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Academy for Educational Development

ARMENIA ENERGY TRAINING PROGRAM

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Technical Report

Natural Gas Transmission and Distribution Loss Reduction Strategies

August 4, 1999

Submitted to U.S. Agency for International Development

Submitted by the Academy for Educational Development
with Hagler Bailly Services

A

ARMENIA ENERGY SECTOR TRAINING PROGRAM
Technical Report
Course #7: Natural Gas Distribution and Loss Reduction Strategies

USAID Strategic Objective 1.5	A more economically sustainable and environmentally sound energy sector
Intermediate Result 2	Increased economic efficiency in the energy sector
Participant profile	Armenia's energy companies, government ministries and regulatory entities with competence over the energy sector

A. Course Purpose

The Armenian gas system currently operates with unsatisfactory levels of technical losses in natural gas transmission and distribution. This course was designed to provide examples of technical and organizational measures to reduce these losses. Staff from gas sector companies received training in different technical solutions and techniques to improve commercial operations of energy companies in the sector. Course topics included: a description of the methods and procedures for identifying unaccounted-for natural gas; gas purchases; metered and unbilled sales; delivery pressure vs. base pressure; super compressibility; gas temperatures and temperature correction; meter inaccuracies; line breaks; construction loss; leakage; and metered and unmetered theft.

B. Dates/Trainers/Attendees

The course was presented by Mr. Charles Setian and Ms. Candace Weeks on May 24-28, 1999. The target audience for this course was distribution company engineers, inspectors and technical specialists from Haygas, Yerevangas, Armgas, Armtransgas, and representatives of the Energy Regulatory Commission, Yerevan TPP, and GosEnergoNadzor. A total of 18 people completed this course.

Table 1: List of Participants

#	Name	Employer	May 24	May 25	May 26	May 27
1	Nikoghos Hovhannisyan	"ArmRusGaz" Co	√	√	√	√
2	Ivetta Kasparova	ArmGaz Project	√	√	√	√
3	Seriosha Nalbandyan	ArmGaz Project	√	√	√	√
4	Samvel Nazaryan	Energy Commission	√	√	√	√
5	Svetlana Arakelyan	Energy Commission	√	√	√	√
6	Julietta Sevumova	ArmGaz Project	√	√		√
7	Gohar Aivazyan	ArmGaz Project	√	√	√	√
8	Julietta Vardanyan	ArmTransGaz	√	√	√	√
9	Armen Sargsyan	ArmGaz	√	√	√	√
10	Ruben Hakobyan	ArmGaz	√	√	√	√
11	Hrant Tadevosyan	ArmGaz	√			
12	Armen Shahnazaryan	YerevanGaz	√	√	√	√
13	Svetlana Shegunts	ArmTransGaz	√	√	√	√
14	Gagik Yeghiazaryan	Energy State Control	√	√	√	√
15	Samvel Hayrapetyan	Yerevan Gaz	√	√	√	√
16	Garegin Bagramyan	Energy Commission		√	√	√
17	Mary Babajanyan	ArmTransGaz		√	√	√
18	Vardan Zakaryan	ErevanGaz			√	√
19	Anahit Babayan	Energy Commission			√	√
		TOTAL	**15**	**16**	**17**	**18**

C. Material Covered

The principal topics for the seminar included:

- *Unaccounted-for Gas*. Unaccounted for gas is the difference between gas purchased and gas sold. The factors that contribute to unaccounted-for gas are errors in gas measurement, high-pressure measurement errors, meter accuracy, correct factors, company use of gas line purge, accounting practices, as well as uncontrolled losses like theft, leakage and third party damage. Each of these topics was discussed, along with strategies for recovering lost revenue from uncontrolled losses.

- *Correction Factors.* Correction factors applicable to low pressure gas were reviewed. Information covered included metering temperature correction, metering pressure correction, heating value correction, and water vapor correction. Supercompressibility and meter accuracy correction factors were also reviewed.

- *Accounting Practices.* The course covered accounting practices related to unaccounted-for gas, including accurate definition of all quantities purchased and delivered, restatements and adjustments to gas accounting reports, and the effects of billing cycles.

- *Safety.* Safety requirements for natural gas transmission and distribution were reviewed with the program participants.

- *Site Visit.* Charles Setian worked with the Chief Engineer at Yerevangas to assist in solving a repair problem. He also worked with Haygas and Yerevangas on the installation and programming of some equipment.

D. Participant Evaluations

- All of the participants were "extremely satisfied" with the quality of the interpreter.

- The instructors received high marks from the participants in regard to their training and technical ability. The selection of the program's content was also well received, with 72.2% stating it was 'very good.'

- The majority of the participants, 80%, made arrangements to stay in touch with the course instructors.

- Overall, the course was well received by the participants. In an exit questionnaire all participants said that the training program was useful and 88.9% said that they could apply what they learned to their work.

E. Anticipated Outcomes

Short Term: For the attending participants from the Energy Regulatory Commission, we anticipate that the information presented during the course will be useful in helping to the finalize the Commission's natural gas tariff method. Commission endorsement of a tariff methodology is expected within the next two months.

Long Term: As a result of this course, we anticipate that the main gas enterprises will be able to more accurately identify and quantify gas losses within their networks, an obviously important component of the commercialization process. Some of the normative standards in the natural gas industry will be revised in line with the concepts and analytical techniques presented in this course.

F. Recommended Follow-up & Conclusions

This training provided a general overview of theory and principle and was not aimed at specific problems. Many of the questions received were specific real life concerns. Future training programs should take place in each distribution company using actual customer data. Such training courses would cover the actual calculation and analysis of unaccounted-for gas.

APPENDIX A

Seminar Outline

Natural Gas Transmission and Distribution Loss Reduction Strategies

Day 1

I. Terms and Conditions of Metering

Ownership
Testing Requirements
Maintenance
Billing Inaccuracies
Installation
Meter Records
Tampering
Safety
Revenue Protections

II. Theft

A. Various methods of stealing gas
-bypass
-dropping the meter
-piping appliance before the meter
-meter reading errors
-curb reading
-reversing the meter
-removing the dials

B. How to follow up on discrepancies
-how to handle theft by company personnel
-Internet access to revenue protection information

Day 2

III. Unaccounted for Gas

A. General Overview
-contributing factors

B. Measurement error
-errors in gas sales measurement
-large volume High pressure measurement error
-Low pressure measurement error

C. Ideal Gas Law

D. Correction factors Applicable to low pressure measurement

E. Super Compressibility

F. Meter accuracy correction factor

G. Measurement in Storage Operations

H. Company use gas
- -fuel for operating equipment
- -compressor stations
- -control of measurement and regulation of equipment
- -operating and testing relief valves

I. Residential meter change

J. Line purge blow down

K. Uncontrolled losses
- -leakage in piping system
- -leak repair programs
- -third party damage
- -loss caused by diversion or theft

L. Accounting Practices
- -Accurate definition of all quantities purchased and delivered
- -restatements and adjustments to gas accounting reports
- -billing cycle effect

M. Methods of Defining and Minimizing UFG
- -prompt accurate reporting
- -Accurate records
- -analysis and review of trends

Day 3

IV. Safety
- -Maintenance
- -need for protective barricades
- -electrical installation
- -ventilation
- -test for odorant.

Day 4

V. Computer systems and software available

-discussion and demonstration of ABACUS
- Meter reading documentation
-Consumption history
-Meter records
-Collection documents
-Payment record

APPENDIX B

Natural Gas Transmission and Distribution Loss Reduction Strategies

Training Materials

TRAINING MATERIALS

SESSION 6 and 7

1. GAS METER SELLECTION AND MODERN METER READING, BILLING AND COLLECTION TECHNIQUES

2. NATURAL GAS TRANSMISSION AND DISTRIBUTION LOSS

DATES of TRAINING: 05/17/99-05/27/99

TRAINERS: Charles Satyan, Candace Weeks, CENEX

BASIC FUNDAMENTALS OF GAS FOR NON-UTILITIES

TABLE OF CONTENTS

CHAPTER	TITLE	PAGE
1	Natural Gas Facts	
	a. Natural Gas Facts	1
	b. Specific Gravity	1
	c. Natural Gas Analysis	2
	d. Conversion Factors	3-5
2	Combustion	
	a. The Meaning of Combustion	1
	b. Requirements for Combustion	1
	c. Basic Chemistry of Combustion	3
	d. Complete Combustion	5
	e. Combustion Process	10
	f. Flammable Range - Natural Gas	11
	g. Gas Burners	12
	h. Orifices	
	1. Measuring Gas Flow	16
	2. Gas Input Tables	22-26
	i. Gas Pressure	27-33
	j. Burner Problems	34-43
	1. Carbon Monoxide	44
3	Controls	
	a. Rod and Tube	2
	b. Bi - metals	5
	c. Differential	10
	d. Snap Acting	11
	e. Hydraulic	12
	f. Bellows	16
	g. Thermocouples	17
	h. Electromagnetic - Power Unit	21

CHAPTER	TITLE	PAGE
3 (contd.)	i. Thermocouple and Electromagnet Safety Troubleshooting Procedures	26
	j. Spill Switches	32
	k. AGA Guidelines for Recognizing Gas Conversion Kits	33
	l. Troubleshooting Pilot Light Problems on Millivolt Controlled Gas Fired Water Heater Applications	37
ADDENDUM 1	Millivolt Charts	
4	Gas Meters	
	a. Reading Your Meter	3
	b. Meter Flow Rate Computation	10
	c. Testing for Gas Leaks	13
5	Gas Regulators	
	a. High Pressure Regulators	2
	b. Troubleshooting Service Regulators	4
	c. Appliance Pressure Regulators	5
	1. Principle of Operation	6
	2. Types of Gas Pressure Regulators	12
	3. Capacities of Gas Pressure Regulators	13
	4. Proper Location and Position	14
	5. Facts About Regulators	14
	6. Servicing	18
	7. Maxitrol Bulletin MC1056 Condensed Catalog	21
	(a) Helpful Data	26
	(b) Sizing a Regulator	26

CHAPTER	TITLE	PAGE
6	Venting	
	a. Venting Definitions	1-6
	b. Vented Appliance Categories	7-13
	c. General Rules	14
	d. Alternate Method for Sizing a Flue Pipe	16
	e. Table for Determining the Area of a Flue Pipe	17
	f. Troubleshooting Chimneys	18-29
	1. Spillage	30
	g. Mechanical Draft and Direct Vent System	33
	h. Type "B" Gas Vent Components	1-5
	i. Gas Vent Sizing	6-33
7	Air for Combustion	
	a. Chart for determining Air for Combustion requirements	1
	b. Air for Combustion Introduction	2-3
	c. Combustion Air Definitions	4
	d. What Constitutes Tight Construction	5
	e. Example of Calculations	6
	f. Method for Determining Adequate Air Requirements for Equipment Operation	7
	g. Make up air	8
	h. BOCA Code	9
	i. National Fuel Gas Code	10
	(1) Equipment located in Confined Spaces	11-15
	j. Table for determining size of openings for confined spaces	16-17
	k. Air for Combustion Work Sheet	18-24

Meter

The meter, as the chart and other material show, contains a number of gas-measuring chambers. The filling and emptying of these chambers operates the meter. The meter shown in the cutaway drawings illustrates the principle on which displacement meters work. Low-pressure gas entering one chamber in the meter pushes out, or displaces, a certain volume of gas flowing to an appliance from another chamber. This displaced volume is always the same.

The meter shown is just one of several different types of displacement meters made today. Some meters have three chambers, some have four. Your meter may look like one of those shown on the preceding page.

In a four-compartment meter, the order in which these compartments fill, stand by, and empty, under the control of valves, is shown on the chart. But what works the valves?

The valves in a four-compartment meter are made to move at the right time by an arrangement of levers and axles; or, as they are called by meter people, flags, flag rods, flag arms, and cranks. They work in this way:

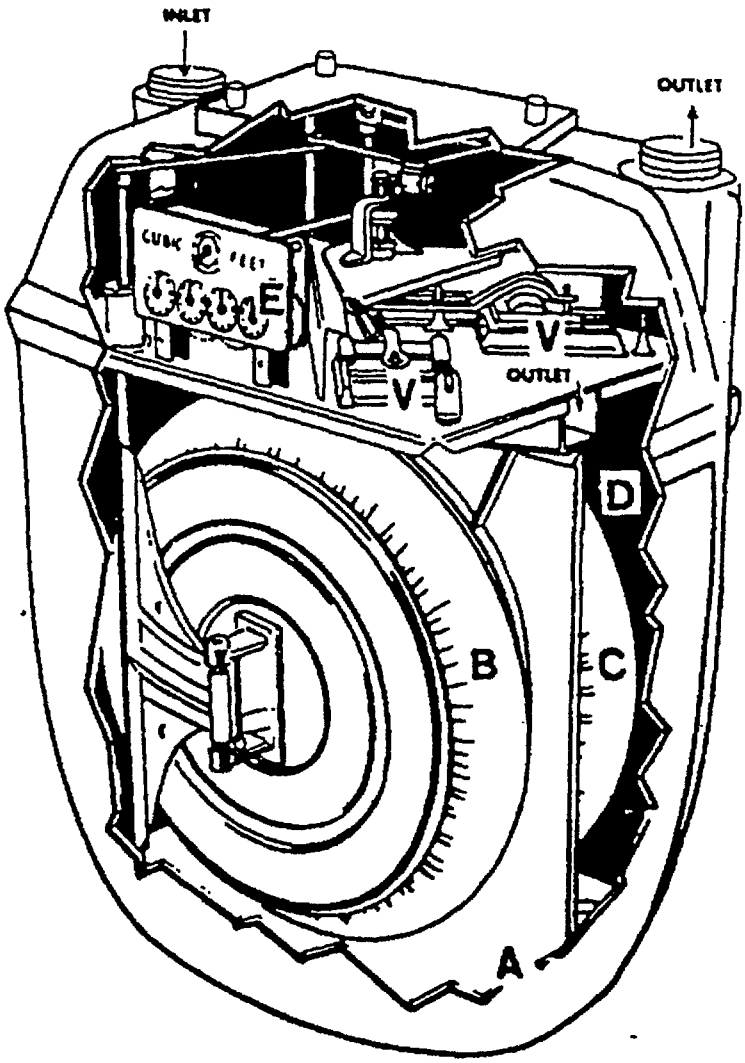
1. The gas starts to flow out of one of the meter compartments when you turn on an appliance. The flexible diaphragm (B) begins to move.

2. The movement of the diaphragm is picked up by the metal piece (F) called a flag. The flag is attached to the center of the diaphragm.

HOW YOUR GAS METER WORKS

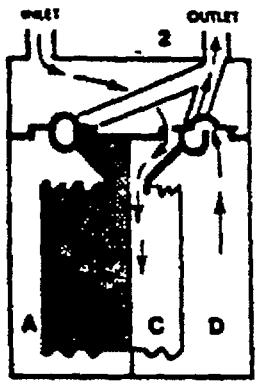
WHEN YOU TURN ON THE GAS—

- *the pressure drops* a little in the gas "outlet" line from the meter to the appliance. But pressure in the "inlet" line going into the meter stays at the pressure in the supply line. This causes an unequal pressure on opposite sides of the movable diaphragm in the meter. This unequal pressure produces the force that makes the meter work. The force pushing on the movable diaphragm or bellows makes it expand like an accordion. Gas flows.
- the flow of gas into and out of the separate chambers in the meter is controlled by sliding valves (V) so that the gas output is smooth and steady.
- each of the chambers is filled with the *same volume* of gas every time.
- the meter dials (E) keep count of the number of times the chambers are filled and emptied. Thus the volume of gas that passes through the meter is recorded.

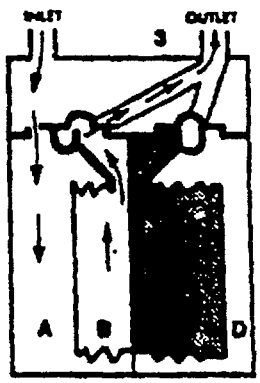


HERE'S HOW SLIDING VALVES CONTROL THE GAS FLOW THROUGH A FOUR CHAMBER METER

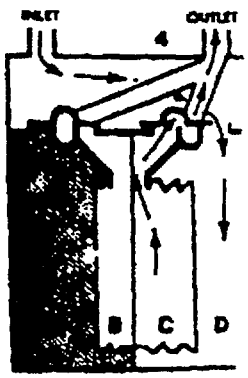
Chamber A is emptying, B is filling, C is empty, and D is full.



Chamber A is empty, B is full, C is filling, and D is emptying.



Chamber A is filling, B is emptying, C is full, and D is empty.



Chamber A is full, B empty, C is emptyin and D is filling.

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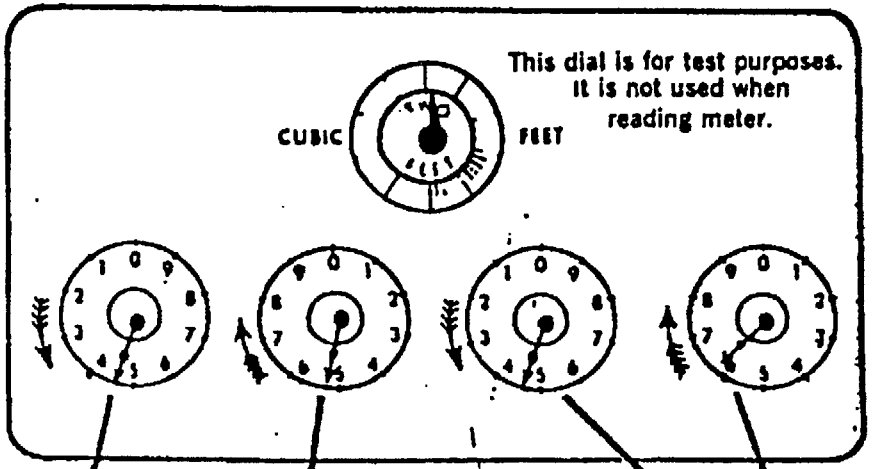
15

READING YOUR METER

Your gas meter is an accurate automatic measuring instrument. It keeps track of how much gas flows through it by counting the filling and emptying of the compartments inside the meter. Since each compartment fills with just the same amount of gas every time, the measuring is very accurate. And because one compartment is emptied as another is being filled, the flow of gas to the various appliances is smooth and uninterrupted. Here's how to read your meter:



Take the number the first pointer has just passed . . . 4

And the number the second pointer has just passed . . . 5

And the number the third pointer has just passed . . . 4

But take the number the last pointer is *nearer* . . . 6

Add two zeros . . . 454600

This is the meter reading (in cubic feet of gas). 454600

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3. The movement of the flag is carried by the turning flag rod (G) to the upper chamber of the meter (H).

4. The flag rod passes into the upper chamber through a gas-tight stuffing box.

5. The turning of the flag rod is transferred to two jointed flag arms (I).

6. The motion of the flag arms turns the crank (J). The turning crank moves the valves attached to it by crank arms (K).

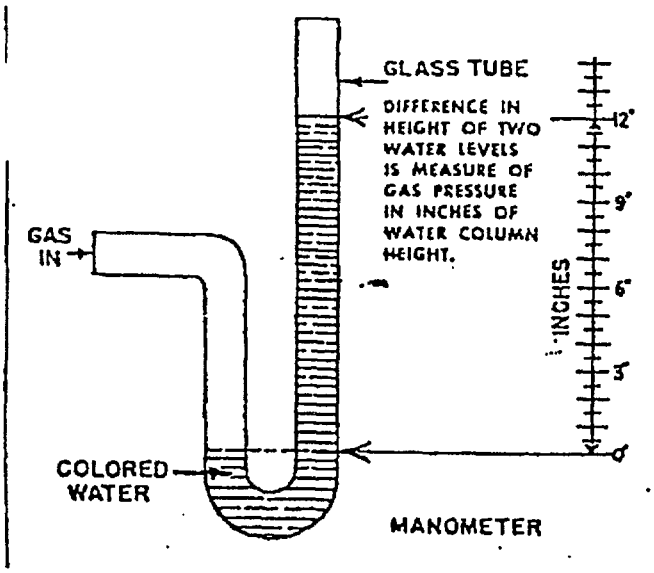
7. The point where the crank enters the valve box is made gas-tight by a stuffing box.

8. At the same time the turning of the crank is carried by the axle (L) to the meter dial mechanism (E). This mechanism records the turns of the crank. It counts the number of times the measuring compartments are emptied of gas.

Notice that the angle between the crank arms and the crank determines the timing of the valve movements.

Pressure

Pressure of the gas entering your burner or other appliance may vary from city to city. Pressure may be expressed as pounds per square inch (psi), or ounces per square inch (oz/in^2), or height in inches of a column of water. (Inches W. C. or inches of water. The pressure at the bottom of a column of water 1 inch high is 0.58 ounces per square inch.)



1 atmosphere = 14.7 pounds per square inch atmospheric pressure (psia) = 235 ounces per square inch = 407 inches of water column (407" W. C.)

Gas pressure is easily measured by means of a U-shaped glass tube containing water, called a manometer. In the illustration, the gas enters the left side of the manometer and pushes the water down on that side of the tube. This raises the water level on the other side. The difference in height of the two water levels is a measure of the gas pressure in inches of water column. (How to construct a manometer is described in Experiments with Gas, Experiment 5, a book of classroom experiments available without charge from Educational Services, American Gas Association.)

In each community the gas company determines the best operating pressure and regulates its entire system to this pressure.

The natural gas enters the meter in your home through the service line. The gas is at a specific pressure determined by your local gas company's distribution system and rate structure. The pressure is usually from 4 to 12 inches of water, or from 2.3 to 7 ounces per square inch.*

Force

When an appliance is turned on, the pressure of the gas on the opposite sides of the movable diaphragm in the meter becomes unequal. This unequal pressure produces the force that makes the meter work. How large is this force?

The unbalanced pressure on the diaphragm amounts to about 0.2 inch of water, or about 0.12 ounces per square inch. In the low-pressure meter shown on the chart, the diameter of one of the movable diaphragms is about 8.6 inches. Its area, therefore, is approximately 58.09 square inches ($A = \pi r^2$). The force on the diaphragm can be calculated.

Total force = pressure X area of diaphragm
Total force = 0.12 ounces per square inch X 58.09 square inches
Total force = 6.97 ounces

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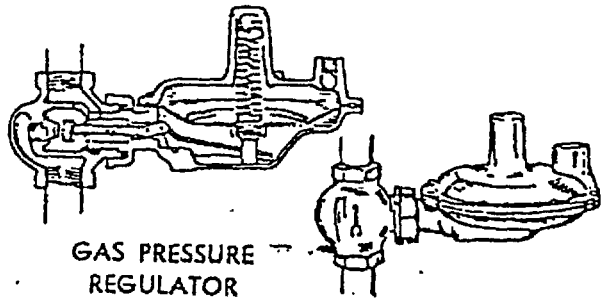
*Since 1 inch of water exerts a pressure of 0.58 ounces per square inch, you can work arithmetic problems changing one unit of measure (inches of water) into the other unit of measure (ounces per square inch). For example, (a) 7 inches of water can be expressed as how many ounces per square inch? 7 in X 0.58 $oz/in^2/in$ = 4.06 oz/in^2 (b) How tall is the column of water that exerts a pressure of 6.96 ounces per square inch? 6.96 oz/in^2 ÷ 0.58 $oz/in^2/in$ = 12 in of water.



The gas in the main under the street may be at a pressure of several pounds per square inch. If so, a gas pressure regulator valve is placed in the service connection. The valve reduces the pressure in the supply pipe to the correct value for home use. Pressures in gas mains, however, vary from city to city, depending on the design of the underground distribution system and the type of gas used. Your own gas company will be pleased to give further information about the pressures used in your local system.

Volume

All the gas used in your home must first pass through the meter. The low-pressure meter shown on the chart can handle up to 175 cubic feet of gas per hour. A gas range top burner, when turned on full, will use from 9 to 23 cubic feet of gas in one hour, depending upon the size of the burner and the type of gas. A 175 cubic foot capacity meter is usually adequate for the domestic uses of gas in a home, including space heating.

Larger meters are made to measure the large volumes of gas used by industrial plants. The largest meter of this diaphragm displacement type, working on the same principles as your home meter, can handle 11,000 cubic feet of gas per hour on low pressure. It is a large meter, 3 1/2 feet high.

The Standard Cubic Foot of Gas is the quantity of gas contained in one cubic foot of volume at a barometric pressure of 14.731 pounds per square inch (pressure of the air at sea level)*, and at a temperature of 60°F. This standard volume has to be stated in terms of a specified temperature and a specified pressure since the volume of a gas changes when the temperature or the pressure changes. Boyle's law states that the volume occupied by a given mass of confined gas varies inversely with the absolute pressure (volume decreases as pressure increases, and vice versa) if the temperature remains constant. Charles' law states that the volume of a given mass of gas is directly proportional to the absolute temperature (volume increases as temperature increases, and vice versa) if the pressure is constant.

Since there is approximately 1% volume change per 5°F temperature change, meters have been constructed in order to adjust for temperature changes. As a result, the homeowner will always receive the heat (BTU) value that is stated in his contract with the utility company.

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*The average atmospheric pressure in the United States is 14.4 pounds per square inch, the pressure at 500 feet elevation.

21

Heat Content

The heat content of natural gas varies from place to place. Here again your gas company can give you definite information.

Heat content is measured in terms of BTU (British thermal units). One BTU is the amount of heat required to raise the temperature of one pound of water one Fahrenheit degree. Natural gas releases approximately 1,000 to 1,150 BTU's when one cubic foot of the gas burns completely.

Meters were not used in Baltimore when the first gas company in the United States was established there in 1816. Gas was sold more or less by the hour and by the number of lights used. Inspectors were sent out by the company to

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Meters were not used in Baltimore when the first gas company in the United States was established there in 1816. Gas was sold more or less by the hour and by the number of lights used. Inspectors were sent out by the company to see that customers did not use more gas than they were entitled to. The inspectors warned householders when the gas lights were kept on too late at night by rapping on the curb or sidewalk outside the home.

Accuracy

Accuracy of gas meters is specified by state public service commissions. Generally, for example, a meter taken from a home for inspection must check within 2%, plus or minus; that is, it may be in error by no more than 2% too little to 2% too much. In some states a meter being installed, however, is allowed an error of minus 2% only; and that being in favor of the customer. In other words, a meter must be 98% to 100% accurate.

Chemical action by some of the components in natural gas may, over a period of years, affect the soft, flexible diaphragms or bellows in the meter. Meters are, therefore, changed and inspected at regular intervals to make sure they are working properly. The accuracy of the gas meter is so high, however, that the time between inspections or changes--set by state regulatory bodies--is often seven to twelve years.

The flexible diaphragms once made of leather are today made of synthetic materials.

Computing of gas bills is done on the basis of local rate schedules. Your gas company will be glad to mail a copy to you if you request it, using letterhead stationery.

Meter Flow Rate Computation

To determine the cubic foot value of each segment on dials that are 1 cu. ft. or larger per revolution, simply put the dial size over the number of segments in the dial.

EXAMPLE: 2 cu. ft. dial with 8 segments. Each segment value is:

$\frac{2}{8}$ dial size / no. of segments, or 1/4 cu. ft.

To figure the cubic foot value of each segment on dials that are only a fraction of a cubic foot per revolution (i.e.,

1/2, 1/4), multiply the number of segments in the dial times the <u>lower</u> number in the fraction.

<u>EXAMPLE</u>: 1/2 cu. ft. dial with 8 segments

$$\frac{1}{2 \times 8} = \frac{1}{16} \text{ cu. ft. per segment}$$

If the registration is more than 1 segment of the dial, figure the value of the segment first, then multiply by the number of segments moved.

<u>EXAMPLE</u>: 2 cu. ft. dial with 10 segments. Test hand moved 2 segments

Value of each segment $\frac{2}{10}$ or $\frac{1}{5}$ cu. ft.

Multiply by number of segments moved:

$2 \times \frac{1}{5} = \frac{2}{5}$ cu. ft. total registration

The amount of registration occurring in a given time will determine the size of the leak. This is known as clock testing. As an example, a registration of 1/4 cu. ft. that occurs in one minute is larger than a 1/4 cu. ft. registration that occurs in two minutes.

25

If the movement of this test hand were observed for two minutes, its registration would indicate a leakage of 1/4 cu. ft. in two minutes. For our purposes we need to know how many cubic feet per hour (CFH) that would be. To do this:

2 minutes = 120 seconds, and there are 3,600 seconds in an hour. Therefore, divide 3,600 by 120:

3600 ÷ 120 = 30

1/4 cu. ft. = .25

.25 X 30 = 7.5 CFH actual gas per hour that is leaking

ALTERNATE METHOD OF DOING FLOW RATE COMPUTATIONS

$$\frac{\text{DIAL SIZE} \div \text{\# OF SEGEMENTS X \# OF SEG'S DURING TEST X 3600}}{\text{TIME IN SECONDS}} = \text{C.F.}$$

(TO FIND B.T.U.'S - MULTIPLY C.F.H. X 1050)

PART 4

INSPECTION, TESTING AND PURGING

4.1 Applied to supervisory functions of inspection, testing and purging.

4.2 System and Equipment Check.

4.2.1 Before Turning Gas On: Before gas in introduced into a system of new gas piping or back into an existing system after being shut off, the entire system shall be checked to determine that there are no open fittings or ends and that all manual valves on equipment are closed and all unused valves at outlets are closed and plugged or capped.

4.2.2 Check for Leakage: Immediately after turning on the gas, the piping system shall be checked to ascertain that no gas is escaping. (See Appendix D for suggested method).

If leakage is indicated, the gas supply shall be shut off until the necessary repairs have been made.

4.2.3 Placing Equipment in Operation: Gas utilization equipment may be placed in operation after the piping system has been tested and determined to be free of leakage and purged in accordance with 4.3.2. See also Training Manual Vol. I Section 8.

APPENDIX D

SUGGESTED METHOD FOR CHECKING FOR LEAKAGE

(This Appendix is informative and is not part of the Code).

Use of Lights: Artificial illumination used in connection with a search for gas leakage shall be restricted to battery-operated flashlights (preferably of the safety type) or approved safety lamps. In searching for leaks, electric switches should not be operated. If electric lights are already turned on, they should not be turned off.

a. Checking for Leagage Using the Gas Meter. Immediately prior to the test it should be determined that the meter is in operating condition and has not been bypassed.

Checking for leakage can be done by carefully watching the test dial of the meter to determine whether gas is passing through the meter. To assist in observing any movement of the test hand, wet a small piece of paper and paste its edge directly over the center line of the hand as soon as the gas is turned on. Allow 5 minutes for a ½ foot dial and proportionately longer for a larger dial in checking for gas flow. This observation should be made with the test hand on the upstroke.

27

In case careful observation of the test hand for a sufficient length of time reveals no movement, the piping shall be purged and a small gas burner turned on and lighted and the hand of the test dial again observed. If the dial hand moves (as it should), it will show that the meter is operating properly. If the test hand does not move or register flow of gas through the meter to the small burner, the meter is defective and the gas should be shut off and the serving gas supplier notified.

b. Checking for Leakage Not Using a Meter. This can be done in two ways: (1) by attaching to an appliance orifice a manometer or equivalent device calibrated so that it can be read in increments of not more than 2 percent of operating system pressure, and momentarily turning on the gas supply and observing the gaging device for pressure drop with the gas supply shut off. No discernible drop in pressure shall occur during a period of 3 minutes; or (2) by insertin a pressure gage between the container gas shutoff valve and the first regulator in the system, admitting full container gas shutoff valve and the first regulator in the system, admitting full container pressure to the system and then closing the container shutoff valve. An appliance valve shall then be opened momentarily dropping the pres sure in the system between the first regulator and the container shut off valve 10 psi. The system shall then be allowed to stand for 10 minutes without showing an increase or a decrease in the pressure gage reading.

It should be emphasized that at no time do we purge a line when a source of ignition is available. Proper purging procedures will be taught in other portions of the training.

Table D-1

Test Observation Times for Various Meter Dials

Dial Styles Cubic feet	Test Time Minutes
¼	5
½	5
1	7
2	10
5	20
10	30

28

SECTION 14.6
METER SELECTION

INTRODUCTORY INFORMATION

An important matter to the gas industry is the measurement of gas volumes with particular attention given to obtaining the highest degree of accuracy in keeping with the economics of initial and long-term metering costs. The new metering concepts presently on the market offering a greater rangeability, a higher degree of accuracy, and electronic readout with computer compatibility have contributed to complicating the problem of meter selection. The following compilation of information is provided to assist the user in selecting the correct type of gas meter for a specific application.

In the selection of a meter it is important to know the particular load characteristics of the various types of meters that have been found acceptable by the gas industry and subsequently approved for revenue metering by the respective state regulatory agencies. A number of meter types, other than the common diaphragm and orifice meter, are finding increasing acceptance and usage; therefore, it is important to be knowledgeable on each type and know the benefits of using one type over another. This reasoning also applies to reviewing the adequacy of present methods of volumetric measurement versus other methods of measurement, i.e., weight (pounds) and energy (Btu) measurement, which show promise of useful application.

With any system of measurement, a definition of the basic measured unit must be provided. Currently, in the gas industry, the most common method of measurement is by volume. The unit of measurement is the dimensional cubic foot referenced to a standard pressure and temperature base and for the convenience of accounting is generally referred to in terms of 1,000 standard cubic feet (Mscf). The pressure and temperature bases are contractually agreed upon units which permit the gas metered at actual line conditions (Macf) to be converted to base conditions. In the gas industry, the most widely used volume measurements are referred to a standard base absolute pressure of 14.73 psia and a temperature of 60° F. The volumetric capacity of most meters is rated on an hourly basis or standard cubic feet per hour (scfh). In the following discussion, wherever volumes, flow rates, meter capacities, etc. are mentioned, they are made with reference to this standard volumetric unit and time frame.

For convenience, Meter Selection has been broken down into three basic areas: Types of Commercial Meters, Meter Selection Factors and Load Survey Information.

TYPES OF COMMERCIAL METERS

The meters used in the gas industry operate on simple physical principles and have a long history of reliable service performance. The types of commercial meters (a meter through which gas is measured and revenue exchanged) commonly used for gas measurement are grouped under two major categories; Displacement Meters and Velocity Meters.

Displacement Meters. Common types of displacement meters used for measuring gas flows are the Diaphragm, Rotary Lobed Impeller and Rotating Vane. In these types of meters, the gas to be measured passes through the meter in successive and isolated quantities, by alternately filling and emptying compartments or cavities of known volume. The filling and emptying process is usually translated into rotary motion which operates a counter or dial to register the total quantity of gas that passes through the meter. (See Section 2.1).

Displacement meters operate at static pressures from 4 ounces to 1440 psig and at capacities ranging from 0 to 1,000 Mscfh. When a meter is operated at pounds pressure rather than ounces, it is desirable to have some means that will not only register the volume of gas passed, but also relate it to the pressure and temperature conditions prevailing at the meter. This is accomplished by installing on the meter a gage, which will record the desired parameters so that subsequent corrections can be made, or by installing an integrating device that will continuously correct the registration (See Section 6.1).

Displacement meters can be equipped with a bi-metal temperature compensator (TC element) which will enable the index to register in measurement units at base temperature conditions. Pressure compensating indexes, accomplished through gearing and usually limited from 2 to 10 psig, are also offered by most suppliers for applications where metering pressures are maintained constant. This type of measurement is referred to as Fixed Pressure Factor Metering (FPFM) (See Section 7.2).

There is one other general observation applicable to all displacement meters. Their accuracy is usually determined by comparing the quantity of gas the meter will register with the actual quantity passed through it as determined by a reference meter of known accuracy. This is termed proving, calibrating or certifying a meter. The reference meter is called a "prover".

Diaphragm Meters. Currently, there are two design concepts for diaphragm meters; those having three chambers and those having four chambers. Both designs will perform comparably and are shown in Figure 14.6.1. The principle on which the diaphragm meter operates is one in which two diaphragms and either one rotating or two reciprocating slide valves (depends on meter concept) with connecting linkage accomplish three actions as the gas flows through the meter; (1) they drive the displacement meter continuously as long as gas is moving through the meter, (2) they control the gas displacement throughout each cycle and (3) by means of the meter index, they count the cycles and express the results in cubic feet of gas passed. These actions take place regardless of the time required for such gas to pass through the meter.

The force required to operate the meter results from the difference between the pressure of the gas at the meter inlet and outlet. It usually is about 0.5 inch of water column differential pressure (0.02 psig) at the maximum flow rate for meters measuring gas in ounces and 2.0 inch of water column differential pressure (0.07 psig) at the maximum flow rate for meters measuring gas in pounds pressure.

Rotary Lobed Impeller Meters. The rotary lobed impeller meter is quite simple but rugged and is shown in Figure 14.6.2. The measuring chambers are created when two lobed rotors or impellers, supported on parallel shafts and confined within a meter body, rotate. As the gas flows through the meter, the impellers turn in opposite directions and are either trapping definite volumes of gas between the impellers and the body, or are discharging a previously entrapped volume of gas. The machined clearances between the impellers and the impellers and meter body are such that there is almost rolling contact between the surfaces providing an effective capillary sealing action of the measuring chambers. The impellers are synchronized by timing gears, which are installed on the impeller shaft outside the headplates of the meter body and running in a bath of oil. They are caused to rotate when a slight

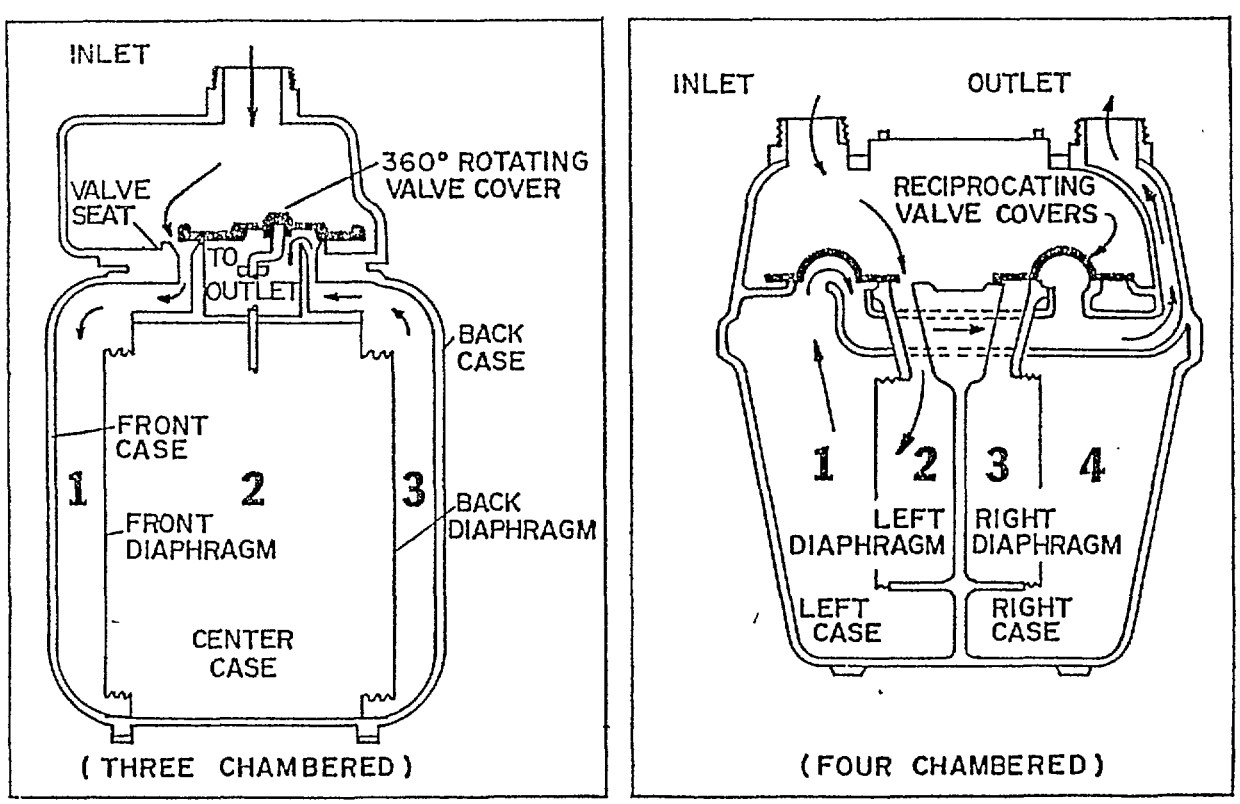

Figure 14.6.1—Diaphragm Displacement Meters

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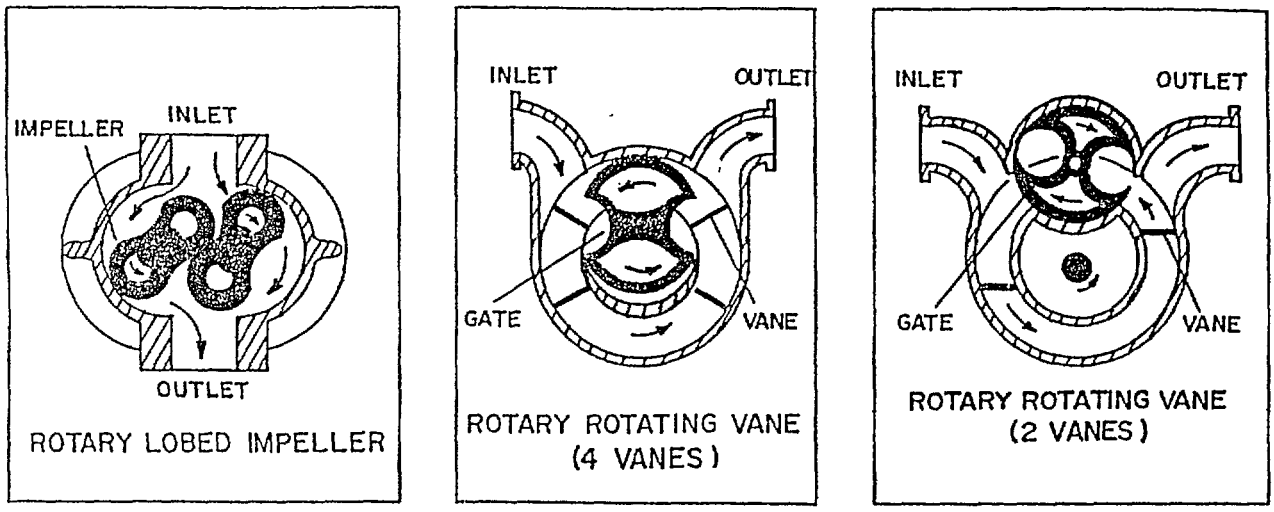

Figure 14.6.2—Rotary Displacement Meters

differential pressure, about 0.05 to 0.10 inch of water column, is created between the inlet and outlet of the meter; while the speed at which they rotate is a function of differential pressure and the velocity of the gas through the meter.

The accuracy of the meter is a function of the machined clearances, synchronization of the timing gears and bearing friction. A typical meter accuracy curve, percent accuracy versus flow rate, would fall within an accuracy band of 99.5 to 100.5 percent at flow rates between about 20 and 100 percent of its maximum capacity and 99.0 to 100.5 percent at flow rates between about 10 to 20 percent of its maximum capacity. Below 10%, the accuracy curve abruptly turns down and becomes a function of clearance flow and meter friction.

Rotating Vane Meters. The rotating vane meter is shown in Figure 14.6.2 and differs from the rotary lobed impeller meter in that it utilizes a rotating "gate" and a rotating vane assembly contained within a casing to form the metering chambers. The displacement volume essentially remains constant since the clearances between the gate, vane assembly and the stationary members (end plates) are fixed and the relationship of the moving members are maintained with timing gears. This means that once calibrated, meter adjustments are normally unnecessary.

A second variation of this meter has four instead of two rotating vanes. The operation of the meter is basically the same except that the gate rotates at twice the vane speed but in the same direction. The design is bi-directional and the primary measuring element is a calibrated cartridge that is interchangeable. The cartridge may be removed and its accuracy either certified by the manufacturer or by certified equipment of the user. The measurement cartridge utilized in the low pressure meter is also interchangeable with a high pressure meter. Permanently lubricated bearings are used eliminating the need for lubrication in the meter end chambers.

Velocity Flow Meters. In contrast to displacement meters, a velocity flow meter or rate of flow meter operates by passing a steady stream of gas, rather than isolating and counting individual volumetric units of gas. Common types of velocity flow meters are the orifice meter and the turbine meter which are shown in Figure 14.6.3 (See Sections 3.1 and 4.1). The velocity of gas through an orifice meter is not measured directly, but is inferred by measuring an induced pressure differential; while the velocity of the gas through a turbine meter can be related to a direct measurement of the rotational speed of the rotor.

Orifice Meter. The orifice meter consists of a primary and secondary measuring element. The primary element includes the specified inlet and outlet piping, the straightening vanes, the orifice fitting or flanges and the orifice plate. The secondary element includes the necessary gages and related equipment to sense, measure, and record the flowing gas conditions for calculation of the quantity of gas delivered over a selected time period. Included under this classification are the orifice meter duplex differential pressure and pressure recorder, temperature recorder and specific gravity recorder (See Section 6.1).

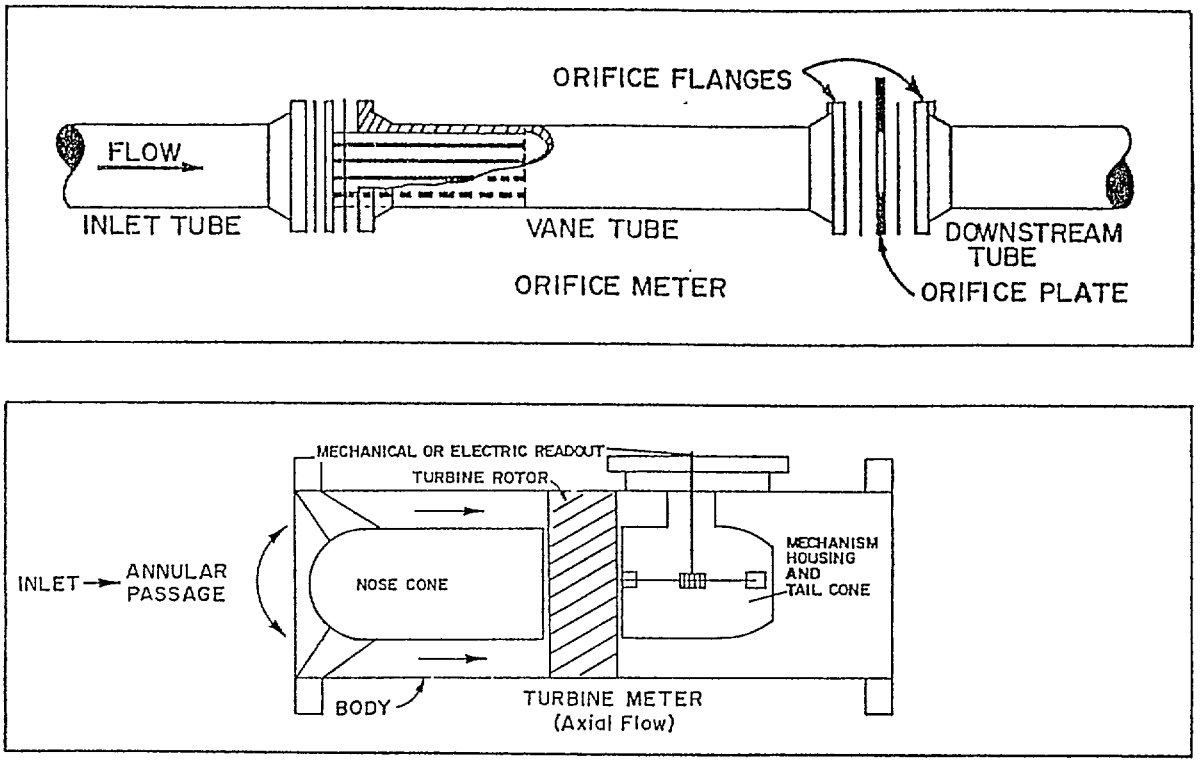

Figure 14.6.3—Velocity Flow Meters

The orifice meter for gas flow measurement has gained wide acceptance as the "workhorse" of the industry because of its inherent construction simplicity, ease of maintenance, ease with which the accuracy of the primary element can be recertified (inferred via dimensional check) and the fact that for years it has enjoyed the uniqueness of being the only meter available that could measure large volumes of gas at very high pipe line pressures. In addition, its wide acceptance can be attributed to the recognition given the meter through the published reports of the joint research efforts made by the American Gas Association, the American Society of Mechanical Engineers and the National Bureau of Standards that recommend correct methods of installation, the necessary flow adjustment factors and the operating parameters and requirements to produce a meter having a predictable and sustained operating accuracy.

Generally, large volume measurement used for custody transfer has been confined to the 2" through 16" orifice meter sizes and the larger size meters have been limited to the control of gas. This is further discussed under the category of installation factors.

Turbine Meter. The turbine meter is a velocity measuring device that is able to mechanically relate the gas velocity directly to an integrated reading in cubic feet. The meter is composed of a meter body and a nose cone concentrically located within the meter body which supports a multi-bladed rotor. Gas entering the meter increases in velocity through the restrictive annular area formed by the nose cone and the interior wall of the body. The movement of gas over the angled rotor blades imparts a force to the rotor, causing it to rotate. The ideal rotational speed of the rotor is directly proportional to the flow rate. The actual rotational speed of the rotor is a function of meter design, internal mechanical friction, fluid drag, external loading and the gas density. Rotor revolutions are counted mechanically or electrically and converted to a continuously totalized volumetric registration.

Capacities of turbine meters operating at elevated pressures are calculated in the same manner as displacement meters. An instrument is required to obtain the operating pressure and temperature so that an adjustment can be made to correct the meter registration to base conditions. Like other displacement meters, a supercompressibility factor must be applied to adjust the registration for the deviation from Boyle's Law.

METER SELECTION FACTORS

In Table 14.6.1, entitled "Summary of Gas Meter Selection Factors", the scope of factors that affect meter selection in gas measurement has been reduced to tabular form. This table includes only those meters that are normally used by the gas industry for billing purposes, thus narrowing down the possible choices and presenting enough information on each so that alternate approaches can be considered. The table is intended only as a guide and should not preclude further investigation to find additional information that would contribute to the selection of the best meter for a particular application.

Part of the problem in selecting a meter is understanding the factors involved. What is meant by proof, accuracy, rangeability, maximum flow rate, etc.? Another aspect that should be considered is how important are such factors as "first cost", "installation costs", and other costs relating to operation and maintenance. The following discussion is presented to provide information that will contribute to a better understanding and more effective communication of proper measurement terminology. The headings used across the top of Table 14.6.1 group the various columns under the categories of Gas Properties, Meter Characteristics, Installation Factors, and Economic Factors. The vertical column farthest to the left lists the types of meters commonly used for custody transfer.

GAS PROPERTIES

Maximum Working Pressure. Values given in the tables represent the highest static pressure rating of that particular meter type. A line of commercially available meter models usually span several working pressures. For example, a domestic diaphragm meter may have a maximum working pressure rating of only 5 psig; while a line of larger diaphragm meters may have maximum working pressure ratings from 10 to 500 psig. In accordance with ANSI standards, a meter case shall be able to withstand a burst pressure of at least four times the maximum allowable operating pressure (MAOP) of the meter. In addition, each new meter is shell (or case) pressure tested by the manufacture at pressures of 1½ to 2 times the MAOP. In the selection of a meter, it is necessary to stay within the manufacturer's working pressure to maintain the meter warranty and the incorporated design safety factor can be used to assure safe operations.

Flowing Fluid Temperature Limits. The temperature is that of the flowing gas to which the meter is actually exposed. When applicable, the limits shown are those for which a temperature compensated meter will function properly. Consideration should be given to the installation site; underground, in a pit, in a heated or air-conditioned room and the variations possible with seasonal changes in weather. Also, consideration should be given to the possible side effects of ambient temperature; if low enough it can cause condensation of vapors resulting in moisture that can affect the working parts of certain meters. If LNG or LPG is being vaporized, provisions should be made to bring the gas up to within the meter temperature limits at the point of measurement.

The close manufacturing tolerances of the rotary meter impose certain operating temperature limitations worthy of mentioning. For unusual conditions where the ambient to flowing gas temperature differential approaches 75° F, measures may be required to prevent excessive clearance close-up from unequal expansion-contraction caused by the meter body being at a much different temperature than the internal rotating parts. When the condition is predictable, the meter can be insulated, brought on line slowly to enable equalization, quick temperature changes of the gas avoided or other appropriate measures taken as required by the installation. Accuracy can also be appreciably affected by excessive temperature differentials that change the clearances of the meter.

Suitability for Corrosive Gas. Seemingly innocuous gases, under certain conditions, are surprisingly corrosive. For example, sulfur-bearing gas (SO_2) with water vapor forms sulfurous acid; carbon dioxide with moisture forms carbonic acid, which can attack brass or bronze and even some steels. The presence of oxygen and moisture can cause rust.

Acids used to stimulate wells, if inadvertently allowed to enter the gas stream, can result in corrosive liquids in the metered gas. Mercaptans and other odorants, although usually no problem at normal injection ratios, may be corrosive if accidentally dumped into a pipeline at concentrated levels.

Influence of Condensate. Ideally, a gas stream should be completely free of all liquids to obtain optimum measurement and meter operation. Liquids produced by production wells or inadvertently left in a pipeline after a hydrostatic pressure test create a wet gas service and many related measurement problems which are difficult to overcome. Distillates (petroleum compounds) and water vapor in a saturated gas stream will condense in the pipeline or meter due to changes in pressure or temperature.

The accumulation of liquids, movement of free liquids or the freezing of a liquid in a meter will normally cause measurement errors and if the condition is not corrected an eventual malfunction of the meter.

Another problem which is accentuated as the water vapor content of gas increases is the formation of hydrates. These hydrates form at reasonably predictable pressures, temperatures, and water conditions and are physically similar to dense ice. Pieces of hydrate can move through a pipeline at a velocity such that they can be violently destructive to measurement equipment. Their formation can affect measurement accuracy by partially blocking orifices, forming in the straightening vanes upstream to a meter creating a turbulent or a jetting condition and generally changing the velocity flow profile at the meter entrance. Many times they are difficult to detect because they have a melting point of approximately +50°F to +60°F and hence at atmospheric temperature disappear when the pipeline is disassembled to look for the cause of trouble.

The installation of atmospheric drips and/or separators, catalytic heaters and indirect fired gas heaters will help to reduce the condensate related measurement problems. The installation of a basket strainer (hole area greater than pipeline area) in the upstream meter piping will cause slugs of condensate to take an atomized state which can be passed by some meters without damage. Where known wet conditions persist the frequency of maintenance will in all probability have to be increased. Where liquid problems can be anticipated the installation should be designed to prevent liquid accumulation in the meter.

METER CHARACTERISTICS

Base Maximum Capacity Range. The capacity range values presented in Figure 14.6.4 and shown in Table 14.6.1 are the representative capacity ranges of those sizes of meters which are available commercially. The chart is intended to give preliminary comparative capacity information that can be used for a specific gas measurement problem. Since the chart includes the published meter ranges of most meter manufacturers, it is possible that individual manufacturers may not offer models of a given type that have the exact capacity as shown. The base maximum capacity range is the maximum capacity at a base pressure and temperature of 14.73 psig and 60° F that can be achieved by a line of meters representing that particular measurement method. The minimum range was determined by taking the base maximum capacity of the smallest meter and dividing by the rangeability, except for the orifice meter where the minimum range is a function of plate size (Beta ratio 0.15 and 10 inches water column differential pressure). The maximum range was determined by taking the base maximum capacity of the largest meter (orifice Beta ratio 0.70 and 90 inches water column) and correcting it to the maximum rated pressure.

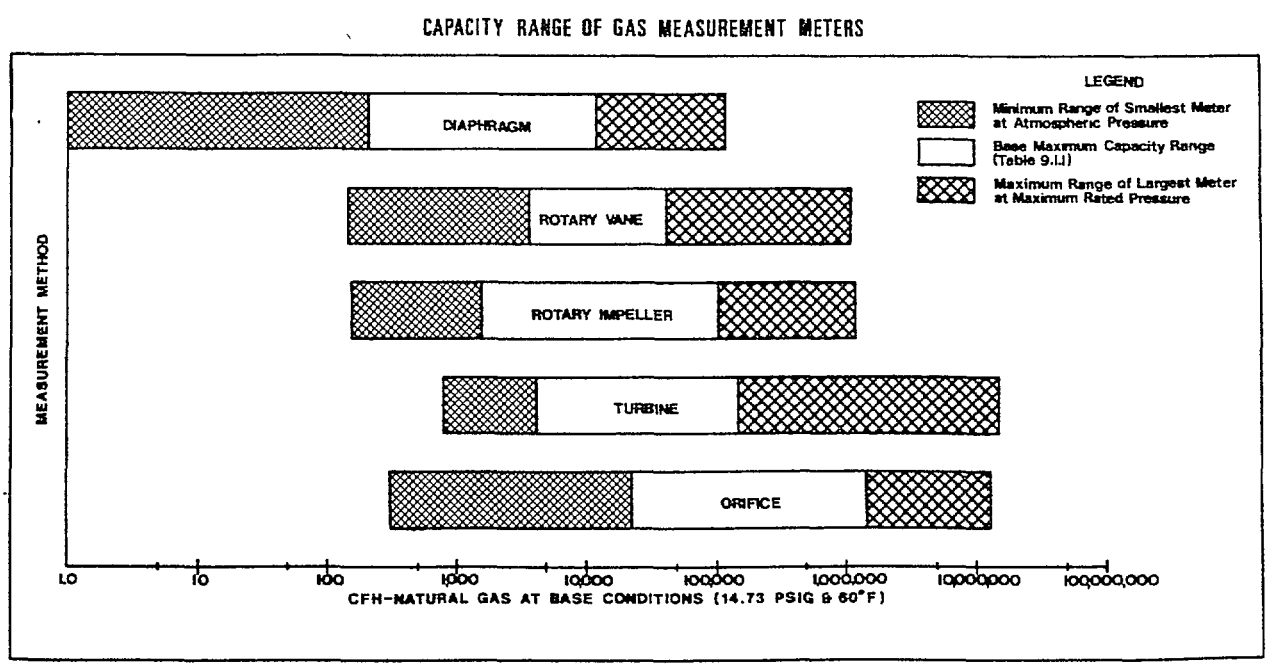

Figure 14.6.4—Capacity of Gas Measurement Meters

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Accuracy % of Reading. Probably no single factor in flow meter selection is more important yet often incorrectly applied than is "accuracy". Accuracy of a meter, which may be a proven quantity, is not necessarily the accuracy of a metering system. The accuracy of a metering system is a function of the meter's accuracy, the accuracy in obtaining and applying the sensed parameters (pressure, temperature, and specific gravity, etc.) and the influence of gas stream variations. These consist of pulsation, two and three phase flow (solid, liquid, and gas), and velocity profile variations due to turbulences caused by restrictions, protrusions and piping configurations adjacent to the meter. Through good design and installation practices, a number of the variables mentioned can be minimized improving system accuracy.

In gas flow measurement, the accuracy of a meter is usually stated in percent of reading. In order to accomplish this equitably, the characteristic accuracy curve peculiar to a type of meter is recognized and a plus or minus percent accuracy is stated at 10, 50 and 100 percent of the maximum flow rate at atmospheric pressure conditions. The manufacturer, in published literature or upon request will present data showing the accuracy versus flow rate for a particular line of meters, or will often state the sustained accuracy through the recommended flow range of a meter.

Another common method of stating meter performance peculiar to the gas industry is percent proof, often confused with accuracy. For example, calibration of a domestic diaphragm meter is almost always stated as:

$$\text{Percent Proof} = \frac{\text{Quantity indicated by reference standard}}{\text{Quantity indicated by meter}} \times 100$$

The definition that is used to calculate percent accuracy is the following:

$$\text{Percent Accuracy} = \frac{\text{Quantity indicated by meter}}{\text{Quantity indicated by reference standard}} \times 100$$

On the basis of the above definition, a "slow" meter will have a percent proof greater than 100% and a percent accuracy less than 100%.

Oftentimes, to simplify presentation, proof or accuracy is given in terms of percent "correction" or "percent error", respectively. A deviation of the meter percent proof from 100% is called percent correction and is defined as:

$$\text{Percent Correction} = \frac{\text{Quantity indicated by meter} - \text{quantity indicated by reference standard}}{\text{Quantity indicated by meter}} \times 100$$

The deviation of the meter percent accuracy from 100% accuracy is called percent error and is defined as:

$$\text{Percent Error} = \frac{\text{Quantity indicated by meter} - \text{quantity indicated by reference standard}}{\text{Quantity indicated by reference standard}} \times 100$$

Assume, for example, that a meter indicates 10 cubic feet when the reference standard indicated 10.2 cubic feet (a slow meter). Its performance using the four definitions is the following:

$$\text{Percent Proof} = \frac{10.2}{10} \times 100 = 102\%$$

$$\text{Percent Accuracy} = \frac{10}{10.2} \times 100 = 98.04\%$$

$$\text{Percent Correction} = \frac{10 - 10.2}{10} \times 100 = 2.0\%$$

$$\text{Percent Error} = \frac{10 - 10.2}{10.2} \times 100 = -1.96\%$$

The practice of using percent proof and percent accuracy interchangeably introduces no appreciable error for values near 100%. However, as a word of caution, there is a difference which become appreciable as the deviation from 100% exceed 3%. Even though the meter is referred to a standard in each case, as can be seen from the foregoing equations, the terms percent proof and percent correction use the meter as a base of reference, while percent accuracy and percent error use the reference standard as a base of reference. The practice of indicating a meter's calibration by "proof" was an expedient that developed from the method of meter testing and also it facilitated the correction of customer's bills. The term "percent accuracy" is becoming the accepted practice for indicating the calibration of a meter.

Base Rangeability. Rangeability is equal to:

$$\text{Rangeability} = \frac{\text{Maximum hourly flow rate}}{\text{Minimum hourly flow rate}}$$

A meter may have the capability of measuring a wide range of flows, but if it does not maintain a stated accuracy over the range (usually plus or minus one percent of reading), its rangeability will be limited. A physical change made to a meter to extend its rangeability may also be a limiting factor. For example, a single orifice meter with one orifice installed has an approximate flow range from minimum to maximum of about 3 to 1, but this is quite often inadequate for the widely varying flow rates found in some gas measurement applications. A change of orifice sizes would extend the rangeability of the meter, but to effect these changes in response to delivery requirements is usually impractical.

A practical method to increase rangeability has been to design an installation using several parallel meter runs, each of which can be opened or closed by an automatic valve. As a station's delivery increases or decreases and approaches the flow range of one meter, parallel meter runs are automatically sequenced on or off to maintain individual meter flow rates within established limitations for accurate metering.

Various techniques have been used to increase the rangeability of an orifice meter installation. Two practices commonly used are the following. A four run multiple orifice meter station having the same size plates installed in each meter run has a rangeability of 12 to 1. If the plates in each succeeding meter run are properly sized (to prevent on-off cycling) larger than the preceding run, the rangeability of the station can be increased to approximately 45 to 1. Where the seasonal load variation at a station causes the delivery to exceed either the minimum or maximum capacity of a particular multiple orifice meter plate sizing, new orifice plates can be sized to handle the seasonal load (spring, fall and winter) and changed out accordingly.

The performance of the turbine meter provides good rangeability at low pressures and is unique in that the rangeability proportionally increases as the gas density, a function of pressure, increases. For example, the 4" turbine meter has a rangeability of 15 to 1 at 0.25 psig. which increases to 46 to 1 at 125 psig. and 147 to 1 at 1440 psig. Several of these meters can be installed in parallel without any sequencing equipment to measure a large variation in deliveries.

The installation of diaphragm or rotary meters in parallel is often used. These meters installed in combination with an orifice or turbine meter will greatly increase the rangeability of a measuring station.

Type of Chart Scale. Terms such as "evenly divided," "linear" or "uniform" are used to describe the scale divisions of a gage chart. Linear implies an exact mathematical relationship which may not exist and generally the term "uniform" is preferred and used in Table 14.6.1. Another type of chart scale, which is applicable to only the orifice meter, is the square root scale. It is not included in Table 14.6.1 since its usage is minimal.

Common Construction Materials. Availability of various materials and construction can obviously be related to the type of corrosion problems that will be anticipated during measurement. Most manufacturers offer comparable materials in the various types of meters listed. The purpose is to indicate the most common materials used in gas measurement and if the constituents composing the gas are exceptional, the manufacturer should be consulted for his recommendation.

Pressure Loss at Base Maximum Capacity. This is the permanent loss in static pressure caused by the primary element or metering assembly in the line. Particular attention should be given to this loss if the control of the downstream pressure is critical or if it must be held within state public utility regulations.

INSTALLATION FACTORS

Nominal Line Size. Orifice meters are practically unlimited as to pipe sizes; published coefficients in AGA Committee Report No. 3 (now published as ANSI/API 2530) cover 2″ to 30″ pipe. In practice, however, most public utilities will limit the orifice meter pipe size to 16″ and less for billing purposes. Normally, one 12″ or one 16″ orifice meter is not installed. To obtain these capacities, smaller meter sizes are installed in parallel. For example, in lieu of installing one 12″ orifice meter, two 10″ orifice meters would be installed. The reasoning supporting this practice is the following: (1) The installation of several orifice meters increases the station rangeability and allows some flexibility for future expansion, (2) statistical analysis of multiple meter stations versus single meter stations indicate that the probability of the variables in each meter being affected the same is highly improbable; and therefore, the chances of compensating errors to occur is enhanced producing a higher degree of overall station accuracy and (3) in the event of a loss of an orifice meter record, the record can be accurately reproduced within reasonable limitations by observing the preceding or succeeding orifice meter record for the corresponding period of time.

Straight Pipe Requirements. Serious distortions of flow profile upstream and downstream of the orifice meter caused by various piping configurations will produce error and generally affect metering accuracy. The AGA Gas Measurement Committee Report No. 3 establishes recommended minimum lengths of straight pipe that should precede and follow an orifice. If the error is caused by induced disturbances, they are to be eliminated or kept within certain tolerance limits as stated in the report.

The straight pipe requirement upstream and downstream of the turbine meter is recommended as ten pipe diameters upstream and five pipe diameters downstream in AGA Report No. 7, "Measurement of Fuel Gas by Turbine Meters". Recent tests conducted by the manufacturers have indicated that this pipe requirement can be greatly reduced by installing flow straightening guides in the entrance to the meter. The manufacturer's published literature and AGA Report No. 7 should be referenced to obtain the correct straight pipe requirements for a given condition.

In the case of the orifice meter or turbine meter any piping configuration or device that would produce a "nozzle effect" should be eliminated from the meter approach piping. Quick transitions, i.e., 2″ to 6″ pipe, regulators or any other piping configurations or devices that would distort the gas velocity profile can adversely affect meter accuracy.

There are relatively few piping restrictions that apply to the rotary type meter. However, these meters do generate a pulse in the gas stream. In 125 psig pressure meters this small pulse is attenuated and has a negligible affect in a closed piping system. In high pressure meters (above 125 psig) it is desirable to avoid upstream reflecting surfaces which will return the pulse to the meter inlet, e.g., a regulator or partially closed valve. One practice which has proven successful in high pressure installations is to provide a surge or plenum volume upstream of the meter (obtain recommendation of manufacturer). As with other meters the inlet and outlet piping should be full line size or larger.

The diaphragm meter is the least affected by the upstream and downstream piping arrangement and an elbow or tee may be installed directly on the inlet and the outlet of the meter.

Ambient Temperature Range. The ambient temperature can affect the gas flowing temperature; and, therefore, consideration should be given to the effect of seasonal variations and the possible effect of adjacent heating and cooling equipment. If the ambient temperature exceeds allowable limits, (usually governed by Company policy), some type of compensation should be installed or applied to correct the registered cubic feet.

Limitations. The limitations shown in Table 14.6.1 are commonly applied design installation limitations. Although the rotary lobed impeller meter must be installed horizontally due to its oil sump, it is available with either vertical or horizontal connections. If a vertical application is required for either the orifice or turbine meter, the manufacturer should be consulted.

Miscellaneous Considerations. Another factor that should be considered in the selection of a meter is its ability to be periodically tested and its accuracy determined. The accuracy of an orifice meter is established through dimensional checks and procedures recommended by AGA Committee Report No. 3. The turbine meter can be transfer tested on site or the internal mechanism removed and replaced with a calibrated cartridge. The rotary meter is normally tested on location, except in one case where the manufacturer offers the feature of an exchangeable calibrated cartridge. Another factor would be the compatibility, ease and cost of installing an on-site flow calculator with telemetering capability.

ECONOMIC FACTORS

Under this heading the relative first cost of the meter type per 5,000 cfh gas is shown. However, even though this is a consideration that must be taken into account, the overall cost involved with a given type meter is the major consideration. The overall cost considerations include the following: (1) first cost of the meter, (2) installation cost, (3) operating cost, (4) cost of maintenance and service, (5) life expectancy, and (6) overall long-term metering accuracy.

The following are example considerations, some based on available capability, that may influence the selection and overall cost of a meter setting.

1. A rotary meter might cost more to purchase and install than an orifice meter, but after a year's operation, savings in other areas, such as no charge to integrate charts, higher degree of accuracy on a fluctuating load, and less maintenance might well outweigh the extra initial expense.

2. A more corrosion-resistant construction material might boost the initial cost, but add sufficiently to life expectancy as to justify it. On the other hand, anticipated changes in load demand or new metering improvements might dictate against over emphasis on expenditures for long life.

3. The development of accurate portable transfer provers have expedited the testing, of a field meter, in lieu of their removal and return to a meter shop, and thus have helped the cost picture for maintenance.

4. A capability offered with the ability to change out the meter mechanism with a calibrated mechanism or cartridge is the central service center concept. Using this concept, all meter mechanisms would be returned to a central service center for recalibration. Some of the advantages offered are that the air blower capacity to check a meter throughout its entire flow range would be available; the repair or recertification can be done on a yearly basis and scheduled without regard to climatic conditions; the meter parts necessary for repair could be located at one point; the time normally required for a meter to be on bypass to conduct a field test would be eliminated except for mechanism changeout time; the meter problems encountered could be resolved with the manufacturer at one point eliminating the travel time to several different stations; and in this electronic age, it would be easier to justify the needed electronic equipment to properly conduct a recertification test.

LOAD SURVEY INFORMATION

Prior to making any meter selection, it is important to become familiar with the gas parameters and load conditions (temperature, pressure, specific gravity, maximum and minimum delivery, steady delivery, cyclic delivery, etc.) that the meter will be subjected to upon installation.

The measurement equipment which is best suited for a specific installation may be selected only if all of the pertinent information regarding the load requirements is available and accurate. Partial or inaccurate information regarding the load requirements may result in improper meter selection resulting in early replacement of the meter and related equipment and/or costly errors in the measurement of gas volumes.

Each load will have its own peculiarities which will dictate the size and type of metering equipment required for the specific installation, consequently, standardization of selection procedures becomes extremely difficult. As an aid, suggested information that should be obtained prior to making a meter selection is the following:

Suggested Load Survey Information

Type of Customer and Knowledge of Operation

Customer Immediate and Future Delivery Rangeability

Meter Inlet Pressure

Delivery Pressure

Available Space

Company Policy/Regulations

Total Cost

SECTION 14.4
METERING ECONOMICS
(Repair or Replace)

INTRODUCTION

This section is devoted to establishing a means of intelligently answering the question, "Should a group of gas meters be repaired or replaced?"

Even though there is no acceptable universal approach to this question and, therefore, no two utilities use exactly the same criteria to answer the question, there are many basic parameters that should be considered by all in answering this question. Whether any one parameter is included and the degree of inclusion in the decision making process depends upon the conditions and circumstances facing a utility at a particular time. This observation points out only the difficulty in adopting a universal approach.

SCOPE

This section will identify various parameters that should be considered in determining when a group of gas meters are to be repaired or replaced. The significance of any one parameter has to be determined prior to making the final decision. This section will include an illustration of an approach that can be used in resolving the repair vs. replace decision. The parameters that have been included are those that can be considered significant to many utilities at this time under existing economic conditions.

BACKGROUND

It may be appropriate at this time to discuss some past practices in metering economics before an overall approach is covered.

Where economic gas meter replacement studies are made, different choices of method of analysis often lead to different conclusions. With the increasingly high level of mathematical complexity in equipment replacement methods analyses appearing in industry literature, it makes it difficult to adopt a universal approach. To illustrate the diversity of approach to the repair-retirement-replacement proposals, review is made of the various methods such as (a) consideration of earning power (or cumulative consumption); (b) accuracy sampling (metering performance); (c) natural attrition; (d) retirement on the basis of age; (e) retirement on the basis of repair costs.

In the case of *earning power (cumulative consumption),* the approach to the repair or replace question is based on the meter's earning power. It is frequently thought to be economical to emphasize new investments in specific areas which have had or expect the greatest earnings. This method retires meters which earn higher revenues more frequently and tends to direct accuracy testing toward customers with higher usage.

A related approach retires meters after a certain economically determined cumulative consumption for a meter type. Many utilities, however, do not keep meter history records, in a manner that accounts for total cumulative consumption.

In the case of *accuracy sampling (meter performance),* instead of recalling all meters for periodic test and repair regardless of age, condition, or type, meters with proven sustained levels of good performance are brought into the shop less frequently. Such a program should relate meter accuracy performance to such factors as meter age, manufacturer, size and kind, type of case, type of diaphragm, bearing materials, internal design, last year tested, and last class of repair. Some utilities have written computer programs for this accuracy sampling approach to the repair or replace question.

In the case of *natural attrition,* this approach would introduce no artificial retirement program of any kind but simply allow meters to attain a "natural mortality", that is, be retired only when they are not repairable because of unavailability of parts, or extensive deterioration or wear to a point where an individual repair equals or exceeds the investment in a new meter.

This program presumes the absence of important costs associated with meter age or design vintage. While the economic considerations here are considerably limited, there may be times when natural attrition is the best course of action. Withholding retirement can be an inexpensive source of temporary capital—cheaper than the cost of borrowed money.

In the case of *retirement on the basis of age,* there are certain incremental costs associated with age or vintage of a particular meter type and can be used as the basis for a repair or replace policy. These cost factors might be tendency to deterioration or complete failure, poor proof when loaded above rated capacity, increasing inability to hold proof or accuracy, increased frequency of needed repairs, greater extent of repair required, improved characteristics of replacement meters, extensive inventories of various meter types and aging parts inventories, and longer out-of-service period during shop repair.

This age approach to meter retirement is, in general, one that attempts to determine economic life as the age at which the average annual cost of investment recovery plus the average of quantifications of "age varying" cost such as mentioned above is at a minimum. There are arithmetical methods for finding the minimum cost age in various literature.

An advantage of this method is that the age of a meter is identifiable through the manufacturer's or company's number or by a year of manufacture embossed on the meter plate. A major disadvantage is that the method is only as reliable as the accuracy and cost accounting data. Often this does not adequately cover the design improvements made in a particular size and kind of meter assembled in a certain year.

In the case of *present repair costs,* this method would retire meters on the basis of cost of present repair and the likely future life of the meter after this repair; versus the cost of a new meter and its projected life. Using statistical methods this approach can be expanded to include consideration of the class or extent of repair that can be economically allowed on a meter.

One difficulty with this method is that the future life of a specific meter is difficult to project. Also, the equivalent replacement value is usually not clear.

PARAMETERS

The following parameters should be considered prior to deciding whether a group of meters are to be repaired or replaced. How these parameters are to be considered and the significance that is to be placed on each will be illustrated in the section that follows. The parameters are grouped into three main headings. These are economic factors, meter performance and design considerations.

Some of the economic factors to be considered are first cost, cost of installation, operating costs and maintenance cost. In considering meter performance, the type of test program becomes a determining factor. A sampling test program provides more of an incentive to retire poor performing meters than does a test program that is based on a fixed interval. In the case of meter design, consideration has to be given to such factors as aesthetics and improvements in measurement.

SIMPLIFIED ANALYSIS OF REPAIR VS. REPLACEMENT

A number of factors enter into an economic analysis of gas meter repair versus replacement. The basic equations are best solved by computerization. It is possible, however, to greatly simplify the analysis. The principal economic factors do not vary outside of certain ranges. It is quite feasible to make a repair or replace decision with the degree of confidence warranted by the data and assumptions involved.

Using the basic economic equations, each major variable can be varied in turn. A plot of the results of such variations constitutes a sensitivity analysis applicable to the particular variable. In making the sensitivity analysis the following information was used in developing graphs:

1. The composite cost of capital ranges from 8 to 12 percent.

2. The debt ratio is 50 percent.

3. The bond interest rate is 2 percent less than the composite cost of capital.

4. The book depreciation method is straight line with a life equal to the average service life for the meter capital account.

5. The service life of a new meter is 60 years (assuming 3 repairs during life.)

6. Federal income tax depreciation is 200 percent declining balance switching to straight line with a life of 28 years.

7. Federal investment tax credit is 4 percent.

8. State income tax depreciation is 200 percent declining balance switching to straight line with a life of 35 years.

9. Federal and State income tax rates are 48 and 9 percent, respectively.

10. Ad valorem tax is based on the system average ad valorem tax rate for gas distribution meters and a 25 percent assessment ratio.

11. Insurance is 0.10 percent.

12. Capital escalation rates range from 4 to 12 percent per year.

13. Maintenance and operation expense escalation rates are 1 percent more than capital escalation rates.

14. Expected salvage is 10 percent.

15. The number of repairs of an existing meter before it is replaced with a new meter, ranges from 1 to 3.

16. Repair costs for a new meter range from 40 to 60 percent of new meter cost.

Graphs 14.4.1 through 14.4.5 summarize the results of sensitivity analyses to changes in assumptions for the proposed solution. The information contained in these graphs is listed below.

Graph	Description of Analysis
14.4.1	Sensitivity analysis for changes in composite cost of capital from 8 to 12 percent.
14.4.2	Sensitivity analysis for changes in capital escalation rates from 4 to 12 percent.
14.4.3	Sensitivity analysis for changes in number of repairs of existing meter before it is replaced for 1 to 3 repairs.
14.4.4	Sensitivity analysis for changes in repair cost of a new meter as a percentage of new meter cost from 40 to 60 percent.
14.4.5	Total range of results for changes in all assumptions.

Graph 14.4.6 is used in making the repair or replace decision. The assumptions used in developing it are consistent with current financial and operating conditions of some utilities:

1. the composite cost of capital is 12%

2. the capital escalation is 6%

3. when a new replacement meter requires repair, after a period of service, the repair cost will be 50% of the replacement cost (including installation cost)

4. the existing meter may be repaired 3 times before it is replaced.

41

To determine whether a particular meter should be repaired or replaced, use Fig. 14.4.6 as follows:

1. On the vertical axis of the graph (labeled "Repair Cost as a Percentage of New Meter Cost") find the cost to repair the particular meter (including reinstallation) as a percentage of the cost for a new meter installed. Costs that should be included in New Meter Costs are: purchase price of the new meter F.O.B. meter shop, sales tax on the meter, warehouse expenses associated with handling and storage of the meter, cost of intesting the new meter, and cost of installation. Costs attributable to repairing a meter should include:
   a) Cost of removing and reinstalling the meter (since the meter changeout may not occur in the same year for both alternatives, these costs must be included in the analysis).
   b) Cost of testing the meter (before and after repair).
   c) Cost of labor (including vacation, sick leave, and other non-productive costs) to repair the meter.
   d) Cost of materials (including applicable warehouse expenses and taxes) used in repair.

2. On the horizontal axis of the graph (labeled "Life After Repair as a Percentage of New Meter Life Before First Repair") find the appropriate percentage calculated as follows:
   a) Estimate the length of the next period of service that may be obtained from the existing meter after a repair.
   b) Divide these years of additional service by 15 years and multiply by 100. Fifteen years is the average number of years a new replacement meter will be in service before it requires its first repair.

3. Find the decision point on the graph at the intersection of a vertical line up from the percentage on the horizontal axis (Step 2) and a horizontal line across from the percentage on the vertical axis (Step 1).

4. If the decision point (Step 3) is in the region of the graph labeled "Replace", the meter should be replaced. If the decision point is in the region labeled "Repair", the meter should be repaired. However, if the decision point falls within approximately ±10 percentage points of the curve, the economic differences between the repair or replace decision become less important and other factors (e.g., cash flow, status of capital and expense budgets, aesthetics, convenience of converting to temperature compensation, parts availability, and repair skills of shop personnel) gain importance.

EXAMPLE A

ASSUME

1. New meter cost is $50, including installation.

2. Cost to repair meter (including reinstallation) is $30.

3. Service period after repair estimated at 10 years minimum.

FIND

Whether meter should be repaired or replaced.

SOLUTION

1. Find ($30/$50) × 100% = 60% on the vertical axis, draw horizontal line from 60% value.

2. Find (10 years/15 years) = 67% on horizontal axis, draw vertical line from 67% value.

3. The intersection falls well within the "Repair" region of the chart so the meter should be repaired.

EXAMPLE B

ASSUME

1. New meter cost is $45, including installation.

2. Repaired meter will be condemned 12 years after repair.

FIND

Maximum amount that can be economically spent on the existing meter's repair and installation.

SOLUTION

1. Find (12 years/15 years) × 100% = 80% on horizontal axis.

2. Find point on curve corresponding to 80% on the horizontal axis and find corresponding point (92%) on vertical axis.

3. 92% × total new meter cost = 92% × $45 = $41.40. This is maximum that can be spent on existing meters' repair and installation.

EXAMPLE C

ASSUME

1. New meter cost is $45, including installation.

2. Cost to repair meter (including reinstallation) is $22.

FIND

Minimum repair life that must be obtained from existing meter to make repair economical.

SOLUTION

1. Find ($22/$45) × 100% = 49% on the vertical axis.

2. Find point on curve corresponding to 49% on vertical axis and find corresponding point (36%) on horizontal axis.

3. 36% × 15 = 5.4 years. The average existing meter must remain in service at least 5.4 years after repair, otherwise replace instead of repairing.

Normally it is not feasible to make a repair or replace analysis for individual meters. Instead, such analysis is made for groups of meters, with all meters in the group being of the same manufacture, size, type and vintage. If the analysis favors a "Repair" decision then a detailed repair procedure should be drawn up to insure that the repair cost, upon which the decision is based, is kept under control. The repair procedure should provide for the exceptional meter, whose condition is found such that repair is not justified. For example, the analysis may show it economical to repair the average meter in the group; but if a particular meter shows a diaphragm leak it would be condemned (assuming the additional repair cost to re-diaphragm is found by analysis to be uneconomical).

COMPUTERIZED ANALYSIS OF REPAIR VS. REPLACEMENT

The foregoing description of a simplified analysis of repair or replacement is based upon the factors and equations presented in this section. The simplified method has the disadvantage of automatically incorporating a number of assumptions which cannot be varied. Accordingly, it is somewhat lacking in flexibility.

The method presented in this section lends itself to computer application. The effect of varying various assumptions can be handled readily.

When a meter is removed from service, the decision must be made to (1) repair the meter or (2) retire it and purchase a new meter. Since utilities are customer oriented, the best decision is the one that requires the least additional revenue from the customer while maintaining reliable service. This decision is made by comparing the additional level annual revenue required to implement each alternative.

Revenue requirements are dollars received from sales to customers which are required to meet expenses and provide a minimum acceptable return on the invested capital. The components of revenue requirements for capital investments include: (1) return on invested capital, (2) depreciation of invested capital, (3) Federal and State income taxes associated with the additional revenue, (4) ad valorem (property) tax, and (5) insurance. Maintenance and

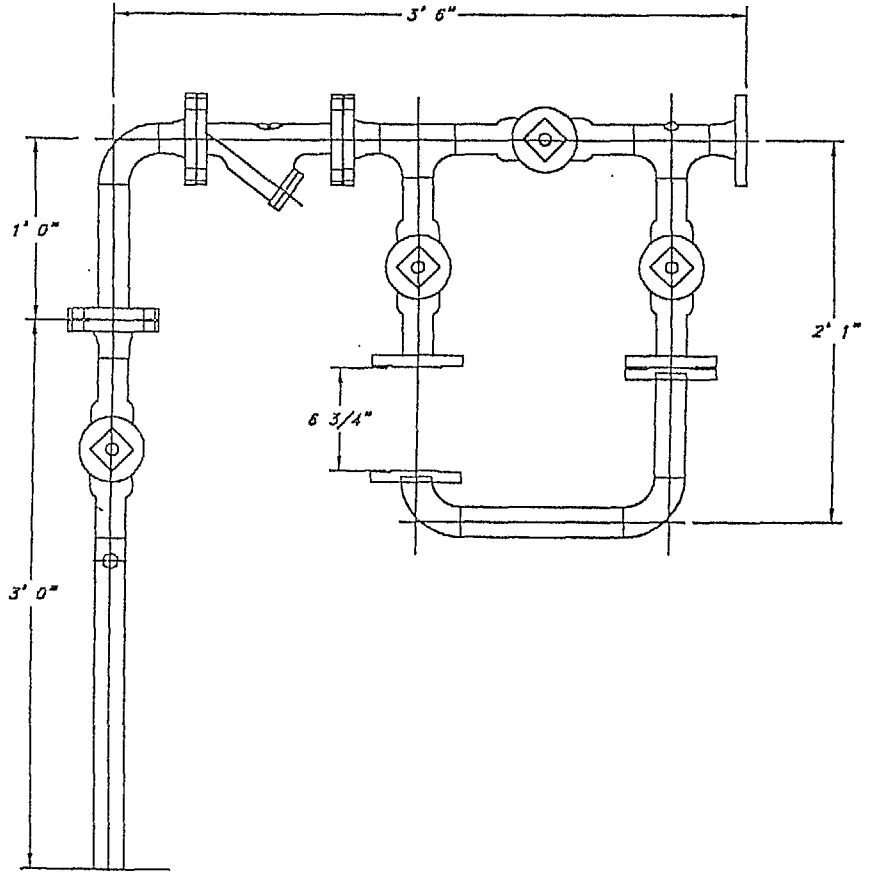
PRESSURE FACTORS

GAUGE PRESSURE POUNDS	PRESSURE FACTOR	GAUGE PRESSURE POUNDS	PRESSURE FACTOR	GAUGE PRESSURE POUNDS	PRESSURE FACTOR	GAUGE PRESSURE POUNDS	PRESSURE FACTOR
1 1.5	1.07 1.10	21	2.42	41	3.78	61	5.14
2	1.14	22	2.49	42	3.85	62	5.21
3	1.20	23	2.56	43	3.92	63	5.28
4	1.27	24	2.63	44	3.99	64	5.34
5	1.34	25	2.70	45	4.05	65	5.41
6	1.41	26	2.76	46	4.12	66	5.48
7	1.48	27	2.83	47	4.19	67	5.55
8	1.54	28	2.90	48	4.26	68	5.62
9	1.61	29	2.97	49	4.33	69	5.68
10	1.68	30	3.04	50	4.39	70	5.75
11	1.75	31	3.10	51	4.46	71	5.82
12	1.81	32	3.17	52	4.53	72	5.89
13	1.88	33	3.24	53	4.60	73	5.96
14	1.95	34	3.31	54	4.67	74	6.02
15	2.02	35	3.38	55	4.73	75	6.09
16	2.09	36	3.44	56	4.80	76	6.16
17	2.15	37	3.51	57	4.87	77	6.23
18	2.22	38	3.58	58	4.94	78	6.30
19	2.29	39	3.65	59	5.00	79	6.36
20	2.36	40	3.72	60	5.07	80	6.43

The above factors are based on 14.73 PSIA base pressure and an assumed average atm. pressure of 14.73 PSIA.

$$\frac{14.73 + \text{Gauge Pressure}}{14.73} = \text{Pressure Factor}$$

1" = .036 .036 X # of inches + 14.73 ÷ 14.73 = factor



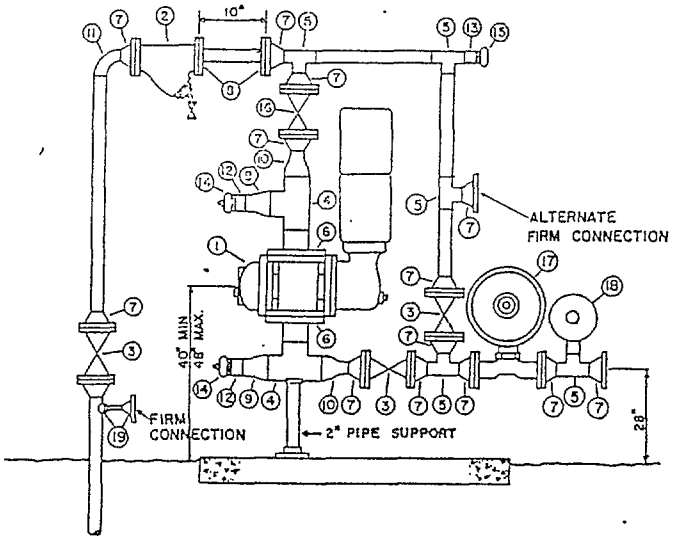
MATERIAL LIST			
ITEM	QUAN.	DESCRIPTION	COST
	1	2" Valve	
	3	2" Wld. N/S. Flng.	
	2	2" Wld. Tee	
	3	2" Wld. Elbow	
	50.5'	2" Steel Pipe	
	23	5/8x4" B7 Studs with Nuts	
	3	2" Wld.x Flng. Valves	
	3	2" Slip Flng.	
	1	2" Y-Style Strainer	
	2	1" Weld-O-Lets	

Fabrication Notes:

1- Inside of meter set to be wire brush cleaned
2 - Meter set to be air tested to 150 PSIG for 1 H
3- All open ends shall have plastic insert and seals (4) after testing.
4- Meter set to be wire brushed and painted
5- Welding shall be in accordance with L.S.C. Co. standards & API 1104.
6- All material and fittings to be schedule 40.
7- All flanges to be "2 Weld".
8- Valves shall be Approved weld ball.

* Any changes to these specification shall have prior approval of the planning and engineering dept.

2" PREFAB METER SET 3M-175 ROOTS METERS LOW PRESSURE	DRAWN D.D.A.	CHK. R.M.
	BAY STATE G	
SCALE NONE	DATE JULY 10 1996	APPROVED



ELEVATION VIEW

ITEM	REQD	DESCRIPTION
1	1	11M or 16M ROOTS ROTARY METER (LINE MOUNTED WITH INSTRUMENT)
2	1	2" STRAINER
3	3	2" FLANGED VALVE
4	2	4" STRAIGHT TEE
5	5	2" STRAIGHT TEE
6	2	4" SLIP-ON FLANGE
7	14	2" WELD NECK FLANGE
8	2	2" SLIP-ON FLANGE
9	2	4" X 3" CONCENTRIC REDUCER
10	2	4" X 2" CONCENTRIC REDUCER
11	1	2" 90° ELBOW
12	2	3" X 3" LONG NIPPLE THREADED ONE END
13	1	2" X 3" LONG NIPPLE THREADED ONE END
14	2	3" THREADED CAP WITH 1/4" PLUG
15	1	2" THREADED CAP
16	1.	2" FLANGED - NON LUBRICATED
17	1	2" FISHER 99 REGULATOR or EQUAL
18	1	1" or 2" FISHER 289H RELIEF VALVE or EQUAL (SIZED FOR OVER PRESSURE COND.)
19	1	1" SOCK-O-LET, 1" SLIP-ON FLANGE

TYPICAL 4" UNREGULATED ROTARY METER

SECTION 6.2
AUTOMATIC METER READING

INTRODUCTION

Traditionally, meter reading has been a manual function, requiring that a meter reader periodically visit the meter set at the customer's premises to record the index reading. This form of data collection is the predominant means for customer billing.

Automatic Meter Reading is a system capable of rapidly identifying a large number of premises, reading a meter (watthour, demand, gas, water or any type meter), preparing and conditioning the data and transmitting the accumulated information from the meter location to a central data accumulation device. The communications link may be radio, telephone line, power line carrier, direct cable or a combination thereof. The data accumulation device will in most cases be a computer.

HISTORY

The history of Automatic Meter Reading probably dates back to 1890. The concept appeared in patent No. 428,900 issued to Mr. Leo Ehrlich on May 27, 1890. Basically, a simple telegraph arrangement, the meter proof hand actuated a switch (a form of telegraph key) which in turn energized a telegraph circuit and repeater. In this case it was a remote meter reading arrangement and not automatic in the strictest understanding. Little is known about the extent of this application.

The idea was no more than a concept until the early 1950s when the necessity to reduce meter reading costs stimulated the mass production of remote reading devices. In the late 1950s and early 1960s, many proposals were made and a number of small scale tests were made, but very little commercial equipment to accomplish Automatic Meter Reading was available until about 1968, when the telephone companies made interconnecting equipment available. The telephone companies invited various equipment manufacturers to join them in a program to develop Automatic Meter Reading.

Phases one and two were to provide a means to develop design concepts, phase three to develop hardware with complete field testing, and phase four to develop the proper tariffs for telephone line use.

Phase one began about 1968 when the telephone companies made telephone interfacing equipment available to various utility companies desiring to participate. In 1969, the equipment was tested in a laboratory environment and then the equipment was installed on customers' facilities for further tests in the 1970s.

The telephone communication link is not the only data link available, however, radio communication has gained some interest. This mode has been demonstrated by at least two companies, one in 1972 using the acronym PURDAX and another some time later using the acronym AAIR. Both companies utilized a transponder mounted in an automatic van. Another company also used this method via an airborne transponder.

In addition, the use of the existing power transmission grid has not been neglected. One company successfully monitored oil well production and has demonstrated its system over an 11 kV electric distribution system. Two large American corporations have successfully demonstrated and are following a similar mode of transmitting the meter reading.

TECHNOLOGY

Automatic Meter Reading communication is the technology of data telemetry—both analogue and digital.

An Automatic Meter Reading system consists of three major parts: Calibrated meters supplied with encoders, a reading center and communication network. The meter, calibrated to specifications, is equipped with an index encoder. The purpose of the encoder is to provide an interface between the mechanical meter index and electrical circuits.

The encoder translates the index dial positions (register reading) into either a coded electrical signal, a series of digital electronic pulses, a binary word or an electrical tone frequency (analogue).

The simplest form of interface device can be a multipole circular permanent magnet fixed to the least significant digit (units) dial of the index. The magnet's rotation closes and opens a single-pole, single or double-throw reed switch. Each switch closure representing a billing unit of consumption. The resulting electrical pulse of energy represents the quantized measurement. The dial encoder is a more complex electronic register that will reproduce actual index readings.

The most important requirement of automatic reading communications is two-way transmission between each meter and a reading center. It is essential that the reading center have random access in time as well as geography and be able to interrogate any meter at any desired time, since it may be necessary to monitor customer consumption.

Another important requirement is that meters must transmit read data only on command from the reading center; therefore, each meter must be individually addressable.

The data link between the meter and the data collection center can be one of the following:

1. Telephone Line
2. Radio
3. Power Line
4. Dedicated Pilot Wire Signaling System
5. CATV Shared Facilities

The transmission of the meter reading can be accomplished by any of the above ways, making possible many combinations of sending coded signals. The use of telephone lines to transmit data would appear to be typical since most natural gas utility subscribers would probably be receiving telephone service or have close access to it.

The analogue method uses composite audio tone (tone combinations) to represent the index dial positions (index read). An electrical switching unit, capable of responding to a specific electrical interrogation signal, is needed to link the reading center with the meter encoder.

One device is commonly called a line coupler. It isolates the meter equipment from the telephone to prevent interference and protects the equipment from lightning. To read a specific customer's meter, one scheme uses a coded pulsating direct current which transforms into a small alerting frequency to activate the line coupler. This small alerting tone is amplified, limited and filtered. The resulting signal energizes one winding (the operate winding) of a dual winding relay. The relay is held in the closed state by direct current drawn by the other winding (hold winding). This current tells the meter reading access circuit in the telephone exchange that the line coupler is ready. When the signal tone is removed, the connection is completed to the reading center for reading the meter and a timer is started.

After a preset time interval, during which the reading center receives the meter reading or readings, the meter reading access circuit restores the line to normal service, completing the reading cycle. The main function of the telephone central office meter reading access circuit is to establish an electrical communication interface between the utility and its customers.

The equipment located at the utility reading center consists of a processor to control the meter reading system and a data communication terminal. A digital computer, with teletype keyboard or tape device, is used to automatically provide the correct customer dialing sequence and address.

An Automatic Meter Reading system that circumvents certain inadequancies of the telephone system is the use of the radio data link. The inadequacies of a telephone system are the presence of a third party in the communication link, obtaining encoder energy, and difficulties in hardware installation. One radio data system consists of a pulse generator for each meter (water, electric or gas), scanning circuits, address circuits and output circuitry, all in a single data accumulator. A transponder (part of the total hardware) consists of a receiving antenna, harmonic generator, coupling unit and transmitting antenna.

A roving van is used to automatically record readings on magnetic tape. It contains the UHF transmitter and receiver with their antennas. The van also contains a decode and verifications unit and computer compatible tape recorder.

The power line mode of data link also has its good and bad points. The power line offers an excellent mode of data transmission which is a universal system reaching all electric, gas and water customers. It also supplies needed energy but may require third-party billing.

The most severe criticisms are its noise level and constantly changing impedance due to load and additional distribution lines being added. This, however, can be reduced by the selection of the proper operating frequency, signal boosters and signal levels.

Automatic Meter Reading using the communications media of signal wire (wholly-owned pilot wire) overcomes most of the disadvantages of those types of signal links with the exception of cost. Its first cost greatly exceeds that of any of the systems mentioned, approaching that of a cable TV system.

So far, several modes of data links have been mentioned. It should be kept in mind that these systems are not limited to reading meters. Any data link between a utility and its customers can be multifunctioned, not only reading meters but also performing monitor and switching work.

USES FOR AN AUTOMATIC METER READING NETWORK

Listed below are some uses for an Automatic Meter Reading system:

1. *Read Meters*
   A. Main kWh Meter
   B. Auxiliary kWh Meter
   C. Gas Meter on System
   D. Gas Meter on Another System
   E. Water Meter
   F. "Turn-off" and "Turn-on" Readings (Read and Leave On)

2. *Reading Special Tariffs*
   A. Time-of-Day Billing
   B. Demand Billing
   C. Versatility (Change Billing Mode With Software)

3. *Load Management*
   A. Electric Water Heaters
   B. Air-Conditioning Compressors
   C. Electric Heaters
   D. Electric Vehicle Battery Charges
   E. Pump Back Control
   F. Rate On-Peak, Off-Peak Devices
   G. House Heater Load Shedding, Gas

4. *Distribution Automation*
   A. Capacitor Switch Control
   B. Outage Reporting
   C. Small Substation Supervisory and Control
   D. Motor-Operated Line Switch Control
   E. Restoration

5. *System and Customer Monitoring*
   A. Meter Tampering
   B. Load Reduction Compliance
   C. Customer Outages
   D. Low Voltage
   E. Cathodic Protection Systems

6. *Transformer Load Management*
   A. Transformer Load
   B. Transformer Temperature
   C. Transformer Voltage

7. *Load Survey*
   A. Routine Customer Surveys
   B. Energy Balance, Generated Vs Billed
   C. Gas Distribution
   D. Water Distribution

This list is not complete or all inclusive.

AVAILABILITY

Field trials have demonstrated that Automatic Meter Reading is technically feasible and in the larger utilities, a combination of data links will be more economical than any one single type. Further economies can be realized when the system can be used daily for load management and system control instead of monthly to only obtain meter reads.

Suppliers of the equipment are frequently announcing system improvements and other manufacturers are withdrawing from the market; therefore, the reader should consult current trade magazines for current suppliers of Automatic Meter Reading equipment and obtain their latest literature.

SECTION 6.3
REMOTE METER READING

GENERAL DESCRIPTION

Remote meter reading refers to the method employed to mechanically or electrically transmit the meter reading from the meter itself to another location in the general area. Depending on the system used, the meter reader may either read the meter from a remote index in the usual way, or by use of a plug-in remote display unit, or record the reading on magnetic tape from the terminal at the remote location. In the latter instance the tape is returned to the company for transcribing. The technique of using a remote reader is to obtain a reading from a meter that is located in an inaccessible or inconvenient location.

HISTORY

Most gas companies which serve urban areas with severe fluctuations of climate and many inside meters, realized many years ago that something had to be done to enable them to get scheduled meter readings on a constant and consistent basis. In the 1960's the magnitude of the problem increased due to a number of factors: such as no one at home because both members of the family were working, and the increasing reluctance on the part of the customer to allow any outside party to enter their residence. As the need increased the interest increased and many companies organized an internal task force to examine the problem and to arrive at possible solutions.

The problem affected several phases of the companies' operations. The remote register was the solution selected by personnel from the operating departments, finance departments, and those involved in the computer and data processing areas. The objectives were:

1. To enable the company to obtain accurate meter readings.
2. To achieve this objective without severe economic impact to the company.
3. To adopt a system that would be clearly workable in the present and adaptable to the refinements that might occur in the future.

WHY A REMOTE REGISTER

Public utilities are efficient in providing safe service to their customers. When the meter reader cannot gain access to an inside meter to record the exact index reading, the efficiency decreases. The customer has used the energy and the company must read the meter to determine the exact amount of energy used. The national average of missed meter readings for the Gas Industry is about 15% of all meters each month. The meter reader is paid to do his job whether or not he is able to read the meter. When he cannot get access to an indoor meter, a considerable amount of time and money is lost. Estimating a gas bill is not without hazards. Meter failure, although unlikely, is a possibility, and a meter which does not register might be missed for several months when access to the meter is not possible.

If the meter is not registering, it is extremely hard to make a case to bill for the gas consumed but not registered. "No Reads" represent extra cost to the utility. This extra cost is wasted manpower and money, repeat calls, estimated bills, answering customer complaints about estimated bills, re-billing and loss of cash flow, is what prompted the utilities to seek a better means by which to read their meters.

ALTERNATIVES

Utilities have tried many ways to solve their problem of "No Reads". The customer will sometimes provide a house key, which is given to the meter reader along with his route. The meter reader can leave a card for the customer to mark the exact position of the index hands. Unfortunately the average return of self-read cards is very low—about 20%. This means that the utility has already paid for the meter reader, paid for the card he leaves, and still gets only one out of five actual meter readings due to lack of cooperation by the customer. The customer can arrange to be put on a budget plan, whereby the customer pays a pre-determined amount every month. A settling

of any differences are made at the end of the billing year. When conditions permit, the meter can be set outside, making it accessible to the meter reader. These ideas are all workable, but not 100% sound, and they do not completely solve the problem. The answer to the problem may be to install a remote reading system. The experience of many utilities is that, after installing a remote system, they have doubled the number of meters that a meter reader can read in a single day, thereby cutting their billing time in half and reducing drastically the errors in meter reading. One utility in the Midwest found that the meter reader increased his average from 230 calls per day, with 48 missed readings, to an average of 430 calls per day with no missed readings. They realized a vast savings by having to estimate fewer bills every reading period. Figuring the time saved in reading the meters, the time saved by the other departments involved when the meter is not read, the use of a remote register for every inside meter is worth considering. A Midwest gas utility estimated that savings of $250,000.00 per year could be realized for a completely saturated system of 100,000 meters.

AVAILABLE TYPES

There are two types or styles of remotes available to the industry today. They are the type that will fit on a tin gas meter, and the type that will fit on a hard case gas meter.

The Unit for the Tin Gas Meter has a mounting-plate that must first be soldered to the meter, and then the inside register or encorder is mounted to this plate. To prepare a tin meter for a remote assembly, the first operation is to remove the top of the meter or to drill a hole in the top cover to enable the fitter to easily work in the gallery section of the meter. A hole about 3 to 3 1/2" in diameter is sufficient. Next the index cover and index is removed from the meter.

The axle can then be removed and set aside. The surface area, where the index cover was, must be tinned to make it more susceptible to accept the mounting-plate of the assembly. The mounting plate is equipped with an axle box to connect the axle from the meter to the drive dog of the remote register. In attaching the mounting-plate care must be taken to insure the alignment is right for free movement of the axle. Care must be taken, and notice given that the axle is perpendicular to the mounting plate and parallel to the valve cover plate. The mounting-plate is tacked in position and the alignment of the axle is retested. It is recommended at this time that the movement of the axle be tested for any binds. The mounting-plate is then soldered in position. It is recommended that the meter be tested at a very low flow and observe the differential gauge to determine if any binds exist. The assembling of the mounting-plate is now complete and the meter can be treated as any other meter in finishing the repair—through to the final out-test. After the meter is completely repaired the only added task is to install the encoder on the mounting-plate. The meter should be set on a slight angle to enable the operator to more readily see the face of the meter. The mounting-plate has four posts and the encoder is placed over these posts and four sealing screws are put in place. A wire seal can now be installed, or omitted, depending on company policy. The meter with the remote assembly is now complete and ready for temporary storage, or to be set on the customer's premises.

Remote Readers for Hardcase Meters. Many manufacturers of remote hardware are making their remote unit adaptable for most hardcase meters. Installing a remote reading device on a hardcase meter requires very few special tools. Most units can be installed in the shop or field using a screw driver, pliers, wire cutter, adjustable wrench and a wire stripper. For specific instructions as how to install a particular remote reader, the manufacturer's recommendations should be followed. Installing a remote register on a hardcase meter is much easier than installing it on a tin case meter, and therefore, much faster, cheaper and possibly more desirable to the utility. There are only three steps to installing the remote on a hardcase meter. First remove the index cover and the index. Install a drive dog adaptor if required. Next install the adaptor-plate for the particular meter and then the encoder with the screws provided. After testing the complete assembly the unit is ready for installation.

There are Certain Advantages and Disadvantages to remote reading devices;

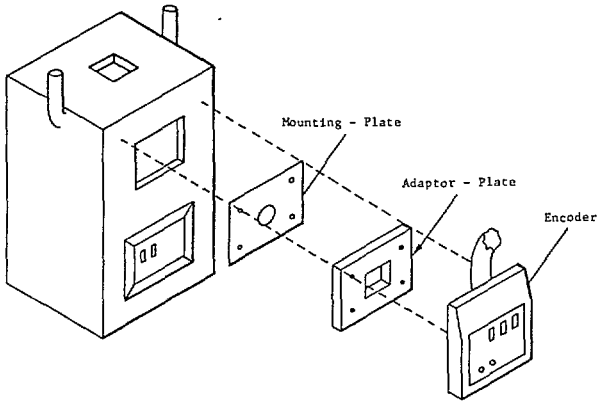
ADVANTAGES

1. Physically able to obtain an accurate meter reading without entering the building.

2. No inconvenience to the customer.

3. Ability to bill customer for the exact energy used.

4. More meter readings per day by the meter reader.



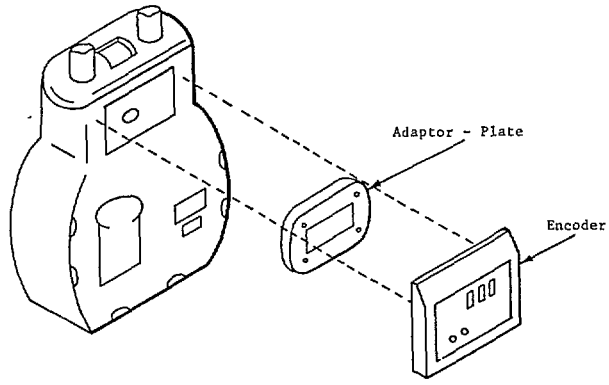


Figure 6.3.1
Tin Meter Assembly

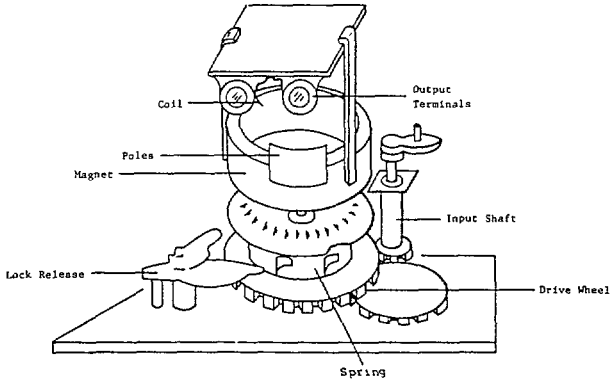


Figure 6.3.3
Pulse Generator

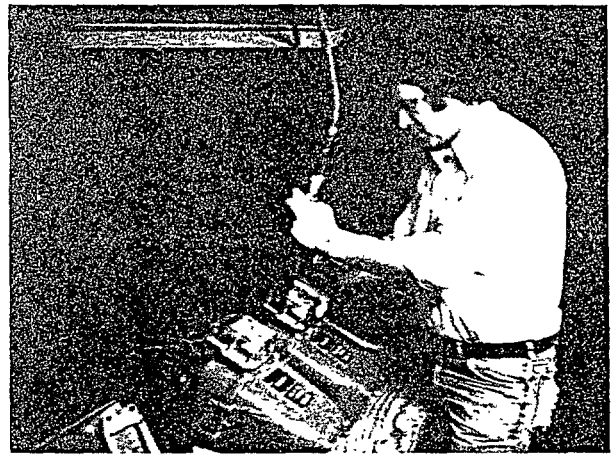


Figure 6.3.2
Hardcase Meter Assembly

DISADVANTAGES

1. Higher meter set installation cost.

2. Remote reading must be verified periodically: either physically in the field, or by a re-check on the bills issued.

3. A battery-operated model requires periodic battery replacement.

4. Reading device on the building is subject to damage and may invite vandalism.

There Are Three Basic Systems at the time of this writing of remoting or transferring the reading from the inside gas meter to the outside register.

1. *Battery Self-Contained.* This system features a special index with a circular permanent magnet fastened to the index. Along with the index, the index box has a reed switch molded into the face of the index box. The reed switch is located so that when the magnet on the index revolves, the resulting change of polarity causes the reed switch to make and break the circuit. For every make of the circuit an impulse is sent to the outside reader. A two conductor wire is used to connect the reed switch with the outside counter. The remote (outside) counter contains a solenoid operated counter equipped with a nine volt battery. The remote counter advances proportionately to the revolutions of the magnet on the index. Each revolution of the magnet results in an impulse being sent to the remote reader causing the remote reader to advance one digit or to register 100 cubic feet.

2. *Pulse Generator.* The generator is mounted on the meter in place of the meter index. The flow of energy thru the gas meter starts the system operating by producing a rotary motion of the drive dog. This motion is transferred to a spring-biased magnet in the generator by means of a reduction gear train and escape gear. When the escape gear is released, the biased spring returns the magnet to its original position. This action produces a low voltage pulse in the coils located near the magnet. This pulse, approximately 8 volts, is transmitted over connecting wires to the outside reader. One pulse is sent for every 100 feet of gas registered by the meter. The outside register advances one digit for every pulse received.

3. *Externally Operated Unit—Battery In The Portable Reader.* This system consists of an encoder mounted over or in place of the existing index on the gas meter. A fourteen or seventeen wire cable carries the reading from the encoder to the outside receptacle. The meter reading is retrieved by inserting the portable reader in the outside receptacle.

PROMOTION OF THE REMOTE INDEX

Before any effort is made to promote the installation of remote readers each company should, by it's own testing, satisfy itself with respect to the soundness of the equipment and to what extent installations are to be made. For an area particularly difficult to read, the company might plan to install a remote reader on every inside meter. An area that presents a high percentage of "no reads" would also be a logical area in which to install a remote reading system. The initial installation should be of sufficient size to insure a good test sample of the equipment being installed. A gas utility in the Midwest had such an area for their first installation. They installed 1000 remotes in a subdivision, one in each house that had an inside meter, which was 98% of the houses in the area. In such an installation about 1% of the sets should be double meter sets, with meters of the same proof and size. One meter should be equipped with a remote index and one should have a regular index. The meters should be set in series, thus enabling the utility company to verify the accuracy of the remote registers by comparing the two meters registration. An initial program, such as this, should be of sufficient duration to cover the four seasons of the year. This will provide sufficient time to establish the reliability and accuracy of the equipment under test.

COST TO CUSTOMER

Many remote register installations will be made for the benefit of the company, and many will be made for the benefit of the customer. Several companies have decided that since the customer is also benefiting from the remote program they therefore should share in the added cost of the meter installation. It should be determined whether the program should cover only the cost of the hardware, the complete cost, or should provide the device at no cost to the customer. The cost to the customer could vary from nothing to actual cost per installation. These costs may be at no interest charge to the customer and payable at a nominal amount per month added to the gas bill. One company that charges the customer $20.00 per installation, has a program to sell the idea to the customer and it works like this: if access to the meter cannot be obtained for three months in a row the meter reader hangs a packet on the door which contains meter reading arrangement alternatives, including promotional material on the remote reader. If another two months go by and no permanent arrangements have been made with the customer, they then follow up with a letter and a telephone call in an attempt to make such arrangements. The results of this program have been very successful. It is understood and easily explainable to the customer, that it is the responsibility of the customer to provide access to the meter for meter reading purposes. The customers, where a remote register is available to them, have made many favorable comments showing that they appreciate the utility company providing them with this sure and convenient method to get accurate gas bills every month.

INSTALLATION

When installing the remote unit on the customer's premises, pick a location that is easily accessible to the meter reader. Remember he has to see it in order to read it. Keep in mind also the esthetic value of the customer's home, and do not install the outside receptacle where it will be unsightly. Check to insure that it is possible to run the cable to that location. Normally all that is needed for the cable is a 3/8" hole through the wall. Make sure there no obstructions which would hinder drilling the hole, such as water pipes, electrical conduit, etc. After the hole is drilled and the meter is installed, run the cable or wire from the encoder through the wall and attach to the outside register.

Attach the outside reader to the wall securely. After the outside register is installed, mark the exact location on a card provided so that the meter readers and service men will know its exact location. Any loose or excess cable should be fastened to the rafters of the basement with insulated staples or plastic ties taking care that the cable is not damaged. Test the unit to make sure that the inside and the outside readings agree. Seal the hole in the wall with caulking compound and the job is finished. Another "no read" has been eliminated.

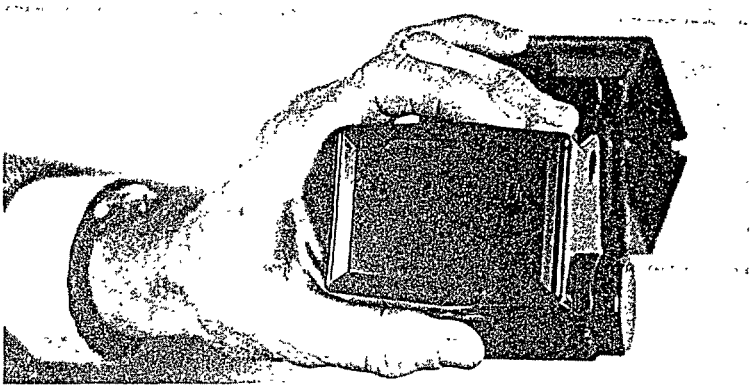


Figure 6.3.4
Outside Register

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Westinghouse Electric Corp.

Technical Publications & Bulletins
Kingman—White Co.

ERT™ MODULE MODEL 40G

The ERT (Encoder, Receiver, Transmitter) 40G is a low-power radio device used in Itron's Off-site Meter Reading (OMR), Mobile AMR and Fixed-Network AMR systems. It is designed to encode energy consumption and tamper information on gas meters. When an ERT module receives a radio frequency "wake-up" signal, it begins transmitting this data, including meter identification, back to a radio-equipped handheld computer, the vehicle-based DataCommand® Unit (DCU) or the Genesis Fixed Network.

A utility installs ERT modules on meters and initializes them using the ReadOne® Pro handheld computer. ERT module installation data is then transferred via ReadOne Link software to your billing computer.

The Mobile AMR system uses an account list downloaded via DataCommand Link software. At the end of the day, all data collected from ERT modules is uploaded to the billing computer. When read by a handheld computer, all module data is processed in the handheld, along with manual reads, and then uploaded to the billing computer.

The ERT module is easily mounted directly on gas meters and works equally well indoors or outdoors. Its unobtrusive profile features a durable polycarbonate plastic housing. The module requires no external antenna or connections, and the original index can be retained. It is powered by a long-life, replaceable "A" cell lithium battery.

The electronics board is completely encapsulated to protect it from environmental hazards and tampering.

SPECIFICATIONS

FUNCTIONAL SPECIFICATIONS

- Meter compatibility: installs on popular American, Equimeter and Sprague aluminum case gas meters with capacities of 175 to 425 CFH
- Power source: "A" cell lithium battery
- Radio programming parameters: index reading, test hand multiplier, index rollover, pressure compensation, security level
- Tamper detection: meter removal, magnetic tamper
- Operating temperatures: -22° to +158°F (-30° to +70°C)
- Operating humidity: 5 to 95% relative humidity
- FCC compliance: Part 15 certified
- ISC compliance: TRC-76 certified; Electricity and Gas Inspection Act compliance and approval
- CCAC approved
- Intrinsically safe per:
  -Factory Mutual Class 1, Division I, Groups A, B, C, D
  -CSA Class 1, Division I, Groups A, B, C, D
- Product identification: numeric and barcoded ERT module serial number
- Materials of construction: gray polycarbonate back plate; clear polycarbonate front cover; encapsulated electronics

OPERATIONAL SPECIFICATIONS

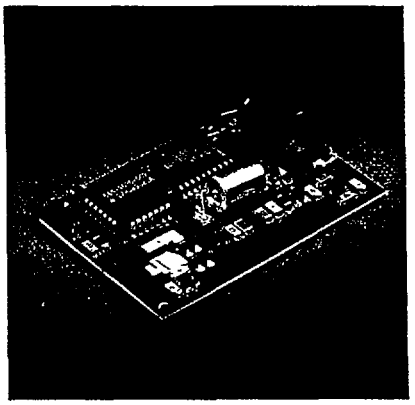
- Receive frequency: 952-956 MHz
- Transmit frequency: spread spectrum 910-920 MHz
- Data integrity: verified in every data message

DIMENSIONS

- 5.54" x 2.57" x 3" (140 x 65 x 76mm)

SHIPPING INFORMATION

- 22 lbs. (9.9kg) per box (30 modules); 20" x 16" x 8" (508 x 406 x 203mm) box size



40G Circuit

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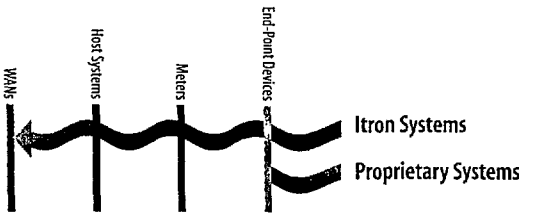
Genesis by Itron®

Best-in-class information solution—today and in the future

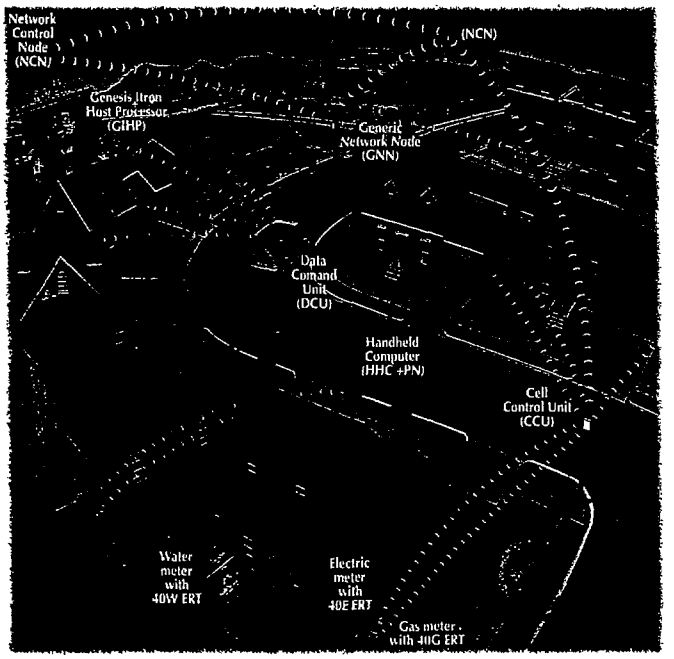
- Proven wireless AMR/DA/DSM networks
- Two-way communications at every level
- Open architecture from top to bottom
- Territory-wide automation solutions
- Fully supported and backed by the right industry alliances

Genesis by Itron is an industry standard forward-compatible solution. It enables organizations to dynamically engineer networked solutions. These solutions target specific customer segments, critical market characteristics and changing business requirements.

Genesis spans all levels of automatic meter reading (AMR), from walk-by Off-site Meter Reading (OMR) and drive-by Mobile AMR to enterprise-wide Fixed Networks.



The same product family effectively builds a wide range of solutions—from a single end-point solution to those requiring millions of end points. This flexibility allows you to grow into networked solutions at your own pace and ensures that you'll never be locked into a predefined, non-migratable solution. Genesis also allows you to leverage your IT investment to enhance bottom-line business value.

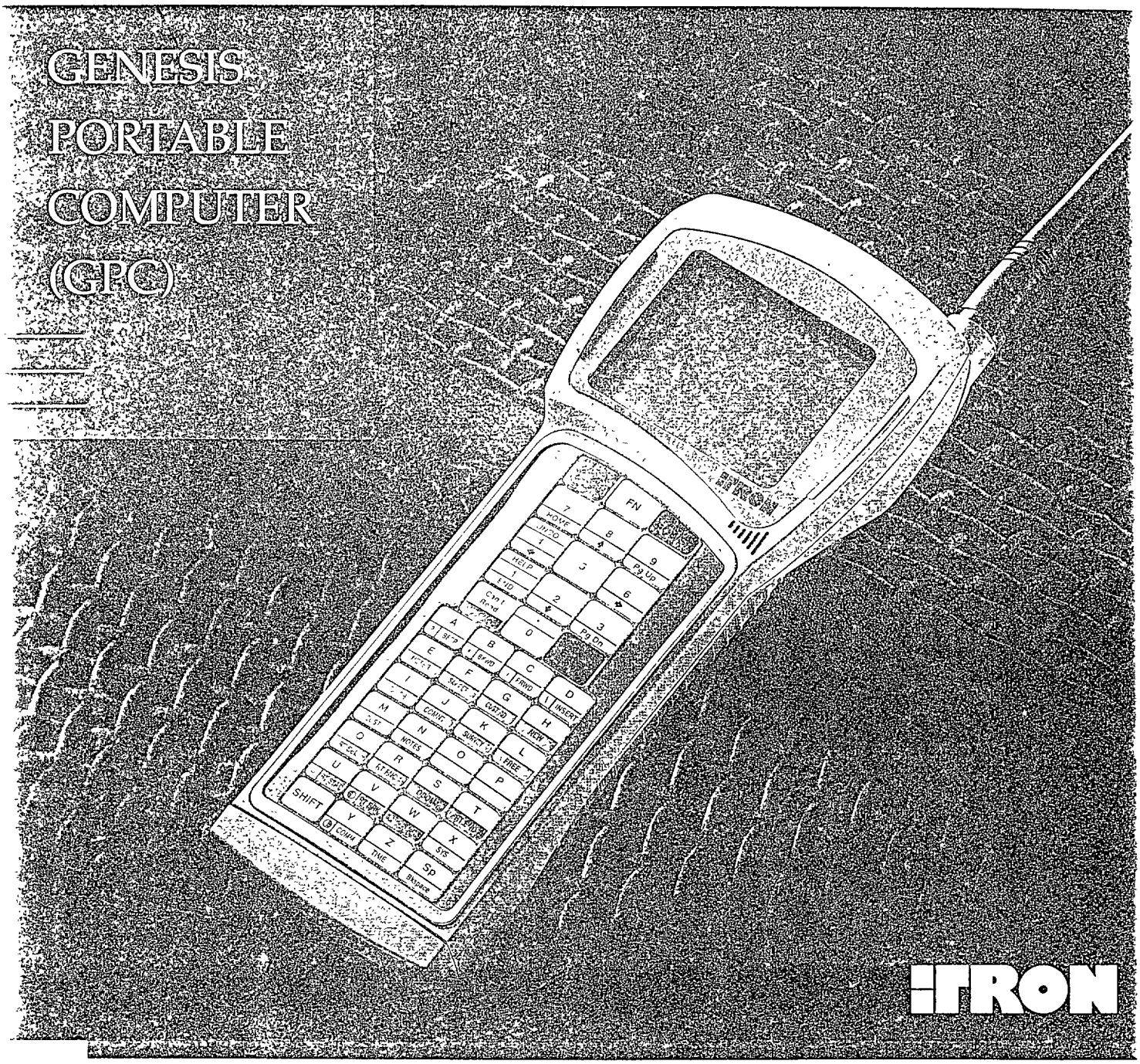


Genesis is your connection to your customer. Once your networked infrastructure is in place, you can begin to look "outside the box" for competitive improvements based on increased consumption and mission-critical data.

The Genesis Alliance™ Program

To provide comprehensive, market-driven solutions, Itron has formed cooperative alliances with the leading providers in utility automation. Through shared technology, coordinated product development and joint marketing efforts, the Genesis Alliance creates a value chain solution that is greater than the sum of its parts. Our partners include strategic business consultants, home automation technology providers, communications suppliers, host system and software integrators, and major meter manufacturers.

GENESIS PORTABLE COMPUTER (GPC)



The Genesis Portable Computer (GPC) takes rugged handheld computer technology to new levels of flexibility and performance:

- High-speed 25 MHz CPU
- Full-PC Compatibility
- Two easy-to-use PCMCIA slots

The GPC is backed by Itron's nearly 20 years of experience building handheld computers exclusively for the utility industry. The GPC is rugged, lightweight, power efficient and has proven survivability in harsh environments. It is fully PC-compatible, so you can develop new applications on a PC. And new software can be downloaded remotely via telephone connection or added through PC-card slots.

Upgrading a handheld computer to OMR (Off-site Meter Reading), has never been easier. Equipping the GPC with a PCMCIA PN (Portable Network) card and antenna will give utilties even greater flexibility in designing their AMR (Automatic Meter Reading) strategies.

Application flexibility, 42 programmable keys, and interchangeable keyboard overlays mean that the GPC can support entirely new functions in minutes. Use it for meter reading on one shift, then on the next shift quickly switch to your utility's field service or other DOS based programs.

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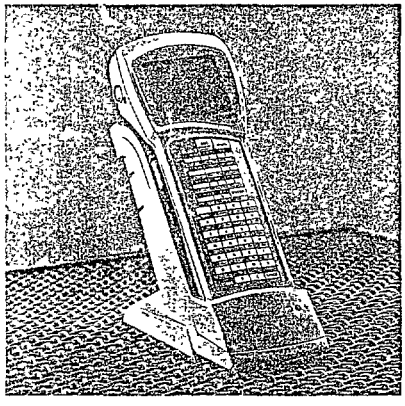
59

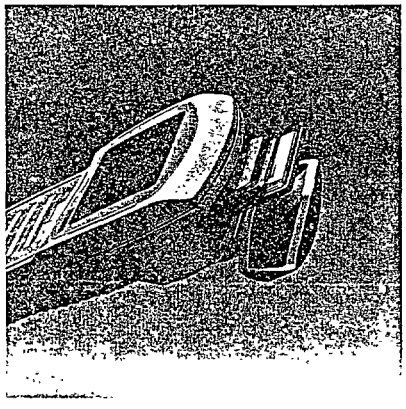
SPECIFICATIONS

DESIGNED FOR UTILITIES

Since a meter reader's keystrokes are 99 percent numeric entry, the GPC meter reading application features an ergonomically designed numeric 10-key keypad in an easy-to-use location.



GPC in space saving charging and communications cradle.



Two user accessible PCMCIA slots.

FUNCTIONAL SPECIFICATIONS

Integrated CPU
- AMD Elan 386SX
- 25 MHz
- Full PC compatibility

Operating system
- MS DOS version 5.0.
- Phoenix Technology 80386 BIOS
- Phoenix Technology card and socket services
- PCMCIA version 2.01 compliant

Memory
- 2 or 4 MB on-board RAM
- 512K Flash EPROM
- User upgradeable via PCMCIA cards

Screen
- 20 characters x 16 lines
- Backlight
- Temperature compensated contrast control

Communications
- Serial port COM 1 with 5V power on GPC
- Serial port COM 2 on cradle
- Multiple cradles can be connected to a single serial port
- PC cards in PCMCIA slots

PCMCIA Slots
- User accessible
- 1-Type II
- 1-Type III

Power System
- Rechargeable NiMH
- User replaceable lithium backup battery
- Low power detection and warning
- 1600/1700 or 3000 ma battery
- 8- to 12-hour battery life
- 1 1/2 hour charge time for 1600 ma battery
- 3 hour charge time for 3000 ma battery

PHYSICAL SPECIFICATION

- Size (with standard battery pack):
  Length: 9.8" (250mm)
  Width: 3" (77mm) hand grip
  Depth: 2.2" (55mm) maximum
- Weight: 22 oz. (626g) with battery
- Ergonomic design

Environmental
- Operating Temperature: -22° to +140°F (-30° to +60°C)
- Storage Temperature: -40° to +158°F (-40° to +70°C)
- Meets or exceeds MIL-STD-810E in drop, humidity, rain, shock and vibration

Keyboard
- 42 user definable keys
- Flat keyboards
- Field replaceable keyboard templates keyboard

GPC COMMUNICATIONS AND CHARGING CRADLE

- Size
  Height: 6.69" (170mm)
  Width: 3.54" (90mm)
  Depth: 8.26" (210mm)
- Weight: 14.4 oz. (408g)
- Cradle power supply is UL listed, CSA certified, TUV & CE approved

CERTIFICATION/COMPLIANCE (GPC & Cradle)

- FCC part 15, class B
- EN 55022, Class B
- CE MARK
- EN 50082-1

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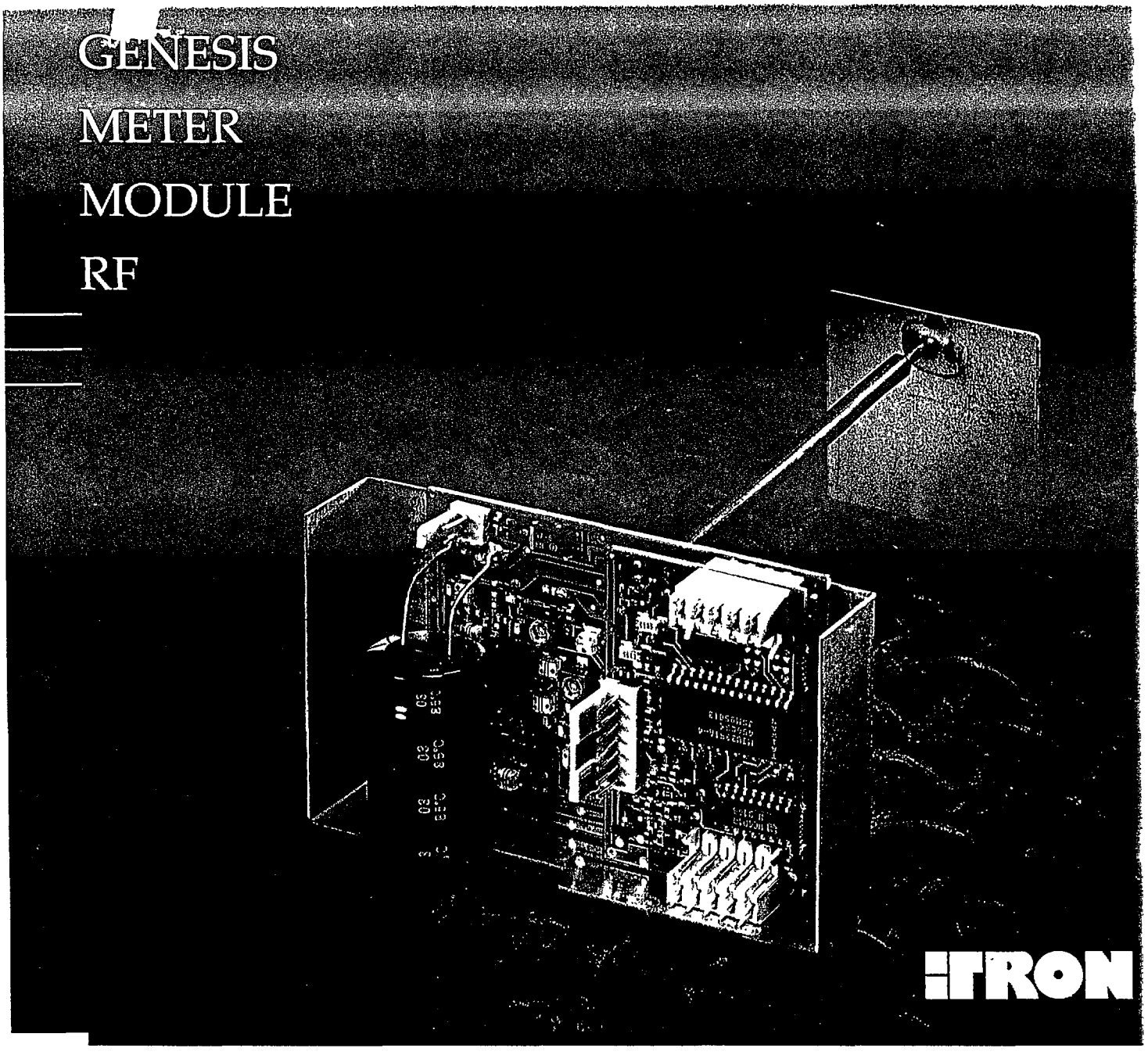
GENESIS METER MODULE RF



The Genesis by Itron® Meter Module (GMM) RF for gas, electric and water meters is a low-power radio automatic meter reading device used in Itron's Off-site Meter Reading (OMR) and Automatic Meter Reading (AMR) systems.

Operating at a fixed frequency in the 433 MHz band, the GMM RF is comprised of a digital logic component that encodes meter and tamper information and an RF component that receives and transmits data.

When the GMM RF receives a radio frequency "wake-up" preamble from an Itron Portable Network (PN) handheld computer or an Itron Fixed Network (FN) node, it listens for its unique address and responds to special commands.

The GMM RF is fully encapsulated to protect it from harsh environments and possible tampering. It may be fitted to a meter situated either indoors or outdoors. Installation is quick and easy, allowing OMR/AMR to be implemented in straightforward, manageable stages.

The GMM RF is battery-powered for gas and water meters and operates from the mains for electricity meters.

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SPECIFICATIONS

RADIO FREQUENCY CHARACTERISTICS

- Communication method: half-duplex single channel sharing
- Transmitter:
  Output power: 6 dbm typ., max. 10 dbm
  Frequency: 433.82 MHz single frequency, category AR1
  Alignment range (per IETS 300 220): AR1 433.05 to 434.79 MHz
  Channel bandwidth: <100 KHz per IETS wide channel
  Modulation:
  —Direct frequency shift keying (FSK)
  —Frequency shift: +/- 3.5 KHz
  —Bit rate 2,380 Bds
  —FCC modulation type 100KOF1D
- Receiver:
  —3dB bandwidth: +/- 10 KHz
  —Minimum sensitivity: 110 dBm for 3% BER
- DGPT approved

RADIO PROGRAMMING PARAMETERS

- Gas meters:
  Index reading, hand multiplier, tamper and tilt
- Electric meters:
  Register reading, tamper and detection
- Water meters:
  Index reading, multiplier, tamper indicator

FUNCTIONAL SPECIFICATIONS

- Power source: 3.6 cell lithium battery
- Tamper detection: Meter removal, on/off or reset
- Operating temperatures: -4°F to +130°F (-10°C to +55°C)
- Operating humidity: 5 to 95% relative humidity
- Safety approval: Intrinsically safe for gas meter application
- Product identification: Numeric and barcoded GMM RF module serial number

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Instrumentation Job Responsibilities

1. Inspect, calibrate and install all new instruments on new and existing meters.

2. Inspect, shop calibrate and reinstall instruments on meters that have been changed due to period testing.

3. Inspect field calibrate and reinstall instruments on all meters that have been changed due to" Does Not Read" or (DNR)

4. Perform annual field calibration on all instruments.

5. Trouble shoot all instruments that are supposed to be out of calibration, in error or damaged and initiate paperwork to resolve same.

6. Maintain record systems to include instrument accuracy reports, field maintenance reports, monthly and annual reports and other pertinent documents.

7. Analyze research and calculate all instrument accounts found in error. This included notifying the appropriate person (s) to complete or adjust bill.

8. All new and revised instrument installations will require a billing check to insure that the proper information has been recorded by customer accounting. This billing check should insure the accuracy of the customer name, address, meter number, meter size code, meter location meter billing factor (if any) and any other pertinent information that may be of interest. This check should be 6-8 weeks after the instrument has been installed.

9. Hi Low customer consumption investigation requests on the instrumented meters should not be directed to the instrument supervisor unless pressure factor calculations are in error.

NORTHERN UTILITIES, INC.
Correcting Index Record

Account No._____ City_____ Cycle_____

Name_____

Address_____

METER DATA			
Meter No.	Size	Date Set	Date Removed

Factor:
Remarks:

INDEX DATA				
Serial No.	Type	Base Plate Numbers	Date Set	Date Removed

Factor Range:
Remarks:

Read Date	Rear or Uncorrected		Front or Corrected		Pres. / Temp.	Calc. Factor	By	Remarks
	Index Read	Use	Index Read	Use				

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LARGE VOLUME METER AND/OR INSTRUMENT FORM

☐ REPLACE SET ☐ STATE SEAL ☐ OTHER W.O. # _____

NOMAD NO. _____ AUTH. _____ DATE _____

CUSTOMER _____ GAS TO BE USED FOR _____

ADDRESS _____ REQUIRED PRESSURE _____

EXIST. LOAD _____ CFH- PROP. LOAD _____ CFH- TOT. LOAD _____ CFH

MONTHLY BASE LOAD _____ USE PER DEGREE DAY _____

SIGNED _____ DATE _____

EQUIPMENT TO BE INSTALLED: (To be used for State Seal change also)

METER SIZE & CODE _____ (___ ___ ___) COMPANY NO. _____

READING _____ BY-PASS LOCKED _____

INSTRUMENT TYPE _____ SERIAL NO. _____

PRESSURE RANGE _____ DRIVE _____

CORRECTED READING _____ UNCORRECTED READING _____

CORRECTED MULTIPLE _____ UNCORRECTED MULTIPLE _____

CORRECTED COUNTER # _____ UNCORRECTED COUNTER # _____

ATMOSPHERIC PRESSURE _____ BASE PRESSURE _____

UPSTREAM REGULATOR _____ OUTLET PRESSURE _____

DOWNSTREAM REGULATOR _____ OUTLET PRESSURE _____

ORIFICE SIZE _____ SPRING RANGE _____

VENT PIPING _____ REG. PIPING _____ FILTER _____

COMMENTS _____

INSTALLERS SIGNATURE _____ DATE _____ INSTRUMENT SIGNATURE _____ DATE _____

EQUIPMENT REMOVED: (To be used for State Seal change also)

METER SIZE & TYPE _____ COMPANY NO. _____

READING _____ BY-PASS LOCKED _____

INSTRUMENT TYPE _____ SERIAL NO. _____

PRESSURE RANGE _____ DRIVE _____

CORRECTED READING _____ UNCORRECTED READING _____

CORRECTED MULTIPLE _____ UNCORRECTED MULTIPLE _____

CORRECTED COUNTER # _____ UNCORRECTED COUNTER # _____

ATMOSPHERIC PRESSURE _____ BASE PRESSURE _____

REGULATOR TYPE _____ OUTLET PRESSURE _____

ORIFICE SIZE _____ SPRING RANGE _____

COMMENTS _____

SIGNED _____ DATE _____

WHITE — PLAN. & ENGINEERING

CANARY - CUSTOMER SERVICE

PINK — CUSTOMER INQ. WESTBOROUGH

GOLD — METER SHOP

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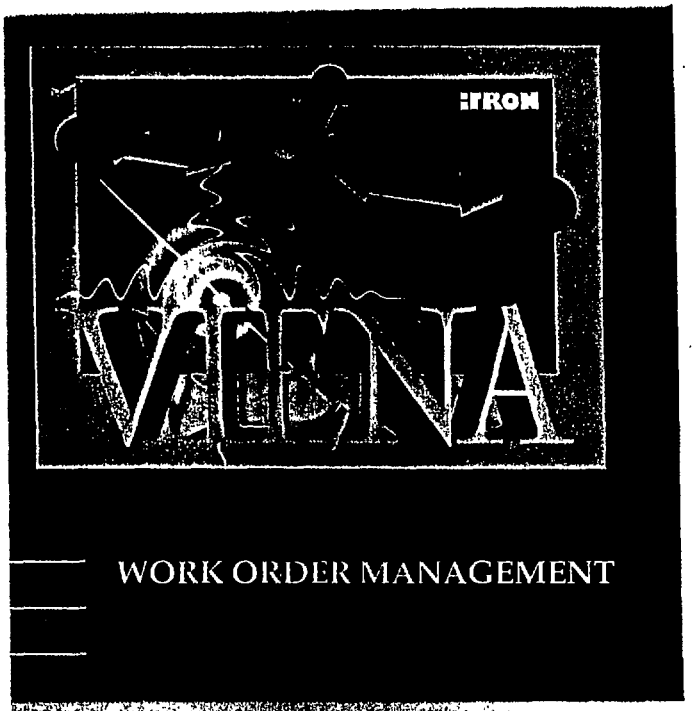


WORK ORDER MANAGEMENT

Based on Itron's 20 years' experience in developing data collection systems for utilities, VIENA combines the strength of a relational database with a graphical user interface.

VIENA is designed to help utilities manage the complex workload associated with collecting data from the field (meter reading, field service applications) and transferring that data to billing and other utility systems.

How does it work?

Customer and route data is downloaded from the utility's mainframe.

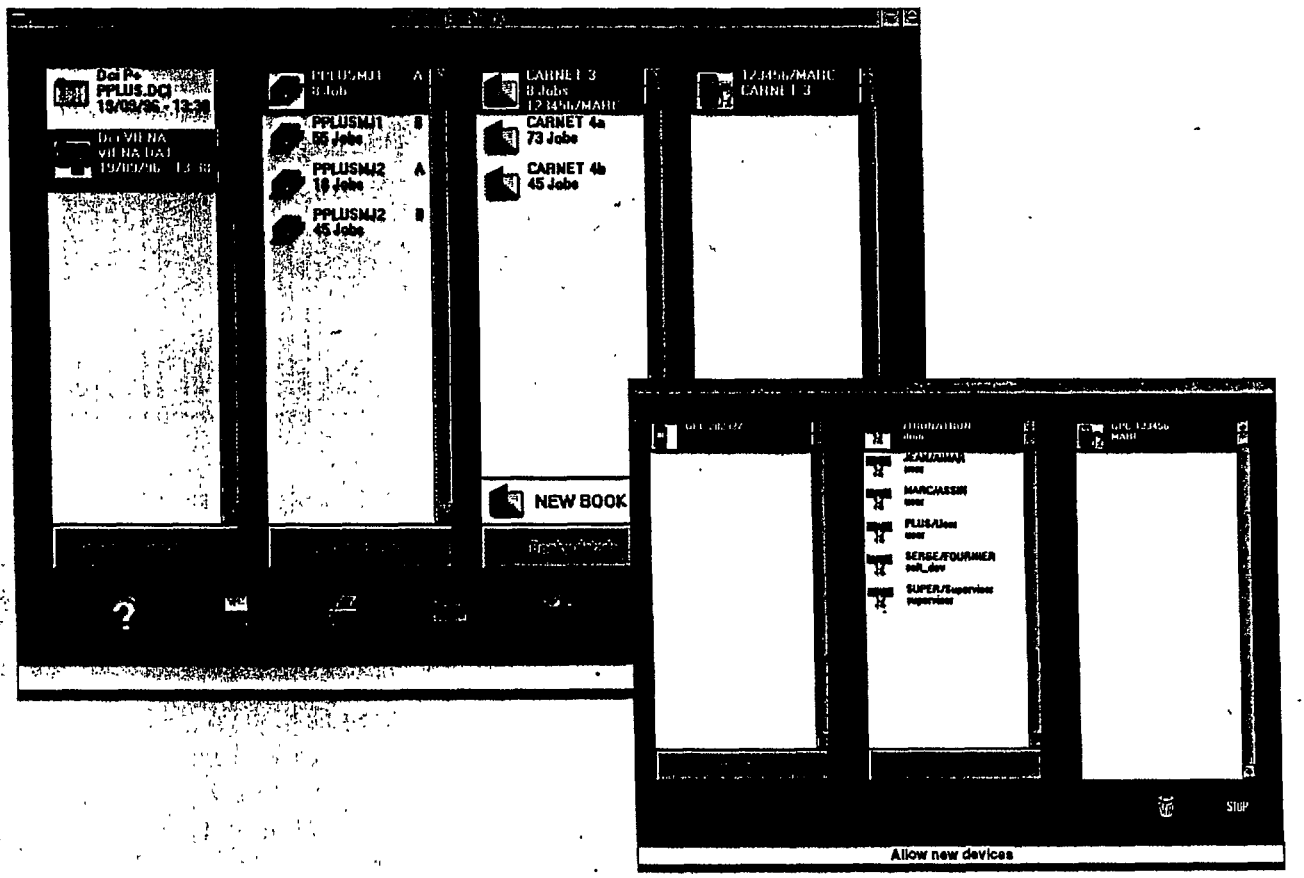
The input file is then split (manually or automatically) into routes before being allocated to a hand held computer and field operative.

The process of allocating a route to a hand held computer - like many other processes in VIENA - is achieved through simple *drag and drop*.

Data can be transferred to a variety of hand held computers: T3500, GPC and other DOS-compatible hand held computers, depending on which application is used: meter reading, radio-based remote meter reading, field service and so on.

The method of transfer can vary too: directly via an RS232 connection between the PC and the hand held computer cradle, by modem link between utility depot and field personnel's home, or even PCMCIA card.

Once work has been carried out, field operatives return the hand held computer to the cradle. This is all that is required to initiate data transfer back to the PC, where routes are merged again before being uploaded to the utility's mainframe for billing purposes.



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KEY FEATURES

Design specifications

- Object-oriented design
- ODBC-compliant
- Relational database architecture
- Context sensitive help
- Parameterised setup

Main benefits

- Intuitive, graphical user interface
- Easy to learn, easy to use
- Data transfer from cradle automatically initiated

Hand Held Computers supported

- T3500, T3500 PN
- GPC, GPC PN
- Other DOS-compatible hand held computers

Meter Devices supported

- Water, gas, electricity, heat
- Euridis, IEC1107, Mbus, Flag
- Radio 433MHz
- AMR

Specifications

- IBM compatible PC
- 486 DX 66 minimum
- 8 Mb RAM
- 120 Mb Hard Disk
- Windows 3.11, Windows 95, Windows NT

Company Profile

Itron is the leading provider of data collection solutions for energy and water distribution companies worldwide.

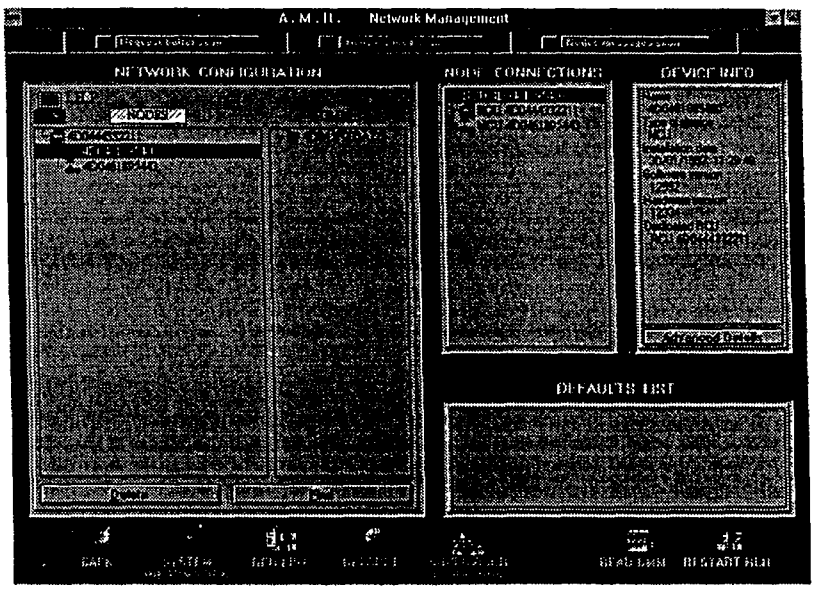
The company designs, develops, manufactures, installs, maintains hardware, software and integrated systems for electronic meter reading (EMR), off-site meter reading (OMR), automatic meter reading (AMR) and field service.

Over 1500 companies in 40 countries use Itron solutions today.

VIENA AMR

This is a software add-on which provides AMR network control and management.

While VIENA is used for the management of meter reading and field service workload, VIENA AMR is specifically designed to access and communicate remotely with components (GMMs, CCUs) of a radio-based fixed network.



Due to continuous research, product improvements and enhancements, Itron reserves the right to change product or system specifications without notice.

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NORTHERN UTILITIES, INC

METER READERS STANDARDS OF PERFORMANCE

1. Meter readers must be neat in appearance, well mannered, polite, and in uniform. Remember, Northern Utilities' meter readers represent the company, and must conduct themselves in an exemplary manner in order to maintain the company's public image at its highest level.

2. Detection of leaking gas shall be called into CIC clerk or supervisor immediately. Meter reader will ask CIC clerk's name or employee number and document same on mark-sense card.

3. Meter readers will observe all instructions on mark-sense card for entry, must knock two or three times or ring bell at designated door per instruction card and allow reasonable time to answer.

4. ~~Meter readers will leave a meter reading return postcard at every stop~~ marked CGI. CLEARLY MARK CARD NOT READ

5. Meter readers shall not deliberately skip any meters on their routes, for any reason, without first recording the reason on the mark-sense card.

6. Meter readers shall record only actual readings or customer readings. They will not record an estimated reading. Falsification of company records will result in discharge. Extra care must be taken in reading commercial and industrial meters to which the company has added instruments. Meter readers must become familiar with the special instructions issued for reading instruments.

7. Meter reader will record the following information on all CGI mark-sense cards showing 6 or more estimated months.

   a. Meter readers initials.
   b. Time and date.

   In addition, on the return postcard that he leaves, change the first line that reads "our meter reader was unable to read your gas meter today _____", to "our meter reader was unable to read your gas meter for 6 months." (or whatever number of months is appropriate.)

8. Meter readers will mark-sense readings neatly. Readings will also be written numerically in the area above the date on the mark-sense card. All information and explanations on the card shall be clearly written.

9. ~~Meter readers books will be turned in daily in three distinct piles of~~ work.

   a. All read meters.
   b. All unread meters (with newly mark-sensed sequence numbers on top).
   c. Meters with acts of vandalism or mutilation, new meter numbers, or any other problems.

10. Meter readers will update all information on mark-sense cards to insure reading the meter each time. Any changes or deletions shall be noted on card. Any meter thought to be in a wrong book should be brought to the meter reading supervisors attention with an explanation of the recommended change.

11. Observances of irregularities in the area of name changes, date moved in, meter changes, wrong addresses, appliances added or deleted (rate change) must be documented on mark-sense cards.

12. a. Meters or fits with noticed acts of vandalism, mutilation or tampering (broken wire seals, loose index screws, etc.) must be noted on the mark-sense card and sorted as a separate group of cards to be turned in to the meter reading supervisor at the end of the work day. (see #9 above).

    b. Meters turned the wrong way, meters disconnected, meters bypassed, locked meters in use, other bypasses, or any attempt to divert or steal gas, must be reported immediately on discovery to the meter reading supervisor, supervisor in CIC or the service supervisor.

~~13.~~ Mark-sense cards show previous ~~reading and projected readings. When meter~~ reader has a reading significantly higher than projected or lower than previous reading, he will prove the reading by re-reading the meter number and index again and will mark the dials on the mark sense card.

14. Meter readers in each division will be responsible, where applicable, for company vehicles, rain wear, uniforms, flashlights, first aid kits, mark-sense cards, keys, maps, and any additional material used. Particular care must be taken to maintain company vehicles in a clean condition and to report promptly, anything in need of repair or maintenance.

15. Meter readers will insure extra precautions are taken on construction sites, dwellings with dogs, and other unsafe areas or dwellings. Meter readers will select the best approach and exercise good judgement before entering any area. Meter readers must immediately report any incident involving personal injury or accident, to himself or to a customer that may occur while the meter reader is on customer premises or any personal injury or accident to himself while anywhere on his route. In addition, meter readers should anticipate a customers communication to the meter reading supervisor in particular, for any unusual incident such as a verbal exchange with a customer, a dog bite or the spraying of a dog, or any incident involving damage to a customers' property.

16. Meter readers are expected to attend safety instruction and general informational meetings as scheduled.

17. Once a meter reader's route has progressed through the last mark-sense card sequence number, meter readers are expected to attempt to complete previous CGI's for both meter reading and collections, when time in excess of the allowed travel time back to the office is available.

18. Meter readers should always be in his or her assigned work area. Meter readers shall not leave the assigned work area during working hours, except for the purpose of personal relief, or for lunch break.

19. During the course of a normal work day when it becomes obvious to the meter reader that he or she may be unable to complete the daily work assignment, the meter reading supervisor must be notified immediately.

§ 192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion is found, remedial action must be taken to the extent required by § 192.483 and the applicable paragraphs of §§ 192.485, 192.487, or 192.489.

§ 192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

§ 192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential—

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

§ 192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet, or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to insure that it is operating.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be

72

checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by paragraphs (b) and (c) of § 192.455 and paragraph (b) of § 192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-35A, 45 FR 23441, Apr. 7, 1980]

§ 192.467 External corrosion control: Electrical isolation.

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.469 External corrosion control: Test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976]

§ 192.471 External corrosion control: Test leads.

(a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

(b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

§ 192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

73

§ 192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 standard cubic feet (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.477 Internal corrosion control: Monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.479 Atmospheric corrosion control: General.

(a) *Pipelines installed after July 31, 1971.* Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.

(b) *Pipelines installed before August 1, 1971.* Each operator having an aboveground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall—

(1) Determine the areas of atmospheric corrosion on the pipeline;

(2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of §§ 192.485, 192.487, or 192.489; and

(3) Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.481 Atmospheric corrosion control: Monitoring.

After meeting the requirements of § 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and at least once each calendar year, but with intervals not exceeding 15 months, for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

[Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

§ 192.483 Remedial measures: General.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of § 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

74

§ 192.485 Remedial measures: Transmission lines.

(a) *General corrosion.* Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

(c) Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978; Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) *General corrosion.* Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) *Localized corrosion pitting.* Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

§ 192.489 Remedial measures: Cast iron and ductile iron pipelines.

(a) *General graphitization.* Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced.

(b) *Localized graphitization.* Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

§ 192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§ 192.465 (a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.

[Amdt. 192-78, 61 FR 28785, June 6, 1996]

75

Subpart J—Test Requirements

§ 192.501 Scope.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

§ 192.503 General requirements.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

(1) It has been tested in accordance with this subpart and § 192.619 to substantiate the maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is—

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in § 192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-60, 53 FR 36029, Sept. 16, 1988; Amdt. 192-60A, 54 FR 5485, Feb. 3, 1989]

§ 192.505 Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet of such a building, but in no event may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station regulator station, and measuring station, must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that—

(1) The component was tested to at least the pressure required for the pipeline to which it is being added; or

(2) The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added.

(e) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

§ 192.507 Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i.g.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or

76

above 100 p.s.i.g. must be tested in accordance with the following:

(a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium—

(1) A leak test must be made at a pressure between 100 p.s.i.g. and the pressure required to produce a hoop stress of 20 percent of SMYS; or

(2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.

(c) The pressure must be maintained at or above the test pressure for at least 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.509 Test requirements for pipelines to operate below 100 p.s.i.g.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i.g. must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 p.s.i.g. must be tested to at least 10 p.s.i.g. and each main to be operated at or above 1 p.s.i.g. must be tested to at least 90 p.s.i.g.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.511 Test requirements for service lines.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i.g. but not more than 40 p.s.i.g. must be given a leak test at a pressure of not less than 50 p.s.i.g.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i.g. must be tested to at least 90 p.s.i.g., except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with § 192.507 of this subpart.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-74, 61 FR 18517, Apr. 26, 1996]

§ 192.513 Test requirements for plastic pipelines.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 psig, whichever is greater. However, the maximum test pressure may not be more than three times the pressure determined under § 192.121, at a temperature not less than the pipe temperature during the test.

(d) During the test, the temperature of thermoplastic material may not be more than 38 °C (100 °F), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-77, 61 FR 27793, June 3, 1996; 61 FR 45905, Aug. 30, 1996]

§ 192.515 Environmental protection and safety requirements.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

77

§ 192.517 Records.

Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:

(a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

(b) Test medium used.

(c) Test pressure.

(d) Test duration.

(e) Pressure recording charts, or other record of pressure readings.

(f) Elevation variations, whenever significant for the particular test.

(g) Leaks and failures noted and their disposition.

Subpart K—Uprating

§ 192.551 Scope.

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

§ 192.553 General requirements.

(a) *Pressure increases.* Whenever the requirements of this subpart require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following:

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

(b) *Records.* Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) *Written plan.* Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) *Limitation on increase in maximum allowable operating pressure.* Except as provided in § 192.555(c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, the MAOP may be increased as provided in § 192.619(a)(1).

[35 FR 13257, Aug. 10, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.555 Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

(1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and

(2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under § 192.619, using as test pressure the highest pressure to which the segment of pipeline was previously

78

subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if:

(i) It is impractical to test it in accordance with the requirements of this part;

(ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and

(iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to:

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

§ 192.557 Uprating: Steel pipelines to a pressure that will produce a hoop stress less than 30 percent of SMYS: plastic, cast iron, and ductile iron pipelines.

(a) Unless the requirements of this section have been met, no person may subject:

(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or

(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(6) If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i.g. or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses,

79

and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

(1) In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill.

(2) Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured.

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Pipe size (inches)	Allowance (inches)		
	Cast iron pipe		Ductile iron pipe
	Pit cast pipe	Centrifugally cast pipe	
3 to 8	0.075	0.065	0.065
10 to 12	0.08	0.07	0.07
14 to 24	0.08	0.08	0.075
30 to 42	0.09	0.09	0.075
48	0.09	0.09	0.08
54 to 60	0.09	.....	.....

(4) For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 p.s.i. and a modulus of rupture of 31,000 p.s.i.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

Subpart L—Operations

§ 192.601 Scope.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

§ 192.603 General provisions.

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall keep records necessary to administer the procedures established under § 192.605.

(c) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 *et seq.*) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-66, 56 FR 31090, July 9, 1991; Amdt. 192-71, 59 FR 6584, Feb. 11, 1994; Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

(a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

80

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

(9) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including—

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i) Unintended closure of valves or shutdowns;

(ii) Increase or decrease in pressure or flow rate outside normal operating limits;

(iii) Loss of communications;

(iv) Operation of any safety device; and

(v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.

(2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) Notifying responsible operator personnel when notice of an abnormal operation is received.

(4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

(5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.

(d) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of § 191.23 of this subchapter.

(e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§ 192.613(a), 192.615,

81

and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994, as amended by Amdt. 192-71A, 60 FR 14381, Mar. 17, 1995]

§ 192.607 [Reserved]

§ 192.609 Change in class location: Required study.

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be ascertained from available records;

(d) The operating and maintenance history of the segment;

(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

§ 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§ 192.553 and 192.555.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study

82

under § 192.609 must be completed within 18 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 18-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

[Amdt. 192-63A, 54 FR 24174, June 6, 1989 as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.612 Underwater inspection and re-burial of pipelines in the Gulf of Mexico and its inlets.

(a) Each operator shall, in accordance with this section, conduct an underwater inspection of its pipelines in the Gulf of Mexico and its inlets. The inspection must be conducted after October 3, 1989 and before November 16, 1992.

(b) If, as a result of an inspection under paragraph (a) of this section, or upon notification by any person, an operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802 of the location, and, if available, the geographic coordinates of that pipeline;

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards long, except that a pipeline segment less than 200 yards long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year the discovery is made, place the pipeline so that the top of the pipe is 36 inches below the seabed for normal excavation or 18 inches for rock excavation.

[Amdt. 192-67, 56 FR 63771, Dec. 5, 1991]

§ 192.613 Continuing surveillance.

(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with § 192.619 (a) and (b).

§ 192.614 Damage prevention program.

(a) Except for pipelines listed in paragraph (c) of this section, each operator of a buried pipeline shall carry out in accordance with this section a written program to prevent damage to that pipeline by excavation activities. For the purpose of this section, "excavation activities" include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earth moving operations. An operator may perform any of the duties required by paragraph (b) of this section through participation in a public service program, such as a "one-call" system, but such participation does not relieve the operator of responsibility for compliance with this section.

(b) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provide for general notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (b)(1) of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

83

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, any inspection must include leakage surveys.

(c) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(4) Pipelines that are part of a petroleum gas system subject to § 192.11 or part of a distribution system operated by a person in connection with that person's leasing of real property or by a condominium or cooperative association.

[Amdt. 192-40, 47 FR 13824, Apr. 1, 1982, as amended by Amdt. 192-57, 52 FR 32800, Aug. 31, 1987; Amdt. 192-73, 60 FR 14650, Mar. 20, 1995; Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible.

(b) Each operator shall:

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

84

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

[Amdt. 192-24, 41 FR 13587, Mar. 31, 1976, as amended by Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.616 Public education.

Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

[Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.617 Investigation of failures.

Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under § 192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§ 192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 324 mm (12¾ in) or less in outside diameter and is not tested to yield under this paragraph, 1379 kPa (200 psig).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i.g. or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors[1], segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under § 192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1] For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested in accordance with paragraph (a)(2) of this section after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was uprated in accordance with subpart K of this part.

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

(c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition,

85

considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, or in the case of offshore gathering lines, July 1, 1976, subject to the requirements of § 192.611.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.619, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§ 192.621 Maximum allowable operating pressure: High-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.

(2) 60 p.s.i.g., for a segment of a distribution system otherwise designed to operate at over 60 p.s.i.g., unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of § 192.197(c).

(3) 25 p.s.i.g. in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with § 192.195.

§ 192.623 Maximum and minimum allowable operating pressure; Low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

§ 192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant:

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or

86

harmful to those materials to which the products of combustion will be exposed.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section. Operators of master meter systems may comply with this requirement by—

(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

(2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

[35 FR 13257, Aug. 19, 1970]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 192.625, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§ 192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

§ 192.629 Purging of pipelines.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

Subpart M—Maintenance

§ 192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

§ 192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

§ 192.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

(b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

	Maximum interval between patrols	
Class location of line	At highway and railroad crossings	At all other places
1, 2	7½ months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year.	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year.	4½ months; but at least four times each calendar year.

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.706 Transmission lines: Leakage surveys.

Leakage surveys of a transmission line must be conducted at intervals not

37

exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with § 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(a) In Class 3 locations, at intervals not exceeding 7½ months, but at least twice each calendar year; and

(b) In Class 4 locations, at intervals not exceeding 4½ months, but at least four times each calendar year.

[Amdt. 192-21, 40 FR 20283, May 9, 1975, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.707 Line markers for mains and transmission lines.

(a) *Buried pipelines.* Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

(b) *Exceptions for buried pipelines.* Line markers are not required for the following pipelines:

(1) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

(2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under § 192.614.

(3) Transmission lines in Class 3 or 4 locations until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) *Pipelines aboveground.* Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Marker warning.* The following must be written legibly on a background of sharply contrasting color on each line marker:

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with one-quarter inch stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

[Amdt. 192-20, 40 FR 13505, Mar. 27, 1975; Amdt. 192-27, 41 FR 39752, Sept. 16, 1976, as amended by Amdt. 192-20A, 41 FR 56808, Dec. 30, 1976; Amdt. 192-44, 48 FR 25208, June 6, 1983; Amdt. 192-73, 60 FR 14650, Mar. 20, 1995]

§ 192.709 Transmission lines: Record keeping.

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

[Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.711 Transmission lines: General requirements for repair procedures.

(a) Each operator shall take immediate temporary measures to protect the public whenever:

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery.

As soon as feasible, the operator shall make permanent repairs.

(b) Except as provided in § 192.717(a)(3), no operator may use a welded patch as a means of repair.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27B, 45 FR 3272, Jan. 17, 1980]

§ 192.713 Transmission lines: Permanent field repair of imperfections and damages.

(a) Except as provided in paragraph (b) of this section, each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of SMYS must be repaired as follows:

(1) If it is feasible to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage.

(3) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.

[Amdt. 192-27, 41 FR 34607, Aug. 16, 1976]

§ 192.715 Transmission lines: Permanent field repair of welds.

Each weld that is unacceptable under § 192.241(c) must be repaired as follows:

(a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of § 192.245.

(b) A weld may be repaired in accordance with § 192.245 while the segment of transmission line is in service if:

(1) The weld is not leaking;

(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least ⅛-inch thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

§ 192.717 Transmission lines: Permanent field repair of leaks.

(a) Except as provided in paragraph (b) of this section, each permanent field repair of a leak on a transmission line must be made as follows:

(1) If feasible, the segment of transmission line must be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing a full encirclement welded split sleeve of appropriate design, unless the transmission line:

(i) Is joined by mechanical couplings; and

(ii) Operates at less than 40 percent of SMYS.

(3) If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; or, if the leak is due to a corrosion pit and on pipe of not more than 40,000 psi SMYS, the repair may be made by fillet welding over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

[Amdt. 192-27, 41 FR 34607, Aug. 16, 1976]

§ 192.719 Transmission lines: Testing of repairs.

(a) *Testing of replacement pipe.* If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test

89

may be made on the pipe before it is installed.

(b) *Testing of repairs made by welding.* Each repair made by welding in accordance with §§ 192.713, 192.715, and 192.717 must be examined in accordance with § 192.241.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-54, 51 FR 41635, Nov. 18, 1986]

§ 192.721 Distribution systems: Patrolling.

(a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

(1) In business districts, at intervals not exceeding 4½ months, but at least four times each calendar year; and

(2) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-78, 61 FR 28786, June 6, 1996]

§ 192.723 Distribution systems: Leakage surveys.

(a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at intervals not exceeding 5 years. However, for cathodically unprotected distribution lines subject to § 192.465(e) on which electrical surveys for corrosion are impractical, survey intervals may not exceed 3 years.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-70, 58 FR 54528, 54529, Oct. 22, 1993; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

§ 192.727 Abandonment or deactivation of facilities.

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening

90

of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

[Amdt. 192-8, 37 FR 20695, Oct. 3, 1972, as amended by Amdt. 192-27, 41 FR 34607, Aug. 16, 1976; Amdt. 192-71, 59 FR 6585, Feb. 11, 1994]

§ 192.731 Compressor stations: Inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§ 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.735 Compressor stations: Storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

§ 192.736 Compressor stations: Gas detection.

(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

(1) Constructed so that at least 50 percent of its upright side area is permanently open; or

(2) Located in an unattended field compressor station of 1,000 horsepower or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must—

(1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and

(2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

[58 FR 48464, Sept. 16, 1993]

§ 192.739 Pressure limiting and regulating stations: Inspection and testing.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.741 Pressure limiting and regulating stations: Telemetering or recording gauges.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

91

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

§ 192.743 Pressure limiting and regulating stations: Testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 15 months, but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding 15 months, but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-55, 51 FR 41634, Nov. 18, 1986]

§ 192.745 Valve maintenance: Transmission lines.

Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.747 Valve maintenance: Distribution systems.

Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

[Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982]

§ 192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

92

§ 192.753 Caulked bell and spigot joints.

(a) Each cast-iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i.g. or more must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which:

(i) Does not reduce the flexibility of the joint;

(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§ 192.53 (a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures of less than 25 p.s.i.g. and is exposed for any reason, must be sealed by a means other than caulking.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-25, 41 FR 23680, June 11, 1976]

§ 192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§ 192.317(a), 192.319, and 192.361(b)-(d).

[Amdt. 192-23, 41 FR 13589, Mar. 31, 1976]

APPENDIX A TO PART 192—INCORPORATED BY REFERENCE

I. List of Organizations and Addresses

A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.

B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.

C. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.

D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, NY 10017.

E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NW., Vienna, VA 22180.

G. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. 9101, Quincy, MA 02269-9101.

II. Documents Incorporated by Reference (Numbers in Parentheses Indicate Applicable Editions)

A. American Gas Association (AGA):

(1). AGA Pipeline Research Committee, Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 22, 1989).

B. American Petroleum Institute (API):

(1) API Specification 5L "Specification for Line Pipe (41st edition, 1995).

(2). API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe" (4th edition, 1990).

(3) API Specification 6D "Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves)" (21st edition, 1994).

(4) API Standard 1104 "Welding of Pipelines and Related Facilities" (18th edition, 1994).

C. American Society for Testing and Materials (ASTM):

(1) ASTM Designation: A53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (A53-95a).

(2) ASTM Designation A 106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A 106- 94a).

(3) ASTM Designation: A 333/A 333M "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service" (A 333/A 333M-94).

(4) ASTM Designation: A 372/A 372M "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A 372/A 372M-95).

(5) ASTM Designation: A 381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems (A 381-93).

(6) ASTM Designation: A 671 "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A 671-94).

(7) ASTM Designation: A 672 "Standard Specification for Electric-Fusion-Welded

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THE METHANE GAME IT'S A GAS!

Most common gas meters today work on the bellows principle, i.e.- a gas bag, usually made of leather, is forced to "breathe" like a lung when gas flows through it. A metal rod connected to the bag pushes the wheels which turn the dials of the meter, which displays the amount of cubic feet of gas which has passed through the meter. This meter is common for houses and apartments because it is accurate with small flows, such as in pilot lights in stoves and heaters. Since pilot lights use up 1/3 of the average gas bill, the power company wants to be sure to get it registered properly.

To be a Gas Raider one must follow these important rules: First, before doing anything, write down the conditions that you're starting with and the situation that you will end up with. Second, do not allow the power co. to become suspicious. Finally, and most importa', use all safety precautions, bar none! A careless Ra ar is a dead Raider!

The first step is to make notes on the before and after situations. This is important because even seasoned professional Raiders can easily forget where a particular screw came from, or whether the washers were under the frame or over the frame, etc. And by knowing in advance what changes you're going to make, it will be easier to see what notes you'll have to make on the "before" situation. Some things you'll have to watch are in the next step, below.

Second, you must keep a grip on your security by not leaving tell-tale signs. Here's how:

1- Don't cut down your gas bill to nothing overnight. The power company knows how much you use and if the computer notices a sharp dip in your bills they'll ask you why. Saying that you've been on vacation helps, but it's best to cut down gradually. Remember, greed is the power company's downfall. Don't let it be yours.

2- Check old bills and use them as a guide. Figure out your usage in cubic feet and you'll know how much to cut down your reading by. The bills also tell the date that the meter reader comes by, another good thing to know.

3- Some meters are clean, but most are filthy. The face of the dials are usually unsmudged. Write down the appearance of your meter before you touch it, and make sure it looks exactly the same when you're done. This is absolutely imperative. If you're lazy, plan on getting caught. Gas Raiding is a precision art, requiring patience and finesse.

4- Use proper tools. Without a big enough pipe wrench you may scratch the pipe and/or the bolts enough to be noticeable.

5- Seals are often used on meters. You may be able to use a technique that doesn't require breaking the seal. You may be able to break the seal and put it back looking uncut, but it's not too easy. You can often get a seal and a sealing tool from a friend in the company, from a friendly employee who needs a few bucks, or by getting a job yourself for a month and ripping off a few hundred thousand. Sometimes meters are bolted on, and the threads on the bolts or nuts have a sealer-type glue. Get a bit of the stuff and be sure it looks the same when applied (and dried). If you have to break a seal that you can't replace, wait at least 8 months before touching the meter again, because they may be suspicious and waiting. Waiting is also important to see if they put a new seal on. If they don't, then they just don't care and you're in business again.

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To suck the meter, connect the output of the vacuum to the output (supply) side of the meter. To suck back the meter, connect the input hose of the vacuum to the input of the meter. Tape up the connections with plastic tape and let 'er rip! Be sure you disconnect the meter from the pipes (Method 1) before connecting the vacuum cleaner, stupid!

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REMOVING DIALS

Some meters have a removeable dial assembly that is simply removed by unscrewing the frame and pulling the whole thing off. Then plug up the hole where the rod comes through so that no gas leaks out. Any gas that you now use won't register on the dials, and you can even open up the assembly that you just removed and turn the dials back to a more equitable reading. When repositioning these dials it is extremely important to understand how the numbering system on the dials works. Every time the "Cubic feet" dial rotates one full turn, the "Tens of cubic feet" dial moves one digit upwards. Thus, when the "Cubic feet" dial is on zero, the "Tens" dial should be pointing right at a particular number. And when the "Cubic feet" dial is halfway around, the "Tens" dial must be halfway between two numbers. The same holds true for all the dials, when compared to the dial right next to them. Meter readers do nothing but read meters all day, and they will know if the dials are pointing in the wrong positions. Mark down the dial readings of your meter before playing with it. If the dials aren't labeled with "Feet", "Tens", etc., then turn your gas on and see which dial moves fastest. This will be the "Cubic feet" dial, usually the right-most dial. The "Tens" dial will be next to it, and so on. Be sure no one in your home lets the meter reader in with the dials off, the meter reversed, or anything else looking funny.

SAFETY

Natural gas is a mixture of 80% methane and smaller amounts of ethane, propane, butane, nitrogen and a few other gases. It is highly explosive and very poisonous. The shutoff valve should be regarded as your "Live-Die" switch. You MUST remember to turn it off before working on gas lines. You can faint before you realize it if you have a gas leak.

Super-Important- Work with plenty of ventilation. If impossible to have ventilation, don't work! Even after you shutoff the valve there is still enough gas in the pipes to be dangerous. With fresh air coming in you'll have no problems.

Sparks or flame will ignite any gas in the air. Do not smoke. Electric motors, drills, saws or appliances make sparks and must not be used while working on gas lines.

When you're done, check for leaks by cupping your hands around the pipe and pouring in some water. Watch for bubbles of gas escaping. This method is better than sniffing because your sense of smell will decrease if you've been smelling gas for a few minutes, and either everything will smell like gas or nothing will. Do not try the old trick of lighting a match to find a leak!

Do not work alone. With two people you have protection from fainting and not being found until it's too late. Both of you should know all safety rules and be aware of how you are feeling while working. Work slowly and carefully and you should have complete success and safety.

Before starting, locate every single pilot light that works on gas in your home. They must be relit after you finish or you'll be finished off. In one house there was a gas heater, a gas dryer, a gas water heater and a gas stove, each with its own pilot light. The stove itself had 7 pilot lights! Know your appliances and it's a good idea to have the manuals for them so you can find the pilot lights before you begin to work. Some people have gas refrigerators. Many N.Y. people only have a gas stove with one or two pilots. Your pilot lights are also good for checking that the shutoff valve is working before you turn the nuts on the meter. If you smell gas in your home after finishing, turn off the valve at once. You'll breathe easier for it!

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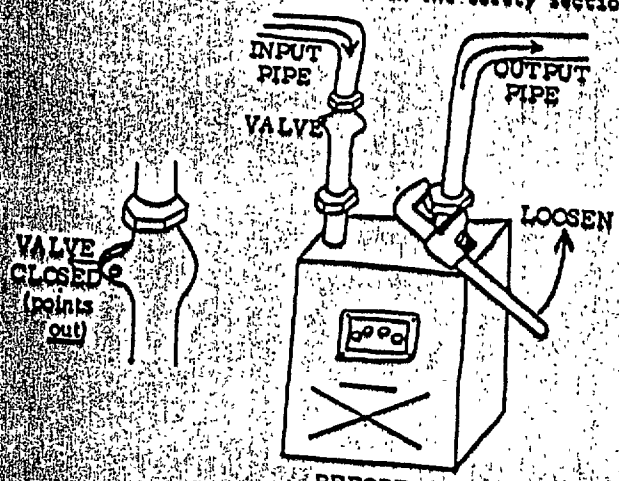
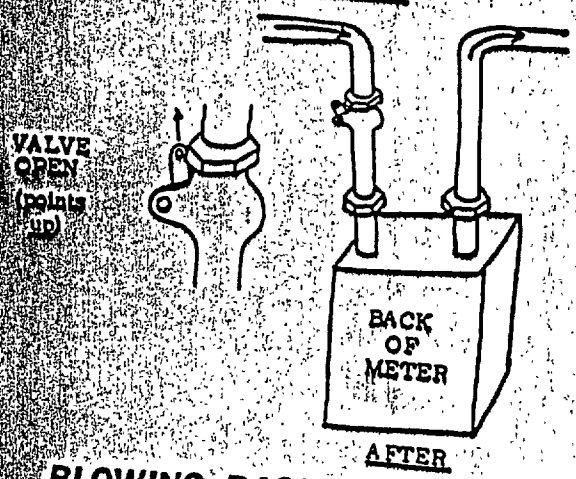
REVERSING METER

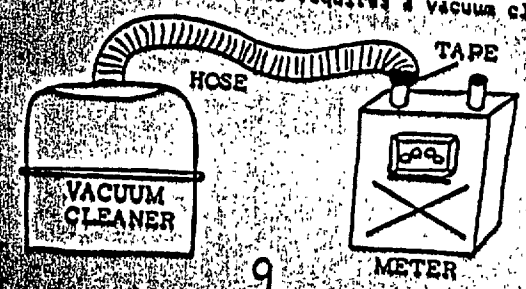
This is the easiest method of rewinding your meter. First, turn off the valve that supplies gas to the meter. When the power co. cuts you off, it uses this valve to do so. They use a wrench to turn the valve so that the hole on the pipe and the moving hole on the valve handle line up. Then they put a lock(usually a rollersmith lock-see Issue 21) or a seal through the two holes. When the valve handle is pointing in the direction of the pipe the gas is on. Turn the handle with a wrench so the holes line up. Take a bigger pipe wrench and loosen the big nuts that connect the input and output pipes to the top of the meter. Then turn them by hand, holding the meter so it doesn't fall when it comes off. Now turn the meter around so the dials face the opposite direction that they did before, and the gas is going backwards through the meter. Tighten the nuts by hand while pushing up on the meter. Make sure they are turning smoothly and properly, straight onto the meter. Then tighten them snugly (but not as tight as possible, or you may strip the threads) with the big wrench. As you use gas the meter will run in reverse, unless it has a ratchet mechanism to prevent it. At the very least the meter won't move, thus-Free Gas! Check for leaks as shown in the safety section.





BLOWING BACK METER

This ingenious method requires a vacuum cleaner. To



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Chapter 5

UNACCOUNTED-FOR GAS

Unaccounted-for Gas (UFG) is defined as the difference between the total gas available to a distribution or transmission pipe system from all sources and the total gas accounted for as sales, net interchange, and company use. This difference includes discrepancies caused by meter inaccuracies; variations of temperature, pressure, and other atmospheric variables; measurement of gas quantities at different times; cycle billing; theft of gas; unmetered use in operations; and system leakage. It is usually expressed as:

- A volume of gas or function of system send-out—actual volume,
- Percent of gas available,
- Percent of system send-out, or
- Loss per mile of main or pipeline.

UFG expressed as a positive percentage means gas lost. UFG expressed as a negative percentage means gas gained.

SCOPE

The various physical conditions and operating practices in gas distribution and transmission operations that contribute to UFG are discussed in this chapter. Factors that contribute to the total volume, accounting practices, and methods to define and minimize UFG will be covered as well.

GENERAL OVERVIEW

UFG is an important guide for engineering and operations analysis. It is not a definitive expression of the performance of a gas measure-

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ment system, nor the validity of related records, nor the leakage in a pipeline or distribution system, nor the unauthorized use or theft of gas. Accounting reports show it as a quantity of gas, percentage, or dollar value to indicate the economic significance. Regulatory agencies historically have used it as a measure of system safety. UFG should not be used for its absolute value, but more as an indicator of change under comparable conditions.

FACTORS CONTRIBUTING TO THE TOTAL UFG QUANTITY

The total volume of UFG can consist of losses caused by:

- Errors or omissions in measurement of the production, purchase, sale, or exchange of gas;
- Injection and withdrawal from storage; and
- Gas used for company operations.

In addition, UFG can include the uncontrolled losses caused by piping system leakage and diversion or theft of gas at the customers' premises.

MEASUREMENT ERROR

Factors that contribute to measurement error occur in both transmission and distribution systems. Errors in gas purchase measurement occur at points of delivery from gas supply companies, independent producers, storage facilities, points of exchange with other companies, and points of supply from nontraditional sources such as synthetic gas or liquefied natural gas.

The potential for UFG is minimal when dealing with one or two sources of supply. As the number of sources and complexity of transportation arrangements increase, there can exist a self-cancelling effect between positive and negative errors occurring at several measuring devices.

Errors in gas sale measurement occur at:

- Excess pressure delivery points to large volume customers,
- Locations of company use,
- Points of gas storage injection,
- Points of exchange with other companies, and at
- Outside domestic meters in distribution systems.

Measurement errors can also occur when a high- or low-volume flow is outside the specified tolerance of the metering device. Reasons for other possible errors follow.

Large-Volume High-Pressur

A.G.A. Gas Measurement, *Displacement Measurement*, (*ing*, Catalog No. XQ0684; *Ot* XQ0483; *Auxiliary Devices*, Ca *tions and Data Gathering*, Ca *Control*, Catalog No. XQ0584: *ing*, Catalog No. XQ0278; and XQ0381) provide the correctio: to volumes measured at high

- Flowing gas temperat
- Metering pressure,
- Barometric pressure,
- Specific gravity,
- Heating value,
- Gas humidity, and
- Supercompressibility.

Serious errors can occur a stations when contract tempe are used for flow calculations result in incorrect or interru

Typical measurement speci volumes require that flowing g A one percent error in measu for each 10°F (5.5°C) variation ment meter, the same error from the base temperature.

Examples of operating pr

- Freezing in gauge line
- Control equipment ma
- Pen or clock failure o
- Incorrect recording ga
- Poor meter inspection

Chart interpretations, sucl differential pressure recordin proaching 20 percent.

Development and implen measurement require the inc tors; chart changing and chart UFG in large volume measu

Low-Pressure Measuremen

Low-pressure measureme

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Large-Volume High-Pressure Measurement Error

A.G.A. Gas Measurement Manuals (General), Catalog No. XQ1081; *Displacement Measurement*, Catalog No. XZ0277; *Gas Turbine Metering*, Catalog No. XQ0684; *Other Measurement Methods*, Catalog No. XQ0483; *Auxiliary Devices*, Catalog No. XQ0779; *Measurement Calculations and Data Gathering*, Catalog No. XQ0379; *Pressure and Volume Control*, Catalog No. XQ0584; *Meter Proving and Distribution Metering*, Catalog No. XQ0278; and *Meter Repair and Selection*, Catalog No. XQ0381) provide the correction base conditions. The corrections applied to volumes measured at high pressure are for:

- Flowing gas temperature,
- Metering pressure,
- Barometric pressure,
- Specific gravity,
- Heating value,
- Gas humidity, and
- Supercompressibility.

Serious errors can occur at large-volume, high-pressure measuring stations when contract temperatures or average flowing temperatures are used for flow calculations and when improper operating practices result in incorrect or interrupted measurement records.

Typical measurement specifications for stations delivering very large volumes require that flowing gas temperature be recorded continuously. A one percent error in measured volume by an orifice meter will occur for each 10°F (5.5°C) variation from the base temperature. In a displacement meter, the same error occurs for each variation of 5°F (2.7°C) from the base temperature.

Examples of operating practices that cause poor records include:

- Freezing in gauge lines,
- Control equipment malfunction,
- Pen or clock failure on recording gauges,
- Incorrect recording gauge and chart sizing, and
- Poor meter inspection procedures.

Chart interpretations, such as wide-line-differential pressure or low-differential pressure recording, can result in measurement errors approaching 20 percent.

Development and implementation of policies based on accurate measurement require the incorporation of appropriate correction factors; chart changing and chart interpretation are necessary to minimize UFG in large volume measurement.

Low-Pressure Measurement Error

Low-pressure measurement errors on the customers' premises con-

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tributing to UFG result primarily from measurement at a pressure and temperature other than base conditions. Assuming base conditions at 14.73 lbf/in² (101 kPa) and 60°F (15°C), meter accuracy for a residential meter installed outside could vary from plus 5 percent in the summer to minus 5 percent in the winter. Using temperature-compensated meters will minimize UFG related to flowing gas temperature in a low-pressure system. This is also true for inside meter sets during most flow conditions where the flowing gas reflects outside ground temperatures rather than basement temperatures.

Also contributing to low-pressure measurement errors are:

- Variation in operating pressure in the low-pressure piping system,
- Elevation of the distribution system above sea level,
- Barometric pressure,
- Heating value, and
- Specific gravity of the flowing gas.

The relationship of average barometric pressure to elevation above sea level is shown in Figure 10.

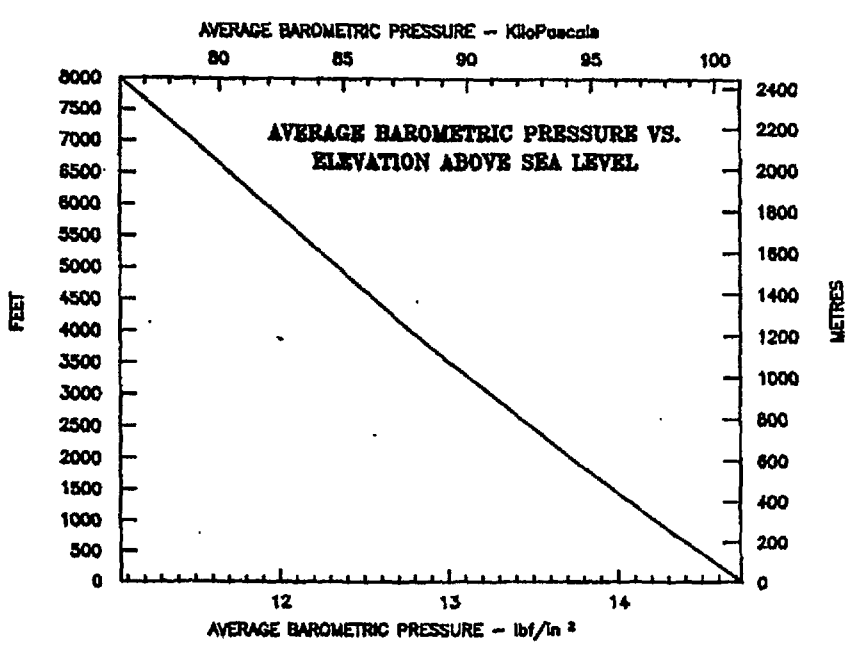

Figure 10. **Relationship of average barometric pressure to elevation above sea level.**

IDEAL GAS LAW

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Boyle's Law, stated math

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$$PV = \text{Constant}$$

A century later Charles's
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absolute temperature if the
Stated mathematically:

$$V = \text{Constant} \times T$$

or

$$\frac{V}{T} = \text{Constant}$$

In practice, both the tem
To accommodate this reality,
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$$\frac{P_S V_S}{T_S} = \frac{P_M V_M}{T_M}$$

where the subscript S con
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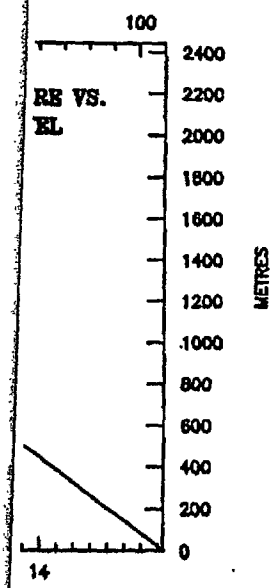

ssure to elevation

IDEAL GAS LAW

In 1662, British physicist Robert Boyle reported the effects that he observed when the pressure on a sample of air was varied from 1/30th of an atmosphere to 4 atmospheres at room temperature. This and subsequent experiments led to the relationship that became known as Boyle's law, which may be stated as follows:

"The volume occupied by a given mass of gas varies inversely with the absolute pressure if the temperature is not allowed to change."

Boyle's Law, stated mathematically, is:

$$V = \frac{\text{Constant}}{P}$$

or Eq. 4

$$PV = \text{Constant}$$

A century later Charles's Law complemented Boyle's Law and dealt with the effect of temperature. Charles's Law, which is ideal, states:

"The volume of a given mass of gas is directly proportional to the absolute temperature if the pressure remains fixed."

Stated mathematically:

$$V = \text{Constant} \times T$$

or Eq. 5

$$\frac{V}{T} = \text{Constant}$$

In practice, both the temperature and the pressure are likely to vary. To accommodate this reality, a combination of Boyle's and Charles's Laws may be applied, and the following expression can be used:

$$\frac{P_S V_S}{T_S} = \frac{P_M V_M}{T_M} \qquad \text{Eq. 6}$$

where the subscript S connotes standard conditions and subscript M, metered.

Both laws can be applied individually or in combination throughout this chapter.

One method sometimes found useful in correcting for deviations from the ideal gas law is to insert a correction factor as a multiplier. Rather than PV = constant, one may write PV = ZT, where Z is the

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compressibility factor used in the orifice equation adopted by the Natural Gasoline Association of America in 1942. Variations of Z appear in A.G.A. Report No. 3, *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids*, Catalog No. XQ0285.

Using the compressibility factor would modify Equation 6 to read:

$$\frac{P_S V_S}{Z_S T_S} = \frac{P_M V_M}{Z_M T_M} \qquad \text{Eq. 7}$$

CORRECTION FACTORS APPLICABLE TO LOW-PRESSURE MEASUREMENT

The component of UFG in low-pressure measurement caused by an error in determining the volume of gas delivered to the customer at a pressure, temperature, and heating value other than standard base conditions can be calculated theoretically. The correction format is:

Actual volume = Billed volume × correction factor

UFG Impact = Billed volume − actual volume

A positive UFG impact means that applying the correction will increase UFG because less gas was sold than was actually metered. A negative impact means that this correction will reduce the UFG. The examples below show the appropriate contribution that correcting each factor makes to the UFG.

The absolute temperature in the Fahrenheit system is obtained by adding 459.6°, in practice rounded off to 460°, to the temperature as measured in degrees Fahrenheit. The value thus obtained is referred to as degrees Rankine or degrees Fahrenheit absolute.

EXAMPLE 1. METERING TEMPERATURE CORRECTION FACTOR

To calculate the flowing gas displacement meter temperature correction factor, C_T, given a standard base temperature, T_B, of 60°F (15°C), the following equation is used

$$C_T = \frac{T_B}{T_f} \qquad \text{Eq. 8}$$

where

T_B = Base temperature (520°R)

T_f = Actual temperature of the flowing gas (°R)

If the flowing gas temperature is given as 32°F (0°C), the correc-

tion factor for temperature va

$$C_T = \frac{T_B}{T_f} = \frac{520°R}{492°R} = 1.057$$

The impact on UFG wou

$(1.000 - 1.057) \times 100 = -5$

At a flowing temperature

be:

$$C_T = \frac{T_B}{T_f} = \frac{520°R}{540°R} = 0.963$$

In this case, the impact

$(1.000 - 0.963) \times 100 = 3.7$

EXAMPLE 2. METERIN CORRECT

To calculate the flowing

standard base pressure, P_B,

equation is used:

$$C_P = \frac{P_{atm} + P_{gauge}}{P_B}$$

where

P_{atm} = Actual atmospheri

P_{gauge} = Pressure at mete

P_B = Base pressure = 14.7

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As an example, the press

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°F (0°C), the correc-

tion factor for temperature variation for a displacement meter would be:

$$C_T = \frac{T_B}{T_f} = \frac{520°R}{492°R} = 1.057$$

The impact on UFG would be equal to:

$(1.000 - 1.057) \times 100 = -5.7\%$

At a flowing temperature of 80°F (27°C), the correction factor would be:

$$C_T = \frac{T_B}{T_f} = \frac{520°R}{540°R} = 0.963$$

In this case, the impact on UFG would be:

$(1.000 - 0.963) \times 100 = 3.7\%$

EXAMPLE 2. METERING PRESSURE CORRECTION FACTOR

To calculate the flowing gas pressure correction factor, C_p, for a standard base pressure, P_B, of 14.73 lbf/in² (102 kPa) abs, the following equation is used:

$$C_P = \frac{P_{atm} + P_{gauge}}{P_B} \qquad \text{Eq. 9}$$

where
P_{atm} = Actual atmospheric pressure, lbf/in² (kPa) abs
P_{gauge} = Pressure at metering gauge, lbf/in² (kPa) abs
P_B = Base pressure = 14.73 lbf/in² (101.559 8 kPa) abs

Actual atmospheric pressure is the atmospheric pressure, corrected for the effect of elevation, multiplied by the ratio of actual barometric pressure to a standard base barometric pressure. The standard base barometric pressure is usually assumed to be 30 in. (762 mm) of mercury.

As an example, the pressure correction factor for the following set of conditions would be calculated as:

Given: System pressure = 6 in. (152.4 mm) W.C.
Elevation = 1 000 ft (304.8 m)
Atmospheric pressure at 1 000 ft = 14.21 lbf/in² (98 kPa) abs

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Barometric pressure = 29 in. (736.6 mm) Hg
Base pressure (P_b) = 14.73 lbf/in² (102 kPa) abs
Base barometric pressure = 30 in. (762 mm) Hg
Conversion factor: 1 in. (25.4 mm) W.C. = 0.036 09 lbf/in² (0.249 kPa) abs

$$P_{atm} = 14.21 \text{ lbf/in}^2 \times \left(\frac{29 \text{ in. Hg}}{30 \text{ in. Hg}}\right)$$

$$= 13.73 \text{ lbf/in}^2 \text{ (95 kPa) abs}$$

$$P_{gauge} = 6 \text{ in. W.C.} \times \left(\frac{0.0360\ 9 \text{ lbf/in}^2}{\text{in. W.C.}}\right)$$

$$= 0.22 \text{ lbf/in}^2 \text{ (1.52 kPa)}$$

$$C_P = \frac{P_{atm} + P_{gauge}}{P_B}$$

$$= \frac{13.73 + 0.22}{14.73}$$

$$= 0.947$$

The impact of UFG would be:

$$(1\ 000 - 0.947) \times 100 = +5.3\%$$

EXAMPLE 3. HEATING VALUE CORRECTION FACTOR: C_{hv}

The heating value correcting factor can be stated as follows:

$$C_{hv} = \frac{HV_{pg}}{HV_{std}} \qquad \text{Eq. 10}$$

where:
HV_{pg} = Heating value of purchased gas
HV_{std} = Standard heating value

Most gas purchased by a distribution company is measured as a quantity of energy, but most gas sales in the U.S. are measured by volume (cubic feet). The standard heating value used for billing purposes varies according to regulatory jurisdiction. The variation in heating value of the gas purchased and the standard heating value for billing purposes can affect UFG.

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Example: Given a sta
MJ/m³) and, for billing pu
1 050 Btu/scf, then:

$$C_{hv} = \frac{1\ 050 \text{ Btu/ft}^3}{1\ 020 \text{ Btu/ft}^3} =$$

UFG Impact = (1.000 -

For a heating value of

$$C_{hv} = \frac{950 \text{ Btu/ft}^3}{1\ 020 \text{ Btu/ft}^3} =$$

UFG Impact = (1.00 -

EXAMPLE 4. WATER CORRE

This correction factor is a
and is then humidified ai
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a saturated basis and is s
a dry basis.

The water content co
the following equations:

Conversion from dr

$$C_{W1} = \frac{P_B}{P_B - (P_v \times RH)}$$

Conversion from we

$$C_{W2} = \frac{P_B - (P_v \times RH)}{P_B}$$

where:
P_B = Pressure base =
P_v = Vapor pressure
14.73 lbf/in² ab
RH = Relative humid

As an example, if gas

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kPa) abs
2 mm) Hg
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Eq. 10

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Example: Given a standard heating value of 1 020 Btu/scf (37.98 MJ/m³) and, for billing purposes, a heating value for purchased gas of 1 050 Btu/scf, then:

$$C_{hv} = \frac{1\,050 \text{ Btu/ft}^3}{1\,020 \text{ Btu/ft}^3} = 1.029$$

UFG Impact = (1.000 − 1.029) (100) = −2.9%

For a heating value of purchased gas equivalent to 950 Btu/ft³, then:

$$C_{hv} = \frac{950 \text{ Btu/ft}^3}{1\,020 \text{ Btu/ft}^3} = 0.93$$

UFG Impact = (1.00 − 0.93)(100) = +7%

EXAMPLE 4. WATER VAPOR CONTENT CORRECTION FACTOR: C_w

This correction factor is applied when gas is purchased on a dry basis and is then humidified after purchase to provide saturated gas. Conversely, the correction factor is also applied when gas is purchased on a saturated basis and is subsequently dehumidified to be delivered on a dry basis.

The water content correction factor, C_W, can be calculated using the following equations:

Conversion from dry to wet:

$$C_{W1} = \frac{P_B}{P_B - (P_v \times RH)} \qquad \text{Eq. 11a.}$$

Conversion from wet to dry:

$$C_{W2} = \frac{P_B - (P_v \times RH)}{P_B} \qquad \text{Eq. 11b.}$$

where:

P_B = Pressure base = 14.73 lbf/in² (102 kPa) abs
P_v = Vapor pressure of water at standard conditions = 60°F and 14.73 lbf/in² abs (15.5°C and 102 kPa) abs
RH = Relative humidity, expressed as a decimal fraction

As an example, if gas is purchased under dry conditions, and is then

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delivered saturated (RH = 100%) to end users, the end user meter readings, to be consistent with purchased volumes, should be converted from wet to dry as follows:

$$C_W = \frac{P_B - (P_v \times RH)}{P_B}$$

$$= \frac{14.73 - (0.256\,8 \times 1.00)}{14.73}$$

$$= \frac{14.4\,737}{14.73}$$

$$= 0.9\,826$$

$$\text{UFG impact} = (1.00 - 0.982\,6) \times 100 = +1.7\%$$

EXAMPLE 5. SUPERCOMPRESSIBILITY CORRECTION FACTOR: C_p,

Boyle's Law states that, when the temperature remains constant, the specific weight of a gas is directly proportional to the absolute pressure. The actual specific weight of natural gas under pressure higher than atmospheric is usually greater than the theoretical. The supercompressibility factor is applied to calculation of volumes measured at pressures of 1 lbf/in² gauge or greater. Supercompressibility is a function of pressure, temperature, and specific gravity. If it is included in the pressure multiplier factor used to correct the index reading for measurement of gas at high pressure, it does not contribute to UFG.

EXAMPLE 6. METER ACCURACY CORRECTION FACTOR

The accuracy of registration for a displacement meter in a low-pressure system can be affected by:

- Calibration of the meter prover equipment,
- Adjustment of the meter to register fast or slow, and
- Durability of the meter mechanism to maintain proof during the period between meter changes.

However – because of the large market area for major gas distribution companies and the differences in accuracy, tolerance, and length of time allowed between meter tests required by regulatory agencies – it is impractical to consider the UFG volume associated with meter accuracy in a low-pressure system. It is also impractical to consider the potential UFG from inaccurate registration of the volume of gas used for pilot lights on customers' appliances.

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MEASUREMENT ERRO

Minimum UFG will occ
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COMPANY-USE GAS

Company-use gas is th
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spring.

106

MEASUREMENT ERROR IN STORAGE OPERATIONS

Minimum UFG will occur from gas storage when all gas injected and withdrawn is measured in accordance with the same base conditions. Cushion (or base) gas must be considered, and injected/withdrawn volumes calculated with the same volume of cushion gas remaining in the storage pool. Gas withdrawn from storage must be cleaned and dehydrated before measurement to remove water, natural gas fluids, dirt, and paraffin.

Increasing flow from a storage field from near zero to a relatively high rate in a short period of time can cause orifice plates to buckle and turbine meters to overspeed. Because the quantity of gas supplied from storage can represent as much as 50 percent of peak period deliveries, the effect on UFG of the storage practices mentioned above can be substantial.

COMPANY-USE GAS

Company-use gas is that used for company operations, and can be segregated into two general applications:

- Commercial use and
- Operations use.

Commercial use includes gas used at company offices, service centers, warehouses, and other buildings for space conditioning, water heating, etc. Gas used as fuel for equipment such as line heaters, electric power generators, dehydration plants, compressor stations, supplemental supply, and peak shaving plants is normally measured.

Unmeasured company-use gas includes gas used for routine operations: calorimeters and analyzers, instrumentation for measurement and control, and normal operations and maintenance procedures where small quantities are vented.

Residential Meter Change

Each time a residential meter is changed, approximately 2 ft^3 (0.05 m^3) per meter changed will be vented and lost. Changes in line pack, where the amount of gas in a pipeline section or main is increased or decreased by changing the pressure to meet customer demand, can contribute to UFG. This quantity usually can be calculated. If calculations are not made, UFG will increase when system pressure is increased as winter approaches and decrease when the pressure is reduced in the spring.

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Line Purge Blow-Down

The largest component of unmeasured company-use gas is that which is vented to the atmosphere when line purge or blow-down is required for operations testing or construction tie-in. The laws of corresponding states can be used to calculate the volume of gas vented to the atmopshere.

$$\frac{P_1 V_1}{Z_1 R T_1} = \frac{P_2 V_2}{Z_2 R T_2} \qquad \text{Eq. 12}$$

where

P_1 = Initial pipeline pressure, lbf/in² (kPa) abs
V_1 = Volume of gas @ P_1 and T_1, scf (m³ std)
T_1 = Initial gas temperature, °R
P_2 = Pressure at atmospheric conditions, 14.7 lbf/ft² (102 kPa) abs
V_2 = Volume of gas at standard conditions, scf (m³ std)
T_2 = Standard temperature, 520°R
Z_1 = Gas compressibility factor at P_1 and T_1
Z_2 = Gas compressibility factor at standard conditions = 1.00
R = Gas constant

The physical dimensions of the pipeline must also be known in order to determine the volume occupied by the gas under the initial flowing conditions.

$$V_1 = \frac{\pi D^2}{4\,(12)^2} L \qquad \text{Eq. 13}$$

$$= 0.005\,454\,1\, D^2 L$$

where

D = Pipe inside diameter, in. (mm)
L = Pipe length, ft (m)
Substituting into the ideal gas relationship,

$$V_2 = \left(\frac{P_1}{14.73}\right)\left(\frac{520°}{T_1}\right)\left(\frac{1.00}{Z_1}\right)\left(\frac{\pi D^2 L}{4\,(12)^2}\right) \qquad \text{Eq. 14}$$

$$= 0.192\,5\,\frac{P_1}{Z_1 T_1}(D^2 L)$$

As an example, the gas vented to the atmosphere when a line is purged is calculated as follows:

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Given:
Initial pressure = 100 1
Initial temperature = 8
Compressibility factor
Pipe inside diameter =
Pipe length = 75 ft (2

The volume occupied
calculated as:

$V_1 = 0.005\,454\,1\,(8^2)$ (
= 26.18 scf (0.741 r

At standard conditions
as:

$V_2 = 0.192\,5\,\frac{100 \text{ lbf/}}{0.987 \times}$

= 173.36 scf (4.8 m

USES FOR GAS

- Fuel for operating
  - Compressor sta
  - Line heaters a
  - Feedstock in S
  - Electric power
  - Miniature expa electrical, mec
  - Thermopiles fo
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  - Steam generat
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Eq. 13

Eq. 14

here when a line is

Given:

Initial pressure = 100 lbf/in² (689 kPa) abs
Initial temperature = 80°F (27°C)
Compressibility factor = 0.987
Pipe inside diameter = 8 in. (20.32 mm)
Pipe length = 75 ft (23 m)

The volume occupied by the gas under flowing conditions is calculated as:

$$V_1 = 0.005\,454\,1\,(8^2)\,(75)$$
$$= 26.18 \text{ scf } (0.741 \text{ m}^3 \text{ std}) \text{ @ } T_1 \text{ and } P_1$$

At standard conditions, the volume occupied by the gas is calculated as:

$$V_2 = 0.192\,5\,\frac{100 \text{ lbf/in}^2 \text{ abs}}{0.987 \times 540°\text{R}}\,(8^2 \times 75)$$

$$= 173.36 \text{ scf } (4.8 \text{ m}^3 \text{ std})$$

USES FOR GAS IN COMPANY OPERATIONS

- Fuel for operating equipment
  - Compressor stations
  - Line heaters and vaporizers
  - Feedstock in SNG plant
  - Electric power generators
  - Miniature expansion turbine for power (instrument, electrical, mechanical)
  - Thermopiles for instrumentation and telemetry
  - Flarestack pilot
  - Dehydration systems
  - Steam generators for various operating processes
- Samples for gas quality (calorimeter, gravitometer, and chromatograph)
- Gas vented in company operational uses in:
  - Control of measurement and regulation equipment
  - Changing meters
  - Operating and testing relief valves
  - Operating valve operators
  - Gas conditioning equipment blow-down for routine maintenance

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- Emergency shutdowns (compressor stations, pipelines)
- Pipeline and main stopping and tapping
- Tie-in and removal from service (pipelines, mains, service lines)
- Pipe joining operations (controlled fire technique)
- Running pigs through pipelines to remove dirt and liquids
- Drip operations, removal of scrapers and pigs

• Line pack in high pressure pipelines
• Training (fire schools for company employees and fire departments)
• Non gas system uses
  - Fuel for power generation for resale
  - Fuel for steam generation in steam distribution system
  - Feedstock for production of petrochemicals

UNCONTROLLED LOSSES

Volumes of gas lost because of conditions other than errors in measurement or accounting are considered to be uncontrolled losses.

Loss Caused by Leakage in Piping Systems

Before the widespread use of pipe coating and cathodic protection to protect underground transmission and distribution facilities, one of the major sources of UFG was leakage caused by corrosion. The implementation of comprehensive corrosion control programs (see *Corrosion Control/System Protection*, GEOP Book TS-2, Catalog No. XY0186) in the industry over many years, plus the mandatory requirement for conformance to Part 192, Title 49 CFR, Minimum Federal Safety Standards for Gas Lines (Appendix A), have continued to reduce this source.

Leakage Repair Programs

Large volumes of unmeasured gas can pass through at bypass installations at city gate measuring stations, compressor stations, and points of exchange, or emergency connection as a result of leakage through pipeline valves. Implementing valve inspection and maintenance programs should minimize such instances of UFG.

Leakage as a major cause of UFG is suspect when there is an abrupt change in the long-term UFG trend. Verification of leakage as the root cause can only be accomplished by a detailed leak survey, or by installation of check measurement at various points to isolate a portion of the

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system. It is important to identify every point of input and output in the isolated section.

Loss Caused by Damage to Piping Systems

A major line break resulting from a facility failure or damage by outside forces can cause substantial uncontrolled gas loss. Excavating equipment is one major cause of a line break. Gas loss from a line break is very difficult to determine, particularly if the break occurs in a segment of an interconnecting pipeline network. Equations are available to assist in obtaining a close approximation of gas lost. Calculation of the approximate amount of gas lost should be a part of an official report each time a line break occurs.

Loss Caused by Diversion or Theft of Gas

In recent years, the component of UFG associated with diversion or theft of gas by a customer has become significant enough that it must be counteracted. The theft can be accomplished by removal of the meter for part of the period between meter reading dates, hidden damage to the meter or index mechanism, or connections to the service line pipe upstream of the meter. The volume of UFG attributable to this problem can be estimated only after a case has been confirmed.

Theft can be minimized by continually reviewing individual customer's gas consumption. This can be done by comparing the current registered volume to consumption for a similar previous period or by estimating the volume that should be consumed by the connected appliances. Routine surveillance is necessary by the meter reader to detect temporary or noncode piping or suspicious evidence of ditching in the vicinity of the meter.

ACCOUNTING PRACTICES

Accounting practices used to track gas volumes purchased and delivered to the customer contribute to the total quantity of UFG.

ACCURATE DEFINITION OF ALL QUANTITIES PURCHASED AND DELIVERED

The accuracy of the calculations used to determine UFG is dependent on how well the "measured area" is defined. A measured area defines a piping system wherein the location of each point of gas supply

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and each point of gas delivery has been verified. For a simple distribution system, the measured area encompasses all meters downstream of the city gate measuring station. In a large, complex distribution system, there can be many separate measured areas, requiring detailed facility and customer record keeping to maintain an acceptable level of accuracy. Experience proves that it is not necessary to maintain detailed UFG records for each measured area in a large system, unless a change in the long-term UFG trend justifies a more thorough investigation.

RESTATEMENTS AND ADJUSTMENTS TO GAS ACCOUNTING REPORTS

Monthly accounting of gas purchased and delivered can include volumes that are estimated because of meter malfunctions, meter reading errors, or use of estimated volumes purchased or delivered to customers. In transmission companies, accounting errors can cause imbalances in gas exchanged or transported in a certain month. These estimates or imbalances are normally corrected in subsequent months when gas measurement charts are processed and actual volumes determined. The accuracy of the UFG volume is a function of how accurately such restatements and adjustments are identified and recorded. The implementation of electronic flow measurement (EFM) technology has significantly improved the accuracy and timeliness of gas measurement data.

BILLING-CYCLE EFFECT

In both transmission and distribution systems, both gas purchased and gas delivered may not be accounted for on the basis of a common month-end closing date. The resulting accounting lag, a contributor to UFG, is called the billing-cycle effect. The billing dates for gas available—local producer purchases, pipeline supply company purchase, and storage or peak shaving supply—can occur at different times during the calendar month. The billing dates for gas deliveries to large-volume, high-pressure customers can occur at several different times in the calendar month. The billing date for distribution system customers is a function of meter-reading scheduling and is scheduled over all of the working days in each month. The billing-cycle effect is complicated further when bi-monthly meter-reading and billing are practiced.

It is a relatively simple task to convert high-pressure gas deliveries to a common calendar period if the proper meter charts are used. However, it is virtually impossible to calendarize the gas quantity

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measured at low pressure by displacement meters based on monthly or bi-monthly meter readings. Because gas consumed by these customers usually amounts to a sizable portion of the total gas consumed in a distribution system, the only UFG calculation that can be made with acceptable accuracy is one done annually. UFG for the 12-month period ending August is generally accepted as being the most accurate figure, because the error caused by the difference between recorded volumes purchased and sold is smallest at the end of the summer period.

METHODS OF DEFINING AND MINIMIZING UFG

Assuming that accounting, measurement, and system maintenance programs are adequate, it becomes very important that changes to the gas balance be reported accurately and the UFG records and trends be properly interpreted.

It can be beneficial to present data required to show accounting differences between recorded volumes purchased and sold for the end of the summer period since the billing lag factor will be least then.

PROMPT, ACCURATE REPORTING

A portion of UFG can result from an error in the "Gas Balance Equation." Therefore, it is vitally important to report to the gas measurement department any change occurring in the system that will affect the gas balance, or any situation that has been found and corrected that might have affected the gas balance in the past. The amount of detail that should be reported depends on the magnitude of potential impact.

RECORDS AND REVIEW OF TRENDS

UFG records should be of sufficient detail to maintain a cumulative 12-month ending record and should be updated each month. Pertinent data can be extracted from monthly accounting statements. This information should include volume of gas available and volume of UFG. Calculations will be required to determine 12-month ending volumes and the percentage rate of UFG.

It can be beneficial to present data from the accounting statements as well as calculation results in graph form. Analysis of the UFG trend over 12 or more months can be accomplished easily. A trend of increasing UFG could support an investigation to identify the reason and location. A trend of decreasing UFG could indicate the effect of corrective action or a measurement problem.

113

Collections

- System generated report lists all accounts that have received a termination notice. (Collector's turnoff list)

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Field Collections (former method)

- Reviews report for accounts to contact
- Contacts customer to collect or turns off gas
  - If customer pays, gets receipt
  - If not, turns off and notes reading and time
- Money is turned in to office.

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Field Collections (current method)

- Send customer to the nearest Pay Center
- Technician does not handle money

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Payment Arrangements

- One time payment arrangement
  - In person
  - If not received on agreed date, set up for collection
  - Extensions granted in some circumstances

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Deferred Payment Arrangements

- Used for 2 or more payments
  - In person
  - If not received on agreed date, set up for collection
  - Extensions granted in some circumstances

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SECTION 13.2
METER RECORDS

Introduction

In an era in which utilities are regulated to an increasing degree by local, state or federal commissions, it is virtually impossible for a gas company to operate without detailed records of all phases of its business. Reports on investment, finance, tax, budget, operating functions, personnel, safety, and gas quantity/quality are parts of these requirements. Meters represent a significant portion of invested capital; they are the immediate, daily contact with customers; and they are the monitor of all gas sales.

These factors make it mandatory that some type of meter records be kept and that some degree of analysis be made to indicate various facets of meter performance and status. To be sure, requirements will vary widely, and each gas company must determine which meter records and what degree of analysis of these records best fit its needs.

Measurement of gas at elevated pressures, whether it be by diaphragm, rotary, turbine or orifice meter, requires additional instrumentation as a part of the meter to determine corrected volume. A contract will stipulate the conditions of measurement and all instrumentation and equipment necessary to comply with the contract becomes a part of the basic measuring device. Individual records, as they relate to a specific measuring location, must indicate all pertinent data and equipment and be a historic source of maintenance or change as it would relate to the ultimate calculation of corrected gas volumes.

The attached *Appendix A* lists in outline form many of the items that can be included in a set of meter records. *Appendix B* contains an assortment of typical forms and computer print-outs used by various gas companies in their meter record systems. *Appendix C* contains samples of forms used for high pressure meter records. No one company uses all of them—most use only a selected portion. Below is a short discussion of some of these items and an explanation of why and how they are utilized.

Type of Record

The Meter History Card is a paper card on which is maintained manually a limited amount of information such as make, size, serial number, dates of tests/repairs, and location addresses. Although limited in scope, such cards serve rather well in producing information on any one (or a few) meters. However, analyzing a large number of these cards is cumbersome because all data must be read, recorded, and manipulated by hand.

In high pressure measurement, there are many instances in which metering specifications are related to minimum and maximum demand. To accurately meter the variable in demand, different types of metering could be used separately or in conjunction with each other through control equipment to meet these requirements. A record of all equipment involved in this type of a situation might better be controlled by a metering station file which would include an individual history of all transactions pertaining to that particular delivery point.

Computerized meter data is stored in punch cards, on magnetic tape, or on magnetic discs. The system can be made as limited or as extensive as required. The important point is that all information is in a form that is immediately legible to the computer, and relatively simple programming will direct the computer to analyze the data in an almost endless variety of ways.

Computerized meter records are more effective if they are made compatible with the data processing system used throughout the company for accounting, billing, inventory, and other such functions.

Retained Data

Make, size, and type of meter are basic identification designations and should be considered permanent data. Date purchased, serial/company number, dial calibration, pressure rating, whether or not temperature compensated, and purchase cost are not likely to change and should be considered permanent, also.

Variable data would include dates of proof tests, repairs, and dial readings associated with various transactions involving the meter. Other useful information is why the test/repair was made, disposition of the meter, where the work was done, and total amount of gas passed during the life of the meter. The list, of course, can include any item that will be of value.

Meter dials should be given special consideration. Until fairly recently, dials indicated nothing more than cubic feet (or some multiple thereof) and perhaps pounds per square inch pressure. Increasingly the gas industry is making transactions in BTU, therms, and pounds. With the apparent inevitability of the United States converting to the metric system, units such as cubic meters, joules, and pascals will appear. A meter records system must be sufficiently flexible to accommodate these units, to handle them properly, and to function on both English and metric units during the transition period.

Updating Records

Any meter records system must be updated periodically in order to keep it current. This new data can originate as a field prepared document, a meter shop report, or computer generated change lists from some source such as customer billing records. Whatever the case, the update information must be simple in form and immediately compatible with the meter records system. It is a waste of time and money to have source documents in *words* that must be converted by hand to *numeric* codes, or to have source data in a random order that does not fit the format sequence of the meter records. A little planning can eliminate much of this problem.

The frequency with which meter records are updated can range from daily to once or twice a year. The only rule for this is that which is dictated by individual requirements.

Records Analysis

Analyzing meter records is the process of extracting specific items of information from the total mass of data and accumulating it in a logical form to show some specific result. A well arranged set of meter records would 1) have a complete set of records in one location, and 2) be constructed for simple, easy access to the data. Routine reports should be produced regularly from these records.

The reports produced from meter records vary from company to company. One of the basics that seems common to all is the "time vs. accuracy" report. Essentially, the report is a comparison of how meter accuracy varied over certain time spans. The analysis can be refined to indicate a specific make/model/size of meter or the particular location in which it was used. Other reports could show the status of a systematic maintenance program, or produce data for state and/or federal commission reports.

The costs of a meter maintenance program cannot be derived from records that contain only physical data on meters. Money spent on meters generally is recorded in operating expense accounts that are not immediately related to the physical data on meters in the meter records. This is a compelling reason for compatibility between a meter records system and the records system used by other departments within the company. If this compatibility exists, cost data can be relatively simple to compute.

Storage of Records

A system of meter records must be arranged with some type of storage and retention schedule. Whether the records are active or inactive, they should be in a location that is clean, dry, fireproof, and as easily accessible as usage requires. It is common practice to microfilm paper records after a fixed period of time—e.g., perhaps five years—then destroy the paper records and keep the microfilm for an indefinite period. The microfilm takes very little space, is easily stored in fireproof vaults, and data can be retrieved fairly simply. Magnetic computer tapes can be preserved in a fireproof vault by standard procedures. Such tapes will hold a great deal of data, occupy very little space, and can be processed on a computer at any time.

On occasions there may be controversy over the fact that meter records tend to be accumulations of large numbers of highly detailed items that are maintained for many years longer than any other company record. It must be recognized however, that the useful life of a gas meter quite often exceeds thirty or forty years, that a meter is in service several years between updating entries, and that an old record is likely to be as valuable as a new record in computing trends in meter performance, maintenance, and service quality. Again, individual needs will determine retention schedules.

Meter records are an essential part of a gas company's administrative function, and a well planned system of storing, maintaining, and analyzing this information can be a big asset in having an effective business operation.

APPENDIX A
METER RECORDS

I. Type Record, each meter (or instrument)

a—Meter history card

b—Computer stored data

1—separate system
2—combined with customer billing system
3—separate system that works in conjunction with customer billing system

c—Other—as may be required by law.

II. Retained Data

a—Permanent

1—make
2—size (incl. cfh rating)
3—type unit (diaph., rotary, turbine, orifice, etc.)
4—when purchased
5—mfg. serial number
6—company number
7—number dials (or reading and calculation code)
8—pressure rating
9—temperature compensated
10—purchase cost
11—other as needed

b—Variable

1—dates
2—proof test as found
3—proof test as left
4—type, kind of repairs
5—dial readings
6—why test made (customer request, routine, damaged, etc.)
7—disposition of meter (retired, junked, returned to service)
8—location of meter
9—where test made (meter shop, field repair, outside contractor)
10—type diaphragm and when installed
11—type load
12—mileage
13—other as needed

III. Updating

a—Source documents

1—field prepared
2—meter shop prepared
3—computer generated
4—commercial office prepared

b—Compatibility—input must transfer quickly and easily into record system.

c—Frequency of preparation

IV. Records Analysis

a.—Data retreval

1—simple, easy access to data
2—any specific item accumulated quickly
3—complete set of records in one location
4—reports produced regularly

b—Typical Reports (partial list only)

1—time vs. accuracy
2—status of test program (those tested vs. those to be tested)
3—type repairs made

c—State/Federal Commission Reports

d—Other detailed information as required to support maintenance and test program

e—Relate to cost of test and repairs, as available through accounting system

V. Storage of Records

a—Time of retention
b—Method

1—files for paper cards (conventional)
2—files for computer punch cards
3—computer tape
4—microfilm

Administrative Rules

Purpose

The purpose of this section of the terms of use is to standardize the process by which gas companies and customers interact .

Definitions

Customer means any person firm partnership corporation tenant governmental unit or municipality who has contracted for service.

Meter A device installed and owned by the utility company to measure natural gas use of billing

Bill an amount of money due to the utility for natural gas use

Due Date means the date that payment must be received by the company, which should be no more than 10 days after the bill is delivered to the customer.

Past Due Any amount that has been billed that remains unpaid at the time the next bill is delivered.

Termination is a function by which a customers account is closed permanently

Disconnection The physical severing of the meter from the gas supply

Late Charles Penalties charged by the company if payment is not made within 7 days after the bill is delivered

Initiation of Service

All applicants for gas service are required to sign a contract
The customer is required to make an upfront payment of $30.00.

When the customer has completed all of the requirements the utility will connect the customers service without undue delay

Deposits

The utility shall keep detailed records of all upfront payments by customer account.

Meter Reading

The gas company will read the meters at regular intervals not to exceed 30 days.

The meter reading will be used to bill the customer

The customer must provide access to the meter to obtain the reading.

Specific rules regarding metering devices are found in section on Meters

Rates

The rates charges for gas service will be in accordance with the terms of use and agreed upon by the gas company and the Energy Commission of the Republic of Armenia.

Billing

Bills will be delivered at regular intervals not to exceed 30 days.

The bills will indicate the:

- the date of the bill
- the amount past due if any
- late payment % and amount
- all payments made since the last bill
- current meter reading
- the amount due for this bill period
- the total due to the company
- the due date of payment

The will be separate bills produced for each meter number

The bills will be hand delivered to the customers home and handed to the customer or slipped under the door.

The gas company will keep accurate records for each meter number and each customer who has that meter number.

The records will show:

- the customer name
- customer address
- meter number
- Upfront payment
- all bills for that customer
- all payments made by that customer
- all late charges and penalties

The company has the right to bill for gas used should the metering device fail. The company will bill for gas used based on the history of gas used previously.

The customer has the right to request all of the billing records for his account and the company must supply those records in 5 days of the request.

Billing Errors

If the meter fails on a new account without history then the company will bill using an estimate bases on the rated Capacities of the appliances in use.

If the meter fails on an account with history then the prior gas usage will be used to estimate the bill

If the customer believes there is a billing error the company must investigate the complaint and correct any error found within two days.

If the consumer believes that the meter reading device is in Error, the company has 5 days to check the meter reading. The consumer may be present when the meter is read again.

If the meter reading is correct then the customer has the right to request that the meter be tested once per year at no charge.

The customer may pay the company all of the costs associated with testing the meter more than once per year.

If the meter test indicates that the meter has been fast and the consumer paying for more gas than he used then the company is obligated to return six months overcollection to the customer.

Late Charges

A penalty of 0.5% of the amount past due will be charged each day after the 7 day due date that a consumer is late with the payment

Termination of Service

The utility may terminate service to a residential customer:

who has not paid for gas service in a reasonable time

a customer who has not provided access to read the meter

a customer who has illegally connected to the gas system
A customer who moves or decided not to use gas

When there is an unsafe technical condition .

Reconnection

To obtain service again the customer must pay all charges outstanding and make another upfront payment.

When the charges are paid the company will reconnect the service within 8 hours after the customer shows proof of payment

If the customer believes that the disconnection has been unfair he/she has the right to contact the Energy Commission for a review.

If the Energy Commission finds that the disconnection was not fair or illegal they will require the company to reconnect the service immediately and without charge.

The customer can continue his gas service for a term not exceeding 45 days after delivery of the bill, by providing a guarantee for payment. If payment is not made at the end of the guarantee then service will be cut off and no further extension will be accepted.

The company may discontinue service to the customer and deny any future service if the customer bypasses the billing meter. The customer will be billed for any gas estimated to have been used based on the maximum rated capacity of the equipment, and they will be prosecuted to the fullest extend of the laws of the Republic of Armenia.

Metering Accuracy and testing

All gas sold in the Republic of Armenia will be billed for on a metered basis.

The unit of measure will be meters cubed

The company will provide each customer with a company owned meter

Customers must provide at no charge a place to install the meter

The company has the right to enter the premises of the customer at all reasonable hours to read the meter, install or remove a meter, or terminate service to the customer.

Each gas company shall provide and install at it's own expense and shall continue to own maintain and operate all equipment necessary for the regulation and measurement of gas to its customers.

Customers are responsible for damage to a meter and will reimburse the company for any and all repairs to the meter.

All new meters shall be inspected for correctness before being installed on a customers premise.

All meters removed from one premise to be installed at another premise shall be tested for correctness before installation

The standard deviation of a gas meter shall be within two (2) per cent

Customers may request a meter test for accuracy once a year at the company's expense to resolve a billing dispute. Testing more than once a year is considered excessive.

The company will keep accurate records of the meter tests and the results of the tests and submit the results to the Energy Commission every 6 months.

If the Commission believes after looking at the test reports that the number of meters that test fast is excessive they may open an investigation to determine why the company's customers are being overcharged and take appropriate action to correct the problem.

Each gas company will keep numerically arranged records for each meter owned. The records shall include the identification number, the date of purchase, name of manufacturer, serial number, type, rating, name and address where the meter is set.

Contracts

Gas is supplied to consumers in accordance with agreements concluded between suppliers, transporters, distributors and consumers in accordance with contracts approved by the Energy commission of the Republic of Armenia.

Residential Consumer will sign a contract with the distribution company to become a customer. The format of the contract will be approved by the Energy Commission

Interruptible Contracts Gas distribution companies may sell gas to present or future customers on an interruptible basis under special contracts approved by the Energy Commission. Deliveries to such interruptible customers will be interrupted or curtailed by the company at any time or period of time in order to safeguard supply to firm gas customers. Contracts with such customers provide, in effect, that the quantities of gas available for sale to the customer shall be determined by the company .

Customer Installations

The customer will provide a satisfactory place for the installation of the company owned billing meter. The meter will be accessible to the company to read the meter, terminate service or remove the meter.

All customers' piping and equipment beyond the company's meter shall be installed and maintained by the customer at the customers expense. The customer shall bring his piping to a point for connection to the company meter at a location satisfactory to the company.

The company or it's agent reserves the right to inspect and approve the customers installation of pipe and equipment but such inspection or failure to make inspection shall not make the company liable for any loss or damage which occurs. The company may refuse to provide gas service to any installation it considers unsafe.

Service Connections

The company reserves the right to designate the locations and specifications for all its piping, meters, fixtures, and fittings, and to determine the amount of space which must be left unobstructed for installation and maintenance.

Applicant may request an alteration of such designation but if the company agrees to such an alteration, the excess cost over and above the cost of the original company design will be paid by the customer.

Customers Use of Service

The company shall have the right to enter the property of the customer at all reasonable hours for the purpose of reading the meter, installing removing testing or replacing its property.

All property of the company installed in or upon the customer's premises uses and useful in supplying service is placed there under the customers protection. All reasonable care should be uses by the customer to prevent loss or damage to the gas company's property. The customer will be help responsible for any loss or damage and shall pay to the company the cost of necessary repairs.

The customer will be held responsible for breaking seals, tampering or interfering with the company meter or meters or other equipment of the company installed on the customers property. No one except the employees of the company will be allowed to make repairs or adjustments to the meter or equipment belonging to the company.

The customer shall not directly or indirectly sell sublet assign or otherwise dispose of to others gas purchased from the company without the consent of the company. Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the company's supply system and in case of violation of this rule the company may discontinue service or require the customer to modify his installation with approved controlling devices.

Service Continuity

The company will use reasonable diligence in furnishing an uncurtailed and uninterrupted supply of gas except where rate schedules provide otherwise. The company may interrupt its service for the purpose of making necessary alterations and repairs but only for such a time as is reasonable or unavoidable.

In the event that the supply of gas shall be interrupted as a result of a shortage the company must provide for approval by the energy commission a curtailment priority.

Limitations of Liability

Neither the company nor the customer shall be liable in damage to the other for an act omission or circumstance occasioned by any act of God, acts of public enemy , wars, blockades, insurrections riots epidemics landslides lightening earthquakes fires storms floods unusual weather conditions arrest and restraint of rulers and people civil disturbances explosions breakage or accident to machinery or lines of pipe line freeze ups temporary failure of gas supply the binding order of court or governmental authority which has been resisted in good faith by all reasonable legal means and any other cause except willful neglect.

Definitions

Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, cooking, water heating, and other residential uses.

Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local and State Government agencies for uses other than those involving manufacturing.

Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power.

Interruptible: Service from schedules or contracts under which the Seller is not expressly obligated to deliver specific volumes within a given period of time and which anticipates and permits interruption on short notice or service under schedules or contracts which expressly or impliedly require installation of an alternate fuel.

Safety

The gas company will adopt comprehensive instructions for the safety of employees in regard to the operation construction or maintenance of its plant and facilities

The control of fire safety and technical operation of gas facilities is performed by the Haylertekhhskoghutyum department of the Ministry of Emergency Situations of the Republic of Armenia.

The control of efficient and safe use of gas at gas facilities is performed by the Energapetjskoghutyun (Energy State Inspection) a department of the Ministry of Energy of the Republic of Armenia.

Construction and Maintenance

Proximity to buildings

Road and Railroad crossings

Proximity to underground structures

Protections

Electrical installations

Ventilation

Purging

Gas Service Pipes

Odorization

Leak Reporting : The gas company will have procedures filed and approved by the Ministry for consumers to report gas leaks

Periodic Leak Surveys each gas operator will provide for periodic leak testing of its system, and prioritize and repair those leaks in order of their severity.

System Maps Each distribution company hall have on file at its principal office suitable maps and or drawings showing the following:

Size character location of mains including valves

Size and location of each service connected to the system

layout of all principal metering and regulatory stations to show size location character of all major equipment pipelines connections valves and other equipment used

Quality of Gas Service

Heating Value Requirements

Purity Requirements

Pressure Requirements

BILLING POLICIES

Billing for utility service will occur at regular intervals. Each utility is required to keep an accurate account of all charges billed to each customer and all payments received from each customer.

A utility will not present a bill for payment without having read the meter first.

All bills will be based on an actual reading. The company may be subject to a penalty
if the meter reading is falsified and billed to the customer.

All bills will be calculated using the rates as established and approved by the Commission.

The bill will show the number of units, KW or CM, used , and the rate charged for those units, and show the calculation.

The company has the right to re bill a customer if an error has been made in the billing.
The customer will be responsible to pay charges that were not billed because of an error, and the company is responsible to repay the customer if they have collected too much as a result of an error.

All residential customers will pay the bill in a timely fashion.

They will provide the meter reader access to the meter so that a bill can be rendered.
The company can disconnect a meter for the customer's failure to provide access to the meter.

The utility company may charge a penalty (late fee) for any bill that has not been paid in a timely fashion.

COLLECTION AND DISCONNECTION POLICIES

The utility can disconnect the utility service for the following reasons: non payment of the bill, safety, refusal to allow access to the meter, tampering, or theft of service.

The utility, after having correctly presented the customer a bill, has the right to terminate service to any customer that has not paid the bill in a timely fashion.

A Utility employee will attempt to contact the customer to ask if payment has been made. If the employee sees a receipt, they will leave the service on, if the customer cannot provide a receipt, then the utility person will discontinue the service.

After the service has been turned off, the customer must then go to the payment agency or bank, and pay the whole bill. Then the customer must go to the utility company office and show the receipt to the designated person, who will then schedule the meter to be turned on again.

The utility will turn the meter back on as soon as possible but not to exceed 1.5 days.

They may charge you a fee to reconnect the meter.

If the customer has demonstrated that he will not pay his utility bill, the company has the right to demand a security deposit to protect the company and the other paying customers from commercial losses.

The deposit amount will not exceed the amount equal to 2 billing periods.
The utility will keep a log of all deposits that they have received. They will note the account number, customer name, address, amount of deposit and the date taken.

If a customer moves, or their meter is locked for nonpayment, and they do not turn the service back on, then the deposit will be applied to the bill to reduce the debt. If the customer wants service again, either at the same location, or a new one, then another deposit will be required.

The deposit will be returned when the customer moves, or demonstrates that they will continue to pay the utility bill on time.

METERING POLICIES

All Utilities shall meter their product with metering devices that register in cubic meters (?).

The gas meters are installed, owned and maintained by the utility at it's expense.

Gas Meters will be tested by the Haygasard in a company owned testing facility.

The devices shall be tested prior to installation at a residence or business, and shall comply with the accepted State standards for divination.

If a meter is found to be out of compliance with the standard, it will be repaired before installation at a home or business.

A customer has the right ,after the meter is installed, to question the accuracy of the metering device and request a meter test. However he may not question, and request a test, more than one time in 12 months, without being charged for the test.

If the meter is found to be in error beyond the standards (fast meter) the company will repay the customer for the over billing. If the company finds that the meter is slow the company ,May, but is not required to, charge the c customer for the over billing.

To ensure fairness, all meters that are tested ,that are not in compliance, where an adjustment to a customers bill will be made, must report to the commission,monthly, the meter number, the test results, the repairs made , and the amount of the adjustment.

The customer will provide within their premises, without charge, suitable space for the installation of the company's meter.

The customer will not re meter or sub meter for the purpose of re selling gas to another party.

The company has the right to access their meter at all times. A customer may not unreasonably refuse access. If the customer does not permit access, he may be disconnected without notice.

Tampering with, or destruction of, the utility company's metering devices, is not permitted. The penalty for tampering is loss of gas service without notice, and any other penalty defined by the statutes of The Republic of Armenia.

Subpart A—General

§ 192.1 Scope of part.

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to:

(1) Offshore pipelines upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(2) Onshore gathering of gas outside of the following areas:

(i) An area within the limits of any incorporated or unincorporated city, town, or village.

(ii) Any designated residential or commercial area such as a subdivision, business or shopping center, or community development.

(3) Onshore gathering of gas within inlets of the Gulf of Mexico except as provided in § 192.612.

(4) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(i) Fewer than 10 customers, if no portion of the system is located in a public place; or

(ii) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-67, 56 FR 63771, Dec. 5, 1991; Amdt. 192-78, 61 FR 28782, June 6, 1996]

§ 192.3 Definitions.

As used in this part:

Administrator means the Administrator of the Research and Special Programs Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.

Distribution line means a pipeline other than a gathering or transmission line.

Exposed pipeline means a pipeline where the top of the pipe is protruding above the seabed in water less than 15 feet deep, as measured from the mean low water.

Gas means natural gas, flammable gas, or gas which is toxic or corrosive.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet, as measured from the mean low water.

Hazard to navigation means, for the purpose of this part, a pipeline where the top of the pipe is less than 12 inches below the seabed in water less than 15 feet deep, as measured from the mean low water.

High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Listed specification means a specification listed in section I of appendix B of this part.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Municipality means a city, county, or any other political subdivision of a State.

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator means a person who engages in the transportation of gas.

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 1434 kPa (208 psig) at 38°C (100°F).

Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders.

Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Service line means a distribution line that transports gas from a common source of supply to (1) a customer meter or the connection to a customer's piping, whichever is farther downstream, or (2) the connection to a customer's piping if there is no customer meter. A customer meter is the meter that measures the transfer of gas from an operator to a consumer.

SMYS means specified minimum yield strength is:

(1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107(b).

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

Transmission line means a pipeline, other than a gathering line, that:

(a) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;

(b) Operates at a hoop stress of 20 percent or more of SMYS; or

(c) Transports gas within a storage field. A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

[Amdt. 192-13, 38 FR 9084, Apr. 10, 1973, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-67, 56 FR 63771, Dec. 5, 1991; Amdt. 192-72, 59 FR 17281, Apr. 12, 1994; Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.5 Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

(1) A "class location unit" is an onshore area that extends 220 yards on either side of the centerline of any continuous 1- mile length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

(2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

(3) A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

140

(ii) An area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

(4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards from the nearest building in the cluster.

[Amdt. 192-78, 61 FR 28783, June 6, 1996; 61 FR 35139, July 5, 1996]

§ 192.7 Incorporation by reference.

(a) Any documents or portions thereof incorporated by reference in this part are included in this part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this part.

(b) All incorporated materials are available for inspection in the Research and Special Programs Administration, 400 Seventh Street, SW., Washington, DC, and at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, the incorporated materials are available from the respective organizations listed in appendix A to this part.

(c) The full titles for the publications incorporated by reference in this part are provided in appendix A to this part. Numbers in parentheses indicate applicable editions. Earlier editions of documents listed or editions of documents formerly listed in previous editions of appendix A may be used for materials and components manufactured, designed, or installed in accordance with those earlier editions or earlier documents at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR for a listing of the earlier listed editions or documents.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; Amdt 192-51, 51 FR 15334, Apr. 23, 1986; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.9 Gathering lines.

Except as provided in §§ 192.1 and 192.150, each operator of a gathering line must comply with the requirements of this part applicable to transmission lines.

[Amdt. 192-72, 59 FR 17281, Apr. 12, 1994]

§ 192.11 Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and ANSI/NFPA 58 and 59.

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and of ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and ANSI/NFPA 58 and 59, ANSI/NFPA 58 and 59 prevail.

[Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.13 General.

(a) No person may operate a segment of pipeline that is readied for service after March 12, 1971, or in the case of an offshore gathering line, after July 31, 1977, unless:

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part in accordance with § 192.14.

(b) No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed after November 12, 1970, or in the case of an offshore gathering line, after July 31, 1977, unless that replacement, relocation, or change has been made in accordance with this part.

141

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.14 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with subpart J of this part to substantiate the maximum allowable operating pressure permitted by subpart L of this part.

(b) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.15 Rules of regulatory construction.

(a) As used in this part:

Includes means including but not limited to.

May means "is permitted to" or "is authorized to".

May not means "is not permitted to" or "is not authorized to".

Shall is used in the mandatory and imperative sense.

(b) In this part:

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

§ 192.16 Customer notification.

(a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to § 192.465 if the customer's buried piping is metallic, survey for leaks according to § 192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.

(b) Each operator shall notify each customer once in writing of the following information:

(1) The operator does not maintain the customer's buried piping.

(2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.

(3) Buried gas piping should be—

(i) Periodically inspected for leaks;

(ii) Periodically inspected for corrosion if the piping is metallic; and

(iii) Repaired if any unsafe condition is discovered.

(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.

(5) The operator (if applicable), plumbers, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

(c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators

142

of master meter systems may continuously post a general notice in a prominent location frequented by customers.

(d) Each operator must make the following records available for inspection by the Administrator or a State agency participating under 49 U.S.C. 60105 or 60106:

(1) A copy of the notice currently in use; and

(2) Evidence that notices have been sent to customers within the previous 3 years.

[Amdt. 192-74, 60 FR 41828, Aug. 14, 1995, as amended by Amdt. 192-74A, 60 FR 63451, Dec. 11, 1995]

Subpart B—Materials

§ 192.51 Scope.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

§ 192.53 General.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

§ 192.55 Steel pipe.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of—

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part; or

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of appendix B to this part;

(2) It meets the requirements of:

(i) Section II of appendix B to this part; or

(ii) If it was manufactured before November 12, 1970, either section II or III of appendix B to this part;

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of appendix B to this part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of appendix B to this part.

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Specification 5L.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 191-1, 35 FR 17660, Nov. 17, 1970; Amdt. 192-12, 38 FR 4761, Feb. 22, 1973; Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; 58 FR 14521, Mar. 18, 1993]

§ 192.57 [Reserved]

§ 192.59 Plastic pipe.

(a) New plastic pipe is qualified for use under this part if:

(1) It is manufactured in accordance with a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated;

(3) It has been used only in natural gas service;

143

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

(2) Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-19, 40 FR 10472, Mar. 6, 1975; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.61 [Reserved]

§ 192.63 Marking of materials.

(a) Except as provided in paragraph (d) of this section, each valve, fitting, length of pipe, and other component must be marked—

(1) As prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D 2513; or

(2) To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970, as amended by Amdt. 192-31, 43 FR 883, Apr. 3, 1978; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; Amdt. 192-61A, 54 FR 32642, Aug. 9, 1989; 58 FR 14521, Mar. 18, 1993; Amdt. 192-76, 61 FR 26122, May 24, 1996; 61 FR 36826, July 15, 1996]

§ 192.65 Transportation of pipe.

In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless:

(a) The transportation is performed in accordance with API RP 5L1.

(b) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

[Amdt. 192-12, 38 FR 4761, Feb. 22, 1973, as amended by Amdt. 192-17, 40 FR 6346, Feb. 11, 1975; 58 FR 14521, Mar. 18, 1993]

Subpart C—Pipe Design

§ 192.101 Scope.

This subpart prescribes the minimum requirements for the design of pipe.

§ 192.103 General.

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

§ 192.105 Design formula for steel pipe.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

$$P=(2\ St/D)\times F\times E\times T$$

P=Design pressure in pounds per square inch gauge.

144

S=Yield strength in pounds per square inch determined in accordance with § 192.107.
D=Nominal outside diameter of the pipe in inches.
t=Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with § 192.109. Additional wall thickness required for concurrent external loads in accordance with § 192.103 may not be included in computing design pressure.
F=Design factor determined in accordance with § 192.111.
E=Longitudinal joint factor determined in accordance with § 192.113.
T=Temperature derating factor determined in accordance with § 192.115.

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900° F (482° C) at any time or is held above 600° F (316° C) for more than 1 hour.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-47, 49 FR 7569, Mar. 1, 1984]

§ 192.107 Yield strength (*S*) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of appendix B of this part, the yield strength to be used in the design formula in § 192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in § 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section 24,000 p.s.i.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.109 Nominal wall thickness (*t*) for steel pipe.

(a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in § 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

§ 192.111 Design factor (*F*) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Class location	Design factor (*F*)
1	0.72
2	0.60
3	0.50
4	0.40

(b) A design factor of 0.60 or less must be used in the design formula in § 192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) Crosses without a casing, or makes a parallel encroachment on, the

145

right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in § 192.105 for—

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.113 Longitudinal joint factor (*E*) for steel pipe.

The longitudinal joint factor to be used in the design formula in § 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M.	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	1.00
ASTM A 672	Electric-fusion-welded	1.00
ASTM A 691	Electric-fusion-welded	1.00
API 5 L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
Other	Pipe over 4 inches	.80
Other	Pipe 4 inches or less	.60

If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other."

[Amdt. 192-37, 46 FR 10159, Feb. 2, 1981, as amended by Amdt. 192-51, 51 FR 15335, Apr. 23, 1986; Amdt. 192-62, 54 FR 5627, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993]

§ 192.115 Temperature derating factor (*T*) for steel pipe.

The temperature derating factor to be used in the design formula in § 192.105 is determined as follows:

Gas temperature in degrees Fahrenheit	Temperature derating factor (T)
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

§ 192.117 [Reserved]

§ 192.119 [Reserved]

§ 192.121 Design of plastic pipe.

Subject to the limitations of § 192.123, the design pressure for plastic pipe is determined in accordance with either of the following formulas:

$$P = 2S\frac{t}{(D-t)}0.32$$

$$P = \frac{2S}{(SDR-1)}0.32$$

Where:

P=Design pressure, gauge, kPa (psig).

S=For thermoplastic pipe, the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to 23°C (73°F), 38°C (100°F),

146

49°C (120°F), or 60°C (140°F); for reinforced thermosetting plastic pipe, 75,842 kPa (11,000 psi).

t=Specified wall thickness, mm (in).

D=Specified outside diameter, mm (in).

SDR=Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

[Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.123 Design limitations for plastic pipe.

(a) The design pressure may not exceed a gauge pressure of 689 kPa (100 psig) for plastic pipe used in:

(1) Distribution systems; or

(2) Classes 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:

(1) Below −29°C (−20°F), or −40°C (−40°F) if all pipe and pipeline components whose operating temperature will be below −29°C (−20°F) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) Above the following applicable temperatures:

(i) For thermoplastic pipe, the temperature at which the long-term hydrostatic strength used in the design formula under § 192.121 is determined. However, if the pipe was manufactured before May 18, 1978 and its long-term hydrostatic strength was determined at 23°C (73°F), it may be used at temperatures up to 38°C (100°F).

(ii) For reinforced thermosetting plastic pipe, 66°C (150°F).

(c) The wall thickness for thermoplastic pipe may not be less than 1.57 millimeters (0.062 in.).

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal size in inches	Minimum wall thickness in millimeters (inches)
2	1.52 (0.060)
3	1.52 (0.060)
4	1.78 (0.070)
6	2.54 (0.100)

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-31, 43 FR 13883, Apr. 3, 1978; Amdt. 192-78, 61 FR 28783, June 6, 1996]

§ 192.125 Design of copper pipe.

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches and must be hard drawn.

(b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard size (inch)	Nominal O.D. (inch)	Wall thickness (inch)	
		Nominal	Tolerance
½	.625	.040	.0035
⅝	.750	.042	.0035
¾	.875	.045	.004
1	1.125	.050	.004
1¼	1.375	.055	.0045
1½	1.625	.060	.0045

(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i.g.

(d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains per 100 standard cubic feet of gas.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

Subpart D—Design of Pipeline Components

§ 192.141 Scope.

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

§ 192.143 General requirements.

Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind

147

of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

[Amdt. 48, 49 FR 19824, May 10, 1984]

§ 192.144 Qualifying metallic components.

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in appendix A of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if—

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in appendix A:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings.

[Amdt. 192-45, 48 FR 30639, July 5, 1983]

§ 192.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements, or equivalent, of API 6D. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve must comply with the following:

(1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

(2) The valve must be tested as part of the manufacturing, as follows:

(i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.

(ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

(iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

(c) Each valve must be able to meet the anticipated operating conditions.

(d) No valve having shell components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i.g.; and

(2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

(e) No valve having pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.147 Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5, MSS SP-44, or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993]

§ 192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than

specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

(b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

§192.150 Passage of internal inspection devices.

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each line section of a transmission line where the line pipe, valve, fitting, or other line component is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to: (1) Manifolds;

(2) Station piping such as at compressor stations, meter stations, or regulator stations;

(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) Cross-overs;

(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;

(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

(7) Offshore pipelines, other than transmission lines 10 inches or greater in nominal diameter, that transport gas to onshore facilities; and

(8) Other piping that, under §190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why an impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Amdt. 192-72, 59 FR 17281, Apr. 12, 1994]

§192.151 Tapping.

(a) Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that

(1) Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

(2) A 1¼-inch tap may be made in a 4-inch cast iron or ductile iron pipe, without reinforcement.

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch or larger pipe.

§192.153 Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of section VIII, Division 1, of

the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with section I, section VIII, Division 1, or section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i.g., or more, or is more than 3 inches nominal diameter.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970; 58 FR 14521, Mar. 18, 1993; Amdt. 192-68, 58 FR 45268, Aug. 27, 1993]

§ 192.155 Welded branch connections.

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

§ 192.157 Extruded outlets.

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

§ 192.159 Flexibility.

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

§ 192.161 Supports and anchors.

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

(c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

(d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

(3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

(e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have

enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.163 Compressor stations: Design and construction.

(a) *Location of compressor building.* Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either—

(1) Pipe more than 2 inches in diameter that is carrying gas under pressure; or

(2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) *Exits.* Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

(d) *Fenced areas.* Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

(e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, ANSI/NFPA 70, so far as that code is applicable.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976; Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; 58 FR 14521, Mar. 18, 1993]

§ 192.165 Compressor stations: Liquid removal.

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must:

(1) Have a manually operable means of removing these liquids.

(2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

(3) Be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

§ 192.167 Compressor stations: Emergency shutdown.

(a) Except for unattended field compressor stations of 1,000 horsepower or less, each compressor station must have an emergency shutdown system that meets the following:

(1) It must be able to block gas out of the station and blow down the station piping.

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

(3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that:

151

(i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(ii) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least two locations, each of which is:

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station:

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building:

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility which conforms to Class I, Group D, of the National Electrical Code is not a source of ignition.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34605, Aug. 16, 1976]

§ 192.169 Compressor stations: Pressure limiting devices.

(a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.

(b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

§ 192.171 Compressor stations: Additional safety equipment.

(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

(e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

§ 192.173 Compressor stations: Ventilation.

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

§ 192.175 Pipe-type and bottle-type holders.

(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the

156

holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

$$C=(3D\times P\times F)/1{,}000$$

in which:

C=Minimum clearance between pipe containers or bottles in inches.
D=Outside diameter of pipe containers or bottles in inches.
P=Maximum allowable operating pressure, p.s.i.g.
F=Design factor as set forth in §192.111 of this part.

§ 192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance (feet)
Less than 1,000 p.s.i.g	25
1,000 p.s.i.g. or more	100

(2) Designed using the design factors set forth in § 192.111; and

(3) Buried with a minimum cover in accordance with § 192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A 372/A 372M.

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after installation as required by subpart J of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt 192-62, 54 FR 5628, Feb. 6, 1989; 58 FR 14521, Mar. 18, 1993]

§ 192.179 Transmission line valves.

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow

153

of gas to an offshore platform in an emergency.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.181 Distribution line valves.

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

§ 192.183 Vaults: Structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inch, and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

§ 192.185 Vaults: Accessibility.

Each vault must be located in an accessible location and, so far as practical, away from:

(a) Street intersections or points where traffic is heavy or dense;

(b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and

(c) Water, electric, steam, or other facilities.

§ 192.187 Vaults: Sealing, venting, and ventilation.

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated as follows:

(a) When the internal volume exceeds 200 cubic feet:

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet but less than 200 cubic feet:

(1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

(2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

159

§ 192.189 Vaults: Drainage and waterproofing.

(a) Each vault must be designed so as to minimize the entrance of water.

(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI/NFPA 70.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-76, 61 FR 26122, May 24, 1996]

§ 192.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517.

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.193 Valve installation in plastic pipe.

Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

§ 192.195 Protection against accidental overpressuring.

(a) *General requirements.* Except as provided in § 192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§ 192.199 and 192.201.

(b) *Additional requirements for distribution systems.* Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

(1) Have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Be designed so as to prevent accidental overpressuring.

§ 192.197 Control of the pressure of gas delivered from high-pressure distribution systems.

(a) If the maximum actual operating pressure of the distribution system is under 60 p.s.i.g. and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i.g., or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i.g., one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

(1) A service regulator having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i.g. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 p.s.i.g. or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i.g. or less), and remains closed until manually reset.

(2) A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

(3) A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 p.s.i.g. For higher inlet pressures, the methods in paragraph (c) (1) or (2) of this section must be used.

(4) A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 7, 1970]

§ 192.199 Requirements for design of pressure relief and limiting devices.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

(b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;

(d) Have support made of noncombustible material;

(e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

(f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

(g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system:

156

(i) If the maximum allowable operating pressure is 60 p.s.i.g. or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i.g. or more, but less than 60 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i.g.; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-9, 37 FR 20827, Oct. 4, 1972]

§ 192.203 Instrument, control, and sampling pipe and components.

(a) *Applicability.* This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

(b) *Materials and design.* All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

(3) Brass or copper material may not be used for metal temperatures greater than 400° F.

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

(9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996]

Subpart E—Welding of Steel in Pipelines

§ 192.221 Scope.

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

157

§ 192.225 Welding—General.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify the procedure shall be determined by destructive testing.

(b) Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

[Amdt. 192-52, 51 FR 20297, June 4, 1986]

§ 192.227 Qualification of welders.

(a) Except as provided in paragraph (b) of this section, each welder must be qualified in accordance with section 3 of API Standard 1104 or section IX of the ASME Boiler and Pressure Vessel Code. However, a welder qualified under an earlier edition than listed in appendix A may weld but may not requalify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-43, 47 FR 46851, Oct. 21, 1982; Amdt. 192-52, 51 FR 20297, June 4, 1986; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.229 Limitations on welders.

(a) No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has engaged in welding with that process.

(c) A welder qualified under § 192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under section 3 or 6 of API Standard 1104, except that a welder qualified under an earlier edition previously listed in Appendix A of this part may weld but may not requalify under that earlier edition; and

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder qualified under § 192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder has requalified under § 192.227(b); or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For welders who work only on service lines 2 inches or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10159, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.231 Protection from weather.

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

§ 192.233 Miter joints.

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3°.

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12½° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

153

(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°.

§ 192.235 Preparation for welding.

Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

§ 192.241 Inspection and test of welds.

(a) Visual inspection of welding must be conducted to insure that:

(1) The welding is performed in accordance with the welding procedure; and

(2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with § 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:

(1) The pipe has a nominal diameter of less than 6 inches; or

(2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 6 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-37, 46 FR 10160, Feb. 2, 1981; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.243 Nondestructive testing.

(a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

(2) By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under § 192.241(c).

(d) When nondestructive testing is required under § 192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under § 192.241(b).

(f) When nondestructive testing is required under § 192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-50, 50 FR 37192, Sept. 12, 1985; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under § 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under § 192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 192-46, 48 FR 48674, Oct. 20, 1983]

Subpart F—Joining of Materials Other Than by Welding

§ 192.271 Scope.

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

§ 192.273 General.

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

§ 192.275 Cast iron pipe.

(a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

(b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.277 Ductile iron pipe.

(a) Ductile iron pipe may not be joined by threaded joints.

(b) Ductile iron pipe may not be joined by brazing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-62, 54 FR 5628, Feb. 6, 1989]

§ 192.279 Copper pipe.

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192-62, 54 FR 5628, Feb. 6, 1989, as amended at 58 FR 14521, Mar. 18, 1993]

§ 192.281 Plastic pipe.

(a) *General.* A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints.* Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be deterimental to the joint.

(2) The solvent cement must conform to ASTM Designation D 2513.

(3) The joint may not be heated to accelerate the setting of the cement.

(c) *Heat-fusion joints.* Each heat-fusion joint on plastic pipe must comply with the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater

160

element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints.* Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM Designation D 2517.

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints.* Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-34, 44 FR 42973, July 23, 1979; Amdt. 192-58, 53 FR 1635, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.283 Plastic pipe: qualifying joining procedures.

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under § 192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of—

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure (Quick Burst)) of ASTM D 2513;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517; or

(iii) In the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM Designation F1055.

(2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

(3) For procedures intended for nonlateral pipe connections, follow the tensile test requirements of ASTM D638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638 (except for conditioning).

(2) The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength.

(3) The speed of testing is 5.0 mm (0.20 in) per minute, plus or minus 25 percent.

(4) Pipe specimens less than 102 mm (4 in) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area.

(5) Pipe specimens 102 mm (4 in) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress

161

equal to or greater than the maximum thermal stress that would be produced by a temperature change of 38° C (100° F) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) Results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

(d) Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981; 47 FR 32720, July 29, 1982; 47 FR 49973, Nov. 4, 1982; 58 FR 14521, Mar. 18, 1993; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.285 Plastic pipe: qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a) applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person:

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under § 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

[Amdt. 192-34A, 45 FR 9935, Feb. 14, 1980, as amended by Amdt. 192-34B, 46 FR 39, Jan. 2, 1981]

§ 192.287 Plastic pipe: inspection of joints.

No person may carry out the inspection of joints in plastic pipes required by §§ 192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

[Amdt. 192-34, 44 FR 42974, July 23, 1979]

Subpart G—General Construction Requirements for Transmission Lines and Mains

§ 192.301 Scope.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

§ 192.303 Compliance with specifications or standards.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

162

§ 192.305 Inspection: General.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

§ 192.307 Inspection of materials.

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

§ 192.309 Repair of steel pipe.

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS:

(1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than one-quarter inch in pipe 12¾ inches or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12¾ inches in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.311 Repair of plastic pipe.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired by a patching saddle or removed.

§ 192.313 Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with § 192.315, must comply with the following:

(1) A bend must not impair the serviceability of the pipe.

(2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

(3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless:

(i) The bend is made with an internal bending mandrel; or

(ii) The pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches or more in diameter unless the arc length,

as measured along the crotch, is at least 1 inch.

[Amdt. No. 192-26, 41 FR 26018, June 24, 1976, as amended by Amdt. 192-29, 42 FR 42866, Aug. 25, 1977; Amdt. 192-29, 42 FR 60148, Nov. 25, 1977; Amdt. 192-49, 50 FR 13225, Apr. 3, 1985]

§ 192.315 Wrinkle bends in steel pipe.

(a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

(2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.

(3) On pipe 16 inches or larger in diameter, the bend may not have a deflection of more than 1½° for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

§ 192.317 Protection from hazards.

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[Amdt. 192-27, 41 FR 34606, Aug. 16, 1976, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.319 Installation of pipe in a ditch.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that:

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet deep but not more than 200 feet deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet of water must be installed so that the top of the pipe is 36 inches below the seabed for normal excavation or 18 inches for rock excavation.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.321 Installation of plastic pipe.

(a) Plastic pipe must be installed below ground level unless otherwise permitted by paragraph (g) of this section.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch, except that pipe with an outside diameter of 0.875 inch or less may have a minimum wall thickness of 0.062 inch.

(e) Plastic pipe that is not encased must have an electrically conductive

164

wire or other means of locating the pipe while it is underground.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(g) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

(1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28784, June 6, 1996]

§ 192.323 Casing.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.

(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

§ 192.325 Underground clearance.

(a) Each transmission line must be installed with at least 12 inches of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in § 192.175(b).

§ 192.327 Cover.

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil	Consolidated rock
	Inches	
Class 1 locations	30	18
Class 2, 3, and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches of cover if the law of the State or municipality:

(1) Establishes a minimum cover of less than 24 inches;

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum

165

cover of 48 inches in soil or 24 inches in consolidated rock between the top of the pipe and the natural bottom.

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet deep, must be installed with a minimum cover of 36 inches in soil or 18 inches in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in § 192.3, must be installed in accordance with § 192.612(b)(3).

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-78, 61 FR 28785, June 6, 1996]

Subpart H—Customer Meters, Service Regulators, and Service Lines

§ 192.351 Scope.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

§ 192.353 Customer meters and regulators: Location.

(a) Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage. However, the upstream regulator in a series may be buried.

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet from any source of ignition or any source of heat which might damage the meter.

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

§ 192.355 Customer meters and regulators: Protection from damage.

(a) *Protection from vacuum or back pressure.* If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

(b) *Service regulator vents and relief vents.* Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must—

(1) Be rain and insect resistant;

(2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

(3) Be protected from damage caused by submergence in areas where flooding may occur.

(c) *Pits and vaults.* Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-58, 53 FR 1635, Jan. 21, 1988]

§ 192.357 Customer meters and regulators: Installation.

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

§ 192.359 Customer meter installations: Operating pressure.

(a) A meter may not be used at a pressure that is more than 67 percent

166

of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i.g.

(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.361 Service lines: Installation.

(a) *Depth.* Each buried service line must be installed with at least 12 inches of cover in private property and at least 18 inches of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill.* Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage.* Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading.* Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings.* Each underground service line installed below grade through the outer foundation wall of a building must:

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings.* Where an underground service line is installed under a building:

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.363 Service lines: Valve requirements.

(a) Each service line must have a service-line valve that meets the applicable requirements of subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

(c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

§ 192.365 Service lines: Location of valves.

(a) *Relation to regulator or meter.* Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

(b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) *Underground valves.* Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

167

§ 192.367 Service lines: General requirements for connections to main piping.

(a) *Location.* Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) *Compression-type connection to main.* Each compression-type service line to main connection must:

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-75, 61 FR 18517, Apr. 26, 1996]

§ 192.369 Service lines: Connections to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of § 192.273.

(b) If a threaded tap is being inserted, the requirements of § 192.151 (b) and (c) must also be met.

§ 192.371 Service lines: Steel.

Each steel service line to be operated at less than 100 p.s.i.g. must be constructed of pipe designed for a minimum of 100 p.s.i.g.

[Amdt. 192-1, 35 FR 17660, Nov. 17, 1970]

§ 192.373 Service lines: Cast iron and ductile iron.

(a) Cast or ductile iron pipe less than 6 inches in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

§ 192.375 Service lines: Plastic.

(a) Each plastic service line outside a building must be installed below ground level, except that—

(1) It may be installed in accordance with § 192.321(g); and

(2) It may terminate above ground level and outside the building, if—

(i) The above ground level part of the plastic service line is protected against deterioration and external damage; and

(ii) The plastic service line is not used to support external loads.

(b) Each plastic service line inside a building must be protected against external damage.

[35 FR 13257, Aug. 19, 1970, as amended by Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.377 Service lines: Copper.

Each copper service line installed within a building must be protected against external damage.

§ 192.379 New service lines not in use.

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]

§ 192.381 Service lines: Excess flow valve performance standards.

(a) Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 psig must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

168

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 psig:

(i) Be sized to close at, or not more than 50 percent above the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow—

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour; or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour; and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator should locate an excess flow valve beyond the hard surface and as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

[Amdt. 192-79, 61 FR 31459, June 20, 1996]

Subpart I—Requirements for Corrosion Control

SOURCE: Amdt. 192-4, 36 FR 12302, June 30, 1971, unless otherwise noted.

§ 192.451 Scope.

(a) This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

(b) [Reserved]

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-27, 41 FR 34606, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

§ 192.452 Applicability to converted pipelines.

Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with § 192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

[Amdt. 192-30, 42 FR 60148, Nov. 25, 1977]

§ 192.453 General.

The corrosion control procedures required by § 192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Amdt. 192-71, 59 FR 6584, Feb. 11, 1994]

§ 192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of § 192.461.

(2) It must have a cathodic protection system designed to protect the

169

pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within 6 months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a)(2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that—

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed 5 years beyond installation, corrosion during the 5-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a)(2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended at Amdt. 192-28, 42 FR 35654, July 11, 1977; Amdt. 192-39, 47 FR 9844, Mar. 8, 1982; Amdt. 192-78, 61 FR 28785, June 6, 1996]

§ 192.457 External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

(c) For the purpose of this subpart, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.

[Amdt. 192-4, 36 FR 12302, June 30, 1971, as amended by Amdt. 192-33, 43 FR 39390, Sept. 5, 1978]

170