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BLENDING OF HYDROGEN IN NATURAL GAS
DISTRIBUTION SYSTEMS, VOLUME 1

Gas Blends Flow in Distribution System, Mixing Points
and Regulatory Standards

Final Report, June 1, 1976—August 30, 1977

September 1977

Work Performed Under Contract No. EY-76-C-02-2925

Public Service Electric and Gas Company
Newark, New Jersey

U. S. DEPARTMENT OF ENERGY

Division of Energy Storage Systems

MASTER

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BLENDING OF HYDROGEN IN NATURAL
GAS DISTRIBUTION SYSTEMS

Volume I

Gas Blends Flow in Distribution System,
Mixing Points and Regulatory Standards

Final Report

Performance Period: June 1, 1976 - August 30, 1977

Prepared by

Public Service Electric and Gas Company
80 Park Place
Newark, NJ 07101

Report Date: September 1977

Prepared for the

Energy Research and Development Administration
Office of the Assistant Administrator for Conservation
Division of Energy Storage Systems
Chemical Storage Branch

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FOREWARD

This is the final report of "Blending of Hydrogen In Natural Gas Distribution Systems". It is separated into three volumes:

- Volume I Gas Blends Flow in Distribution
 System, Mixing Points and
 Regulatory Standards
- Volume II Combustion Tests of Blends in
 Burners and Appliances
- Volume III Gas Blends Leakage Tests of
 Selected Distribution System
 Components

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- C. R. Guerra, PSRC - Research and Development Department
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- K. Kelton, PSE&G - Gas Transmission and Distribution
- D. Cundari, PSE&G - Gas Production

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ABSTRACT

This volume of the subject study "Blending of Hydrogen in Natural Gas Distribution Systems" describes studies on the determination of gas distribution system flows with hydrogen - natural gas blends, potential hydrogen admission points to gas distribution systems, and the impact of hydrogen - natural gas blends on regulatory standards for gas distribution systems.

The studies resulted in the following principal findings:

1. Most existing natural gas distribution systems could adequately transport 20% blends of hydrogen by volume with little or no modification.
2. The best point of admission of the hydrogen into a natural gas distribution system would be at the meter and regulating stations supplying a particular distribution system.
3. The impact of hydrogen - natural gas blends on state regulatory standards appears to be minimal for PSE&G, but requires further study for various National Codes and for other states.

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DETERMINATION OF GAS DISTRIBUTION SYSTEM FLOWS

INTRODUCTION

Natural gas is distributed in the United States today by means of a well integrated network of transmission lines operated by pipeline companies and by the distribution systems of hundreds of utilities which carry the gas to the ultimate user. The schematic below depicts the flow from gas well to customer.

The moving force which causes the gas to flow from wellhead to customer is the difference in the pressure of the gas from one point in the system to another. Different gases, since they have different characteristics such as heating value and specific gravity, require different pressure differentials for the delivery of an equivalent amount of energy. This study examines the ability of a typical utility distribution system to deliver hydrogen while conforming to the pressure limitations of a system designed for natural gas.

SUMMARY

The purpose of this sub-task was to determine if an existing gas distribution system presently used to distribute natural gas would have adequate capacity to distribute either a 10% or a 20% blend by volume of hydrogen with natural gas. The study shows that such a system's energy-carrying capacity is only slightly reduced when carrying these blends. It also concludes that each distribution system's ability to perform satisfactorily with these hydrogen blends depends upon the excess capacity in the system when distributing straight natural gas. That is, some systems can carry 20% hydrogen blends with no problems while others cannot carry even 10% blends. While the generalization is true that the system's energy-carrying capacity is only slightly reduced when carrying 10% or 20% hydrogen blends, each system is a separate case and must be individually studied. Nevertheless, it appears likely that most existing distribution systems could adequately transport 20% blends of hydrogen by volume with little or no modifications.

METHODOLOGY

The flow of gas in a pipe can be computed by flow formulas which take the following basic forms:

For intermediate pressures (1 PSIG to 60 PSIG)

$$Q = C \sqrt{\frac{P_1^2 - P_2^2}{SL}}$$

where Q = Quantity of gas flowing, cubic feet per hour at 14.73 PSIA and 60°F

P₁ = Initial pressure, PSIA

P₂ = Final pressure, PSIA

S = Specific gravity of the gas

L = Length of pipe, feet

C = A factor which takes into account pipe diameter and friction.

For utilization pressures (Below 1 PSIG)

$$Q = C \sqrt{\frac{h_1 - h_2}{SL}}$$

where Q = Quantity of gas flowing, cubic feet per hour at 14.73 PSIA and 60°F

h₁ = Initial pressure, inches of water column

h₂ = Final pressure, inches of water column

S = Specific gravity of the gas

L = Length of pipe, feet

C = A factor which takes into account pipe diameter and friction.

For both formulas, we can see that for a pipe of a given length and size carrying a certain gas (i.e., C, S, and L remaining unchanged), if the (Q) increases the pressure loss ($P_1^2 - P_2^2$ or $h_1 - h_2$) will also increase.

Also for both formulas, we can see that for a pipe of a given length and size operating at a fixed pressure drop (i.e., C, L, and $P_1^2 - P_2^2$ or $h_1 - h_2$ remaining unchanged) if the specific gravity (S) decreases, flow (Q) increases.

Figures 1A & 1B and 2A & 2B illustrate these two effects for both intermediate pressure and utilization pressure systems.

Table I shows the characteristics of straight natural gas and blends of hydrogen mixed with natural gas. It can be seen that as the percentage of hydrogen in the mixture increases, the heating value and the specific gravity both decrease. Since the heating value decreases, the energy in each cubic foot of the mixture decreases and a greater total flow is required to meet the energy demand of the customers on the system. Any additional flow required for the same amount of energy (at the same specific gravity) will result in greater pressure losses in the system, shown in Figures 1A & 1B.

The specific gravity of the mixture, however, also decreases with increasing hydrogen. This partially offsets the increased pressure losses caused by the greater flow because the lower specific gravity allows more gas to flow at a given pressure loss, shown in Figures 2A & 2B.

The net outcome of these two changes is that slightly more pressure loss for a given amount of energy is experienced when substituting 10% and 20% hydrogen blends for straight natural gas. Or conversely, at the same input and output pressure conditions, slightly less total energy can be delivered with hydrogen blends. For a 10% hydrogen blend, only 97.6% of the energy of straight natural gas can be delivered, and for a 20% hydrogen blend only 95.1% of the energy of straight natural gas can be delivered. (See Appendix-pages 1-3). This is illustrated in Figures 3A and 3B.

Computing the flow in a given pipe for different types of gases is relatively simple, however, flow computations for complicated networks of mains such as those common in gas distribution systems can be quite tedious and time consuming. For this reason, PSE&G commonly conducts network studies on a Univac 1106 Digital Computer.

For this sub-task, a large PSE&G feeder main network was analyzed when carrying 100% natural gas at peak load conditions; when carrying 10% hydrogen and 90% natural gas at peak load conditions; and when carrying 20% hydrogen and 80% natural gas at peak load conditions. Comparisons of the results were then made to see what modifications would be necessary for the system to carry these different blends. A similar study was done on a medium sized utilization pressure section.

FIGURE 1A
PRESSURE LOSS VS FLOW
FOR
ONE MILE OF 6" STEEL MAIN
(USING SPITZGLASS FORMULA WITH $P_1 = 30$ PSIG AND Sp.Gr.=.6)

FIGURE 1B
PRESSURE LOSS VS. FLOW
FOR
2000' OF 6" STEEL UTILIZATION PRESSURE MAIN
(USING JOURNAL LOW PRESSURE FORMULA WITH SP. GR.=0.6)

FIGURE 2 A
SPECIFIC GRAVITY VS. FLOW
FOR
ONE MILE OF 6" STEEL MAIN
(USING SPITZGLASS FORMULA WITH $P_1 = 30$ PSIG, $P_2 = 25$ PSIG, Sp. Gr. = .6)

FIGURE 2B
SPECIFIC GRAVITY VS. FLOW
FOR

2000' OF 6" STEEL UTILIZATION PRESSURE MAIN
(USING JOURNAL LOW PRESSURE FORMULA WITH $\Delta P=1.5''$)

TABLE I

PHYSICAL PROPERTIES OF HYDROGEN AND NATURAL GAS BLENDS

<u>Blend</u>	<u>(Btu/ft.³) Heating Value</u>	<u>Specific Gravity</u>	<u>Energy of Blend ÷ Energy of Nat. Gas</u>	<u>Volume (ft.³) Required for Same Energy As 1 cu.ft. Natural gas</u>
100% Natural Gas	1030	.60	1.0	1.0
5% H ₂ & 95% Nat. Gas	995	.57	.966	1.035
10% H ₂ & 90% Nat. Gas	960	.55	.932	1.073
15% H ₂ & 85% Nat. Gas	924	.52	.897	1.115
20% H ₂ & 80% Nat. Gas	889	.49	.863	1.159
25% H ₂ & 75% Nat. Gas	854	.47	.829	1.206
30% H ₂ & 70% Nat. Gas	819	.44	.795	1.258
50% H ₂ & 50% Nat. Gas	678	.33	.658	1.519
75% H ₂ & 25% Nat. Gas	501	.20	.486	2.056
100% Hydrogen	325	.0696	.316	3.169

FIGURE 3A
PRESSURE LOSS VS. ENERGY
FOR
ONE MILE OF 6" STEEL MAIN
(USING SPITZGLASS FORMULA WITH $P_1 = 30$ PSIG)

FIGURE 3B
PRESSURE LOSS VS. ENERGY
FOR
2000' OF 6" STEEL UTILIZATION PRESSURE MAIN
(USING JOURNAL LOW PRESSURE FORMULA)

DESCRIPTION OF UTILITY GAS DELIVERY SYSTEM STUDIED - PSE&G

PSE&G serves over 1.3 million gas consumers in a service area of approximately 2350 square miles. The consumer sector may be classified on the basis of annual BTU's delivered as 57% residential, 26% commercial, 11% firm industrial, and 6% interruptibles. Its distribution system consists of 12,000 miles of gas mains ranging in size from 2" to 42". These mains are classified as either 120 PSIG design, 60 PSIG design, 15 PSIG design, or utilization pressure (6" water column) design.

Approximately 1800 miles of these mains are called "feeder mains". A network of feeder mains is used to deliver gas from one or more supply points, such as a natural gas meter station, to a large portion of the service area, and most are 15PSIG or 60 PSIG design mains. Gas is taken from the network of feeder mains (at many points) and carried to individual neighborhoods through smaller "distribution mains". In some cases gas is taken from the network of feeder mains, reduced in pressure at distribution regulators, and then carried to individual neighborhoods in "utilization pressure mains". (See Figure 4.)

Because of the size of the area served by PSE&G, there are fourteen different feeder main networks in the distribution system. Each of these networks can be analyzed separately on PSE&G's digital computer to determine pressure conditions under various load and operating scenarios. For purposes of this study the "Central West System" was chosen to determine the effects of distributing 10% and 20% blends of hydrogen in a typical natural gas feeder main network. It is a system which is used to distribute straight natural gas at all times except for the few occasions when peak-shaving gases are produced.

Utilization pressure mains are usually not analyzed on the digital computer because these systems are primarily in older areas which experience little growth. In addition, most utilization pressure systems were built in the period before PSE&G converted to natural gas. Since these systems were designed for manufactured gas there is generally much excess capacity in these systems now. Nevertheless, for purposes of this study a utilization pressure system which is fed by the "Central West System" was studied to determine the effects of distributing 10% and 20% blends of hydrogen.

FIG. 4

DISTRIBUTION SYSTEM MAIN CLASSIFICATIONS

DISTRIBUTION PRESSURE SUBSYSTEM:
CENTRAL WEST AREA - CAPACITY STUDY AND RESULTS

The Central West System is made up of 300 miles of feeder mains ranging in size from 2" to 36". Approximately 142,000 customers in an area of 421 square miles are served by this system. The municipalities served are shown in Figure 5.

This system is supplied gas from the following sources:

- a. Central Gas Plant, which distributes gas from meter stations supplied by Texas Eastern Transmission Corporation and Transcontinental Gas Pipeline Corporation. The plant also produces peak-shaving gases when required.
- b. A regulating station at Campus Drive and Elizabeth Avenue, South Bound Brook, which distributes gas received from the Franklin Meter Station. Franklin Meter Station is part of a separate small system.
- c. Hillsboro Meter Station, which distributes gas supplied by Texas Eastern Transmission Corporation.

The estimated consumption of these 142,000 customers during the maximum hour of a zero degree day¹ for the winter of 1976/77 is 8991.4 MCFH² of natural gas. Since PSE&G has a design criteria that distribution facilities must be able to meet the maximum hour demand on a zero degree weekday, (See Appendix - page 4), the Central West System must be able to deliver 8991.4 MCFH. There are two other design criteria that must be met. The first is that the maximum pressure at any point in the Central West System must not exceed previously established limits in accordance with Federal Department of Transportation Standards (DOT). (See Appendix - Page 5-9.) The second is that the minimum pressure at any point in the network must not fall below the minimum allowable pressures established in PSE&G's Design Standards (see Appendix - page 10).

The Central West System is a 60 PSIG design system with a previous maximum operating pressure of 35 PSIG. Therefore, it must operate at a maximum of 35 PSIG, unless it is uprated according to DOT Operating Procedures. In accordance with the design criteria concerning minimum pressures, it can have no pressure below 3 PSIG. If the flow studies show that the load on a zero degree day maximum hour results in pressures lower than the minimum allowable, then modifications of some type must be made to the system. These modifications could consist of one or more of the following:

- a. Installing additional feeder mains at key points of the system to increase load carrying capacity.

¹ A zero degree day is a day with a mean temperature of 0°F.

² MCFH is one thousand cubic feet per hour.

FIG. 5
CENTRAL WEST AREA

- b. Install additional supply points to the system.
- c. Uprate the system to operate at higher pressures. Uprating consists of raising the pressure in stages and conducting extensive leakage tests at each stage. In some cases some system components must be replaced with higher rated components before uprating begins. Uprating costs can vary widely from system to system, but generally uprating is the most economic method of correcting pressure problems.

Study Results:

100% Natural Gas

As a first step in this sub-task, the Central West System was analyzed on the computer for the 1976/77 maximum design hour of 8991.4 MCFH of natural gas. The results showed that this load could be handled without violating any of the aforementioned criteria and without requiring reinforcements of any type. As shown in Figure 6, Central Plant sends out 7904.2 MCFH at 35 PSIG. Hillsboro Meter Station sends out 393.8 MCFH at 31 PSIG, and the regulating station in South Bound Brook sends out 693.4 MCFH at 31 PSIG. The lowest pressures in the system are 3.5 PSIG at Mountain and Hillcrest Avenues, Warren Twp. and 3.5 PSIG at Sawmill and Reinman Rds., Warren Twp.

Blend of 10% Hydrogen

The Central West System was then analyzed for a 10% blend of hydrogen. As explained previously, more total flow from the supply points was necessary to meet the energy demand because of the reduced heating value of the blend. In this analysis, the pressures at each supply point were kept the same as in the case of the straight natural gas, and the percent sendout from each of the supply points remained the same. As shown in Figure 7, Central Gas Plant sends out 8082.1 MCFH at 35 PSIG, Hillsboro Meter Station sends out 411.0 MCFH at 31 PSIG, and the regulating station in South Bound Brook sends out 714.4 MCFH at 31 PSIG. The lowest pressures in the system are .5 PSIG at Mountain and Hillcrest, Warren Twp., and .6 PSIG at Sawmill and Reinman, Warren Twp. These pressures are far lower than the minimum acceptable pressures previously established in the PSE&G design criteria. Several other points in the system can also be seen to have pressures below the design criteria of 3.0 PSIG.

The system was then analyzed to see what the minimum pressures would be if some supply points were set at higher pressures. Since Central Gas Plant was already at the maximum, raising the pressures at the other supply points had the effect of increasing flow from these points and decreasing flow from the Central Gas Plant. As shown in Figure 8, Central Gas Plant sends out 7927.0 MCFH at 35 PSIG, Hillsboro Meter Station sends out 506.9 MCFH at 33.7 PSIG, and the regulating station in South Bound Brook sends out 773.6 MCFH at 33.7 PSIG. The lowest pressures in the system are now 2.8 PSIG at Mountain and Hillcrest, Warren Twp., and 2.9 PSIG at Sawmill and Reinman, Warren Twp. Although these are close to the minimum acceptable pressures, they are slightly below them.

A third study with the 10% hydrogen blend was then run with all supply points feeding gas at 35 PSIG. As shown in Figure 9, all pressures then became greater than the 3.0 PSIG minimum acceptable pressure.

We can conclude that the Central West System could supply blends of 10% hydrogen and natural gas during the 1976/77 maximum hour zero degree day merely by raising supply point pressures to the maximum acceptable level.

Blend of 20% Hydrogen

The procedure just described for a 10% blend of hydrogen in natural gas was repeated for a 20% blend.

As shown in Figure 10, because of the decreased heating value of a 20% hydrogen blend, the total flow necessary to meet the energy demand increases to 8277.2 MCFH at Central Gas Plant, 429.6 MCFH at Hillsboro Meter Station, and 737.1 MCFH at the regulating station in South Bound Brook. When starting with the same pressure conditions as in the 100% natural gas case, this increased flow results in minimum pressures which are far below acceptable levels at many points in the system.

The system was then studied with all supply points feeding gas at 35 PSIG. As shown in Figure 11, pressures at some points are still not sufficient. The lowest pressures in the system are now .5 PSIG at Mountain and Hillcrest and .5 PSIG at Sawmill and Reinman.

A third study with the 20% hydrogen blend was then run to see what supply point pressures were necessary in order to get acceptable pressures at the low points of the system. As shown in Figure 12, Central Gas Plant sends out 7875.6 MCFH at 35 PSIG, Hillsboro Meter Station sends out 667.3 MCFH at 38.4 PSIG, and the regulating station in South Bound Brook sends out 901.1 MCFH at 38.4 PSIG. All main pressures are now at or above the minimum acceptable levels.

We conclude that the Central West System can supply 20% hydrogen blends during the 1976/77 maximum hour on a zero degree day only by making modifications of some type. In this case, the modification chosen was to uprate the system so that operating pressures could be raised above present maximums. The additional pressure needed to operate at higher pressure levels is readily available at no added cost from the transmission company pipelines which operate at approximately 500 PSIG.

It must be emphasized that the test results for a different system could give different results. A different system might require modification even at a 10% hydrogen blend, or it might not require modification with a 20% blend. Each system is unique, and its ability to carry hydrogen blends without modification is related to its excess capacity with straight natural gas.

FIGURE NO. 6

FIGURE NO. 9

CENTRAL WEST DISTRIBUTION SYSTEM PRESSURE CONDITION
10% HYDROGEN & 90% NATURAL GAS

FIGURE NO.10

LOCATION KEY

1 MOUNTAIN & HILLCREST	WARREN TOWNSHIP
2 SAWMILL & REINMAN	WARREN TOWNSHIP
3 ROUND TOP & MOUNTAINVIEW	WARREN TOWNSHIP
4 KING GEORGE & MT HOREB	WARREN TOWNSHIP
5 WATCHUNG & MANNING	NORTH PLAINFIELD
6 PLAINFIELD & OAK TREE	EDISON TOWNSHIP
7 WASHINGTON VALLEY & VOSSELER	BRIDGEWATER TOWNSHIP
8 OLD YORK & WEST HOLBROOK	BRANCHBURG TOWNSHIP
9 GLEN GERY INC	HILLSBOROUGH TOWNSHIP
10 BROWN & RTE 206	BRIDGEWATER TOWNSHIP
11 RTE 22 & MAIN	READINGTON TOWNSHIP
12 NATIONAL LEAD INC	SOUTH AMBOY
13 BUCKELEW & STATE HOME	MONROE TOWNSHIP
14 MATAWAN & MORGANVILLE	MADISON TOWNSHIP
15 AMWFI & DeMOTT	FRANKLIN TOWNSHIP

LEGEND

- LOCATION
 PRESSURE (PSIG)

FIGURE NO. 7

CENTRAL WEST DISTRIBUTION SYSTEM PRESSURE CONDITION
10% HYDROGEN & 90% NATURAL GAS

LOCATION KEY

1 MOUNTAIN & HILLCREST	WARREN TOWNSHIP
2 SAWMILL & REINMAN	WARREN TOWNSHIP
3 ROUND TOP & MOUNTAINVIEW	WARREN TOWNSHIP
4 KING GEORGE & MT HOREB	WARREN TOWNSHIP
5 WATCHUNG & MANNING	NORTH PLAINFIELD
6 PLAINFIELD & OAK TREE	EDISON TOWNSHIP
7 WASHINGTON VALLEY & VOSSELER	BRIDGEWATER TOWNSHIP
8 OLD YORK & WEST HOLBROOK	BRANCHBURG TOWNSHIP
9 GLEN GERY INC	HILLSBOROUGH TOWNSHIP
10 BROWN & RTE 206	BRIDGEWATER TOWNSHIP
11 RTE 22 & MAIN	READINGTON TOWNSHIP
12 NATIONAL LEADING	SOUTH AMBOY
13 BUCKELEW & STATE HOME	MONROE TOWNSHIP
14 MATAWAN & MORGANVILLE	MADISON TOWNSHIP
15 AMWFI & DeMOTT	FRANKLIN TOWNSHIP

LEGEND

- LOCATION
— PRESSURE (PSIG)

FIGURE NO. 8

CENTRAL WEST DISTRIBUTION SYSTEM PRESSURE CONDITION
10% HYDROGEN & 90% NATURAL GAS

FIGURE NO.11
CENTRAL WEST DISTRIBUTION SYSTEM PRESSURE CONDITION
20 % HYDROGEN & 80 % NATURAL GAS

FIGURE NO.12

CENTRAL WEST DISTRIBUTION SYSTEM PRESSURE CONDITION
20 % HYDROGEN & 80 % NATURAL GAS

UTILIZATION PRESSURE SUBSYSTEM:

TUNISON ROAD AREA - CAPACITY STUDY AND RESULTS

The utilization pressure system chosen for computer analysis is the Tunison Road system. The Tunison Road Utilization Pressure System consists of 18,035 feet of 3", 4", 6", and 8" cast-iron and plastic mains. There are 383 customers served by this system and most of them use gas for space heating. Gas is fed into this system from distribution regulators located at Tuthill and Pennington and at Tunison and North Pennington Roads. This system is shown in Figure 13.

The estimated consumption of this system during the maximum hour of a zero degree day for the winter of 1976/77 was 29.4 MCFH of natural gas. The design criteria which must be met for this system is that the pressure at the lowest point cannot be below 4.2" water column, and the outlet pressure at the distribution regulator cannot exceed 7.5 inches water column under normal circumstances (see Appendix - Page 10).

If the flow studies show that the load on a zero degree day maximum hour with maximum input pressures results in pressures at any point lower than the minimum allowable, then modifications of some type must be made to the system. These could consist of one or more of the following.

- A. Increasing main sizes at key points in the system to increase load carrying capacity.
- B. Installing additional distribution regulators to supply the system.

Study Results:

100% Natural Gas

As a first step, the Tunison Road Utilization Pressure System was analyzed on the computer for the 1976/77 maximum design hour load of 29.4 MCFH of natural gas. The results showed that the demand could be met without violating any of the aforementioned criteria and without requiring reinforcements of any type. As shown in Figure 14, with the two regulators feeding at 6.0" water column pressure, the lowest pressure in the system is 5.38" at the end of Tunison Road. This is well above the minimum allowable 4.2".

Blend of 10% Hydrogen

This system was next analyzed for a 10% blend of hydrogen. The results shown in Figure 15, show that with the regulators still feeding at 6.0" water column pressure, the lowest pressure is now 5.35" at the end of Tunison Road. This is also well above the minimum allowable 4.2". Figure 15 does not show pressures at all points because only the lowest pressure points were tested.

Blend of 20% Hydrogen

The system was again analyzed for a 20% blend of hydrogen. The results, shown in Figure 16, again reveal that the lowest pressure, 5.32" at the end of Tunison Road, is still well above the minimum allowable 4.2". Figure 16 does not show pressures at all points because only the lowest pressure points were tested.

We conclude that the Tunison Road Utilization Pressure System can supply 20% hydrogen blends during the 1976/77 maximum hour on a zero degree day with no problems whatsoever.

Once again, it must be emphasized that test results for a different system could give different results. The system's ability to carry hydrogen blends is related to its excess capacity with straight natural gas.

PENNINGTON

DISTRIBUTION REGULATOR

1000'-4" PL

PIPE MATERIAL (PL IS PLASTIC
ALL OTHERS ARE CAST-IRON)

PIPE DIAMETER

LENGTH OF PIPE

CONNECTION TO OTHER PIPE

TUNISON ROAD UTILIZATION PRESSURE SYSTEM

TUNISON ROAD UTILIZATION PRESSURE SYSTEM

LEGEND

5.73" - PRESSURE, INCHES OF WATER COLUMN

1.7 - FLOW, THOUSAND CUBIC FT. PER HOUR

← - DIRECTION OF FLOW

0% HYDROGEN & 100 % NATURAL GAS

FIGURE 14

TUNISON ROAD UTILIZATION PRESSURE SYSTEM

LEGEND

5.72" - PRESSURE, INCHES OF WATER COLUMN

1.1 - FLOW, THOUSAND CUBIC FT. PER HOUR

— - DIRECTION OF FLOW

10% HYDROGEN & 90% NATURAL GAS

FIGURE 15

TUNISON ROAD UTILIZATION PRESSURE SYSTEM

LEGEND

5.70" - PRESSURE, INCHES OF WATER COLUMN

1.1 - FLOW, THOUSAND CUBIC FT. PER HOUR

← - DIRECTION OF FLOW

20 % HYDROGEN & 80 % NATURAL GAS

FIGURE 16

SERVICE SUBSYSTEM

The final link in the distribution system delivering gas to the customer's premises is the service pipe, which carries gas from the gas main to the building. As is the case with gas mains, services may be designed for utilization pressure or for 15, 60, or 120 PSIG. Again, as in the case of gas mains, graphs could be drawn to show the relationship between pressure loss and energy delivered for different blends of hydrogen in natural gas. These curves would be similar to Figures 3A and 3B and would show that in order to deliver the same amount of energy with a blend of hydrogen and natural gas as with straight natural gas, a larger pressure loss would occur.

Since PSE&G has criteria relating to acceptable pressure losses in a gas service, the increased pressure losses necessary for hydrogen blends would have to be within these criteria or modifications would have to be made. The modifications could consist of one or more of the following:

- a. Replacing all or part of the service with a larger pipe.
- b. Increasing operating pressures in the main system.

Because each service has its own characteristics (length, pressure at the main, load) no all inclusive statement can be made about the ability of all services to carry blends of hydrogen with natural gas. However it seems proper to make the generalization that all but a very small percentage of the services in the PSE&G system have the ability to carry up to 20% blends of hydrogen without exceeding the pressure loss criteria. This statement is based upon an examination of Figures 3A and 3B which show that for a given pressure loss, the total energy delivered with a 20% blend is about 5% less than with 100% natural gas. It is probable that the vast majority of services have at least this much excess capacity, and thus could carry the 20% blend with no problem.

DISCUSSION OF EXCESS CAPACITY IN SYSTEM

We have seen that for the two PSE&G distribution systems studied, 20% blends of hydrogen could be carried with little modification or reinforcing problems.

It must be remembered that the results for the main networks apply only to the particular systems studied. Figures 3A and 3B illustrate that for a given section of straight pipe with a given pressure loss, about 5% less energy is carried with a 20% blend of hydrogen than with straight natural gas. However, for an entire distribution network with its myriad of interconnecting pipes, it is impossible to predict in advance exactly what will be the effect on the pressure losses when distributing hydrogen blends rather than straight natural gas. We know the pressure loss will be greater, but we don't know how much greater or if it will have a significant effect on the ability of the network to deliver the required energy. That will depend on the existing excess capacity in the particular distribution network. Some systems will not have enough excess capacity to distribute blends of hydrogen, but most systems have excess capacity and can probably distribute 20% hydrogen blends with no problem.

The amount of excess capacity in any distribution system is the result of several factors. The most important of these factors are:

Design Capacity

When a gas main or system is originally designed, the engineer must consider not only the known load on the system, but also the expected load that will be added to the system in future years. Depending on how the actual load growth compares to the predicted load growth after a period of time, there may be excess capacity, or there may be no excess capacity. For instance, if the design was based on all future customers using gas for heating, but not all of them choose gas for heating, there will be excess capacity. If the design is based on homes being built on 100 foot lots but 125 foot lots are eventually built, then fewer homes and a smaller load results, and again there will be excess capacity. If the design considered only connected load for each customer and did not consider diversity of use¹, again there will be excess capacity. It is probable that most designs overestimate load.

1 Diversity of use means that the maximum load for all customers in a group does not occur simultaneously.

Pipe Sizes

Pipe used in gas systems come in a limited number of sizes. For instance, typical size mains now installed in the PSE&G system are 2", 3", 4", 6", 8", 12", 16", 20", 24", 30", and 36". If a new main is needed in the system, and a size in between these typical sizes (ie., - 9") is adequate, the next largest common size (12") would be installed. This also tends to give systems excess capacity.

History of System

A large portion of many distribution systems, particularly in the Northeast part of the nation, were originally designed to deliver 500-600 Btu manufactured gas. When natural gas was brought to those areas, the effect of having 1030 Btu natural gas was to approximately double the existing system capacities. Even with the growth in load since the conversion to natural gas, some of this excess capacity may remain in some systems.

As these companies expanded, additional supply points in the form of new meter stations had the effect of increasing capacity by more evenly spreading the load among more feeder mains.

Conservation

The vast majority of the gas distribution systems in the nation were designed prior to the current energy crisis. People are now exceedingly conscious of gas use because of rising prices and dwindling supplies, and consequently are using less gas. In addition, many government sponsored programs to spur the conservation of gas by lowering thermostats, installing more insulation, and designing more efficient appliances will have an additional effect on conservation. The effect of these efforts should be to provide more excess capacity in existing distribution systems.

One additional consideration is that a third gas with a higher heating value than hydrogen, such as propane or LNG, could possibly be blended at the same time as hydrogen. The increased heating value of these gases might enable 20% blends of hydrogen to be carried with no pressure increases needed. It is recommended that this be further evaluated.

While this study examined only one feeder main network and one utilization pressure network, it seems proper to state that most systems throughout the nation can probably handle 20% blends of hydrogen with little or no modification.

To substantiate this, a questionnaire was sent to approximately 10 utilities throughout the nation, asking their opinion of the extent of modification needed to deliver 20% blends of hydrogen through existing systems designed for natural gas distribution. These utilities were advised of the fact that the changes in heating value and specific gravity had a net effect of reducing energy delivery by about 5% for a 20% hydrogen blend. While some companies felt that major modifications would be necessary, most felt that only minor modifications would be necessary.

CONCLUSION

For the feeder main network studied, a 10% blend of volume of hydrogen in natural gas could be distributed with no delivery problems. For a 20% blend, by volume, some system modifications are necessary. The utilization pressure system studied could carry both 10% and 20% blends of hydrogen with no delivery problems. It is also likely that the vast majority of services could deliver 20% blends of hydrogen with no problems.

While each distribution system is a unique situation and should be studied separately, it appears to be a safe conclusion that 20% blends of hydrogen can be distributed in existing natural gas distribution systems with little or no modification in most cases.

POINTS OF POTENTIAL HYDROGEN ADMISSION

SUMMARY

The selection of the points at which hydrogen should be admitted to a distribution system to supplement natural gas is closely related to the requirements of the State Utility Commission. Aside from safety considerations, the utility commission's chief concern will most likely be that customers receiving the lower heating value blend are billed accordingly. To this end, the commission will probably require that the limits of the area receiving the blend are clearly defined so that these customers can be easily identified. From the utility's standpoint, the simplest way to define these limits would be to supply the blend to an entire distribution system, or if this cannot be done, at least to some easily defined sub-section of the distribution system. This can be done most easily if the utility blends hydrogen into natural gas at the meter stations supplying a particular distribution system.

ADMISSION INTO GAS TRANSMISSION LINES

If hydrogen was blended into a transmission company pipeline, the distribution utility would simply receive the blend mixture and distribute it to all its customers. This method would not only simplify the utility's operation, but it might make the hydrogen cost most economic by concentrating all the necessary equipment and manpower for the blending operation at one location rather than spreading them throughout an entire distribution system.

This method has several drawbacks however. One potential problem concerns hydrogen embrittlement. In the utility distribution system most pressures will be below 100 PSI, and pressures will rarely be above 400-500 PSI. At these pressures, hydrogen embrittlement of the pipeline materials is not expected to be a problem.

However, at the higher pressures at which pipelines commonly operate, hydrogen embrittlement may present a problem and preclude transporting hydrogen in this manner.

In addition, the lower specific gravity of hydrogen will result in a lower specific gravity of the blend with resultant increased compression costs. Coupled with the lower energy carrying capacity of the mixture, the overall affect will be that transmission costs for hydrogen blends will be higher than for straight natural gas.

Another problem is that once hydrogen is blended into a transmission pipeline at a certain point, all customers of the pipeline downstream of that point will have to receive the hydrogen-blend. Therefore if a transmission pipeline company decides to blend hydrogen at the request of a few utilities, the other utilities downstream of that point could have no choice in the matter.

Blending done by an interstate pipeline company could also involve regulation by Federal Agencies, whereas blending done by a utility alone would not involve any federal agency.

There are some systems where blending by the pipeline transmission company may not enable all customers in the distribution system to receive the same blend. Such a system is the Central West System studied in another section of this report. The Central West System is fed by two different transmission companies, Transcontinental and Texas Eastern. Both would have to be transporting hydrogen blends of the same percentage for all customers to get the same mix. This would require extremely close coordination on the part of the pipeline companies and would be quite cumbersome. In addition, either of the transmission lines may then go on to a different area served by some other pipeline company which would then be faced with the same problem. This dual service problem could continue across large areas.

Another deterrent to transporting the blends through transmission pipelines is the existence of natural gas liquefaction plants which are supplied by pipeline. The addition of hydrogen blends to the natural gas will complicate somewhat the natural gas liquefaction process.

Since many pipelines feed underground storage facilities near their markets, the underground storage of hydrogen-natural gas blends may present further problems. It is believed that the underground storage of hydrogen in the same manner in which natural gas is stored is feasible. It is not known if hydrogen-natural gas blends will remain stable over long periods of underground storage, or if the gases would separate or stratify during injection, storage, or withdrawal. Even if stratification is not a problem, storing hydrogen blends in existing natural gas storage fields will initially result in unpredictable heating values of the gas as it is withdrawn. Finally, storage field capacities and injection and withdrawal facilities will have to be increased to handle an equivalent amount of hydrogen-natural gas blends on an energy basis.

ADMISSION AT UTILITY GAS SUPPLY POINTS

Blending hydrogen into the distribution system at the point of supply (the meter station) appears to be the most practical method of blending. While it may require more capital investment to blend at many points rather than at one point on the pipeline system, this method eliminates the problem of utilities downstream being forced to accept hydrogen blends, and it eliminates any potential hydrogen embrittlement problems. It also means that there is no problem in supplying a uniform blend to an area that is fed from two different pipeline companies.

The major constraints to this method could be the lack of sufficient electric power at all meter stations to operate the electrolyzer, and the lack of space to house the necessary equipment.

ADMISSION AT SELECTED POINTS OF DISTRIBUTION SYSTEM

If hydrogen is not blended at the meter station, it would be possible to blend it at selected points in the distribution system at locations where the direction of flow is always constant. This would be necessary in order to keep the hydrogen blend in a known area for customer billing purposes.

This method could be used if only limited amounts of hydrogen for blending are available.

BLENDING METHODS

At the present time gas utilities blend peak shaving gases such as propane-air mixtures or oil gas into their regular natural gas supply as a routine operation. Hydrogen can most likely be blended in the same way using existing technology and equipment. There is extensive information on this topic in the technical and trade literature which need not be elaborated in this report.

IMPACT OF HYDROGEN - NATURAL GAS BLEND ON GAS DISTRIBUTION
SYSTEM AND REGULATORY STANDARDS

SUMMARY

An analysis of the Regulatory Commission rules in New Jersey reveals very few problem areas in distributing hydrogen blends, as far as existing regulations are concerned.

Only a few areas present any problems:

- A. Possible conflicts with a variety of existing codes, such as piping and plumbing codes, welding codes, electrical codes, and compressor station codes, should be determined by detailed study of those codes.
- B. Gas detector calibration could be difficult when the percentage of hydrogen in the blend is constantly varying. This should be further studied to see what difficulties, if any, are encountered.
- C. Odorizing hydrogen-natural gas blends requires further study.
- D. Purging mains for hydrogen-natural gas blends requires further study.
- E. Heating value calculations for billing purposes will be more complicated, but should present no big problem.

Since other states' regulatory standards regarding gas distribution may differ from New Jersey's, further study should be made of each state's rules in relation to distributing hydrogen blends.

REGULATORY STANDARDS

The rules of the Public Utility Commission of the State of New Jersey with respect to the distribution of gas are found in Chapter Six, "Gas", and in Chapter Eleven, Subchapter Eight "Natural Gas," of Title 14 of the New Jersey Administrative Code. (See Appendix - page 10.)

A section-by-section analysis of the effect the code would have on a utility's operations while distributing 10%-20% blends of hydrogen in natural gas follows.

Chapter Six Subchapter 1 Plant

14:6-1.1 Plant Construction

A possible problem arises in this section regarding USA Standard Codes of Pressure Piping, Gas Transmission and Distribution Piping Systems, and the USA Standard Installation of Gas Appliances and Gas Piping. It will be necessary to make a complete study of these codes to see what changes from present operations are necessary when distributing hydrogen and natural gas blends.

14:6-1.2 Tests on Service Installations

No problem complying with this section.

14:6-1.3 Inspection of Property

No problem complying with this section.

14:6-1.4 Service Line Valves

No problem complying with this section.

14:6-1.5 Emergency Shutdown

No problem complying with this section.

14:6-1.6 Gas Detectors

It may be difficult, if the percent of hydrogen in the blend varies with time, to keep gas detectors perfectly calibrated for the gas being distributed at the particular time. The accuracy of a gas detector, calibrated for natural gas, when analyzing gas samples with varying blends of hydrogen should be the subject of further study.

14:6-1.7 Twelve-inch Rule

No problem complying with this section.

Subchapter 2 Service

14:6-2.1 Service Connections; Regular Customers

No problem complying with this section.

14:6-2.2 Service Connections; Interruptible Customers

No problem complying with this section.

14:6-2.3 Heating Value

This section will present the most problems when hydrogen blends are introduced. While it will be possible to fulfill the requirements of this section, the actual mechanics may prove to be difficult at times. This entire question of heating value is discussed more fully later in this section.

14:6-2.4 Purity

No problem complying with this section.

14:6-2.5 Pressure Requirements

No problem complying with this section.

14:6-2.6 Venting of Customers' Service Regulators

No problem complying with this section.

14:6-2.7 Testing of Customer's Piping

No problem complying with this section.

14:6-2.8 Odorization

Some slight modification in odorization rates may be necessary with hydrogen blends, but it is expected that this section can easily be complied with.

14:6-2.9 Customer Information

No problem complying with this section.

14:6-2.10 Liaison with Public Officials

No problem complying with this section.

14:6-2.11 (Reserved)

14:6-2.12 Analysis and Reporting of Odor, Leak and Emergency Calls

No problem complying with this section.

14:6-2.13 Emergency Personnel

No problem complying with this section.

14:6-2.14 Training

No problem complying with this section.

Subchapter 3 Meters

14:6-3.1 Testing of Gas Meters

No problem complying with this section.

14:6-3.2 Periodic Meter Testing

No problem complying with this section.

14:6-3.3 Determination of Gas Meter Accuracy

No problem complying with this section.

Subchapter 4 Uniform System of Accounts

No problem complying with this subchapter.

Chapter Eleven
Subchapter Eight - Natural Gas

14:11-8.1 Scope

No problem complying with this section.

14:11-8.2 Compliance with Standard Code

A possible problem arises in this section regarding the American Standard Code for Pressure Piping, ASA B31.1.8. A complete study of the effect of hydrogen blends with respect to existing codes is required.

14:11-8.3 Classification of System

No problem complying with this section, assuming no code problems.

14:11-8.4 Proscribed Areas

No problem complying with this section.

14:11-8.5 Welding

The American Petroleum Institute and American Gas Association "Specifications for Field Welding and Radiographic Inspection of Pipe Lines" should be studied with regard to hydrogen use.

14:11-8.6 Quality control of field welding

No problem complying with this section, assuming no code problems.

14:11-8.7 Fabrication Details

No problem complying with this section, assuming no code problems.

14:11-8.8 Crossings

A problem complying with this section is unlikely, but the American Petroleum Institute, Code No. 1102 "Recommended Practice on Form Agreement and Specifications for Pipe Line Crossings under Railroad Tracks" should be studied with respect to hydrogen use.

14:11-8.9 Lines under or adjacent to railroads and highways
No problem complying with this section, assuming no code problems.

14:11-8.10 Valve spacing
No problem complying with this section.

14:11-8.11 Automatic valves
No problem complying with this section.

14.11-8.12 Blow-offs
No problem complying with this section.

14.11-8.13 Installation of pipe
No problem complying with this section.

14:11-8.14 Minimum cover
No problem complying with this section.

14.11-8.15 Projections
No problem complying with this section.

14.11-8.16 Corrosion control
No problem complying with this section.

14.11-8.17 Testing
No problem complying with this section, assuming no code problems.

14.11-8.18 Purging
No problem complying with this section. Additional work needs to be done to determine purging requirements when distributing hydrogen-natural gas blends.

14.11-8.19 Piping
The Standard Code applicable to compressor station piping should be studied with regard to hydrogen use.

14.11-8.20 Relief devices

No problem complying with this section.

14.11-8.21 Remote safety shut down

No problem complying with this section.

14:11-8.22 Clearance

No problem complying with this section.

14:11-8.23 Fire prevention

No problem complying with this section.

14:11-8.24 Electric installations

The National Electrical Code should be studied with regard to hydrogen use.

14:11-8.25 Ventilation

No problem complying with this section.

14:11-8.26 Piping

No problem complying with this section, assuming no code problems.

14:11-8.27 Electric Installations

The National Electrical Code should be studied with regard to hydrogen use.

14:11-8.28 Ventilation and protection

No problem complying with this section.

14:11-8.29 Odorization

No problem complying with this section. Additional work needs to be done regarding odorants in hydrogen-natural gas blends.

14:11-8.30 Accidents

No problem complying with this section.

14:11-8.31 Interruptions

No problem complying with this section.

14:11-8.32 Proposed Construction

No problem complying with this section.

14:11-8.33 Compliance; supplementary data on tests

No problem complying with this section.

14:11-8.34 Design consultants

No problem complying with this section.

HEATING VALUE CONSIDERATIONS

At the present time PSE&G is required to deliver to its customers gas with a minimum average heating value of 1020 Btu/scf. To verify that this is the case, the PUC requires from the Company each month a report which lists the daily average heating value of the gas received from each of the three pipeline companies supplying gas to Public Service. These heating values are measured by a calorimeter located at a meter station on each transmission company's pipeline. In addition, for any day in which PSE&G manufactured gas at one of its plants (oil gas, LPA, SNG) the average heating value of the gas sendout from each plant on that day is reported. To meet the State requirements, the heating value may not go lower than 5% below the 1020 level (970 Btu) on any one day, and the monthly average must be at least 1020 Btu's.

If hydrogen blends in natural gas were to be distributed, the customers would receive gas with a substantially lowered heating value. In the case of 10% hydrogen blends, the heating value would be 960 Btu per cubic foot. For 20% hydrogen blends, the heating value would be 889 Btu per cubic foot. It is certain that the Public Utility Commission of any state would require that the customers receiving this much lower heating value gas be billed accordingly.

In order to do this, the area receiving this gas, if it is not the entire Company's system, may have to be very clearly defined so that all customers receiving the lower heating value gas can be identified and billed accordingly. This can be accomplished by blending hydrogen in at key points such as meter stations so that the blend is confined to a specific area. Valving off certain sections of the distribution system to confine the gas to a specific area can also be done, but it is a practice sometimes frowned on by utilities because it decreases the reliability of the distribution system by reducing the number of feeds into an area.

Once the area is identified, the problem of variance in heating value must be faced. There are two basic ways in which the hydrogen blends could be handled.

In one method, a constant amount of hydrogen each hour could be blended into the system. As seen in Table I, the demand of the system would be changing each hour, so that the constant quantity of hydrogen being blended would result in a continually changing heating value. In the second method, a constant percentage of hydrogen each hour could be blended into the system. As shown in Table II, this would result in a constant heating value. It seems likely that a Public Utility Commission would prefer the latter system, or a least one where the heating value was fairly constant from hour to hour.

In a system such as that shown in Table I where the Btu varies each hour, it might be necessary to get a weighted average of the heating value according to the gas sent out in each hour. That is, a straight average of the 24 heating values for the day would not accurately reflect the fact that more 948 Btu gas was delivered between 7 AM and 8 AM than the amount of 889 Btu gas delivered from 11PM to 12AM. This could be corrected by weighting the blend heating value for each hour by the meter station sendout for that hour. While this method does not consider the different usage pattern by hours of the individual customers, it seems that it should be accurate enough to satisfy the regulatory commissions. Any further degree of sophistication may be prohibitive in expense.

There is a possibility that some combination of these two methods might be used. It may develop that the hydrogen is produced by off-peak or spinning reserve electricity, and can only be made during certain hours. If hydrogen storage facilities are found to be too expensive a system may be used where hydrogen is blended in at a constant percentage, resulting in a constant heating value, when electric power is available. The rest of

TABLE I
CONSTANT HYDROGEN PRODUCTION
and
VARYING HEATING VALUE SENDOUT

Hour	System Demand DTh	System Demand MCFH	H ₂ Sendout MCFH	Nat. Gas Sendout MCFH	% H ₂ In Blend By Volume	Btu
12AM-1AM	2068	2302	429	1873	18.6	899
1AM-2AM	2084	2317	429	1888	18.5	900
2AM-3AM	2162	2393	429	1964	17.9	904
3AM-4AM	2241	2470	429	2041	17.4	907
4AM-5AM	2351	2577	429	2148	16.7	912
5AM-6AM	2520	2741	429	2312	15.7	919
6AM-7AM	2901	3111	429	2682	13.8	933
7AM-8AM	3467	3660	429	3231	11.7	948
8AM-9AM	3340	3537	429	3108	12.1	945
9AM-10AM	3015	3221	429	2792	13.3	936
10AM-11AM	2791	3004	429	2575	14.3	929
11AM-12PM	2630	2847	429	2418	15.1	923
12PM-1PM	2492	2786	429	2357	15.4	921
1PM-2PM	2379	2604	429	2175	16.5	914
2PM-3PM	2323	2549	429	2120	16.8	912
3PM-4PM	2334	2650	429	2131	16.7	912
4PM-5PM	2420	2644	429	2215	16.2	916
5PM-6PM	2489	2779	429	2350	15.4	921
6PM-7PM	2360	2585	429	2156	16.6	913
7PM-8PM	2263	2491	429	2062	17.2	909
8PM-9PM	2128	2360	429	1931	18.2	902
9PM-10PM	2093	2326	429	1897	18.4	900
10PM-11PM	2011	2246	429	1817	19.1	895
11PM-12AM	1905	2143	429	1714	20.0	889

TABLE II
CONSTANT HEATING VALUE SENDOUT*
and
VARYING HYDROGEN PRODUCTION

Hour	System Demand DTh	System Demand MCFH	H ₂ Sendout MCFH	Nat. Gas Sendout MCFH	% H ₂ In Blend By Volume	Btu
12AM-1AM	2068	2326	465	1861	20	889
1AM-2AM	2084	2344	469	1875	20	889
2AM-3AM	2162	2432	486	1946	20	889
3AM-4AM	2241	2521	504	2017	20	889
4AM-5AM	2351	2645	529	2116	20	889
5AM-6AM	2520	2835	567	2268	20	889
6AM-7AM	2901	3263	653	2610	20	889
7AM-8AM	3467	3900	780	3120	20	889
8AM-9AM	3340	3757	751	3006	20	889
9AM-10AM	3015	3391	678	2713	20	889
10AM-11AM	2791	3139	628	2511	20	889
11AM-12PM	2630	2958	592	2366	20	889
12PM-1PM	2492	2803	561	2242	20	889
1PM-2PM	2379	2676	535	2141	20	889
2PM-3PM	2323	2613	523	2090	20	889
3PM-4PM	2334	2625	525	2100	20	889
4PM-5PM	2420	2722	544	2178	20	889
5PM-6PM	2489	2800	560	2240	20	889
6PM-7PM	2360	2655	531	2124	20	889
7PM-8PM	2263	2546	509	2037	20	889
8PM-9PM	2128	2394	479	1915	20	889
9PM-10PM	2093	2354	471	1883	20	889
10PM-11PM	2011	2262	452	1810	20	889
11PM-12AM	1905	2143	429	1714	20	889

*A 20% blend of hydrogen in natural gas.

the day no hydrogen would be made and straight natural gas would be distributed. This would probably necessitate a weighting method similar to that just described for the constantly varying heating value.

There is another, more complicated, method which might be used to keep the heating value constant all day regardless of the hours of operation of the hydrogen producing equipment, or the quantity produced. This method would involve blending air with straight natural gas or with the hydrogen-natural gas blend to maintain a steady heating value. This method has many drawbacks, including more sophisticated blending equipment, additional equipment for air supply, and possible objection to injecting air into the gas mains because of possible corrosion. In addition, the combustion characteristics may be such that it would be workable over only a very small range. Extensive work would have to be done on combustion characteristics before such a method could be seriously considered.

Regardless of the method used, it will be necessary to maintain calorimeters at each point where hydrogen is blended, and the entire process would be more complicated than at present. Nevertheless, it is workable.

APPENDIX

FLOW STUDIES FOR GASES OTHER
THAN NATURAL GAS

The computer program is based on natural gas with a heating value of 1030 Btu/SCF and a specific gravity of .60.

Studies for gases other than natural gas can be performed by applying appropriate factors to the natural gas loads, expressed as one thousand cubic feet per hour (MCFH).

For example, suppose a flow study for pure hydrogen is required.

From the Spitzglass formula, $Q \approx \frac{1}{G}$

$$\frac{Q_H}{Q_N} = \sqrt{\frac{G_N}{G_H}}$$

$$= \sqrt{\frac{0.60}{.0696}}$$

$$= 2.936$$

Where Q_H = Flow, hydrogen
 Q_N = Flow, Natural gas
 G_H = Specific gravity hydrogen = .0696
 G_N = Specific gravity nat. gas = 0.60

∴ Under conditions where initial pressures for both gases are equal, and final pressures for both gases are equal, hydrogen flow = 2.936 x natural gas flow.

On a thermal basis:

$$\frac{\frac{B_H}{325}}{\frac{B_N}{1030}} = 2.936$$

$Q = \frac{B}{HV}$, where
 B = Total Btu's
 HV = Heating Value

$$\frac{B_H}{B_N} = 2.936 \times \frac{325}{1030}$$

$$= 0.926$$

HV (hydrogen) = 325
 HV (nat. gas) = 1030

∴ Under conditions where initial pressures for both gases are equal, and final pressures for both gases are equal, hydrogen therms = 0.926 x nat. gas therms.

A. To make Hydrogen Study

1. Multiply natural gas loads (1030 Btu, 0.60 S.G.) by $\frac{1}{0.926} = 1.08$
2. Flow study will give pressures for equivalent (therm basis) hydrogen.

3. Multiply flows in Step 2 by 2.936 to get equivalent hydrogen volumes.

Above procedure can be used for other gases of various heating values and gravities.

B. For 10% Hydrogen Blend (10% H₂ + 90% Nat. Gas)

$$\frac{Q_H}{Q_N} = \sqrt{\frac{G_N}{G_H}} \quad \text{Where } Q_H = \text{Flow, (10\% H}_2 + 90\% \text{ nat. gas)}$$

$$Q_N = \text{Flow, natural gas}$$

$$G_H = \text{Specific Gravity (10\% H}_2 + 90\% \text{ nat. gas)}$$

$$G_N = \text{Specific gravity, natural gas} = .60$$

$$= \sqrt{\frac{.60}{.547}} = 1.047$$

∴ Under conditions where initial pressures for both gases are equal, and final pressures for both gases are equal, 10% mixture flow = 1.047 x natural gas flow.

On a thermal basis:

$$\frac{B_H}{B_N} = 1.047$$

$$\frac{B_H}{B_N} = 1.047 \times \frac{960}{1030}$$

$$= .976$$

Q = $\frac{B}{HV}$, where

B = Total Btu's

HV = Heating Value

HV (mixture) = 960

HV (nat. gas) = 1030

∴ Under conditions where initial pressures for both gases are equal, and final pressures for both gases are equal, 10% mixture therms = .976 x natural gas therms.

C. For a 20% Hydrogen Blend (20% H₂ + 80% Nat. Gas)

$$\frac{Q_H}{Q_N} = \sqrt{\frac{G_N}{G_H}} \quad \text{Where } Q_H = \text{flow (20\% H}_2 + 80\% \text{ nat. gas)}$$

$$Q_N = \text{Flow nat. gas}$$

$$G_H = \text{Specific Gravity (20\% H}_2 + 80\% \text{ nat. gas)}$$

$$G_N = \text{Specific Gravity nat. gas} = .60$$

$$= \sqrt{\frac{.60}{.494}} = 1.102$$

∴ Under conditions where initial pressures for both gases are equal, and final pressures for both gases are equal, 20% mixture flow = 1.102 x natural gas flow.

On a thermal basis:

$$\frac{B_H}{889} \div \frac{B_N}{1030} = 1.102$$

$$\frac{B_H}{B_N} = 1.102 \times \frac{889}{1030}$$

$$= .951$$

$$Q = \frac{B}{HV}, \text{ where}$$

B = Total Btu's
 HV = Heating Value
 HV (mixture) = 889
 HV (nat.gas) = 1030

∴ Under conditions where initial pressures for both gases are equal, and final pressures for both gases are equal,
 20% mixture therms = .951 x natural gas therms.

GAS DISTRIBUTION DEPARTMENT METHODS

2.1

DESIGN STANDARDS

PAGE 1

MAXIMUM DAY AND MAXIMUM HOUR DESIGN LOADS

2.1 Basis of Design

Distribution facilities are designed to meet the estimated maximum hour demand on a weekday with a mean temperature of 0°F and an assumed average wind velocity of 15 m.p.h. with Newark Airport as the measuring base. Production facilities are designed to meet the estimated maximum daily as well as maximum hourly demand.

Where the heating saturation is relatively high, the peak hour occurs between 7-8 A.M. or 8-9 A.M. due to raising thermostat settings. The design temperature used at these hours is minus 5°F.

The magnitude of the System Peak Day and Peak Hour demand and the heating and non-heating component of these demands for the 1972/73 winter season is shown below:

	<u>Peak Day</u>		<u>Peak Hour</u>	
	<u>Thousand</u> <u>Therms</u>	<u>Per</u> <u>Cent</u>	<u>Thousand</u> <u>Therms</u>	<u>Per</u> <u>Cent</u>
All Non-Heating	2,690	18.3	148	19.9
All Heating	12,010	81.7	594	80.1
	14,700		742	

Based on the present forecast of future sales, the heating component of the peak day and peak hour demand will not change significantly over the next 10-year period.

II: Minimum Federal Safety Standards For Gas Lines

relating to transportation of natural gas by pipeline
(Part 192, Title 49, Code of Federal Regulations)

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

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§ 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.

§ 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—Upgrading

§ 192.551 Scope.

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

§ 192.555 Upgrading 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 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

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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 increases, 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 ascertain compliance with § 192.117 or § 192.119, as applicable, the following procedures must be followed:

(1) If the original laying conditions cannot be ascertained, the operator shall assume, when applying the design formulas of ANSI A21.1, that cast iron pipe was supported on blocks with tamped backfill and, when applying the design formulas of ANSI A21.50, 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	Centrif- ugally cast pipe	
3-8	0.075	0.065	0.065
10-12	0.08	0.07	0.07
14-24	0.08	0.08	0.075
30-42	0.09	0.09	0.075
48	0.09	0.09	0.08
54-60	0.09		

NOTE.—The nominal wall thickness of the cast iron is the standard thickness listed in table 10 or table 11, as applicable, of ANSI A21.1 nearest the value obtained under this subparagraph. The nominal wall thickness of ductile iron pipe is the standard thickness listed in table 6 of ANSI A21.50 nearest the value obtained under this subparagraph.

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

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 establish a written operating and maintenance plan meeting the requirements of this part and keep records necessary to administer the plan.

§ 192.605 Essentials of operating and maintenance plan.

Each operator shall include the following in its operating and maintenance plan:

(a) Instructions for employees covering operating and maintenance procedures during nominal operations and repairs.

(b) Items required to be included by the provisions of Subpart M of this part.

(c) Specific programs relating to facilities presenting the greatest hazard to public safety either in an emergency or because of extraordinary construction or maintenance requirements.

(d) A program for conversion procedures, if conversion of a low-pressure distribution system to a higher pressure is contemplated.

(e) Provision for periodic inspections to ensure that operating pressures are appropriate for the class location.

§ 192.607 Plan for confirmation or revision of maximum allowable operating pressure.

(a) Before April 15, 1971, each operator shall complete a study to determine for each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress that is more than 40 percent of SMYS—

(1) The present class location of all such pipeline in its system; and

(2) Whether the hoop stress corresponding to the maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

(b) Each segment of pipeline that has been determined under paragraph (a) of this section to have an established maximum allowable operating pressure producing a hoop stress that is not commensurate with the class location of the segment of pipeline and that is found to be in satisfactory condition, must have the maximum allowable operating pressure confirmed or revised in accordance with § 192.611. The confirmation or revision must be completed not later than December 31, 1974.

(c) Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this section shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule, for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmations or revisions determined to be necessary under § 192.609, to the extent that they are caused by changes in class locations taking place before July 1, 1973.

[35 F.R. 13257, August 19, 1970, as amended by Amdt. 192-5, 36 F.R. 18194, September 10, 1971.]

§ 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.

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 as follows:

(a) If the segment involved has been previously tested in place to at least 90 percent of its SMYS for a period of not less than 8 hours, the maximum allowable operating pressure must be confirmed or reduced so that the corresponding hoop stress will not exceed 72 percent of 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) If the segment involved has not been previously tested in place as described in paragraph (a) of this section, the maximum allowable operating pressure 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.

(c) If the segment of pipeline involved has not been qualified for operation under paragraph (a) or (b) of this section, it 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 so as to be equal to or less than the following:

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

(2) 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.

(3) 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 the SMYS in Class 4 locations.

(d) 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.

(e) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under § 192.609 must be completed as follows:

(1) Confirmation or revision due to changes in class location that occur before July 1, 1973, must be completed not later than December 31, 1974.

(2) Confirmation or revision due to changes in class location that occur on or after July 1, 1973, must be completed within 18 months of the change in class location.

[35 F.R. 13257, Aug. 19, 1970, as amended by Amdt. 192-5, 36 F.R. 18194, Sept. 10, 1971.]

§ 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).

§ 192.615 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

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

(d) 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. 192-24, 41 F.R. 13586, Mar. 31, 1976.]

§ 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.

(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	Factor ¹	
	Segment installed before (Nov. 12, 1970)	Segment installed after (Nov. 11, 1970)
1	1.1	1.1
2	1.25	1.25
3	1.4	1.5
4	1.4	1.5

¹For offshore segments installed or uprated after July 31, 1977, that are not located on a platform, the factor is 1.25. For segments installed or uprated 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.

[Amdt. 192-27, 41 F.R. 34598, Aug. 16, 1976.]

(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) For furnace butt welded steel pipe, a pressure equal to 60 percent of the mill test pressure to which the pipe was subjected.

(5) For steel pipe other than furnace butt welded pipe, a pressure equal to 85 percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

(6) 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) (6) of this section is applicable, 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.

(c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, 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 F.R. 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 F.R. 17660, Nov. 17, 1970; Amdt. 192-27A, 41 F.R. 47252, Oct. 28, 1976.]

§ 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 a 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; or

(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.

(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 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.

(g) The odorization requirements of Part 190 of this chapter, as in effect on August 12, 1970, must be complied with, in each State in which odorization of gas in transmission lines is required by that part, until the earlier of the following dates:

(1) January 1, 1977; or

(2) The date upon which the distribution companies in that State are odorizing gas in accordance with paragraphs (a) through (f) of this section.

[35 F.R. 13257, Aug. 19, 1970, as amended by Amdt. 192-1, 35 F.R. 17335, Nov. 11, 1970; Amdt. 192-6, 36 F.R. 25423, Dec. 31, 1971; Amdt. 192-7, 37 F.R. 17870, Sept. 2, 1972; Amdt. 192-14, 38 F.R. 14943, June 7, 1973; Amdt. 192-15, 38 F.R. 35471, Dec. 28, 1973; Amdt. 192-16, 39 F.R. 45233, Dec. 31, 1974; Amdt. 192-21, 40 F.R. 20279, May 9, 1975.]

§ 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:

Class location of line	Maximum interval between patrols	
	At highway and railroad crossings	At all other places
1, 2,	6 months	1 year.
3,	3 months	6 months.
4,	do	3 months.

[Amdt. 192-21, 40 F.R. 20279, May 9, 1975.]

§ 192.706 Transmission lines: Leakage surveys.

(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 1 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—

(1) In Class 3 locations, at intervals not exceeding 6 months; and

(2) In Class 4 locations, at intervals not exceeding 3 months.

[Amdt. 192-21, 40 F.R. 20279, May 9, 1975.]

§ 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, railroad, and navigable waterway; and

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

However, until January 1, 1978, paragraphs (a)(1) and (a)(2) of this section do not apply to mains installed before April 21, 1975, and until January 1, 1978, paragraph (a)(1) of this section does not apply to transmission lines installed before April 21, 1975.

(b) *Exceptions for buried pipelines.* Line markers are not required for buried mains and transmission lines—

(1) Located offshore or under inland navigable waters;

[Amdt. 192-27, 41 F.R. 34593, Aug. 16, 1976.]

(i) Where placement of a marker is impractical; or

(ii) Where a program for preventing interference with underground pipelines is established by law; or

(2) In the case of navigable waterway crossings, within 100 feet of a line marker placed and maintained at that waterway in accordance with this section.

(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) *Markers other than at navigable waterways.* The following must be written legibly on a background of sharply contrasting color on each line marker not placed at a navigable waterway:

(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.

(e) *Markers at navigable waterways.* Each line marker at a navigable waterway must have the following characteristics:

(1) A sign, rectangular in shape, with a narrow strip along each edge colored international orange and the area between lettering on the sign and boundary strips colored white.

(2) Written on the sign in block style, black letters—

(i) The word "Warning," "Caution," or "Danger," followed by the words "Do Not Anchor or Dredge" and the words "Gas (or name of gas transported) Pipeline Crossing"; and

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

(3) In overcast daylight, the sign is visible and the writing required by paragraph (e)(2)(i) of this section is legible, from approaching or passing vessels that may damage or interfere with the pipeline.

(f) *Existing markers.* Line markers installed before April 21, 1975, which do not comply with paragraph (d) or (e) of this section may be used until January 1, 1980.

[Amdt. 192-20, 40 F.R. 13502, Mar. 27, 1975; Amdt. 192-20A, 41 F.R. 56807, Dec. 30, 1976.]

§ 192.709 Transmission lines: record-keeping.

Each operator shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service.

§ 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 (c), no operator may use a welded patch as a means of repair.

§ 192.713 Transmission lines: permanent field repair of imperfections and damage.

(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 pipelins 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 F.R. 34593, 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 1/8-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 p.s.i. 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 the diameter of the pipe in size.

(b) Submerged offshore pipelines and submerged pipelins 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 F.R. 34593, Aug. 16, 1976.]

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3.2

DESIGN STANDARDS

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3.2 Minimum Allowable Main Pressures

1. The pressures listed below are minimum allowable pressures. The gas pressure shall not be allowed to drop below the minimums listed. If lower pressures occur or are anticipated, some means of reinforcement shall be made.

MINIMUM ALLOWABLE MAIN PRESSURES

<u>Main Classification</u>	<u>Design Pressure</u>	<u>Minimum Allowable Pressure</u>
Distribution	6.0"-7.5" w.c.*	4.2" w.c.
Distribution	15 psi	1 psi
Distribution	60 psi	3 psi
Distribution	120 psi	5 psi
Feeder	15 psi	2 psi
Feeder	60 psi	5 psi
Feeder	120 psi	10 psi

* may be increased to a maximum of 9.0" w.c.
if a pressure booster is used at the distribution regulator.

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CHAPTER 6

GAS

Authority

Unless otherwise expressly noted, all provisions of this Chapter 6 were adopted by the Board of Public Utility Commissioners, pursuant to authority delegated at N.J.S.A. 48:2-13 *et seq.*, and were filed and became effective prior to September 1, 1969.

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SUBCHAPTER 1. PLANT

14:6-1.1 Plant construction

The construction and installation of plant and facilities of gas utilities must be in accordance with N.J.A.C. 14:3-2.1 (Plant construction) and in addition must be in accordance with the applicable

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requirements of the USA Standard Code of Pressure Piping, Gas Transmission and Distribution Piping Systems, and the USA Standard Installation of Gas Appliances and Gas Piping in effect at the time of construction. When and if any controversy arises as to the necessity for adopting specifications calling for construction of a higher standard, the matter may be referred to the Board for determination.

14:6-1.2 Tests on service installations

A leak test shall be made on each service installation.

14:6-1.3 Inspection of property

Prompt investigation of gas leaks should be made and such corrective action taken as is required by the facts and circumstances disclosed. A sufficient number of reliable portable devices for detecting the presence of combustible gas in the atmosphere shall be maintained as well as a sufficient number of reliable devices which will assure a substantially accurate knowledge at all times of the pressure existing in the system. Regulator stations shall be inspected for gas leaks with a combustible gas indicating device. These regulators shall be inspected at least once a year and repaired as necessary. Individual district regulators shall be inspected in such manner and with such frequency as may be necessary to maintain these regulators in condition to render safe and adequate service. A complete record shall be kept for two years of all such inspections, tests, conditions found and the corrective measures taken, in accordance with N.J.A.C. 14:3-6.2 (Plant and operating).

14:6-1.4 Service line valves

An outside shutoff valve shall be installed on every new and every renewed service line.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

14:6-1.5 Emergency shutdown

Each gas utility shall provide a sufficient number of valves in its distribution system, so that any section of its high-pressure distribution system can be shutdown in an emergency. In addition, each utility shall train all employees in the procedures to follow when it is necessary to reduce the flow of gas because of an emergency.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

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14:6-1.6 Gas detectors

(a) Combustible gas detecting instruments shall be assigned to all service men and other personnel who may be involved in the detection of gas leaks. The instruments shall be properly maintained and periodically calibrated in accordance with the manufacturer's reasonable specifications. Records shall be kept of such calibrations.

(b) A combustible gas detecting instrument shall be used by gas company personnel, in conjunction with other means of detection, in the investigation of any suspected gas leak. Any employee who may be called upon to investigate a suspected gas leak shall have adequate training in the use of gas detection instruments as well as other methods of leak detection.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

14:6-1.7 Twelve-inch rule

Mechanical equipment shall not be used within 12 inches of a gas pipe or facility unless the pipe or facility has been located and exposed by hand excavation. Under such circumstances the equipment will be used under adequate supervision. If the work is performed for the company by a qualified contractor, the contractor shall be informed, in writing, prior to the letting of the contract, of the requirements of this regulation.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

SUBCHAPTER 2. SERVICE

14:6-2.1 Service connections; regular customers

Each gas utility shall furnish and place, at no cost to the customer, up to 50 feet of service connection, measured at right angles from the nearest curb line to the customer's building, at the point of service entrance designated by the utility. Where the distance is in excess of 50 feet, the service pipe will be installed subject to a charge equal to the amount by which the cost of the service connection exceeds the greater of either $\frac{1}{2}$ of the customer's annual revenue as estimated by the utility or the cost of the first 50 feet of service connection which otherwise would be furnished without charge as provided above. Should the customer request a service entrance at a location other than that designated by the utility, the customer shall pay the additional cost associated with said change in point of service entrance provided that the customer shall not be required to pay for the first 50 feet of service connection in any case and, provided further, that the customer shall not be required to

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pay for any portion of the cost of the service connection if the cost thereof does not exceed $\frac{1}{2}$ of the estimated annual revenue. The utility will waive the charge to the customer when the amount is \$5.00 or less.

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EXAMPLE

	1st case	2nd case	3rd case
Length of Service Connection	75 feet	75 feet	75 feet
Cost per foot	\$4.00	\$4.00	\$4.00
Cost of Service Connection	\$300.00	\$300.00	\$300.00
Cost of 50 feet of Service Connection, Free 50 feet x \$4.00	\$200.00	\$200.00	\$200.00
1/2 of Customer's Annual Revenue	\$60.00	\$250.00	\$300.00
Cost to Customer	\$100.00	\$50.00	\$0

14:6-2.2 Service connections; interruptible customers

Each gas utility shall provide a service connection for an "interruptible" customer in accordance with its filed tariff or special agreement with the customer if special or unusual circumstances exist.

14:6-2.3 Heating value

(a) Each gas utility shall file with the Board information as to heating value of the gas (or gases) being distributed.

(b) The heating value shall be maintained with as little variation as is practicable and on any one day shall not fall below the standard specified in the tariff on file with the Board by more than five per cent.

(c) Each gas utility shall provide itself with a standard calorimeter outfit constructed and calibrated as approved by the National Bureau of Standards with which periodic tests of the gas shall be made. The utility may use a recording calorimeter which shall be maintained in proper working order and checked periodically with a standard calorimeter or against a standard gas. Such equipment shall be available, at all reasonable times, for the inspection by and the use of any authorized representative of the Board.

(d) The average heating value for any one day may be determined from the record of a recording calorimeter or it shall be taken as the average of all individual tests made that day using a standard calorimeter. The average of all such daily averages shall be taken as the monthly average. If the monthly average heating value is below the standard specified in the tariff, customers' bills shall be adjusted accordingly.

(e) Each gas utility shall report to the Board not later than the 15th of each month the daily average and the monthly average heating value of the gas (or gases) distributed in its system during the previous calendar month.

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(f) Heating value tests shall be made at a location or locations which will insure a representative sample of the gas being sent out to the distribution system.

(g) In maintaining the established heating value, the characteristic quality of the gas shall be such as to permit satisfactory combustion in the customer's appliances at all times without repeated adjustments of the burners.

(h) When a supplemental or substitute gas is distributed, the utility will make every reasonable effort to maintain gas characteristics and quality so that the utilization performance will be satisfactory regardless of the heating value of the gas.

14:6-2.4 Purity

(a) All gas distributed to customers shall be substantially free of impurities which may cause excessive corrosion of mains or piping or form corrosive or harmful fumes when burned in a properly designed and adjusted burner.

(b) Each gas utility supplying manufactured gas shall, except as to gas supplied by means of a liquid propane air plant, make daily tests for the presence of hydrogen sulphide. The hydrogen sulphide shall be considered negligible if a strip of white filter paper moistened with a solution of five per cent, by weight, lead acetate is not distinctly darker than a second strip freshly moistened with the same solution, after the first paper has been exposed for one minute in an apparatus through which gas is flowing at the rate of approximately five cubic feet per hour, the gas not impinging directly from the jet upon the test paper.

(c) All distributed gas shall not contain more than 30 grains of total sulphur per 100 cubic feet nor more than five grains of ammonia per 100 cubic feet.

14:6-2.5 Pressure requirements

(a) The pressure of the gas measured at the outlet of the meter of any customer, sometimes known as normal utilization pressure, shall be maintained to that point required to provide safe and efficient utilization of the gas in any properly adjusted appliance supplied through adequately sized customer's facilities.

(b) The allowable pressure variations within any 24 hour period shall not exceed 50 per cent above or 50 per cent below the normal utilization pressures, except for special arrangements made with industrial and commercial customers.

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14:6-2.9

14:6-2.6 Venting of customer's service regulators

(a) Each gas utility customer's service regulator installed indoors shall be vented to the outside atmosphere and shall have a vent pipe sized no smaller than the manufacturers' vent connection built into the regulator.

(b) The venting capacity of every service regulator shall be such as to protect the customer's appliances from an unsafe operating pressure. As an alternative, a separate pressure relief valve with a capacity such as to protect the customer's appliances from an unsafe operating pressure may be provided.

As amended, R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

14:6-2.7 Testing of customer's piping

Each gas utility, prior to establishing service, shall test the customer's piping for leakage and, if leakage is found, shall refuse service until the condition causing the leakage is corrected.

14:6-2.8 Odorization

All gas transmitted and distributed which does not naturally possess a distinctive odor to serve as a warning agent to employees and the public in the event of the escape of unburned gas shall be odorized with a suitable odorant. The amount of odorant in the gas shall not be less than that which is required to readily permit detection of its presence when the gas concentration in mixture with air is 20 per cent of the lower explosive limit. Each utility shall notify the Board of the type of odorant used and the location of the odorization stations. A suitable record shall be maintained for the most current two years showing the quantity of odorant added and the volume of gas odorized. Sufficiently frequent periodic tests shall be made at various points in each system to determine the adequacy of the odorization of the gas, and a suitable record of such tests shall be maintained for two years. Equipment for introduction of the odorant into the gas shall be designed so as to provide a reasonably uniform level of odor in the gas. The equipment and facilities for handling the odorant shall be located where the escape of odorant would not be a nuisance.

14:6-2.9 Customer information

(a) All customers shall be supplied by the gas company, at the time the meter is turned on or a new account is opened, printed information concerning the odor of gas and its characteristics and action to be taken if gas is detected (including a telephone number for the purpose of reporting such detection). The customer shall be also informed of the potential hazards of gas, the correct

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procedures for using gas appliances and how to keep them in safe operating condition. In addition, verbal instructions on the above matters shall be offered to the customer, if possible.

(b) The printed information shall be such that it can be easily understood and shall also be available in languages other than English which are spoken by a substantial number of non-English speaking people who reside in the company's service area.

(c) Additionally, each gas company shall periodically take steps to inform the general public in its service area of the odor of gas and its hazards along with correct procedures to follow if gas is detected.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

14:6-2.10 Liaison with public officials

Each gas utility shall maintain liaison with emergency personnel of each municipality in its service area and shall periodically make available information concerning the characteristics and hazards of natural gas which would be useful in handling an emergency in which natural gas may be a factor.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

14:6-2.11 (Reserved)

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

14:6-2.12 Analysis and reporting of odor, leak and emergency calls

(a) Each gas utility shall maintain a listed telephone number in appropriate telephone directories designated as a 24-hour number at which leak, odor or emergency calls may be received. These numbers shall be tended by utility personnel in order that such calls can be answered on a 24-hour basis with the assurance that appropriate action will be taken as rapidly as possible.

(b) Each gas company shall maintain a log which shows the receipt and handling of each leak, odor or emergency report received. Information concerning the time that the report was first received, that company personnel were first dispatched to the scene, that such personnel arrived, and that the condition was considered safe should be included. In addition, each gas company is required to analyze its performance in responding to such reports. Both the logs and the analysis shall be made available to the Board upon request. Summary reports shall be furnished to the Board quarterly in the form specified by the Board.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122(a), 6 N.J.R. 201(d).

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14:6-3.2

14:6-2.13 Emergency personnel

(a) Each gas company shall have available and equipped an adequate number of personnel to handle gas emergencies on a 24-hour a day, seven days a week basis. Emergency personnel must be able to reach all parts of the company's service area as rapidly as possible.

(b) Each employee who would respond to a gas emergency shall have adequate training in the proper procedures for handling gas emergencies, including but not limited to emergency shutdown procedures.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122 (a), 6 N.J.R. 201(d).

14:6-2.14 Training

Each gas company employee shall be adequately trained for the job to which he is assigned and shall have adequate knowledge of the characteristics and hazards of natural gas.

R.1974 d.87, eff. April 1, 1974.

See: 5 N.J.R. 122 (a), 6 N.J.R. 201(d).

SUBCHAPTER 3. METERS

14:6-3.1 Testing of gas meters

(a) Each gas utility shall provide itself with equipment necessary for testing meters, such equipment to consist of, as a minimum, a standard meter prover with suitable accessories. Utilities may cooperate in arranging for such facilities. Each prover will be inspected by the Board and furnished with an inspection tag or plate. Provers will be set up permanently in the location where they are to be used, and will be tested by an inspector of the Board, using a standard cubic-foot bottle which has been previously calibrated and certified by the National Bureau of Standards at Washington, D.C.

(b) Large volume displacement, rotary or orifice meters, may be tested by use of devices customarily used in the industry other than the standard as prover, provided the test method proposed to be followed is acceptable to the Board.

14:6-3.2 Periodic meter testing

Unless it has been otherwise authorized by the Board, no gas utility shall allow a gas meter to remain in service for a period longer than six years without checking it for accuracy and readjusting it if found to be incorrect beyond the limits established by Section 3 (Determination of gas meter accuracy) of this Subchapter.

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14:6-3.3 Determination of gas meter accuracy

A gas meter shall be considered correct if, when passing gas at the rate of 20 per cent of its rated capacity, it shows in comparison with a standard gas prover an error which is not greater than two per cent.

SUBCHAPTER 4. UNIFORM SYSTEM OF ACCOUNTS

14:6-4.1 Adoption by reference of the Uniform System of Accounts

The Board adopts by reference the Uniform System of Accounts for Classes A and B Gas Utilities that have been promulgated by the Federal Power Commission as well as all present and subsequent amendments, revisions, deletions and corrections which the Federal Power Commission may adopt insofar as they relate to gas utilities subject to the jurisdiction of the Board and are in accordance with the Board's policies and procedures.

14:6-4.2 Adoption by reference of rules concerning preservation of records; gas utilities

(a) On September 14, 1972, the Board of Public Utility Commissioners in the Department of Public Utilities, pursuant to authority of N.J.S.A. 48:2-1 *et seq.* and in accordance with applicable provisions of the Administrative Procedure Act of 1968, adopted by reference the "Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities" originally proposed to various states for adoption by the National Association of Regulatory Utility Commissioners as promulgated and published in April, 1972, for use by the electric, gas and water utilities.

(b) The Board of Public Utility Commissioners adopts these rules as its modified regulations governing the preservation and destruction of records for all classes of electric, gas and water utilities subject to its jurisdiction and as a supplement to its uniform system of accounts for all classes of electric, gas and water utilities.

(c) Copies of the full text of these rules are available for examination in the Board's offices in Room 208, 101 Commerce Street, Newark, New Jersey 07102, and are included in the case files in these dockets. Additional copies may be purchased from the National Association of Regulatory Utility Commissioners, P.O. Box 684, Washington, D.C. 20044.

R.1972 d.181, eff. September 18, 1972.

See: 4 N.J.R. 241(b).

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SUBCHAPTER 8. NATURAL GAS

Historical Note

Formerly Administrative Order 14:295

14:11-8.1 Scope

Unless otherwise ordered or permitted by the Board the following rules and regulations shall be observed and followed in connection with the construction, operation and maintenance of pipelines for the transmission of natural gas within and through the State of New Jersey.

14:11-8.2 Compliance with Standard Code

Any gas pipeline, other than a gas gathering pipeline, constructed after the effective date of this Subchapter which is subjected to, or is intended to be subjected to, an internal gas pressure in excess of 125 pounds per square inch gauge (psig) (above atmospheric pressure) shall be constructed and operated in compliance with the applicable provisions of the current edition of the American Standard Code for Pressure Piping, ASA B31.1.8-1955, formulated under the auspices of the American Standards Association of New York, New York (hereinafter referred to as the "Standard Code") or such other standard as the Board may from time to time prescribe. Any such pipeline which comes within the scope of the provisions of N.J.S.A. 48:10-2 to 10-9 and which was constructed prior to the effective date of these rules shall be deemed to be subject to any provisions of the Standard Code pertaining to operation and maintenance.

14:11-8.3 Classification of system

(a) Gas pipelines subjected to pressures of 125 pounds per square inch gauge (psig) or more shall be classified in accordance with the provisions of the Standard Code. However no portion of a gas pipeline shall be classified as less than Location Class 3 when such portion of the pipeline is constructed within 300 feet of, or if said pipeline is to operated at a pressure in excess of 500 psig within 500 feet of the following:

1. A place of residence;
2. A building used for public gathering;
3. Any school building, playground, or building devoted to institutional use;
4. Property that is zoned as residential; or

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5. A building devoted to a business in which more than three people are employed when such structures are in existence or under construction at the date of execution of the right-of-way agreement or at the date of filing with the clerk of the Superior Court of a complaint in a condemnation action. This additional classification shall not apply to buildings which are under control of the gas pipeline company.

14:11-8.4 Proscribed areas

Gas pipelines which are to be operated at a maximum pressure in excess of 250 psig shall not be installed within 100 feet of any building intended for human occupancy which is in existence prior to or under construction at the date of execution of the right-of-way agreement or at the date of filing with the clerk of the Superior Court of a complaint in a condemnation action, unless such installation is authorized and approved by the Board.

14:11-8.5 Welding

Welds, other than factory welds, on steel pipe of the physical and chemical properties for which the effective joint American Petroleum Institute and American Gas Association "Specifications for Field Welding and Radiographic Inspection of Pipe Lines" (hereinafter referred to in this Subchapter as Welding Specifications) are applicable shall be made in accordance with such Welding Specifications.

14:11-8.6 Quality control of field welding

All pipeline and piping welders shall be qualified in accordance with the requirements for the qualifications of welders as set forth in Welding Specifications. Throughout the construction period, representative samples of welds made by each welder or welding crew shall be removed from the line and tested to destruction in accordance with the provisions of the Welding Specifications or shall be radiographically examined in accordance with the Welding Specifications or examined by any other acceptable methods. In any pipeline construction project involving five miles or more of 16 inch O.D. or larger pipe at least 20 per cent of the welds in construction classified under paragraph 2 as Location Class 3 or Class 4 piping and at least 10 percent of the welds in construction classified under paragraph 2 as Location Class 1 or Class 2 pipeline, shall be examined radiographically in accordance with the Welding Specifications or examined by other methods deemed to be at least equally acceptable.

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14:11-8.7 Fabrication details

(a) The requirements set forth in subsections (b) through (d) of this Section in addition to the requirements of the Standard Code shall be applicable to the construction of gas pipelines.

(b) Straight pipe may be bent cold in the field by any of the accepted methods of smooth bending provided that the wall thickness and strength of the pipe after bending is not less than that required under the applicable provisions of the Standard Code for straight pipe of the same diameter and grade.

(c) Branch connections fabricated by welding shall be of the reinforced type made in accordance with the rules for reinforced connections as provided in the Standard Code. However, line taps may be made under pressure in the sizes and at the pressure at which the line tapping equipment is recommended for use by the manufacturer, provided that all proper safeguards against injury to persons and property are taken.

(d) Mitre welds shall not exceed $12\frac{1}{2}$ degrees and in any case shall not be used in pipelines subjected to or intended to be subjected to pressure of more than 250 psig.

14:11-8.8 Crossings

At points where a gas pipeline intersects a railroad or a highway, when such pipeline is, or is intended to be, subjected to an internal pressure in excess of 50 psig and having a diameter of six inches or more, the pipeline shall be enclosed in casing as herein provided and shall cross the railroad or highway in such a manner that the angle between the center line of the pipeline and railroad or highway shall be as near as practicable to 90 degrees. A gas carrying pipe within the scope of this Section crossing a railroad shall be enclosed in casing which at least meets the requirements of the specification in American Petroleum Institute Code No. 1102, "Recommended Practice on Form of Agreement and Specifications for Pipe Line Crossings under Railroad Tracks," (hereinafter referred to in this Subchapter as Specifications for Pipe Line Crossings). A gas carrying pipe within the scope of this Section crossing a highway shall be enclosed in a casing which at least meets the requirements of the Specifications for Pipe Line crossings, except that the minimum distance from the top of the casing to the used surface of the road shall be three feet six inches and where terrain permits, the casing shall extend beyond the edge of the pavement a distance of not less than 25 feet or to the line of right-of-way, whichever is less. When

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a highway is widened, the casing shall be extended so that it shall still meet the requirements of this Section. As used in this Subchapter, the term "highway" shall mean only a public road, other than a city or village street, with a hard surface which is intended for use throughout the year.

14:11-8.9 **Lines under or adjacent to railroads and highways**

(a) Every gas pipeline constructed and operated within the boundaries of a railroad right-of-way or a public hard surface highway or street or within 25 feet thereof, shall conform to the standards and requirements of the Standard Code for gas pipelines in Location Class 4.

(b) In the construction of any gas pipeline parallel to railroad tracks consideration shall be given to the character of the railroad traffic and the pressure and diameter of the gas pipeline in establishing the following:

1. The minimum amount of cover required over such pipeline;
2. The minimum proximity of the gas pipeline to the railroad track;
3. The need for additional valves to permit the prompt shutting off of gas in the event of pipeline failure or any other emergency;
4. The need, if any, for casing.

(c) Whenever reasonably possible to avoid doing so a gas pipeline subjected to or intended to be subjected to pressure in excess of 125 psig, should not be installed beneath and parallel to or within 25 feet of any public hard surface road or street. When such a gas pipeline is so installed the construction shall conform, as far as casing is concerned, to the provisions of Section 8.8 (Crossings) of this Chapter to the extent reasonably practicable.

(d) Notwithstanding the provisions of Section 8.8 (Crossings) of this Chapter and this Section, all applicable rules of other State or local agencies having jurisdiction which exceed the requirements of said rules shall be effective.

14:11-8.10 **Valve spacing**

(a) Shut-off valves shall be installed and maintained at strategic points on the pipeline system at intervals which will permit sections of the line to be isolated.

(b) In areas outside the boundaries of cities and villages where there are no houses within 300 feet of the pipeline, the appropriate length of such sections shall not be greater than 16 miles; and where houses are located within 300 feet of the pipeline, the appropriate length of such sections shall not be greater than eight miles.

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(c) Within the boundaries of cities and villages or in the vicinity thereof, sufficient additional valves shall be provided and other appropriate steps taken to provide means for promptly turning off the gas and rapidly reducing the pressure in any section of pipe in the event of a pipeline failure or other emergency.

(d) Each gas pipeline company shall designate a representative or representatives in New Jersey who are familiar with the location and operation of the shut-off valves. The names, addresses and telephone numbers of these representatives shall be furnished to the secretary of this Board and to the clerks of the municipalities through which the line is laid. Such representatives shall be available at all times for emergency service.

14:11-8.11 Automatic valves

Automatic valves should only be installed where the particular circumstances indicate that they will contribute to safer operation.

14:11-8.12 Blow-offs

Automatic blow-off or pressure relieving devices shall be installed in such a manner that the released gas will not present a hazard to nearby persons or property. Manually operated blow-off valves shall be operated in such a manner as to avoid hazard to nearby property or persons.

14:11-8.13 Installation of pipe

Inspection for storage and handling of pipe shall be adequate to assure that the pipe installed will be free of nicks or other forms of damage which would tend to produce a concentration of stresses or otherwise reduce the strength of the pipe below the minimum required under the applicable provisions of the Standard Code for the services conditions at which it is intended to operate the pipeline.

14:11-8.14 Minimum cover

(a) Gas pipelines within the scope of this Subchapter shall be laid with a cover of not less than 24 inches above the top of the pipe except where interference with other subsurface structures makes it impracticable to maintain this depth of cover, in which event the pipe shall be cased or protected with a suitable shield of metal. Gas pipelines shall be laid so as to avoid other subsurface structures and such pipelines shall not be laid within the distance of less than 12 inches from any other subsurface structure

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whenever reasonably practicable to avoid doing so. A structure providing a space in which a substantial volume of an explosive mixture might accumulate in the event that gas escapes from the pipeline shall be avoided when reasonably practicable to do so and preference shall be given to crossing over rather than under such structures.

(b) Whenever conditions permit, gas pipelines within cities and villages shall be laid with a cover of not less than 36 inches above the top of the pipe.

14:11-8.15 Projections

Any portion of a pipeline which protrudes above the ground shall be conspicuously painted, marked or fenced or otherwise protected against damage or tampering.

14:11-8.16 Corrosion control

(a) Where suitable investigation indicates that corrosion protection is needed, pipelines operated in excess of 125 psig shall be protected by any recognized method or combination of methods including coating with protective material, the application of cathodic current, the installation of galvanic anodes, and electrical isolation by sections.

(b) Whenever any gas pipeline company finds upon investigation that corrosion protection of gas pipelines located within the boundaries of cities or villages and to be operated at pressures in excess of 125 psig is not needed, the company shall submit to the Board a report setting forth good and sufficient reasons why such protection is not required, such report to include the results of soil tests and other supporting data.

(c) Whenever pipe coating is applied, the following additional precautions shall be taken by the company:

1. Tests and inspections shall be made before backfill to insure that the coating is adequate and satisfactory;

2. During backfill, precautions shall be taken to insure the coating is not damaged;

3. On completion of backfill, tests shall be made to ascertain if the coating is adequate and satisfactory.

(d) After installation of a pipeline, periodic inspection or tests of the line shall be conducted to determine whether or not the pipe metal is adequately protected. Each company shall maintain a suitable log, indicating the character and results of periodic inspection tests.

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14:11-8.17 Testing

(a) A section of pipeline classed as Location Class 1 gas transmission pipeline under Section 8.3 (Classification of system) of this Chapter shall be subjected to an internal fluid (gas, air or water) pressure test after the line is completed and before it is placed in operation at a test pressure established in accordance with the provisions of the Standard Code for such lines, but in any event at a pressure of at least 50 psig more than the maximum allowable working pressure.

(b) A section of pipeline classed as Location Class 2,3, or 4 pipeline under Section 8.3 (Classification of system) of this Chapter shall be subjected to a water pressure test after the line is completed and before it is placed in operation at a test pressure of not less than 150 per cent of the maximum allowable working pressure.

(c) The Board shall be notified at least two working days prior to pressure testing of any gas pipeline. Officials of municipalities wherein a line is to be tested shall also be notified in order that proper and adequate police protection may be provided.

(d) When water is used for testing, suitable provisions shall be made for disposal of the water on completion of the test. Suitable precautions shall also be taken to avoid contamination of local streams or water supplies in the event of a line failure.

(e) Test pressures, in accordance with the aforementioned, shall be maintained wherever possible for a period of 24 hours but in no event for a period of less than 12 hours.

(f) Subsequent to the pressure test a leakage test in accordance with the methods and procedures outlined in the United States Bureau of Mines Bulletin No. 265 entitled "Leakage from High Pressure Natural Gas Transmission Lines" or in accordance with any other recognized method shall be conducted for a sufficient period of time to detect any defects in the pipeline which may cause gas leakage when the line is placed in operation.

14:11-8.18 Purging

Air shall be purged from pipelines classed under Section 8.3 (Classification of system) of this Chapter as Location Class 2, 3, or 4 piping systems by introducing a suitable quantity of inert gas into the pipelines ahead of the combustible gas, or by any other suitable method which prevents formation of an explosive mixture in the pipeline.

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14:11-8.19 Piping

Gas piping in gas compressor stations shall be installed in accordance with the provisions of the Standard Code applicable to compressor station piping.

14:11-8.20 Relief devices

Pressure relief or other adequate protective devices of sufficient capacity and sensitivity shall be installed and maintained to assure that the maximum allowable working pressure of the station piping is not exceeded. Suitable provision shall be made for safely disposing of the gas released from such devices. Periodic tests and inspection shall be made to assure continued sensitivity of these devices.

14:11-8.21 Remote safety shut-down

Each compressor station with installed horsepower of more than 1,000 and operating at pressures in excess of 250 psig shall be provided with remote emergency shut-down devices which will allow the station to be shut down from a remote point, away from the compressor building.

14:11-8.22 Clearance

Compressor stations to be located on gas pipelines shall not be constructed in areas where such construction is prohibited under applicable zoning regulations and laws. At locations where a compressor station is constructed the distance between a building not under the control of the pipeline company and intended for human occupancy and the main compressor room of a compressor station which is intended to operate at pressures in excess of 250 psig shall not be, at the time of construction of the station, less than the distance indicated in the following table:

Installed Horsepower	Distance from Structure in Feet
Under 1000	250
1000 and over	500

14:11-8.23 Fire prevention

Supplies of gasoline, lubricants, paints and other similar combustible materials in excess of those required in actual operation shall be stored at a safe distance from the compressor building. Gas engine crankcases shall be vented outside the building with a vent not smaller than the connection

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provided by the compressor manufacturer. Warning signs adequate to indicate the danger involved shall be placed in conspicuous locations around the compressor station area.

14:11-8.24 Electric installations

All electric wiring, fixtures and devices within compressor buildings shall be designed and installed in accordance with Article 500 of the current edition of the National Electrical Code and shall meet the requirements thereof for Class I locations and shall also conform to applicable provisions of the current edition of the National Electrical Safety Code.

14:11-8.25 Ventilation

Compressor stations shall be provided with adequate natural draft ventilating devices.

14:11-8.26 Piping

All gas piping in meter and regulator stations shall comply with the requirements of the Standard Code for such piping.

14:11-8.27 Electric installations

All electric wiring fixtures and devices in meter and regulator station buildings shall be designed and installed in accordance with Article 500 of the current edition of the National Electrical Code and shall meet the requirements thereof for Class I locations, and shall also conform to applicable provisions of the current edition of the National Electrical Safety Code.

14:11-8.28 Ventilation and protection

Meter and regulator stations located on gas pipelines shall be provided with adequate ventilation. Any such station constructed underground shall be provided with double duct ventilation, each duct to be of a size sufficient to insure adequate ventilation but not less than four inches in diameter and shall extend a suitable height above ground level. All regulator stations located on gas pipelines shall be provided with a sufficient number of relief valves or other protective devices to insure that the complete failure of one or more regulator stations shall not impose pressures on any part of the

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transmission system beyond those which it is designed for or protected against.

14:11-8.29 Odorization

(a) All gas transmitted by gas pipelines having an insufficient odor of its own to serve as a warning agent in the event of the escape of unburnt gas shall be odorized with a suitable odorant. The Board shall be notified of the type of odorant used and the rates at which it will be added to the gas and the location of the odorization stations. A suitable log shall be kept showing the quantity of odorant added and the volume of gas odorized. Periodic tests should be made at various points in each transmission system to determine the adequacy of the odorization of the gas and a suitable record of such tests should be maintained.

(b) Equipment for introduction of the odorant into the gas shall be so designed as to provide a uniform level of odor in the gas. The equipment and facilities for handling the odorant shall be located where the escape of odorant would not be a nuisance.

14:11-8.30 Accidents

(a) Each gas pipeline company shall keep a record of and report to the Board all accidents which come within the meaning of reportable accidents as defined in this subsection, occurring in connection with the operation of the utility's plant property or facilities within the State.

(b) For the guidance of gas pipeline companies a reportable accident is defined as an accident other than a motor vehicle accident that results in one or more of the following circumstances:

1. Death of a person;
2. Serious disabling or incapacitating injuries to persons, including employees of the company;
3. Damage to the property of the company which materially affects its service to the public;
4. Damage to the property of others amounting to more than \$500.00.

(c) The Board shall be notified promptly by the speediest means of communication available of all accidents which are clearly reportable and those which there is good reason to believe may result in "reportable accidents" as defined herein. If such notification is not given in any case for

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the reason that the accident is not considered reportable, and it subsequently develops that the accident is reportable, the gas pipeline company involved shall notify the Board immediately after it has been ascertained that such accident is reportable.

Cross Reference

For other requirements relating to this subject, see Subchapter 5 (Reporting Accidents) of this Chapter

14:11-8.31 Interruptions

Service interruptions affecting customers in New Jersey shall be reported to the Board promptly by the speediest means of communication available. However, interruptions to service made in accordance with provisions set forth in contracts between gas pipeline companies and their customers need not be reported.

14:11-8.32 Proposed construction

(a) At least 30 days prior to the construction of major reconstruction of any gas pipeline intended to be subjected to pressure in excess of 125 psig, a report shall be filed with the Board setting forth the specifications for such pipeline.

(b) Every gas pipeline company shall, on the 15th day of each month, submit a report to the Board setting forth the progress of such construction or major reconstruction as of the end of the preceding month.

14:11-8.33 Compliance; supplementary data on tests

(a) Before a pipeline is placed in operation, a statement shall be submitted to the Board certifying that said pipeline has been tested and meets the requirements of the Standard Code and other rules herein for the maximum service pressure at which it will be operated. This statement shall also include:

1. Pressures at which the lines were tested;
2. The computation of maximum allowable working pressures in conformity with the provisions of the Standard Code; and
3. The results of leakage or tightness tests made on the line.

(b) No gas pipeline shall be operated at pressures in excess of the pressure for which it was certified to the Board.

(c) In instances where gas pipelines which come within the scope of N.J.S.A. 48:10-2 to 10-9, were placed in service prior to the effective date of

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these rules, a statement shall be filed with this Board within 60 days of the effective date of said rules indicating:

1. The nature of test such pipeline was subjected to before being placed in service;
2. The pressures at which the lines were tested;
3. Computation of maximum allowable working pressures; and
4. The results of leakage or tightness tests made on such line.

14:11-8.34 Design consultants

(a) Whenever the Board participates in the payment of the expense of the construction of a bridge or passage over or under and across a railroad right-of-way where such right-of-way intersects a road, street or avenue, the design work for such construction shall be performed by the Board, the railroad or by a competent consultant engaged by the Board as may be directed by the Board.

(b) Whenever the Board participates in the payment of the expense of the installation of protective devices at railroad grade crossings, the design work may be performed by a competent consultant engaged by the Board.

(c) This administrative order shall be effective on all Board orders directing construction or reconstruction of bridges or grade crossing protection issued on and after April 20, 1972.

R. 1972 d.124, eff. June 27, 1972.

See: 4 N.J.R. 52(c), 4 N.J.R. 197 (c).

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