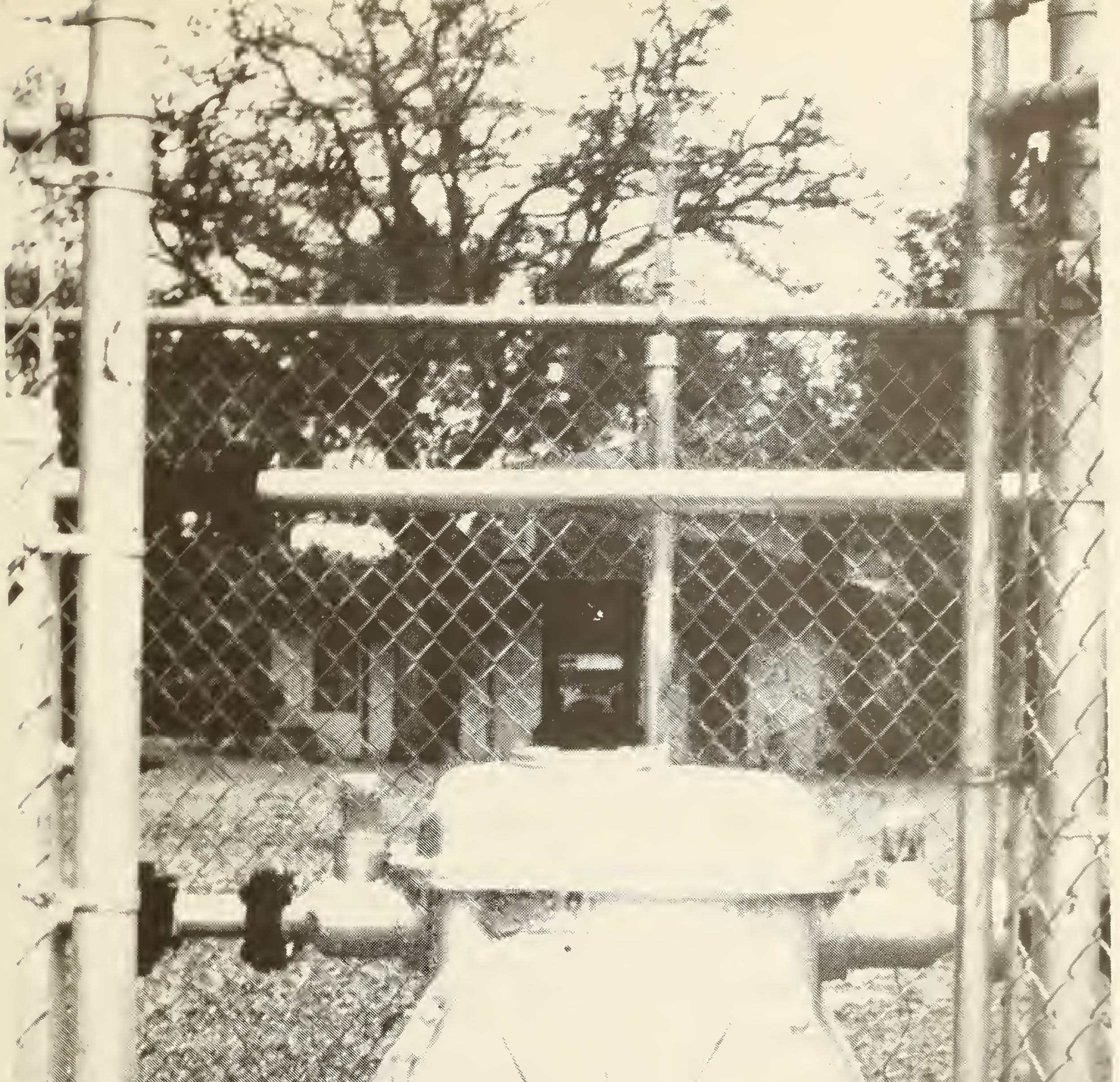
- The aluminum case meters have a maximum pressure of 100 psig.
- The high capacity meters are physically large and must be set level.
- Diaphragm meters should not be operated at extremely low or extremely high flows for an extended period of time; at low flow rates, the leakage becomes a significant portion of total flow, and extended service at high flow rates causes premature wear.

Accuracy Curve for a Diaphragm Meter



Courtesy of the American Meter Company

FIGURE 5.10



Large diaphragm meter with a pressure correcting instrument

FIGURE 5.11

5.2.3 Calculation of Base Volumes

A typical example of a diaphragm type meter calculation would be as follows:

Assume

- The diaphragm meter has the temperature compensated option; thus the volume readings on the meter index are already temperature corrected to 60°F.
- The meter has a simple index attached which senses only meter revolutions; there are no temperature, pressure, or compressibility corrections within the index.
- The average barometric pressure at the location is 14.4 psia, and the pressure regulator upstream of the meter is set for 4 ounces (0.25 psid) pressure differential with respect to atmospheric pressure, P_a. Thus the meter pressure averages 14.4 + 0.25 = 14.65 psia throughout the year.
- The meter index reading for the billing period is 644 MCF (present less previous meter readings).

Given

- The billing base for the utility company is 60°F and 14.73 psia.
- The compressibility correction for non-ideal gas behavior is negligible.

Thus, the calculation to determine base billing volume (the volume of the metered gas at 60°F and 14.73 psia would be as follows:

$$V_b = V_f \times \frac{T_b}{T_f} \times \frac{P_f}{P_b} \times \frac{Z_b}{Z_f}$$

where,

V_b = base billing volume

V_f = metered (flowing) volume of gas

T_b = base billing temperature (absolute) = 60°F + 460 = 520°R.

T_f = flowing gas temperature (absolute) = 60 °F + 460 = 520 °R.

P_f = absolute pressure of the flowing gas = $P_g + P_a$ = gauge plus atmospheric pressure.

P_b = base billing pressure = 14.73 psia.

Z_b = compressibility factor for base condition ≅ 1.

Z_f = compressibility factor for flowing condition ≅ 1.

or,

$$V_b = 644 \text{ MCF} \times \frac{60\,°\text{F} + 460}{60\,°\text{F} + 460} \times \frac{14.65 \text{ psia}}{14.73 \text{ psia}} \times \frac{1}{1}$$

$$V_b = 644 \text{ MCF} \times \frac{14.65 \text{ psia}}{14.73 \text{ psia}} = 640.5 \text{ MCF } [60\,°\text{F} \ \& \ 14.73 \text{ psia}]$$

Thus if all the gas that passed through the meter during the billing period were placed in a chamber at 60 °F and 14.73 psia, the gas would then occupy 640.5 MCF (640,500 cubic feet).

If we further assume the price of gas is $4.75/MCF [60 °F, & 14.73 psia], the billing period gas cost would be

$$\frac{\$4.75}{\text{MCF}} \times 640.5 \text{ MCF} = \underline{\$3,042.38}\ .$$

If the gas were sold on an energy basis, and the average heating value for the billing period was 1032 Btu/ft³ [60 °F & 14.73 psia], and the price of gas was $4.60/dekaTherm, the gas cost would be

$$\frac{644 \text{ MCF}}{} \times \frac{1000 \text{ ft}^3}{\text{MCF}} \times \frac{1032 \text{ Btu}}{\text{ft}^3} \times \frac{\$4.60}{\text{dekaTherm}} \times \frac{1 \text{ dekaTherm}}{1 \times 10^6 \text{ Btu}} = \frac{\$3,057.20}{}\ .$$

One should note that if the gas is to be sold on an energy content basis (Therms or dekaTherms), the average heating value of the gas for the billing period at base conditions (60 °F and 14.73 psia) has to be known. This is why it is most convenient to have a standard or base (of temperature and pressure) to measure, sell, and determine heating value of the gas at that standard condition.

If the diaphragm meter in the above example had not been the temperature compensated type, an average temperature for the flowing gas (T_f) during the billing period would have be measured. This would probably be done with a thermometer well in the gas piping downstream of the meter and a chart recorder; an average temperature for the billing period would then be determined from the charts for that period.

If we assume the average temperature was 46°F, the temperature correction would be as follows:

$$\frac{T_b}{T_f} = \frac{60°F + 460}{46°F + 460} = \frac{520°R}{506°R} = 1.028$$

and the base billing volume would be

$$V_b = 644 \text{ MCF} \times \frac{520°R}{506°R} \times \frac{14.65}{14.73} \times \frac{1}{1} = \underline{658 \text{ MCF}} \text{ [60°F \& 14.73 psia].}$$

During the past in some of the southern states, the gas contract might specify that an average annual temperature of 60°F may be assumed for all gas passing through small diaphragm meters. This eliminates the temperature correction for those meters. In the colder northern climates, the average metered gas temperature will be less than 60°F (since most of the gas is used during the winter months), and it becomes necessary to measure the temperature of the gas if it is to be sold on an equitable basis.

Since the dramatic increase in the cost of natural gas during recent years, the trend is definitely toward measuring consumption correctly. The larger diaphragm meters are being fitted with thermometers and charts or correcting instruments, so the metered gas temperature can be measured correctly.

5.3 Orifice Meters

An orifice meter is a very simple and rugged meter with no moving parts, and this is one of its virtues. An orifice meter consists of a thin plate with a hole (usually concentric) in it and pressure taps on each side of the plate. The plate is usually placed between two pipeline flanges, and static pressure taps are located on both sides of the orifice plate to measure differential pressure across the plate. The leading edge of the orifice bore always has a sharp corner, whereas the trailing or downstream edge is sometimes beveled. The orifice plate is securely placed in a pipeline such that the plane of the plate is perpendicular to the axis of flow.

The hole in the orifice plate (the bore) poses a restriction to the pipeline fluid, and a differential pressure develops across the orifice plate. The pressure drop across the plate is a function of the fluid density and flowrate; this is the basic principle of the meter. Orifice meters are sometimes termed a differential producing primary device. The differential pressure across the orifice plate is measured using static pressure taps; and an appropriate transducer. The two popular pressure tap configurations are termed flange taps and pipe taps. A concentric orifice plate with flange taps is the usual configuration found in the United States for natural gas measurements.

A cross-section drawing of an orifice meter is shown in figure 5.12, with a companion plot for the pressure profile in the vicinity of the meter. The two most popular and most prevalent types of pressure taps are shown in the figure. Ideally, the downstream pressure tap would be located at the vena contracta, but this is a function of β ratio and flow rates, so the plane of the vena contracta is not stationary.

Orifice plates with different bore diameters may be used. A term called "beta ratio" (β) is used to denote the ratio of the orifice bore diameter to the upstream pipe I.D.,

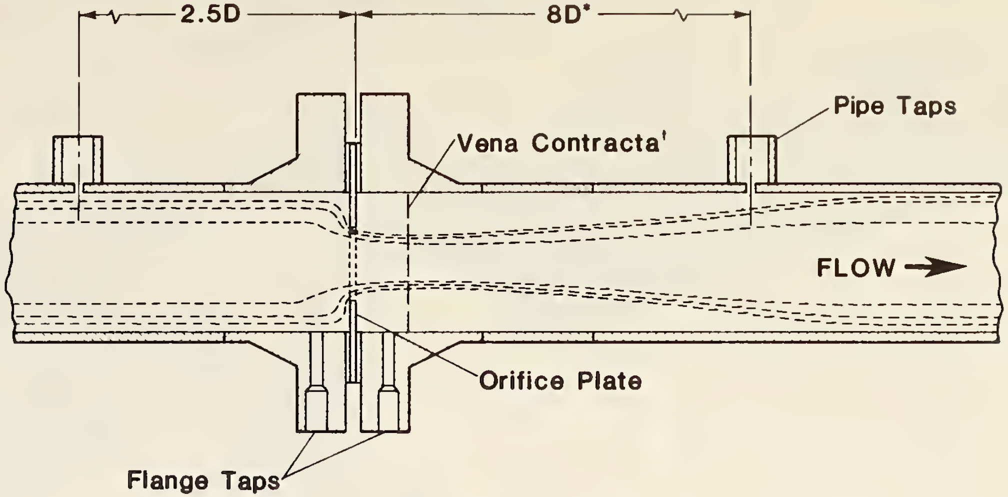
$$\beta = \frac{\text{orifice bore diameter}}{\text{pipeline inside diameter}} \quad .$$

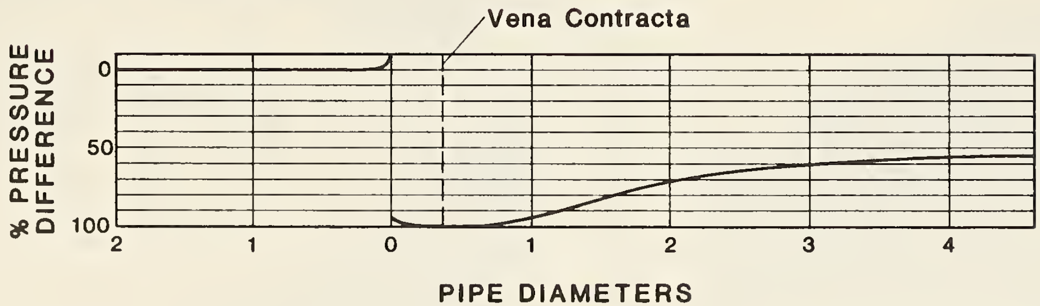
The A.G.A. recommends beta ratio limits of 0.15 to 0.7 for flange taps. Orifice meters are simple but they do have the strict requirements that there be a minimum amount of straight pipe upstream of the orifice plate, and also another smaller amount of straight pipe downstream of the plate. This is to minimize swirl and flow profile distortions in the flow stream which cause inaccuracy in the flow measurement. Straightening vanes may also be used upstream of the orifice plate to minimize swirl and promote straight streamlines. There are detailed recommended guidelines for the installation of orifice meters in the A.G.A. Report No. 3, Orifice Metering of Natural Gas, ANSI/API 2530 [1].

There are three parameters (measurements) from the orifice meter that are continuously recorded, usually on a 24 hour circular chart; these are the static pressure in the pipe, the differential pressure across the orifice plate, and the temperature of the fluid in the pipe. These charts are subsequently processed (read) using a special machine manufactured expressly for this purpose. The two pressure traces are integrated with respect to time to calculate the average daily pressure and the average differential pressure. The static pressure values range from 50 to 200 psig at the retail level, and from 500 to 800 psig at the wholesale level. The differential pressure ranges from 10 to 200 inches of water. The calibration of these pressure transducers should be checked weekly or at least every month.

Orifice Meter Installation

Showing Flange and Pipe Pressure Taps





Pressure Profile Near The Orifice Meter

*Pipe tap dimensions not to scale (D = nominal pipe diameters).

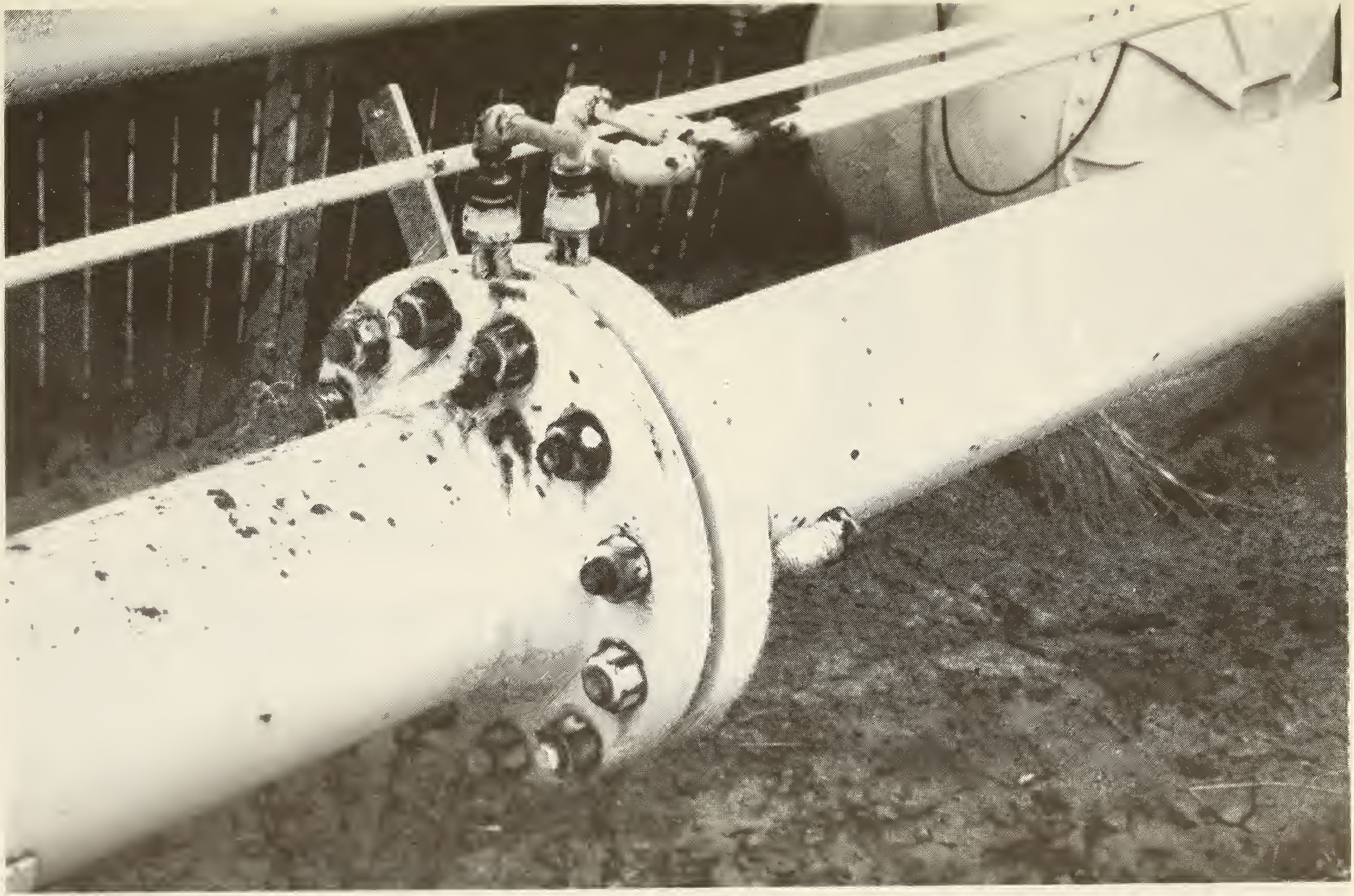
†The plane of minimum pressure downstream of an orifice plate.

FIGURE 5.12

The temperature of the pipeline fluid is usually measured downstream of the orifice plate, with a thermometer/well arrangement. The well is located downstream because placing it upstream would upset the streamline flow of the fluid. The calibration interval on the temperature transducer is not nearly as critical. Usually, the temperature is continuously recorded on a separate 24-hour chart.

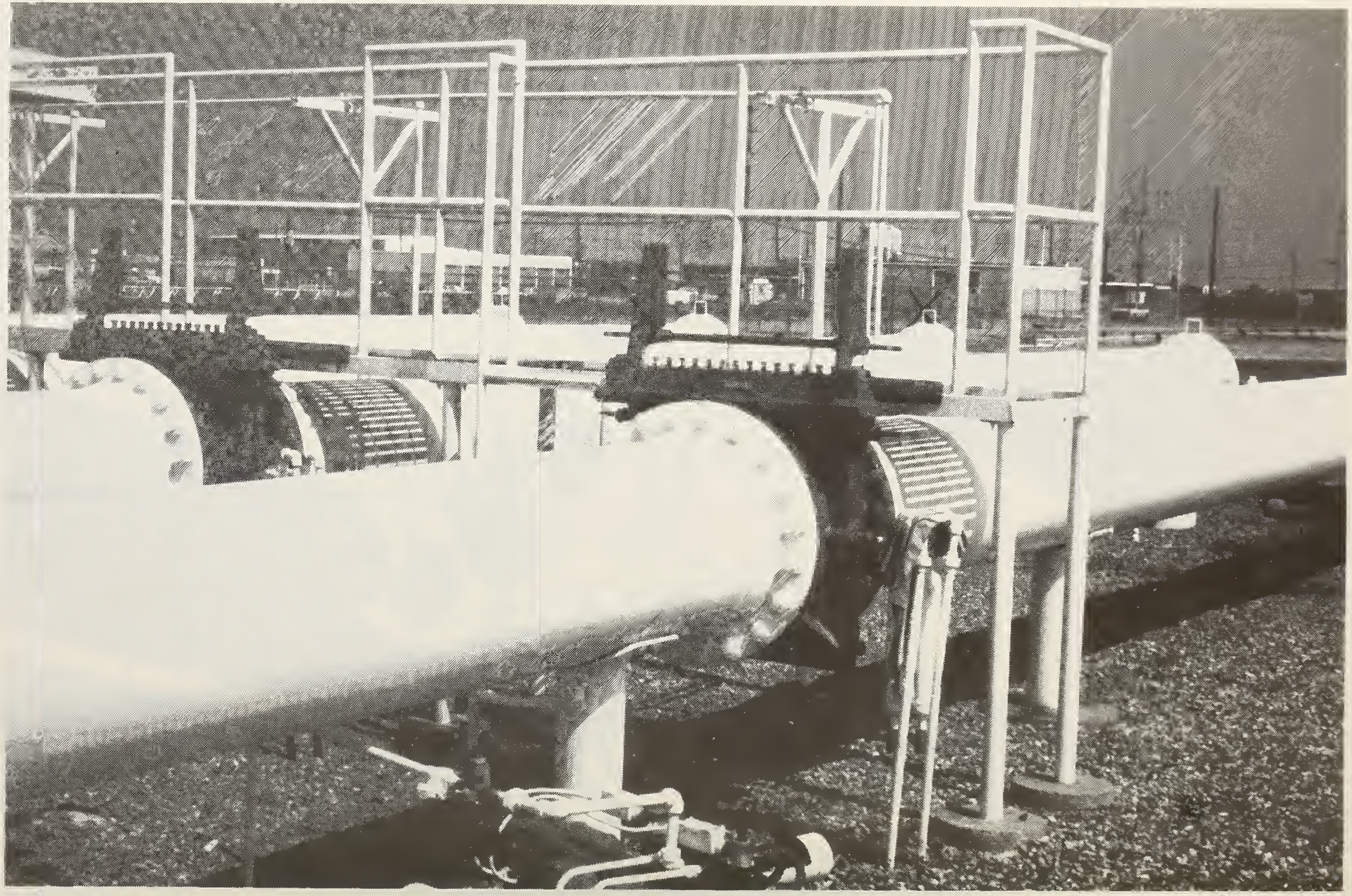
The A.G.A. Report No. 3, Orifice Metering of Natural Gas, ANSI/API 2530 recommends that, "the upstream edge of the measuring orifice shall be square and sharp so that it will not reflect a beam of light when viewed without magnification, and it should be maintained in this condition at all times. Moreover, the orifice plate shall be kept clean at all times and free from accumulations of dirt, ice, and other extraneous material." In order to maintain the orifice plates in proper condition, as described above, the gas utility and pipeline transmission companies normally remove and inspect the orifice plates every 30 to 90 days.

Orifice plates are sometimes placed directly between two flanges with appropriate pressure taps, as shown in figure 5.13. This type of installation requires that the line be depressurized and momentarily taken out of service (or use a bypass) in order to inspect the orifice plate. However, most orifice plates are positioned in the flow stream with special orifice fixtures or fittings, with integral flange taps that afford easy removal of the orifice plate for inspection and changeout. There are two basic types; one type of fitting has a removable top plate which allows access to the orifice plate for inspection, but the line must be depressurized and taken out of service during removal of the orifice plate. A fitting of this type is shown in figure 5.14.



Orifice plate between two flanges.

FIGURE 5.13



Orifice meter fitting.

Courtesy of Colorado
Interstate Gas Company

FIGURE 5.14

Another more sophisticated type of fitting allows removal of the orifice plate for inspection or changeout without depressurizing the line or interrupting flow. This is accomplished by cranking the orifice plate up into a bonnet enclosure, sealing off the bonnet enclosure, depressurizing the bonnet enclosure, removing the orifice plate, then reversing the procedure for reinstallation of the plate into the flow stream. The bonnet type fitting is most desirable if the orifice plate is to be inspected periodically as required, however these fittings are expensive, especially for the larger tranmission pipeline sizes. A photo of a 20-inch bonnet type orifice meter fitting is shown in figure 5.15.

The ability to changeout orifice plates to a larger or smaller bore size gives the orifice meter good rangeability. When gas consumption increases during the extremely cold months, a plate with a larger bore can be installed, and similarly, when gas flow is reduced in the summer months, an orifice plate with a smaller bore can be installed in order to maintain a differential pressure in the desirable range. The rangeability is limited by the necessity of staying in a desirable β and ΔP range.

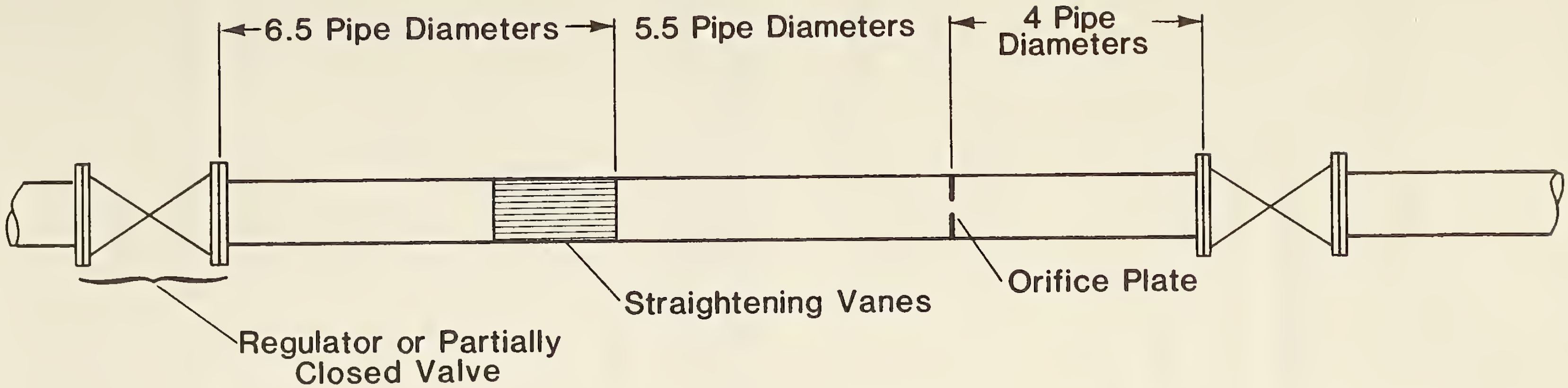
A recommended orifice meter installation is shown in figure 5.16. An adequate amount of straight line upstream of the orifice is very important; upstream straightening vanes are recommended; about five diameters of straight line downstream is desirable; a bonnet type fitting for the orifice plate is desirable; and the temperature probe should be located downstream of the orifice. Very precise guidelines for orifice meter installation configurations are given in A.G.A. Report No. 3 ANSI/API 2530 [1]; it is important that orifice meter installations conform to these recommendations.

Bonnet type orifice meter fitting

Courtesy of Colorado
Interstate Gas Company

FIGURE 5.15

Recommended Installation Configuration for an Orifice Meter



NOTE:

These minimum lengths of straight pipe are for $\beta = 0.6$ and flange type pressure taps.

FIGURE 5.16

The advantages and disadvantages of orifice meters are given below:

Advantages

- Simple, no moving parts
- Reliable
- Rugged
- Good meter at extreme temperatures
- No calibration required
- Useful over a wide flow range
- Relatively Inexpensive

Disadvantages

- Periodic calibration of pressure transducers
- Periodic inspection of orifice plates
- Without a bonnet type fitting, the flow line has to be de-pressurized for orifice plate inspection.

5.3.1 Calculation of Flow Through an Orifice Meter

We get three measurement parameters from an orifice meter:

1) Temperature of the flowing gas
2) Static pressure near the orifice plate
3) Pressure differential across the orifice plate.

In addition, we use the local atmospheric pressure, the local acceleration of gravity, the specific gravity of the gas, and the mole fractions of nitrogen and carbon dioxide to calculate the volume flow rate through an orifice meter.

The expression recommended and used almost universally by the natural gas industry to calculate flow through an orifice is given below, and explained in detail in the A.G.A. Report No. 3, ANSI/API 2530 [1].

$$Q_h = C' \, (P_f \times h_w)^{1/2} \quad [\mathrm{ft}^3/\mathrm{hr}]$$

where Q_h = volume flow rate of natural gas at base temperature and pressure, in units of ft³/hr,

$C' = F_b \times F_r \times Y \times F_{pb} \times F_{tb} \times F_{tf} \times F_g \times F_{pv} \times F_m \times F_a \times F_l$,

P_f = the absolute static pressure in psia, and h_w = the differential pressure across the orifice plate in units of inches-of-water (water at 60°F).

The various factors of C' are specific gravity, compressibility, manometer and thermal expansion corrections, orifice dimensional constants, and pressure and temperature base adjustments. Each factor is concisely described below. Some of these factors are dependent upon the type of orifice pressure taps.

<u>Factors of C'</u>

- F_b = <u>Basic Orifice Factor</u>

$$F_b = 218.44\, d^2\, K_o \frac{T_b}{P_b} \left(\frac{1}{T_f G}\right)^{1/2} .$$

This factor is a function of the type of pressure tap, the orifice bore size, the specific gravity, the flowing temperature, and the pressure and temperature base.

- F_r = <u>Reynolds No. Factor</u>

$$F_r = 1 + \frac{E}{R_d} .$$

This factor is mainly an adjustment for the actual Reynolds number, but it is also dependent upon the β ratio and the type of pressure tap.

$$E = d(830 - 5000\beta + 9000\beta^2 - 4200\beta^3 + B)$$

Where $B = \dfrac{530}{(D)^{1/2}}$ for flange taps, and

$$R_d = \frac{V_f\, d\, \gamma}{12\, \mu} .$$

- Y = Expansion Factor

This is a factor to compensate for the change in gas density between the two pressure taps. This factor is also a function of the type of pressure tap, and whether the absolute pressure was measured at the upstream or downstream static pressure tap. Various expressions, dependent upon the variables above, are given in the A.G.A. Report No. 3, ANSI/API 2530 for calculating the expansion factor.

- F_{Pb} = Pressure Base Factor

This is simply a factor to change to a new contract (or billing) pressure base different from 14.73 psia.

$$F_{Pb} = \frac{14.73}{P_b} \quad \text{(absolute pressures)}$$

Where P_b = the new contract base pressure in psia.

- F_{tb} = Temperature Base Factor

This is a factor to change to a new contract (or billing) temperature base other than 60°F. 60°F = (460 + 60) = 520° Rankine.

$$F_{tb} = \frac{T_b(°R)}{520°R} \quad \text{(Absolute Temperatures)}$$

where T_b = the new contract temperature base in degrees Rankine.

- F_{tf} = Flowing Temperature Factor

This is a factor to change from the assumed flowing temperature of 60°F to the actual flowing temperature T_f.

$$F_{tf} = \left(\frac{520°R}{T_f}\right)^{1/2} \quad \text{(Absolute Temperatures)}$$

where T_f = the actual flow temperature of the gas in degrees Rankine.

- F_g = Specific Gravity Factor

  This is a correction factor to put the real specific gravity of the gas into the expression. The expression assumes a specific gravity of 1.

$$F_g = \left(\frac{1}{G}\right)^{1/2}$$

  where G = the specific gravity of the flowing gas. The specific gravity of air = 1.

- F_{pv} = Supercompressibility Factor

  This is a correction factor to compensate for the compressibility of the flow gas, or what is sometimes termed the deviation from Boyle's law.

$$F_{pv} = \left[\frac{Z_b}{Z_f}\right]^{1/2}$$

  where Z_b = the compressibility factor of the gas at base pressure, and Z_f = the compressibility factor of the gas at flow conditions.

Usually base conditions are 14.73 psia and 60°F, where $Z_b \cong 1$. Thus the expression for the supercompressibility factor becomes

$$F_{pv} \cong \left[\frac{1}{Z_f}\right]^{1/2} .$$

The relationship between the compressibility ratio (s) for turbine and positive displacement meters, and the correction term (F_{pv}) in the orifice flow equation called the supercompressibility factor is as follows:

$$s = \frac{Z_b}{Z_f} = F_{pv}^{\ 2}$$

Both are corrections for the compressibility of the metered gas at flowing conditions, or what is often termed the deviation from Boyle's law. However, there is a distinct difference between the two correction factors, and they should be labelled properly.

For positive displacement and turbine meters:

$$s = \text{compressibility ratio} = \frac{Z_b}{Z_f}.$$

For orifice meters only:

$$F_{pv} = \text{supercompressibility Factor} = \left[\frac{Z_b}{Z_f}\right]^{1/2}.$$

There is considerable confusion about the above two correction factors and the terminology used for each consists of many variations of the above. In addition, the subscripts are often deleted to further confuse the terminology.

There are tables available for the compressibility ratio (s) that should be used for positive displacement and turbine meters [4], and there are also tables for the supercompressibility factor (F_{pv}) for the orifice meters. The current <u>A.G.A. Manual for the Determination of Supercompressibility Factors for Natural Gas</u> [3] contains a table for the supercompressibility factor (F_{pv}). However, it should be pointed out that the F_{pv} table is for what is termed normal natural gas mixtures. This means the table is valid for hydrocarbon gases with a specific gravity less than 0.75, and the inerts are limited to 15 mole percent carbon dioxide (CO_2) and 15 mole percent nitrogen (N_2).

If the delivered natural gas is not 0.6 specific gravity, adjustment factors for temperature (F_t) and pressure (F_p) must be calculated from simple expressions. The adjustment factors are a function of specific gravity, mole percent CO_2, and mole percent N_2. These two adjustment factors are then multiplied by the actual flowing temperature and pressure to obtain an adjusted temperature and pressure that is then used to determine F_{pv} from the tables. This procedure is called the "A.G.A. Standard Method" of calculating the supercompressibility factor, and is explained in detail in reference [3].

If an Air Force base purchases gas measured by orifice meters, the BCE gas utility representative should definitely purchase the A.G.A. Report # 3, ANSI/API 2530 entitled, Orifice Metering of Natural Gas [1], and the A.G.A. companion report, Manual for the Determination of Supercompressibility Factors for Natural Gas [3]. A complete set of F_{pv} tables and sample calculations for the adjustment factors are contained in these reports. The F_{pv} tables can also be used to determine if the supercompressibility factor is close to what it should be; if one knows the average daily temperature and pressure of the flowing gas, the adjustment factors can be neglected, and the F_{pv} from the tables can be checked against the F_{pv} on the gas statement to see if the two are in close agreement.

For flowing gas temperatures of 40 to 60 °F, the supercompressibility factor represents a correction on the order of 0.5 to 1.4 percent for metered pressures of 75 to 150 psig (usual base service entrance pressure). However, for transmission line pressures of 600 to 800 psig at the orifice meter, the supercompressibility correction will be in the range of five to eight percent. Thus at higher pressures, the supercompressibility factor becomes a very significant correction to the metered gas flow.

- F_m = Manometer Factor

  This is a correction factor to account for the weight of the gas column above the mercury, and also to account for the change in the density of the mercury when the mercury temperature is not at 60 °F. The above correction factor is used when a mercury manometer is used to measure static and differential orifice pressures. If other types of non-mercury transducers are used the manometer factor would be omitted.

$$Fm = \left[\frac{\gamma_m - \gamma_g}{846.324}\right]^{0.5}$$

where γ_m and γ_g = the specific weight of the mercury and gas respectively.

- F_l = Location Factor

This correction factor accounts for the change in the density of mercury due to location other than at sea level and 45° latitude, i.e., g ≠ 980.665 cm/sec². This too is a correction factor that pertains to mercury manometers only.

$$F_l = \left[\frac{g_l}{980.665}\right]^{0.5}$$

where g_l = the acceleration of gravity at the measuring location.

- F_a = The Orifice Thermal Expansion Factor

This correction factor accounts for the expansion and contraction of the orifice bore when the orifice plate temperature is appreciably different from the temperature at which it was bored, assumed to be 68°F.

For 304 & 316 SS orifice plates:

$$F_a = 1 + [0.0000185\ (°F-68)]$$

where °F = the operating temperature of the orifice plate.

At moderate temperatures, this correction is negligible.

The average values for the pressure differential (h_w) and the static pressure (P_f) are obtained from the daily orifice meter charts. These charts are processed by special integrating machines which give the average P_f and h_w for the measurement period (usually 24-hours).

All of the above parameters should be included as supplementary information along with the monthly bill. A typical gas measurement statement for two orifice meters is included in Table 5.1. This is a wholesale level statement, but similar statements should be included for any retail level orifice meter located on a government base. The BCE gas utility

JANUARY 1985

GRP	USAGE	SUMMARY	STATION	PAGE
E	SR	2336	36924	1

ATMOSPHERIC PRESSURE	CONTRACT PRESS. BASE	STATEMENT PRESS. BASE	TEMP. BASE	LAT. DEG.	CARBON DIOXIDE	NITROGEN	METHANE	AMBIENT TEMP.	CALORIMETER	MINIMUM SIGNIF.	$F_r \times Y$	AGA
14.650	14.730	14.730	60	30	0.81	0.46		55				#3

FL

METER	DISPLACEMENT: TURBINE	ROTARY	DIAPHRAGM	INDEX	PER CYCLE	CHART	DRIVE	ORIFICE METERS: FLANGE TAP	PIPE TAP	UPSTREAM	DOWNSTREAM	MERCURY	DRY FLOW	LINEAR	SQUARE ROOT	PIPE SIZE	ORIFICE SIZE	PRESSURE RANGE	DIFF. RANGE	[illegible]
12						01		F			D	M			S	7.981	4.000	250	100	
22						01		F			D	M			S	7.981	4.500	250	100	

DAY	METER	TEMP. OF FLOWING GAS	SPECIFIC GRAVITY	STATIC PRESS.	AVERAGE DIFF. h_w	PRESSURE MULTIPLIER OR F_b	F_r	Y	F_{tf}	F_g	F_{pv}	F_m	$F_{pb}F_{tb}F_l$	TOTAL MULTIPLIER C'	MACHINE FACTOR	INT. DIFF. SCANNER INDEX CYCLE	ISXC	Mcf VOLUME	B.T.U.	THERMS	03
01	12	27	593	125	48	3368.5	10004	10021	10333	12986	10118	10000	9993	4581.563	3795	5185	S	9,015	1046	94,297	01
01	22																				01
																		9,015 *		94,297 *	
02	12	26	593	125	44	3368.5	10004	10019	10344	12986	10119	10000	9993	4585.978	3795	4970	S	8,650	1045	90,392	02
02	22	26	593	125	15	4360.5	10008	10006	10344	12986	10119	10000	9993	5931.185	3795	1101	S	2,478	1045	25,895	02
																		11,128 *		116,287 *	
03	12	28	594	125	25	3368.5	10005	10011	10323	12975	10118	10000	9993	4569.145	3795	3746	S	6,496	1046	67,948	03
03	22	28	594	124	20	4360.5	10007	10008	10323	12975	10117	10000	9993	5913.552	3795	3353	S	7,525	1046	78,711	03
																		14,021 *		146,659 *	
04	12	28	591	124	38	3368.5	10004	10017	10323	13008	10116	10000	9993	4582.148	3795	4613	S	8,022	1044	83,750	04
04	22	28	591	124	31	4360.5	10006	10013	10323	13008	10116	10000	9993	5930.375	3795	4162	S	9,367	1044	97,791	04
																		17,389 *		181,541 *	
05	12	26	592	125	35	3368.5	10004	10015	10344	12997	10119	10000	9993	4588.031	3795	4428	S	7,710	1047	80,724	05
05	22	26	592	125	28	4360.5	10006	10012	10344	12997	10119	10000	9993	5938.582	3795	3987	S	8,985	1047	94,073	05
																		16,695 *		174,797 *	
06	12	22	593	125	28	3368.5	10005	10012	10387	12986	10123	10000	9993	4604.104	3795	3963	S	6,924	1048	72,564	06
06	22	22	593	125	23	4360.5	10007	10009	10387	12986	10123	10000	9993	5959.386	3795	3550	S	8,029	1048	84,144	06
																		14,953 *		156,708 *	
07	12	21	595	125	28	3368.5	10005	10012	10398	12964	10124	10000	9993	4601.626	3795	3939	S	6,879	1051	72,298	07
07	22	21	595	125	22	4360.5	10007	10009	10398	12964	10124	10000	9993	5956.179	3795	3489	S	7,886	1051	82,882	07
																		14,765 *		155,180 *	
08	12	21	593	126	26	3368.5	10005	10011	10398	12986	10124	10000	9993	4608.975	3795	3850	S	6,734	1048	70,572	08
08	22	21	593	125	21	4360.5	10007	10008	10398	12986	10123	10000	9993	5965.101	3795	3401	S	7,699	1048	80,686	08
																		14,433 *		151,258 *	
09	12	21	591	125	29	3368.5	10005	10013	10398	13008	10123	10000	9993	4617.249	3795	4011	S	7,028	1046	73,513	09
09	22	21	591	125	23	4360.5	10007	10009	10398	13008	10123	10000	9993	5975.804	3795	3555	S	8,062	1046	84,329	09
																		15,090 *		157,842 *	
10	12	19	592	126	36	3368.5	10004	10016	10419	12997	10126	10000	9993	4624.955	3795	4522	S	7,937	1047	83,100	10
10	22	19	592	125	18	4360.5	10008	10007	10419	12997	10125	10000	9993	5983.393	3795	1909	S	4,335	1047	45,387	10
																		12,272 *		128,487 *	

Orifice meter gas measurement statement

TABLE 5.1

representative may have to specifically ask for this additional information; often times, at the retail level, the utility company will send a bill indicating only the volume (MCF's) or energy (Therms) delivered for the billing period. If there is to be any meaningful check of gas purchased by orifice meter measurements, this additional information is necessary.

An explanation of the gas statement for the two orifice meters is necessary. This statement gives information for the first ten days of January-85. There are two orifice meters, each in the same size (8-inch nominal) pipe, however the orifice bores are of different size (4 and 4.5 inches diameter). The pressure range of the static pressure transducer is 0 to 250 psig, and the differential pressure range is 0 to 100 inches of water. Both orifice plates have flange taps and both transducers have a mercury medium. The contract pressure base is 14.73 psia, and the temperature base is 60°F. They also indicate that A.G.A. Method # 3 is used to compute the volume and energy flow through the orifice meters.

An explanation of the information in the columns of the statement (from left to right) follows:

- There are two different orifice meters, #12 and #22.
- The temperatures of the flowing gas is the average daily temperature for each meter.
- The specific gravity has the decimal point missing--all those numbers are in the range of 0.59. These values are the average specific gravity of the gas flowing through each orifice meter for a given day.
- The static pressure has units of psig.
- The average differential pressure has units of inches-of-water (the water @ 60°F).

- The next eight columns list the daily correction factors for each orifice (F_b thru F_l).
- The total multiplier column (C') is equal to the product of all the correction factors (the previous 8 columns). The correction factors have various units, and some are dimensionless.
- The machine factor column contains a constant associated with the chart and integration machine, including hours of actual gas flow.
- The integrated differential index cycle column contains the $(P_f \times h_w)^{1/2}$ term plus other constants.
- The volume column contains the daily volume of gas delivered in units of MCF at 14.73 psia and 60°F.
- The Btu column contains the daily average heating value of the metered gas in units of Btu/ft³ [14.73 psia & 60°F].
- The column labeled THERMS gives the total energy delivered per day for each meter; the units are Therms.

This gas statement gives the total MCF and total Therms delivered per day or per billing period, so the gas could be sold on either basis. This statement is complete and fairly concise, but some of the units are not given. Units are most important. For example, the temperature base and flowing gas temperature have units of °F. The atmospheric, contract base, and statement base pressures all have units of psia. The static pressure has units of psig, and the average differential pressure has units of inches-of-water. The Btu column evidently has units of Btu/ft³ [60°F & 14.73 psia]; all these units should be clearly specified.

The calculation on this gas statement is conducted as follows:

$$\underset{(C')}{\text{Total Multiplier}} \times \underset{\text{Factor}}{\text{Machine}} \times 1\text{SXC} = \frac{\text{Gas Volume}}{\text{Day}} \text{ [MCF]}$$

The basic A.G.A. # 3 equation for volume flow through an orifice is

$$Q_h = C' \ (P_f \times h_w)^{1/2} \ [ft^3/hr]$$

Thus in the above statement, the

$$\text{Machine Factor} \times 1SxC = (P_f \times h_w)^{1/2} \times 24 \text{ hrs.}$$

Another important aspect of orifice meter gas statements is the manner in which the correction factors and constants are listed. The gas statements from the utility companies will vary somewhat, especially with regard to the integration constant associated with the machine that processes the daily charts. Sometimes the correction factors that remain constant will be lumped together to form another constant.

The main purpose of this section is to acquaint the BCE and property management agency personnel with the basic, fundamental orifice calculation so that after a brief explanation of the orifice meter gas statement by the Utility Company, BCE personnel should be able to clearly understand, calculate, and check the monthly gas statement for an orifice meter.

5.4 Comparison of Natural Gas Flowmeters

Comparison of natural gas flowmeters is not straightforward because there are so many parameters to be considered. Some of the more important factors to be considered in meter selection are given below:

- Flow capacity
- Rangeability
- Operating pressure
- Operating temperature
- The presence of condensates
- Physical limitations on the size of meter
- Present and future compatibility with remote readout instrumentation and flow computers

There are four basic types of meters, and each type has an optimum set of operating conditions. Figure 5.17 shows the flow capacity range for each type meter. The diaphragm meter is best suited for applications where the flow rates are less than 100 SCFH, and the orifice meter is the only suitable meter for flow rates in excess of 10^7 SCFH.

Every type of meter (excluding the orifice) has recommended operating temperatures that are about the same. The manufacturer's recommended operating temperature range for each type meter is given below:

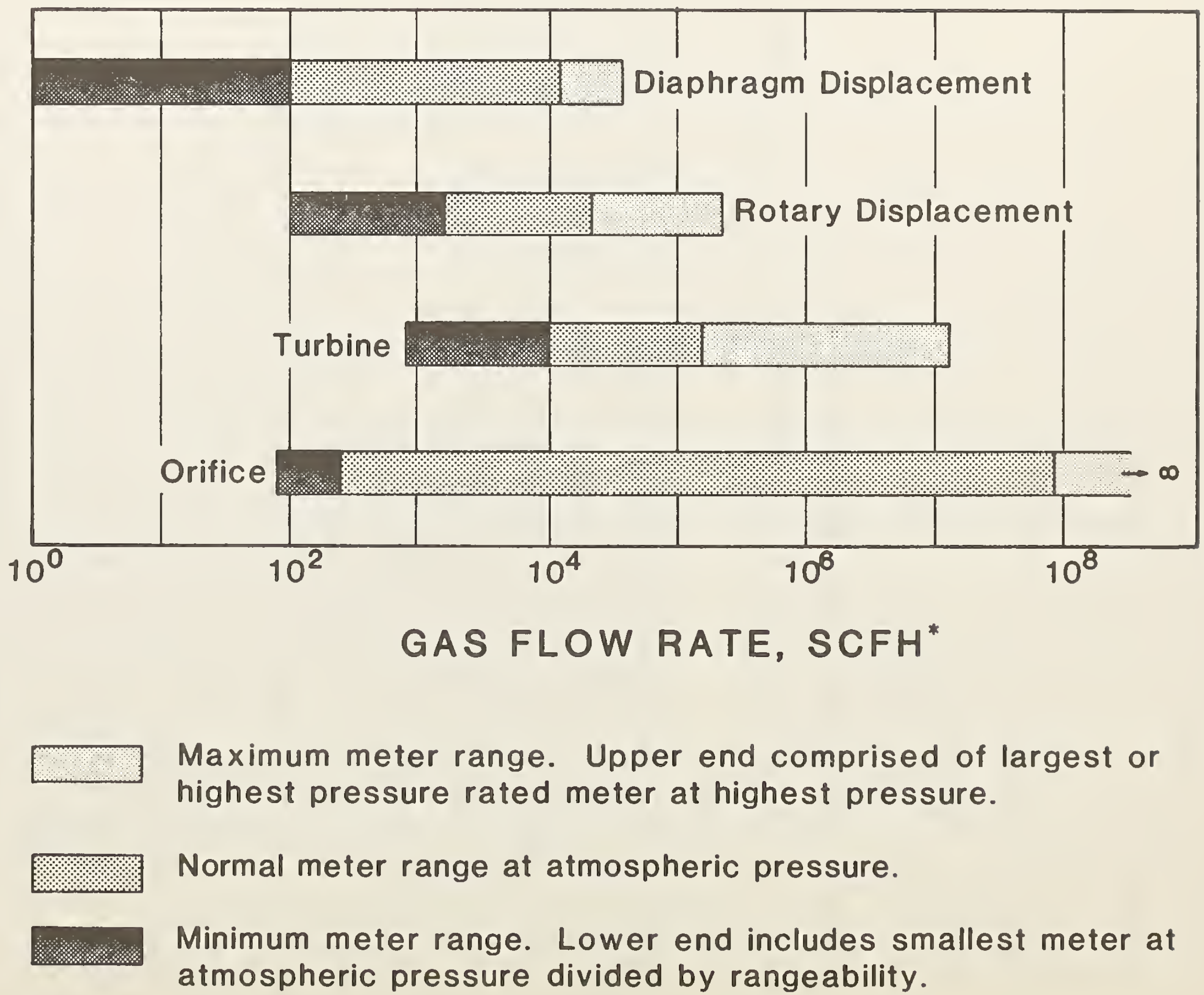
Rotary displacement, -40 to 140°F

Diaphragm displacement, -30 to 150°F

Turbine meters, -40 to 165°F

If the gas meter operating temperature lies outside this envelope, an orifice meter should be considered for the application. Orifice meters have been used in applications where the flowing gas temperatures range from -65 to 500°F.

Comparative Flow Capacities Of The Various Type Meters



Courtesy of the American Meter Company

*0.6 S.G. at 60° F & 14.73 psia

FIGURE 5.17

The accuracy to be expected from the positive displacement and turbine flowmeters is fairly good; all of these meters will read within a ± one percent accuracy band with a factory calibration. Typical accuracy curves for the turbine, rotary displacement, and diaphragm displacement meters are shown in figures 5.3, 5.8, and 5.10 respectively. The diaphragm meters experience minimal leakage at low flow rates, whereas the turbine and rotary displacement meters exhibit more uncertainty at the very low flow rates.

It is more difficult to assign a measurement uncertainty to orifice meters. There are a number of measurement factors, including fluid properties, with individual tolerances that enter into the overall measurement tolerance. The A.G.A. Report No. 3, ANSI/API 2530 [1] indicates that orifice meters are capable of an overall flow measurement tolerance of ±0.75 percent. The ASME report Fluid Meters [2] cites examples of total measurement uncertainties in the range of 0.72 to ±1.25 percent tolerance. Thus it appears that properly configured and instrumented orifice meters are capable of measurement accuracy commensurate with the turbine and positive displacement meters.

5.5 Telemetering of Meter Output

Complete telemetering systems are now available for turbine, rotary displacement, large diaphragm displacement, and orifice meters. These systems consist of a pulse transmitter attached to the meter, wiring to an energy management station or central computing system, then various types of flow totalizers, recorders, and gas flow computers at the central station. Most of the meter manufacturing companies now offer complete telemetering systems.

There is not a lot of gas telemetering equipment in the field yet, but several utility companies indicated that telemetering equipment was being evaluated on a trial basis. There was no telemetering equipment on the main gas service meters at the Air Force bases visited during this study.

Telemetering of gas flow through the main service meters and the large submeters such as at base power plants to central energy management systems would be an ideal application for energy monitoring, management, and peak usage determination.

Although gas meter telemetering equipment is not used extensively at present, BCE personnel will be seeing more of this equipment in the future, as more energy monitoring systems are installed at government bases.

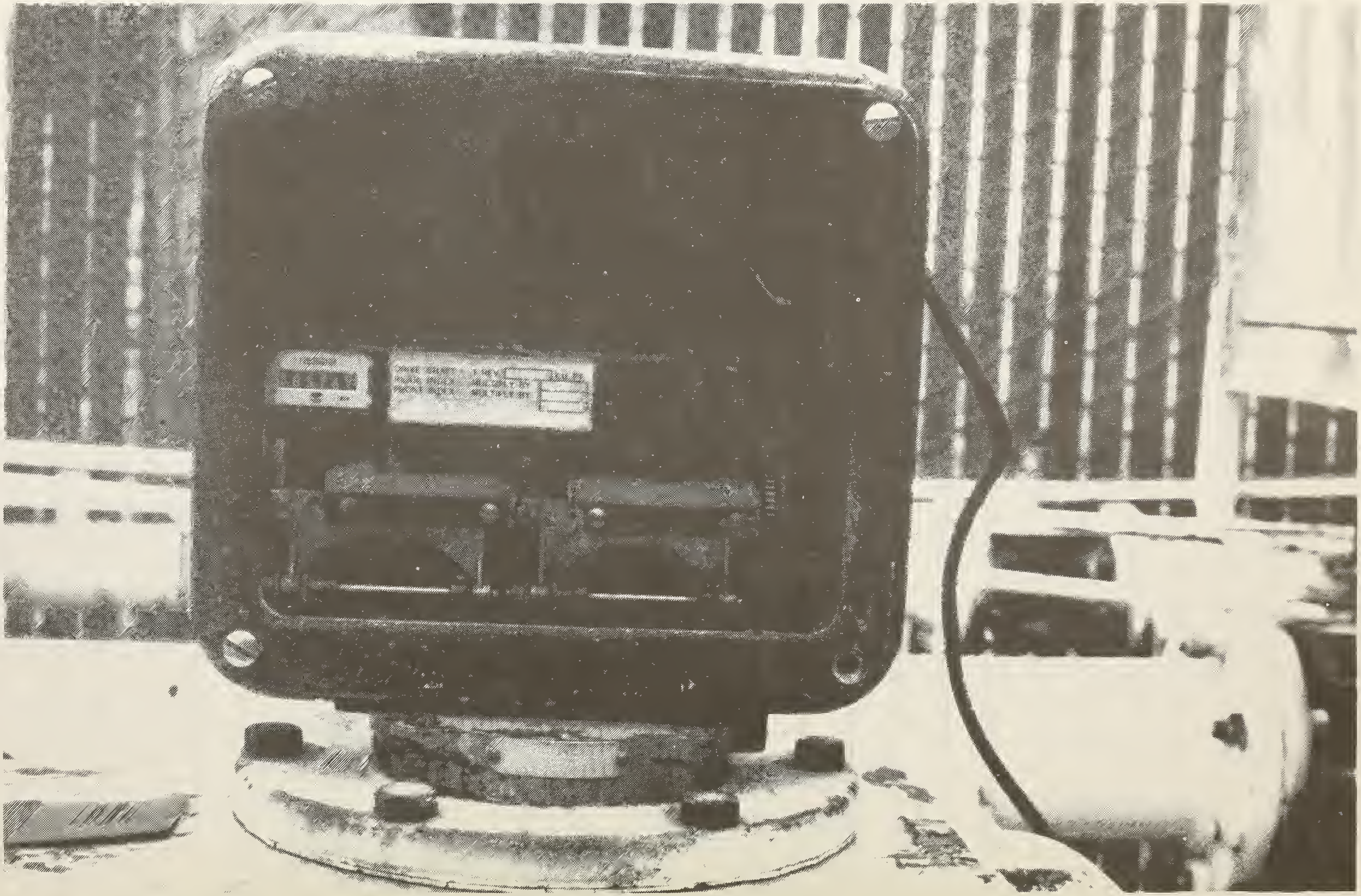
6.0 Meter and Instrument Accuracy Checks

Periodic checks of gas meter accuracy and the associated instruments are necessary, and usually the gas utilities have an established calibration program, wherein the larger gas meters are checked at least once per year and the smaller ones on a less frequent basis. The meters should be adjusted if necessary, and a copy of the calibration results should be forwarded to the BCE office or the Utilities Management Agency for their records (the Utility Brochure). Copies of meter inspection and accuracy test reports are available for inspection at the gas utility meter shop. The utility companies are usually not nearly as concerned about the smaller diaphragm meters. They typically have a statistical calibration program, wherein each of the smaller meters would be checked once during an eight or ten year period.

The correcting instruments attached to the meters should also be serviced and checked on a regular basis; the usual service interval is six to twelve months. A typical pressure and temperature correcting instrument mounted on a diaphragm type meter is shown in figure 6.1, and another similar instrument often found on turbine meters is shown in figure 6.2.

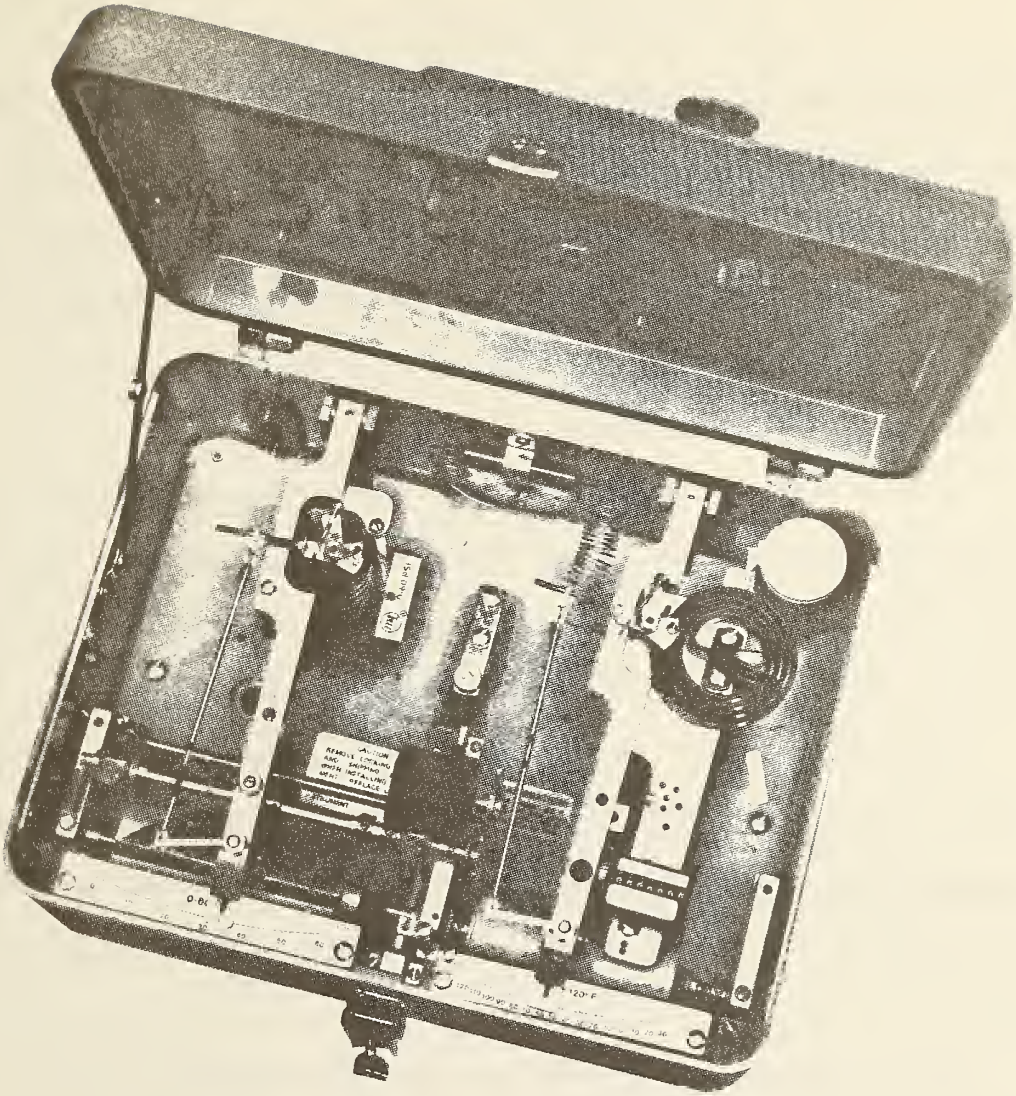
With regard to orifice meters, there are three critical measurements: the static pressure, the differential pressure, and the temperature. The calibration of the two pressure transducers should be checked every two to three weeks, and at least every month. The temperature sensors are much less apt to deviate from calibration, and don't have to be checked as often.

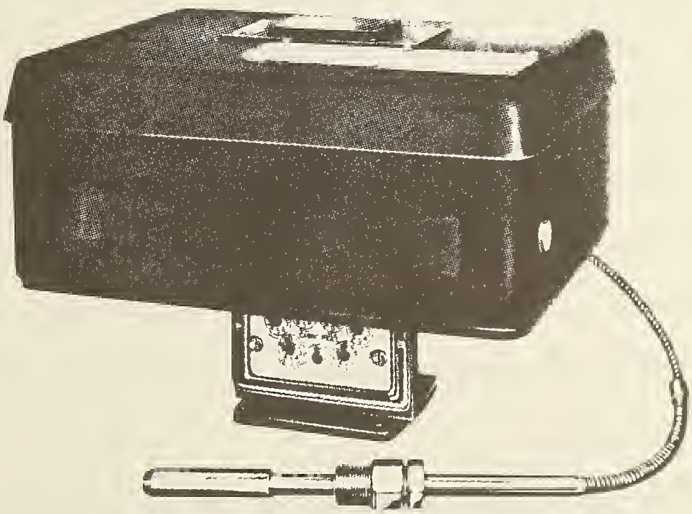
Turbine meters are normally given a spin-time test in the field to obtain an indication of the total friction within the meter. A stream of air is directed toward the rotor to get it up to speed, then the time required for the rotor to cease moving is the criterion used to determine the condition of



Pressure and temperature correcting instrument, odometer type readout

FIGURE 6.1





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Mercury Instruments Inc.

Pressure and temperature correcting instrument with odometer type readout and dial type index

FIGURE 6.2

the bearings and other moving parts. If there is a significant decrease in spin-time, the measuring module should be removed for additional service in the meter shop. The accumulation of dirt and foreign particles is one of the weak points of the turbine meter, however filters (strainers) are almost always used upstream to protect the meter. The spin-time test is easily and quickly conducted in the field.

Another desirable feature of most turbine meters is that they are constructed such that one bolted flange separates the measuring module of the meter from the in-line body or housing; thus a replacement metering section can be bolted into the meter housing very quickly if necessary.

Instructions about how to conduct a spin-time test on a turbine meter are given in the A.G.A. manual, Measurement of Gas by Turbine Meters, Transmission Measurement Committee Report No. 7, 1985 [4]. The typical spin times for turbine meters are listed in the manufacturer's service manuals for the given meter.

Rotary displacement meters are also easily checked in the field; these meters are checked by measuring the differential pressure (ΔP) across the meter without even disturbing the measurement process. Most of the rotary meters have pressure taps right on the meter housing, and a ΔP curve vs. flow is supplied by the meter manufacturer (see figure 5.8). Any significant deviation from the usual differential pressure is a good indication that the meter should be pulled and sent to the shop for servicing. Instructions for checking the differential pressure across the meter are usually given in the manufacturer's meter manual.

The large diaphragm displacement meters are usually checked in-place in the field with some type of portable transfer prover. The small residential type of diaphragm meters are usually checked less often in the meter shop with a bell prover. In that regard, most of the government gas contracts stipulate that a government representative shall have the right to witness the calibration of service gas meters. Thus, BCE employees should feel free to request an invitation to witness the accuracy check of their gas service meters.

7.0 Gas Service Meter Stations

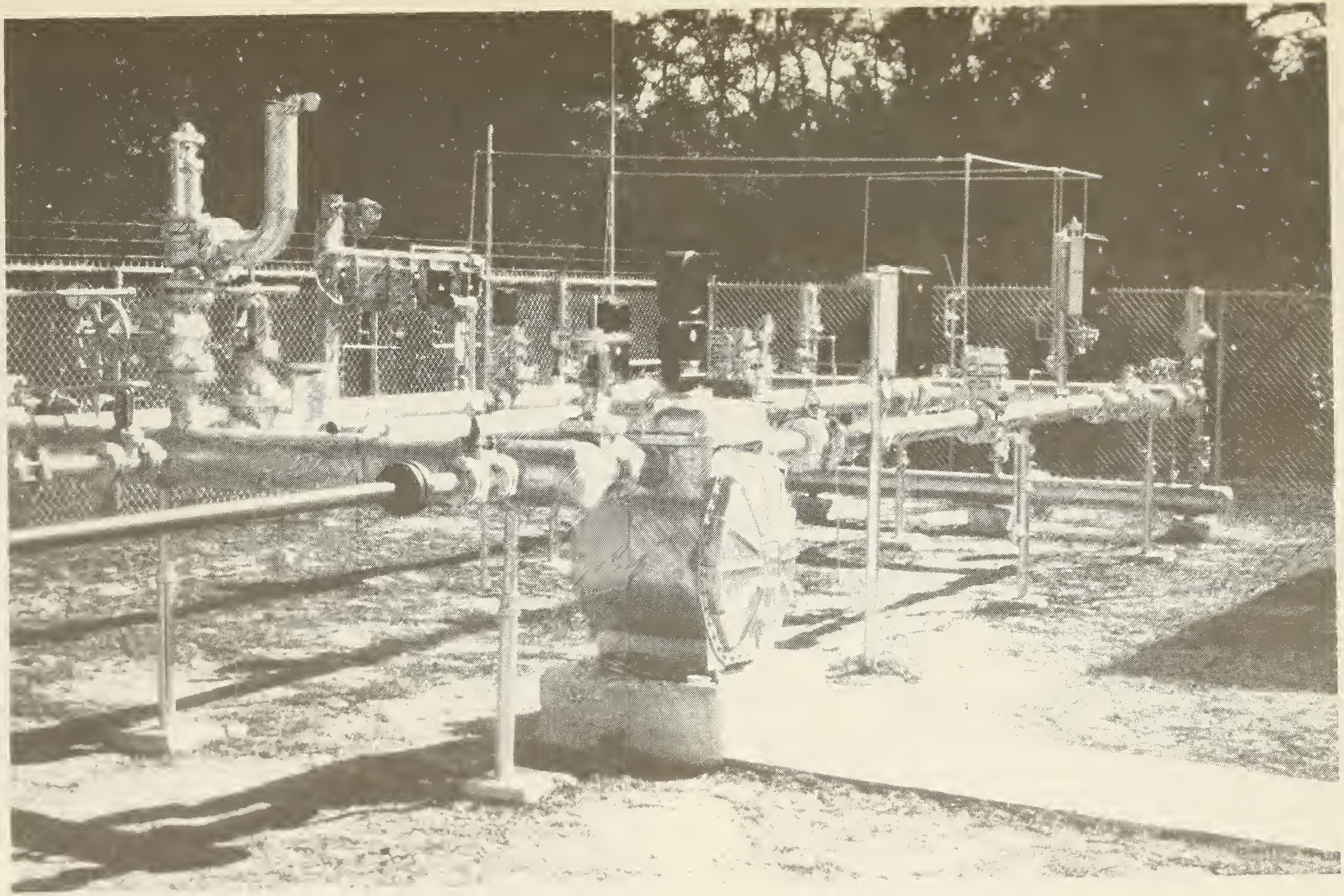
There are usually one or more meter stations near the boundary of an Air Force base, wherein the gas utility service line feeds natural gas into the base distribution system. The meter station serves to regulate the pressure to the base distribution system and to meter the gas going into the base. There are also shutoff valves in case of emergency, and relief valves in case of regulator valve malfunction.

The plumbing sequence at a meter station usually consists of the following:

The gas utility service line entrance (75 to 500 psig), scrubber or filter, shutoff plug valve, pressure reducing valve, pressure relief valve, line heater (extreme cold areas), strainer or filter, flowmeter, flow limiting restriction, shutoff plug valve, base main line gas distribution system. In addition, there is usually a by-pass loop with a shutoff valve around the flowmeter section; thus gas can be routed through the by-pass in case of meter changeout or malfunction.

A typical meter station would be located outdoors but within a locked, fenced-in area, as shown in figure 7.1. Some meter sets are located inside a small meter house with the relief valves vented to the outside and shutoff plug valves located just outside the house on both the entrance and exit lines. The meters are serviced and read periodically by the gas utility field personnel who have keys to the meter stations.

The utility company almost always has responsibility for maintenance of the meter station components, including the periodic calibration of the meters. The utility company also has responsibility for any leaks at the meter station. Any perceptible leakage should be reported to them immediately, especially if



Typical outdoor meter station, Eglin AFB

FIGURE 7.1

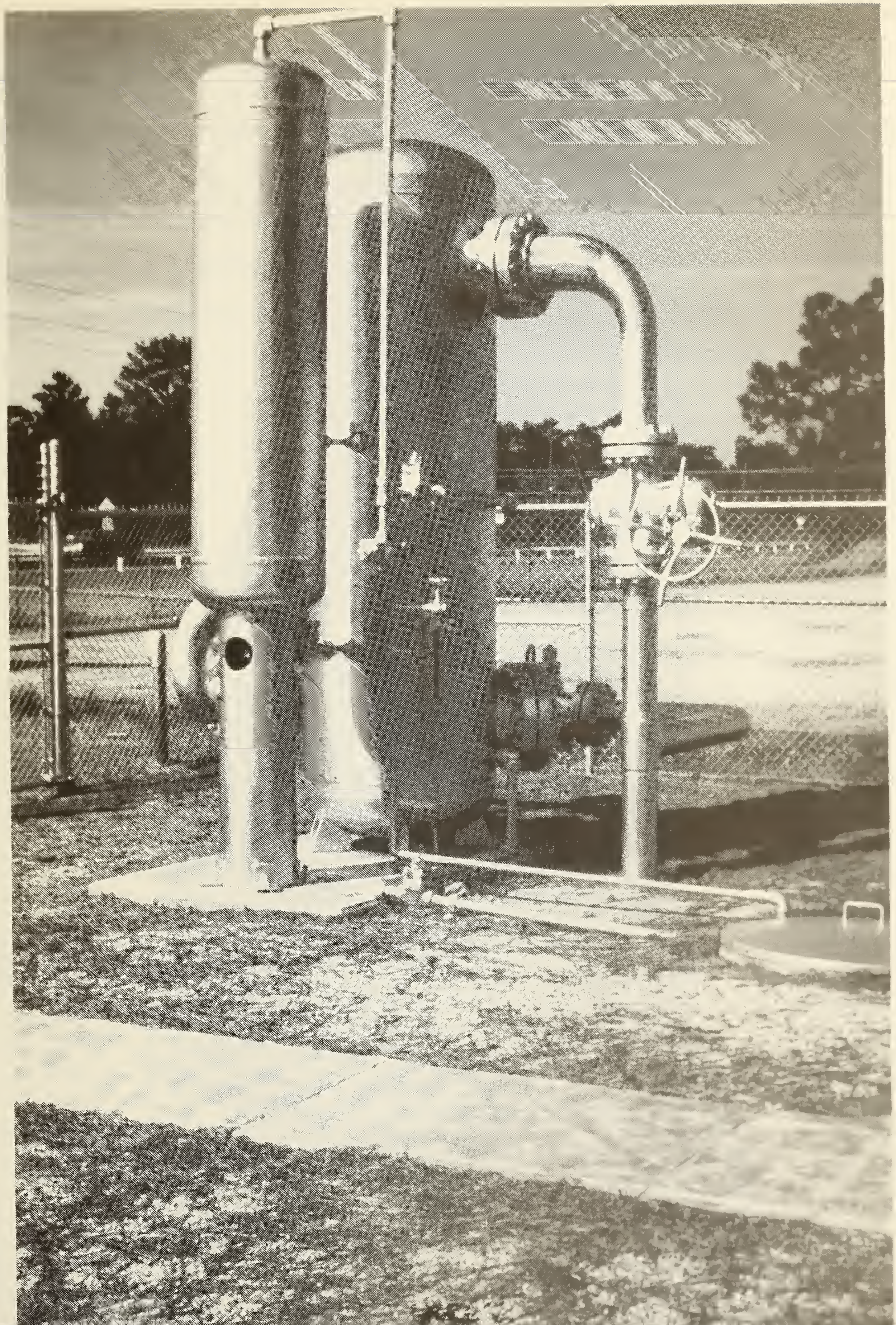
the meter station is enclosed by a building. The lower flammability limit of methane is extremely low - 5 Vol.% in air; thus one has to be very careful about walking into meter houses where there is gas leakage in the meter station piping. It should be pointed out, however, that most of the meter houses are well vented to the outside.

The Government usually has responsibility for all piping and components down stream of the Base meter stations, including corrosion control of the Base gas distribution piping.

Sometimes it is necessary to install a scrubber or filter unit just upstream of the meter station. These units are necessary when the incoming gas contains particulates or entrains scale or rust from the pipeline inner surface at high flow rates. A typical oil type scrubber is shown in figure 7.2.

In some areas of the U.S. line heaters (fired by gas) are used to heat the incoming natural gas to prevent excess ice build-up on the outside of the line downstream of the pressure reducing valve. These are used in extreme cold areas such as Minot, North Dakota and also in cold, humid areas such as Tacoma, Washington. In all cases where heaters are used, there is an isenthalpic expansion at the pressure reducing valve providing refrigeration to the low pressure side of the line. The ice build-up on the outside of the piping becomes a problem because it will cause stress in the meter station piping and has broken pipes in some instances.

The other concern is that some of the heavier hydrocarbons may condense to liquid downstream of the pressure reducing valve. Still another concern is the operating temperature of the downstream gas meter. The gas temperature must not fall below the minimum operating temperature of the meters, usually -20 to -40 °F.



Natural gas oil-type scrubber, Eglin AFB

FIGURE 7.2

The line heaters are provided and maintained by the utility company, and fired by natural gas tapped off upstream of the meter. Thus, the Air Force Base is not charged for the heater fuel. BCE personnel normally have little concern with these heaters, but they should be aware of their purpose and function in case of any malfunction or emergency. The gas service line heater at Minot AFB is shown in figure 7.3.

Gas service line heater at Minot AFB

FIGURE 7.3

8.0 Utility Bills

There are many variations in the format and the amount of information on the gas utility bills received by Air Force bases across the U.S. Some of the bills are fairly complete with all of the correction factors listed separately. Others list just one composite correction factor, while others have vital information missing, or the units are not clearly labelled. Usually, all the gas from one utility company serving various entrance meters at a base will be billed conjunctively, i.e., all the gas meters will be on the same bill. The units listed in Section 1.0 are the units or acronyms usually encountered on the bill, with few variations.

8.1 Methods of Selling Gas

There are three major methods of selling natural gas to Government Bases in the United States:

(1) One method is to sell strictly on a volume basis with a guaranteed minimum energy content (heating value) for the gas.

(2) A second method is to sell on a volume basis with an energy content window; the price increases slightly if the heat content of the gas rises above the energy content window, and similarly, the price decreases slightly if the average heat content of the gas falls below the window. The correction factor is usually called the Btu factor on the bill. The calculation usually goes as follows:
Assume the energy window is 980 to 1020 Btu/ft^3. If the average monthly heating value of the gas lies within the above interval, the Btu factor would be one (1.0). Any values outside the window would be divided by the average window value of 1000 Btu/ft^3 to determine the Btu factor. Thus, if the average monthly heat content were 1030 Btu/ft^3, the Btu factor would be 1030/1000 = 1.030. If the average monthly heating value were 975, the Btu factor would be 975/1000 = 0.975. The Btu factor is then multiplied by the total gas consumed (usually MCF) or the total dollars owed in order to actuate the slight adjustment for deviation from the desired heat content window. Using this method of calculation the gas is sold on a quasi-heat content basis.

(3) A third method is to sell gas strictly on an energy or heat content basis (often referred to as a Therm basis). The gas is still metered on a volume basis, but in addition, the heat content is measured daily, and the monthly average heating value is multiplied by the total volume consumption to calculate the energy (usually Therms) consumed for the

month or billing period. Using this method, the gas is then priced on an energy basis (usually \$/Therm or \$/dekaTherm). A simple monthly bill for 850 MCF of gas priced at \$5.20/dekaTherm would be calculated as follows:

$$850 \text{ MCF} \times \frac{1000 \text{ ft}^3}{\text{MCF}} \times \frac{1015 \text{ Btu}}{\text{ft}^3} \times \frac{1 \text{ dekaTherm}}{10^6 \text{ Btu}} \times \frac{\$5.20}{\text{dekaTherm}} = \underline{\$4,486.30}$$

8.2 Rate Categories

There are usually two basic rate categories for natural gas sold to Air Force bases in the U.S.; these are firm and interruptible. However, there is considerable variation in the rate structure for each category.

- Firm Gas The utility is required to sell gas to the customer as long as gas is available. Some utilities have priority levels within their firm gas category. There is often a demand charge associated with the firm gas category, as explained under miscellaneous charges.
- Interruptible Gas Within this rate category, the utility has the option to suspend or curtail gas service to the base upon fairly short notice. The cost of gas under this rate is normally slightly less than the firm gas rate. The gas supplied to central power plants on bases is often interruptible gas. The annual savings due to the decreased rate can be considerable, however often times an alternate back-up source of energy must be provided in case of gas curtailment, and there is obviously an expense in maintaining these systems, or keeping an alternate supply of fuel on hand. The most popular back-up fuels are fuel oil, propane, and coal.

8.3 Miscellaneous Charges

In addition to the basic commodity cost of gas, there are a number of other charges that appear on the monthly utility bills. The BCE and Property Management Agency personnel should clearly understand the nature and basis of these charges to insure that they are calculated correctly. A brief explanation of these various charges is given below.

- Demand Charge

  The demand charge is normally associated and based on firm gas only. This is an additional charge based on the maximum usage rate (or demand) of natural gas during a previous specified period. It may be regarded as a fee the utility company charges for their investment in transmission equipment in order to serve the customer as much gas as required during peak demand periods. There are many variations of the demand charge; it may be a constant annual or monthly fee, or it may be based on the use of firm gas. It is usually evident from the bill how the demand charge is calculated.

- Service Charge

  The service charge is usually a fixed amount based on a year, month, or billing period. However, the service charge may be based on gas consumption, and have a minimum monthly value. At some bases the utility company may have a service charge for each meter, based on the size of the meter. In some respects, this is similar to a monthly rental charge for the meter. Service charges range from $10 per month for the entire base (just a token amount) to ~ $1,000 per month per large meter at other bases.

  The type and amount of service charge is very dependent upon the utility company providing gas service and the initial contract agreement between the government contracting officer and the utility. Service charges have many variations and there appears to be no set pattern.

- Wheeling or Transportation Charge

  This is usually a charge or credit for gas that passes thru service or base distribution gas lines that belong to some other party. One common wheeling credit on utility bills is for gas that flows thru base distribution lines to a school on base that buys gas directly from the utility. The gas is metered at the school with a utility gas meter, the school pays the utility directly for gas, but the gas flows thru base distribution lines; thus the base is reimbursed for the use of their gas distribution system.

  At Lackland and Kelly Air Force bases the natural gas is purchased from Valero Transmission Company, but the City of San Antonio distributes, meters, and bills the gas to the bases. For this service the City of San Antonio Public Service charges a transportation fee. Wheeling and transportation charges are usually not excessive.

- Gas Cost Adjustment (GCA)

  This cost adjustment reflects charges in the wholesale price the utility company must pay for natural gas. The Federal Energy Regulatory Commission (FERC) allows the utilities to pass along to their customers any increased or decreased costs of gas from their suppliers. The adjustment is based on a cubic foot of gas, thus is proportional to the total amount of gas consumed per billing period. The adjustment can be significant whenever the cost of gas is changing abruptly. The base contracting officer and the utility companies have no control over this adjustment to the cost of natural gas.

- Franchise Fee

  Some utility companies obtain franchises from incorporated cities and towns within their service territory. As part of the franchise, the utility company pays a fee based on the dollar amount of each customers bill for the use of the municipalities alleys, streets, and rights-of-way where gas lines are located. These fees are listed separately on the bill, and Government installations are usually not exempt from this fee.

- Penalty for Non-curtailment of Interruptible Gas

  Most gas utility contracts have a provision allowing the utility company to charge a penalty or exorbitant rate for natural gas consumed after the base has been told to curtail or interrupt the use of their interruptible natural gas. This penalty ranged form three to seven times (3 to 7X) the normal charge for natural gas at the Air Force bases visited during this study. Thus, the use of natural gas after being told to curtail can be prohibitively expensive, and the back-up energy systems for interruptible gas curtailment should be in a state of readiness so they may be fired-up on a relatively short notice.

- Minimum Monthly Charge

  Some utility companies have a minimum monthly charge for gas service. This is just one more miscellaneous charge, obviously of most concern during the summer months when gas consumption is low.

The miscellaneous charges on utility bills vary considerably in nature and dollar value, and usually start with the initial gas contract. It is important to keep them to a minimum since some demand charges are extremely high.

8.4 Required Billing Information

The following information should be on every gas utility bill so that the BCE representative authorizing payment of the bill can easily check the calculations to ensure that the bill is correct:

- Previous and present gas meter readings with appropriate units (CCF or MCF)
- Temperature correction factor
- Pressure correction factor
- Supercompressibility factor or the compressibility ratio; if neglected, that should be so stated.
- The three previous correction factors should not be lumped into one composite correction factor.
- The billing pressure and temperature base
- Each miscellaneous charge should be clearly itemized.
- The average heat content of the gas for the billing period should be clearly defined; the pressure, temperature, and moisture content of the cubic foot of gas yielding the given Btu should be stated.
- The Btu factor (Heat Content Factor) if the gas is sold on a volume basis with a heat content window.
- The firm and interruptible rates should be clearly stated.
- If the gas is measured with an orifice meter, a gas statement including all the orifice correction factors should be sent along with the bill.

There should be sufficient information on the gas bill so that the BCE can easily check the calculations from the meter readings to the dollars owed for the billing period.

9.0 References and Standards

[1] Orifice Metering of Natural Gas, American Gas Association Report No. 3, American National Standard Institute ANSI/API 2530, First Edition, A.G.A. Catalog No. XQ0178.

[2] Fluid Meters, Their Theory and Application, Sixth Edition, 1971, The American Society of Mechanical Engineers.

[3] Manual For the Determination of Supercompressibility Factors For Natural Gas, Par Research Project NX-19, American Gas Association, 1962, A.G.A. Catalogue No. L00340.

[4] Measurement of Gas By Turbine Meters, Transmission Measurement Committee Report No. 7, American Gas Association, 1985, A.G.A. Catalogue No. X20585.

[5] American Gas Association Gas Measurement Manual, General--Part No. One, A.G.A. Catalogue No. X21081.

[6] American Gas Association Gas Measurement Manual, Displacement Measurement--Part No. Two, A.G.A. Catalogue No. XZ0277.

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[8] The Thermophysical Properties of Methane, from 90 to 500 K at Pressures to 700 Bar. NBS Technical Note 653, R.D. Goodwin.

[9] Metric Unit (SI) Application Guide for the A.G.A., Prepared by the Metrication Task Committee, 1980.

[10] Gas Transmission and Distribution Piping Systems, ANSI/ASME B31.8-1982, American Society of Mechanical Engineers.

[11] Orifice Metering of Natural Gas, ANSI/API 2530, Second Edition, A.G.A. Catalog No. XQ0285.

APPENDICES

Appendix No. 1

Air Force Base Survey Information

During the survey phase of this study, we visited fourteen different Air Force bases within the U.S. in order to inspect the natural gas service meters, talk to BCE personnel, and interview technical representatives from the respective gas utility companies. The Bases visited and their location are listed below:

Air Force Base	Location
Offutt AFB	Omaha, Neb.
Air Force Academy	Colorado Springs, Colo.
Hill AFB	Ogden, Utah
Lowry AFB	Denver, Colo.
F.E. Warren AFB	Cheyenne, Wyo.
McChord AFB	Tacoma, Wash.
Kirtland AFB	Albequerque, N.M.
Tyndall AFB	Panama City, Fla.
Eglin AFB	Valparaiso, Fla.
Minot AFB	Minot, No. Dakota
Kelly AFB	San Antonio, Texas
Lackland AFB	San Antonio, Texas
Wright Patterson AFB	Dayton, Ohio
Hanscom Field	Bedford, Mass.

In addition to the above, we had telephone conversations with BCE personnel at Holloman and Ellsworth Air Force bases and obtained utility bills for these two bases.

Pertinent summary information about each base is given in Table A1. This information was gathered during the period November 84 to April 85. The table is useful to compare annual energy consumption for each base, the variation in heating value of natural gas, the demand and service charges, the variation in penalty for non-curtailment of interruptible gas, the different methods of selling natural gas, and the average cost per dekaTherm of energy. The average cost of gas in the last column takes into account all types of additional charges on the utility bill.

The price of natural gas ranged from \$3.88 to \$5.16 per dekaTherm (one million Btu). The monthly demand charge for firm gas varied from zero to \$61,000 per month. This charge should be carefully considered by Air Force contracting specialists when negotiating with the gas utility companies. The heating value of a cubic foot of dry natural gas at 60°F and 14.73 psia varied from 991 to 1068 Btu/ft^3. Hill AFB had the highest annual consumption of natural gas of all the bases visited.

AIR FORCE BASE SURVEY INFORMATION

Air Force Base	Annual Gas Purchase† deka Therms	Annual Gas Purchase† $K	Avg. Gross BTU Value; Dry, 60°F, 14.73 psia	Firm Demand Charge	Service Charge	Non-Curtailment Penalty	Type of Gas Meters	Basis For Selling Gas*	Average Cost of Gas $/dekaTherm	Remarks
Offutt AFB	1,025,141	5,134	993	$61K/Month	None	3.34X	Orifice & Turbine	Volume, with a Btu window	$4.96	
Air Force Academy	1,001,403	4,609	991	$8.16K/Month	$814/mo plus Franchise Fee	$25/MCF 7X	Turbine & Rotary Displacement	Volume. with a Btu Minimum	$4.23	
Hill AFB	1,941,916	10,285	1,068	None	Variable Customer Meter Chg.	$15/daTh 5X	All Types Except Orifice	Therm	$5.30	13 Gas Entry Lines
Lowry AFB	685,453	3,139	994	None	Variable Franchise Fee	$251 MCF 7.56 X	Rotary Displacement	Volume, with a Btu Minimum	$4.58	
F.E. Warren AFB	322,070	1,256	1,028	None	Firm Gas Meter Charge	7.43 X	Rotary Displacement & Turbines	Volume, with a Btu Minimum	$3.88	
McChord AFB	279,616	1,422	1,046	None	Yes, Minimal	$20/daTh 4.93X	Turbine Meters	Therm	$5.09	
Kirtland-Sandia	1,592,596	6,509	1,050	None	$310/Mo.	3X	Diaphragm & Orifice	Therm	$4.09	
Tyndall AFB	186,409	782	1,047	None	$10/Mo.	N.A. Priority 1	Turbine & Diaphragm	Therm	$4.07	No Temp Msm't
Eglin AFB	663,711	3,295	1,039	$42K/Month	None	N.A. Priority 1	Turbine & Diaphragm	Therm	$5.11	High Demand Charge

*All BTU Values @ 60°F & 14.73 psia

† ~ FY84

TABLE A1

AIR FORCE BASE SURVEY INFORMATION (cont'd)

Air Force Base	Annual Gas Purchases†		Avg. Gross BTU Value; Dry, 60°F, 14.73 psia	Firm Demand Charge	Service Charge	Non-Curtailment Penalty	Type of Gas Meters	Basis For Selling Gas*	Average Cost of Gas $/dekaTherm	Remarks
	deka Therms	$K								
Minot AFB	938,494	4,722	1,064	None	$10/Mo.	None Specified	Orifice	Volume, with a BTU Window	$5.04	Plan To Keep the Orifice Meters
Holloman AFB	505,290	2,408	1,010	None	$310/Mo.	3X	Diaphragm	Therm	4.77	Gas Line corrosion Problem
Kelly AFB	1,095,694	4,658	1,033	None	Transportation Charge	None Specified	Orifice & Diaphragm	Volume, with a BTU Minimum	4.25*	SARPMA
Lackland AFB	478,861	2,035	1,033	None	Transportation Charge	None Specified	Orifice, Diaphragm & Rotary	Volume, with a BTU Minimum	4.25*	SARPMA
Wright Patterson AFB	253,175	1,271	1,030	None	$4.15/Mo	None Specified	Diaphragm & Rotary	Volume, with a BTU Minimum	$5.02	
Hanscom Field	597,836	2,830	1,034	None	None	2X	Turbine	Therm	$4.73	Annual Curtailment
Ellsworth AFB	928,825	4,793	1,027	None	$12/Mo.	None Specified	Orifice & Diaphragm	Volume, with a BTU Window	$5.16	

*Cost to SARPMA

TABLE A1, CONTINUED

Appendix No. 2

Unit Conversions

Only the unit conversions and prefixes normally encountered on gas utility bills and natural gas specifications will be given in this appendix.

Volume

28.316 liters = 1 $foot^3$

37.24 $feet^3$ = 1 $meter^3$

Mass

1 grain = 0.0648 grams

1 pound = 7000 grains

1 pound = 453.6 grams = 0.4536 kilograms

1 kilogram = 2.205 pounds

Energy

1 Btu = 1055 joules (it)

1 megajoule = 947.99 Btu

1 Therm = 100,000 Btu

1 dekaTherm = 1,000,000 Btu

1 Therm = 105.5 megajoules

Pressure

1 atm = 29.9212 in. Hg (Hg @ 0°C)

1 atm = 407.19 in. H_2O (H_2O @ 60°F)

1 atm = 14.696 psia

1 atm = 760 torr = 760 mm Hg (Hg @ 0°C)

1 in. Hg = 13.5702 in. H_2O) (Hg & H_2O @ 60°F)

1 torr = 1 mm Hg (Hg @ 0°C)

1 torr = 0.53577 in. H_2O (H_2O @ 60°F)

1 psi = 27.707 in. H_2O (H_2O @ 60°F)

1 psi = 51.715 torr

NBS-114A (REV. 2-80)

U.S. DEPT. OF COMM.

BIBLIOGRAPHIC DATA SHEET (See instructions)

1. PUBLICATION OR REPORT NO.
NBSIR 86-3057

2. Performing Organ. Report No.

3. Publication Date
August 1986

4. TITLE AND SUBTITLE

NATURAL GAS HANDBOOK

5. AUTHOR(S)
Paul R. Ludtke

6. PERFORMING ORGANIZATION (If joint or other than NBS, see instructions)

NATIONAL BUREAU OF STANDARDS
DEPARTMENT OF COMMERCE
WASHINGTON, D.C. 20234

7. Contract/Grant No.

8. Type of Report & Period Covered

9. SPONSORING ORGANIZATION NAME AND COMPLETE ADDRESS (Street, City, State, ZIP)
U. S. Air Force
Engineering and Services Center
Tyndall Air Force Base, FL 32404

10. SUPPLEMENTARY NOTES

☐ Document describes a computer program; SF-185, FIPS Software Summary, is attached.

11. ABSTRACT (A 200-word or less factual summary of most significant information. If document includes a significant bibliography or literature survey, mention it here)

A Natural Gas Handbook has been prepared to help Air Force BCE personnel better understand the principles of metering and selling natural gas on an energy content basis. The various aspects of natural gas such as heating value, moisture content, and hydrogen sulfide content are discussed. The characteristics of the various types of meters currently used for flow measurements are given. The correct procedures for calculating gas utility bills, including compressibility corrections, are presented. The responsibility of the gas utility to periodically check the gas meter and instrument accuracy is discussed. A list of information that should appear on the gas utility bill is given, and the various methods of selling natural gas are discussed.

12. KEY WORDS (Six to twelve entries; alphabetical order; capitalize only proper names; and separate key words by semicolons)

compressibility; gas meters; heating value; natural gas.

13. AVAILABILITY

☒ Unlimited
☐ For Official Distribution. Do Not Release to NTIS
☐ Order From Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402.
☒ Order From National Technical Information Service (NTIS), Springfield, VA. 22161

14. NO. OF PRINTED PAGES
112

15. Price

USCOMM-DC 6043-P80

☆ U. S. GOVERNMENT PRINTING OFFICE: 1986—673-066/45,319 REGION NO. 8