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PART II

Statutory Notifications (S. R. O.)

GOVERNMENT OF PAKISTAN

OIL AND GAS REGULATORY AUTHORITY

NOTIFICAT ION

Islamabad, the 5th August, 2004

SRO No. 675(I)/2004:—In exercise of the powers conferred by Section 42 of the Oil and Gas Regulatory Authority Ordinance, 2002 (Ordinance XVII of 2002) the Oil and Gas Regulatory Authority is pleased to make the following regulations namely: -

1. Short title and Commencement: (1) These Regulations may be called the Natural Gas Transmission Technical Standards Regulations, 2004.

(2) They shall, come into force at once.

2. **Applicability.-** These regulations shall be applicable to all such licensees undertaking the regulated activity of transmission of natural gas including design**,** construction, testing, operation, maintenance and abandonment of a regulated activity.

[648(2004)/Ex. Gaz.]

3. Definitions. – (1) In these regulations, unless there is any thing repugnant in the subject or context,-

(i) "**Casing**" means a conduit through which a pipeline passes. The conduit is meant to protect the pipeline from external load and to facilitate the installation and removal of that section of the pipeline;

(ii) "**Cathodic Protection**" means a technique to prevent the corrosion of metal by making that metal, the cathode of an electrochemical cell;

(iii) "**Company**" means a licensee carrying out regulated activity of transmission of natural gas;

(iv) **"Component"** means any physical part of a pipeline;

(v) "**Corrosion Stray Current**" means corrosion resulting from direct current flow through paths other than the intended circuit;

(vi) "**Defect**" means a discontinuity or imperfection of sufficient magnitude to warrant rejection on the basis of the requirements;

(vii) "**Dent**" means a depression in the external surface of the pipe caused by mechanical damage that produces a visible irregularity in the curvature of the pipe wall without reducing the wall thickness (as opposed to a scratch or gouge, which reduces the pipe wall thickness);

(viii) "**Design Pressure**" means the theoretical pressure determined by the applicable design formula;

(ix) "**Electrical Isolation**" means the condition of being electrically separated from other metallic structures or the environment;

(x) "**Electro fusion**" It is a method of joining plastic pipe and fittings, in which heating, melting and bonding of pipe / or fitting takes place automatically, after an electro fusion fitting that has an electrical coil embedded in it is energized by a controlled and timed current passing through the coil;

(xi) "**Fitting**" means a component, including the associated flanges, bolts and gaskets used to join pipes, to change the direction or diameter of a pipeline, to provide a branch, or to terminate a pipeline;

(xii) "**Foreign Structure**" means any structure that is not part of the pipeline system;

(xiii) "**Heat Fusion Joint**" means a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the material when the parts are pressed together;

(xiv) "**Holiday**" means a discontinuity of the protective coating that exposes the metal surface to the environment;

(xv) "**Hoop Stress**" means circumferential stress acting perpendicular to the longitudinal axis of the pipe, arising from internal pressure;

(xvi) "**Hot Tap**" means a connection made to a pressurized pipeline;

(xvii) "**Hydrostatic Testing**" means the application of internal pressure above the normal or maximum operating pressure to a segment of pipeline, under no-flow conditions, for a fixed period of time, utilizing a liquid test medium;

(xviii) "**Imperfection**" means a material discontinuity or irregularity that is detectable by inspection;

(xix) "**Impressed Current**" means direct current supplied by a device employing a power source external to the electrode system;

(xx) "**Inert gas**" means a non-reactive and non-toxic gas such as argon, helium or nitrogen;

(xxi) "**Location Class**" means an area classified according to its general geographic and demographic characteristics;

(xxii) "**Low Stress Level**" means a stress level up to 6000 psi;

(xxiii) "**Lower Explosive Limit**" **(LEL)** means the lowest concentration of combustible gas in air that can explode;

(xxiv) "**Maximum Operating Pressure**" **(MOP)** is the highest pressure at which a pipeline system is operated during a normal operating cycle;

(xxv) "**Maximum Allowable Operating Pressure**" **(MAOP)** means the maximum pressure at which a pipeline may be operated or has been qualified;

(xxvi) "**Miter Joint**" means two or more straight sections of pipe matched and joined on a line bisecting at the angle of junction so as to produce a change in direction;

(xxvii) "**Nominal Wall Thickness**" means the thickness of the wall of a pipe that is nominated for its manufacture, ignoring the manufacturing tolerance;

(xxviii) "**NPS**" means nominal pipe size; used in conjunction with a non-dimensional number to designate the nominal size of valves, fittings and flanges;

(xxix) **"Person"** includes any individual or any legal entity including any partnership, firm, company, trust or corporation;

(xxx) "**Piping**" means an assembly of pipes, valves and fittings connecting auxiliary and ancillary components associated with a pipeline. This terminology is usually used for above ground pipe, but may sometimes be used for buried pipe also;

(xxxi) "**Private Rights-of-Way**" means rights-of-way not located on roads, streets, or highways used by the public, or on railroad rights-of-way;

(xxxii) "**Sales Meter Station**" means an installation that reduces high pressure gas from transmission system to the distribution system at permissible limits of distribution pressure. It may also measure volume of gas being injected into the distribution system and contain equipment/arrangements for odorization of Natural Gas passed through it;

(xxxiii) "**Specified Minimum Tensile Strength**" means the minimum tensile strength prescribed by the specification under which pipe is purchased from the manufacturer;

(xxxiv) "**Specified Minimum Yield Strength**" **(SMYS)** means the minimum yield strength prescribed by the specification under which pipe is purchased from the manufacturer, abbreviated as SMYS;

(xxxv) "**Station Pipe-Work**" means those parts of a pipeline within a station (e.g. pump station, compressor station, metering station) that begin and end where the pipe material specification changes to that for the mainline pipe-work;

(xxxvi) "**Stray Direct Current**" means current flowing through paths other than the intended circuit;

(xxxvii) "**Strength Test**" means a pressure test that confirms that the pipeline has sufficient strength to allow it to be operated at maximum allowable operating pressure (MAOP);

(xxxviii) "**Telescoped Pipeline**" means a pipeline that is made up of more than one diameter or MAOP, tested as a single unit;

(xxxix) "**Tensile Strength**" means the stress obtained by dividing the maximum load applied in a conventional tensile test by the original cross-sectional area of the test sample;

(xl) "**Trepanning**" means cutting a disk or cylindrical core from the metal;

(xli) "**Town Border Station**" **(TBS)** means a pressure regulating installation that reduces gas from high-pressure supply mains into feeder mains, which have services tapped from them;

(xlii) "**Up Rating**" means qualifying of an existing pipeline to a higher maximum allowable operating pressure;

(xliii) "**Upper Explosive Limit**" **(UEL)** means the highest concentration of gas in air that can explode;

(xliv) "**Vault**" means an underground structure, which is designed to contain piping and other components such as valves or pressure regulators; and

(xlv) **"Yield Strength**" means the stress at which a material exhibits the specified limiting offset or produces a specified total elongation under load, in a tensile test, as specified in the specification or standard under which the material is purchased;

(2) The words and expressions used in these regulations, but not defined herein shall have the same meanings as are assigned to them in the Ordinance.

4. Technical Standards for Transmission

Detailed natural gas transmission technical standards, specified by the Authority are given in the schedule to these regulations.

5. Compliance Compulsory

1) All such licensees, carrying out the regulated activity of transmission of natural gas, shall comply with the technical standards provided in these regulations.

2) The Authority in consultation with the licensee, may review, rescind, change, alter or vary any technical standard specified in these regulations.

SCOPE

This Standard covers the design, construction, operation and maintenance of natural gas pipeline transmission system. The scope of this Standard is limited to portions of pipeline system starting from the outlet of gas field / processing plant to the outlet of the sale meter station (SMS) or to the inlet of a large industrial customer's meter where the customer is supplied directly off a transmission line, at transmission line pressure. Maximum allowable operating pressures above 300 psig shall be classified as transmission pressures. It is not the intention to prevent a transmission lines from operating below 300-psig pressures, nor it is to restrict an enterprise from functioning in gas transmission as well in gas distribution business.

Pipelines from gas fields / processing plants to the outlets of sales meter stations (SMS) shall be classified as Transmission Lines irrespective of their operating pressures. The difference in pressure classification by this Standard and the Mineral Gas Safety Rules 1960 should also be noted. OGRA Gas Transmission Technical Standards' general limits are the Sales Meter Stations, or any system operating pressures above 300-psig. Figure 1 describes the limits of Transmission System.

Fabricated assemblies, pressure vessels, LPG and LNG installations and piping for design temperature below –20 ^{0}F or above 450 ^{0}F are not covered by this Standard.

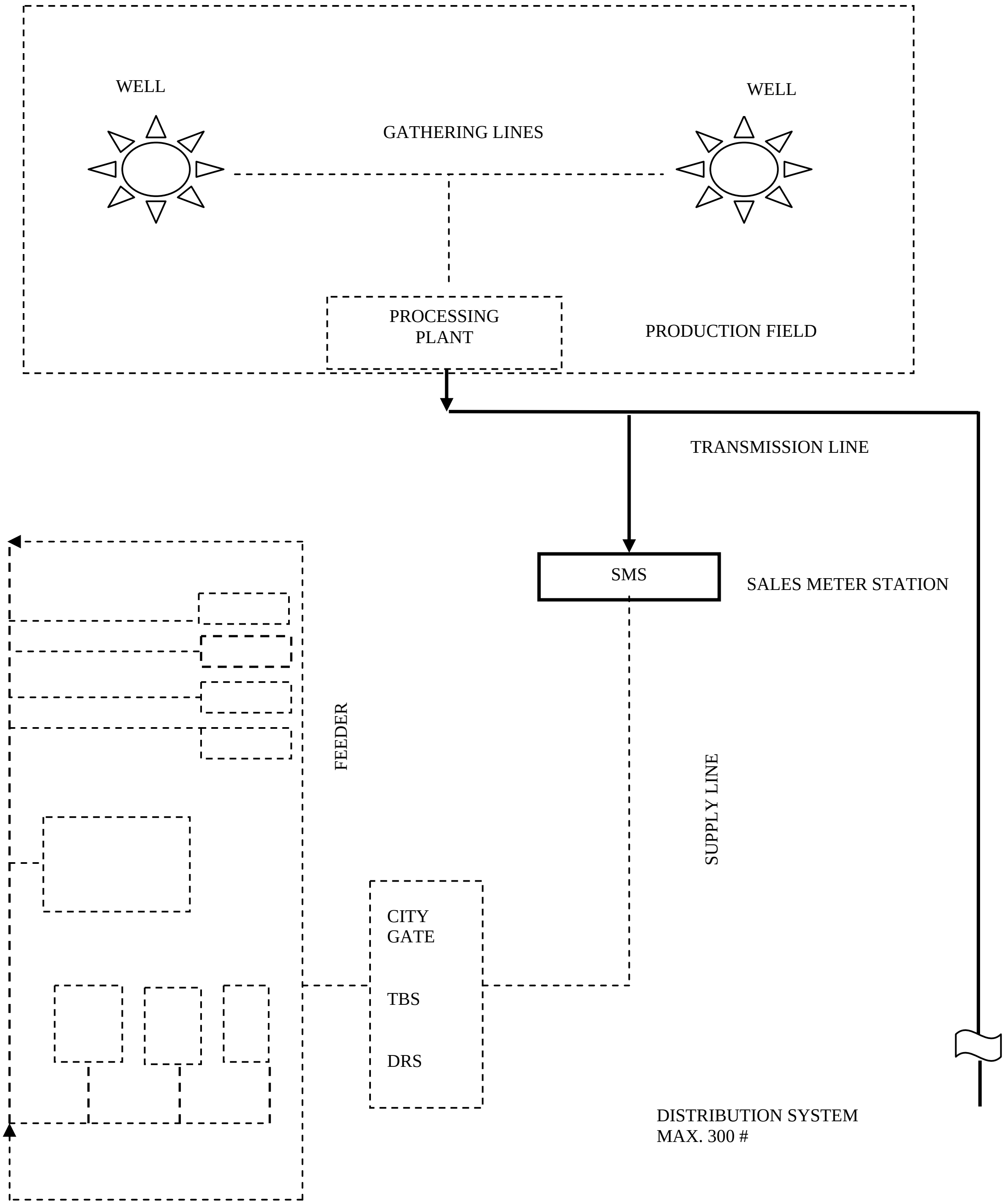

Fig. 1 – TRANSMISSION SYSTEM

(SHOWN IN SOLID LINES)

ABBREVIATIONS

AGA	American Gas Association
API	American Petroleum Institute
ASME	The American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
AWS	American Welding Society
BS	British Standards
CSA	Canadian Standards Association
CGA	Canadian Gas Association, also for Compressed Gas Association of USA
DIN	Deutsches Institut for Normung (German National Standards)
DOT	Department of Transportation, USA
ISO	International Organization for Standardization
MSS	Manufacturers Standardization Society
NACE	National Association of Corrosion Engineers
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration, USA
PE	Polyethylene
RP	Recommended Practice
SP	Standard Practice
WC	Water Column, a unit of pressure.

1. DESIGN

1.1. Pipe Design

Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressure and loads that will be imposed on the pipe after installation.

1.2. Design Formula for Steel Pipe

The design pressure for steel pipe is determined in accordance with the following formula:

$$P = (2St/D) \times F \times E \times T$$

Where:

P = Design pressure in pounds per square inch gauge

S = Yield strength in pounds per square inch

D = Nominal outside diameter of pipe in inches

t = Nominal wall thickness of the pipe in inches. Pipe wall thickness must be equal or greater than minimum wall thickness given in Table 1.2

F = Design factor – see Table 1.4

E = Longitudinal joint factor – see Table 1.1

T = Temperature de-rating factor – see Table 1.5

(Ref: U.S. Department of Transportation 191-192)

1.3. Yield Strength Determination

Some of the commonly used pipe specifications are listed below:-

API 5L	Steel pipe
ASTM A 53	Steel pipe
ASTM A 106	Steel pipe
ASTM A 333/M	Steel pipe
ASTM A 381	Steel pipe
ASTM A 671	Steel pipe
ASTM A 672	Steel pipe
ASTM A 691	Steel pipe

The yield strength to be used in design formula is the SMYS, given for a particular specification pipe.

For pipe that is manufactured in accordance with a specification not listed, or whose specification or tensile properties are unknown, the yield strength to be used in design formula is one of the following.

a) If the pipe is tensile tested, the lower of the following:

- Eighty (80) percent of the average yield strength determined by the tensile tests.

- The lowest yield strength determined by the tensile tests.

b) If the pipe is not tensile tested, use 24000 psi.

1.4. Nominal Wall Thickness

a) If the nominal wall thickness for steel pipe is not known, it is to be determined by measuring the thickness of each piece of pipe at quarter points on one end.

b) If the pipe is of uniform grade, size, and thickness, and there are more than 10 lengths, measure only 10 percent of the individual lengths, but not less than 10 lengths. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

1.5. Design Factor (F)

The design factor is dependent on location classes that are given in Table 1.3. For the design factor, first determine the location class from Table 5.3, and then read the design factor from Table 1.4.

1.6. Longitudinal Joint Factor (E)

The longitudinal joint factor to be used in the design formula is determined in accordance with Table 1.1.

1.7. Temperature Derating Factor (T)

The temperature de-rating factor T is dependent on the maximum operating temperatures of the pipeline. See Table 1.5.

1.8. Valves

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements, of **API 6D** or equivalent. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in those requirements.

(b) Each valve must be able to meet the anticipated operating conditions.

(c) No valve having pressure-containing parts made of ductile iron may be used in the gas pipe components of compressor stations.

1.9. Flanges and Flange Accessories

(a) Flange or flange accessories must meet the minimum requirements of ANSI B16.5, MSS SP-44, or the equivalent.

(b) Flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature that it might be subjected to.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME B16.1 and be cast integrally with the pipe, valve or fitting.

1.10. Standard Fittings

a) The minimum metal thickness of threaded fittings may not be less than specified for the pressure and temperatures in the applicable standards referenced in this part, or their equivalent.

b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.

The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline.

1.11. Welded Branch Connections

Welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight and vibration.

1.12. Extruded Outlets

Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

1.13. Flexibility

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stress in the pipe or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

1.14. Support and Anchors

a) Each pipeline and its associated equipment must have enough anchors or supports to:

- Prevent undue strain on connected equipment
- Resist longitudinal forces caused by a bend or offset in the pipe
- Prevent or dampen excessive vibration.

b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

- Free expansion and contraction of the pipeline between supports or anchors may not be restricted.
- Provision must be made for the service conditions involved.
- Movement of the pipeline must not cause disengagement of the support equipment.

d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:

- A structural support may not be welded directly to the pipe.
- The support must be provided by a member that completely encircles the pipe.
- If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.

f) Each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

1.15. Transmission Line Valves

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows:

- In location class 4, every 5 miles.
- In location class 3, every 10 miles.
- In location class 2, every 15 miles
- In location class 1, every 20 miles.

(b) Each sectionalizing block valve on a transmission line must comply with the following:

(c) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

(d) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached

1.16. Pressure Control

Under normal operation, pressure on the outlet side of the regulating station or a customer service regulator must not exceed the following limits:

Sales Meter Station

300 psig (Supply Line Max. Pressure)

1.17. Design of Pressure Relief and Limiting Devices

Pressure-control / relief systems shall be installed where supply from any source makes it possible to pressurize the piping above its maximum operating pressure. Such pressure-control systems shall be set to operate at or below the maximum operating pressure. Except for rupture discs, each pressure relief or pressure-limiting device must:

a) Be constructed of materials such that the operation of the device will not be impaired by corrosion.

b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative.

c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position.

d) Have support made of noncombustible material.

e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard.

f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity.

g) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

h) Where appropriate, protected with rain caps to prevent the entry of water.

1.18. Required Capacity of Pressure Relieving and Limiting Stations

Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate to ensure the following:

a) The pressure must not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

b) Where failure of the pressure-control system, or other causes, could result in the maximum operating pressure of the piping being exceeded by no more than 10% or by 5 psig (35 kPa) whichever is the greater.

1.19. Instrument, Control, Sampling Pipe and Components

a) This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

b) All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

- Each takeoff connection and attaching boss, fitting or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

- Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blow down valves must be installed where necessary.

- Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

- Pipe or components in which liquids may accumulate must have drains or drips.

- Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

- The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

- Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints must not be used. Expansion must be allowed for by providing flexibility within the piping itself.

- Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

- Suitable precautions shall be taken to protect against corrosion.

VAULTS

1.20. Structural Design Requirements

a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated and maintained.

c) Each pipe entering, or within a regulator, vault or pit must be of steel, for sizes NPS 10 and less, except that control and gage piping may be stainless steel. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening, and to avert strains in the pipe.

1.21. Accessibility

Each vault must be located in an accessible location and, so far as practical, away from:

a) street intersections or points where traffic is heavy or dense

b) points of minimum elevation, catch basins or places where the access cover will be in the course of surface waters

c) water, electric, steam, or other facilities.

1.22. Sealing, Venting, and Ventilation

Each underground vault or closed-top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station must be sealed, vented or ventilated as follows:

a) When the internal volume exceeds 200 cubic feet (6 cubic meters):

- The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of NPS 4 pipe.
- The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit.
- The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged. The recommended height is 8' (2m) from grade.

b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (6 cubic meters):

- If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be means for testing the internal atmosphere before removing the cover.
- If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere.

1.23. Drainage and Water Proofing

a) Each vault must be designed so as to minimize entrance of water.

b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of U.S. National Electrical Code, ANSI/NFPA 70.

(Ref: U.S. Department of Transportation 191-192)

TABLE 1.1 – LONGITUDINAL JOINT FACTOR (E) FOR STEEL PIPE

Specification	**Pipe Manufacturing Classification**	**Longitudinal Joint Factor (E)**
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A 106	Seamless	1.00
ASTM A 333	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric-fusion-welded	0.8
ASTM A 672	Electric-fusion-welded	0.8
ASTM A 691	Electric-fusion-welded	1.00
API 5 L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60
Other	Pipe over NPS 4	0.80
Other	Pipe NPS 4 and smaller	0.60

TABLE 1.2 – LEAST NOMINAL WALL THICKNESS FOR STEEL CARRIER PIPE FOR GAS PIPELINES SYSTEMS

LEAST NOMINAL WALL THICKNESS FOR STEEL CARRIER PIPE (IN.)

	Plain End Pipe			Threaded Pipe*
NPS	Location Class 1	Location Class 2	Location Class 3 & 4	All Classes
3/8	.091	.091	.091	.091
½	.083	.083	.083	.110
¾	.083	.083	.083	.113
1	.083	.083	.083	.133
1¼	.083	.083	.083	.140
1 1/2	.083	.083	.083	.145
2	.083	.083	.083	.154
2 1/2	.083	.087	.087	.204
3	.083	.098	.098	.216
3 1/2	.083	.106	.106	.224
4	.083	.118	.118	.236
5	.083	.125	.125	
6	.083	.134	.154	
8	.125	.134	.173	
10	.154	.165	.188	
12	.173	.173	.204	
14	.188	.188	.208	
16	.188	.188	.219	
18	.188	.188	.250	
20	.188	.188	.250	
22, 24, 26	.219	.219	.250	
28, 30	.219	.250	.281	
32, 34, 36	.219	.250	.312	
38-54 inclusive	.250	.250	.312	

Note:

*The least nominal wall thickness of threaded pipe using National Pipe Threads (NPT) shall be as given in Table 1.2 for threaded pipe, but not less than that specified for plain end pipe. Where threads other than NPT are used, the thickness under the last engaged thread (based on nominal dimensions) shall be at least 0.5 times the nominal wall thickness of the pipe, but in no case shall the nominal wall thickness be less than that specified for plain end pipe.

TABLE 1.3 – LOCATION CLASSES

a) **Location Class 1.** A Location Class 1 is any one mile long section ¼ mile wide containing the gas pipe in the middle that has 10 or fewer buildings intended for human occupancy. A Location Class 1 is intended to reflect areas such as wasteland, deserts, mountains, grazing land, farmland, and sparsely populated areas.

b) **Location Class 2.** A Location Class 2 is any one mile section ¼ mile wide containing the gas pipe in the middle that has more than 10 but fewer than 46 buildings intended for human occupancy. A Location Class 2 is intended to reflect areas where the degree of population is intermediate between Location Class 1 and Location Class 3 such as fringe areas around cities and towns, industrial areas, ranch or country estates, etc.

c) **Location Class 3.** A Location Class 3 is any one mile section ¼ mile wide containing the gas pipe in the middle that has 46 or more buildings intended for human occupancy. A Location Class 3 is intended to reflect areas such as suburban housing developments, shopping centers, residential areas, industrial areas, and other populated areas not meeting Location Class 4 requirements.

d) **Location Class 4.** Location Class 4 includes areas where multistory buildings are prevalent, and where traffic is heavy or dense and where there may be numerous other utilities underground. Multistory means 4 or more floors above ground including the first or ground floor. The depth of basements or number of basement floors is immaterial.

TABLE 1.4 – DESIGN FACTOR (F)

Facility	**Design factor f for location class**			
	1	**2**	**3**	**4**
all pipelines including services with the exception of facilities described in the following rows	0.72	0.6	0.5	0.4
uncased crossings or parallel encroachments of roads, highways and railway tracks	0.6	0.6	0.5	0.4
uncased water bodies or bridge crossings	0.6	0.6	0.5	0.4
fabricated assemblies (station piping)	0.6	0.6	0.5	0.4
compressor stations*	0.5	0.5	0.5	0.4

*It is recommended that piping within the compound of a compressor station be designed to ASME B31.3 Pressure Piping Code.

TABLE 1.5 – TEMPERATURE DERATING FACTOR (T)

Gas Temperature Max.	Temperature Derating Factor (T)
250 ^{0}F (121 ^{0}C)	1.0
300 ^{0}F (149 ^{0}C)	0.967
350 ^{0}F (177 ^{0}C)	0.933
400 ^{0}F (204 ^{0}C)	0.900
450 ^{0}F (232 ^{0}C)	0.867

Interpolate figures for intermediate temperatures.

(Ref: U.S. Department of Transportation 191-192)

COMPRESSOR STATION DESIGN

1.24. Location of Compressor Buildings

Except for offshore pipeline, the main compressor buildings for gas compressor stations should be located at such distances from adjacent properties, not under control of the Company as to minimize the hazard of spreading of the fire to the compressor buildings from structures on adjacent properties. Sufficient open space should be provided around the building to permit the free movement of the firefighting equipment.

1.25. Building Construction

All compressor station buildings that house gas piping in sizes larger than NPS 2, or equipment handling gas (except equipment for domestic purposes) shall be constructed of noncombustible or limited combustibility materials as defined in ANSI / NFPA 220.

1.26. Exits

A minimum of two exits shall be provided for each operating floor of a main compressor building, basements, and any elevated walkway or platform

10 ft. or more above ground or floor level. Individual engine catwalks shall not require two exits. Exits of each such building may be fixed ladders, stairways, etc. The maximum distance from any point on an operating floor to an exit shall not exceed 75 ft., measured along the centerline of aisles or walkways. Exits shall be unobstructed doorways located so as to provide a convenient route for escape, and shall provide unobstructed passage to a place of safety. Door latches shall be of a type that can be readily opened from the inside without a key. All swinging doors located in an exterior wall shall swing outward. They shall be fitted with panic hardware.

1.27. Fenced Areas

Any fence that may hamper or prevent escape of persons from the compressor station in an emergency shall be provided with a minimum of two exits. These gates shall be located so as to provide a convenient opportunity for escape to a place of safety. Any such gate located within 200 ft. of any compressor plant building shall open outward and shall be unlocked (or capable of being opened from the inside without a key) when the area within the enclosure is occupied. Alternatively, other facilities affording a similarly convenient exit from the area may be provided.

1.28. Electrical Facilities

All electrical equipment and wiring installed in gas transmission compressor stations shall conform to the requirements of ANSI / NFPA 70, insofar as equipment commercially available permits. Electrical installations in hazardous locations as defined in ANSI /NFPA 70, and which are to remain in operation during compressor station emergency shutdown shall be designed to conform ANSI / NFPA 70 for Class 1, Division 1 requirements.

1.29. Ventilation

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

1.30. Liquid Removal

(a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to move entrained liquids must have the following features:

- A manually operable means of removing these liquids.

- Where slugs of liquid could be carried into the compressors, the station must have an automatic liquid removal facility, an automatic compressor shutdown device, or a high liquid level alarm.

- Be manufactured in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4 or less.

1.31. Emergency Shutdown

(a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following requirements:

- It must be able to block gas out of the station and blow down the station piping.

- It must discharge gas from the blow-down piping at a location where the gas will not create a hazard.

- It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building except that:

  - Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized.

  - Electrical circuits needed to protect equipment from damage may remain energized.

- It must be operable from at least two locations, each of which is to be

  - o Outside the gas area of the station
  - o Near the exit gates, if the station is fenced, or near emergency exits, if not fenced
  - o Not more than 500 ft. (153 m) from the limits of the station

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time, and thus cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

- In the case of an unattended compressor station:
  - o When the gas pressure equals the maximum allowable operating pressure plus 15 percent.
  - o When an uncontrolled fire occurs on the platform.
- In the case of a compressor station in a building:
  - o When an uncontrolled fire occurs in the building.
  - o When the concentration of gas in air reaches 50 % LEL or more in a building that has a source of ignition.

1.32. Pressure Limiting Devices

a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than ten percent.

b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

1.33. Additional Safety Equipment

(a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

(c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

(d) Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents of the engine distribution manifold.

(e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

2. CONSTRUCTION

2.1. Compliance with Specifications and Standards

Each pipeline must be constructed in accordance with comprehensive written specifications or standards that are consistent with this document.

2.2. Inspection

Construction inspection provisions for pipelines and related facilities shall be adequate to assure compliance with the material, construction, welding, assembly, and testing requirements of this Standard.

2.3. Qualification of Inspectors

a) Inspection personnel shall be qualified by training and experience. Such personnel shall be capable of performing the following inspection services:

- Right of way and grading
- Ditching
- Line up and pipe surface inspection

- Welding
- Coating
- Tie-in and lowering
- Backfilling, compaction and clean up
- Pressure testing
- Special services for testing and inspection of facilities, such as station construction, river crossings, electrical installation, radiography, corrosion control, etc., as may be required.

(Ref: ASME B 31.8- 99)

2.4. Right Of Way

Pipe routing should be selected so as to minimize the possibility of hazards from future industrial or urban development, encroachment of the right of way or line routing, and damage to environmentally sensitive, or archeological and historical sites.

2.5. Construction Requirements

Inconvenience to the residents should be a minimized and safety of the public shall be given prime consideration.

All blasting shall be in accordance with the governing regulations and shall be performed by competent and qualified personnel; it shall be performed so as to provide adequate protection to the general public, livestock, wildlife, buildings, telephone, telegraph, power lines, underground structures and any other property in the proximity of the blasting.

In grading the right of way, every effort shall be made to minimize damage to the land, and to prevent abnormal drainage and erosive conditions. The land is to be restored to as nearly original condition as is practical. In constructing pipeline crossings of railroads, highways, streams, lakes, rivers, etc, safety precautions such as sign, light, guard rails, etc., shall be, maintained in the interest of public safety. The crossing shall comply with the applicable rules, regulations, and restrictions of regulatory bodies having jurisdiction.

2.6. Survey, Staking and Marking

The route shall be surveyed and staked and such staking and marking should be maintained during construction. The pipeline shall be properly located within the right of way by maintaining survey route marker or by surveying during construction.

2.7. Handling, Hauling, Stringing and Storing

Care shall be exercised in the handling or storing of pipe, casing, coating materials, valves, fittings, and other materials to prevent damage. When applicable, railroad transportation of pipe shall meet the requirements of API RP 5L1. In the event pipe is yard coated or mill coated, adequate precautions shall be taken to prevent damage to the coating when hauling, lifting, and placing on the right of way. Pipe shall not be allowed to drop and strike objects, which will distort, dent, flatten, gouge or notch the pipe or damage the coating, but shall be lifted or lowered by suitable and safe equipment.

(Ref: ASME B 31.8-99)

2.8. Ditching

a) Depth of ditch shall be appropriate for the route location, surface use of the land, terrain features and loads imposed by roadways and railroads. All buried pipelines shall be installed with a minimum cover not less than that specified in this Standard, where the cover provisions cannot be met, pipe may be installed with less cover if additional protection is provided to withstand anticipated external forces.

b) Width and grade of ditch shall provide for lowering of the pipe into the ditch to minimize damage to the coating and to facilitate fitting the pipe to the ditch.

c) Location of underground structures intersecting the ditch route shall be determined in advance of construction activities to prevent damage to such structures. A minimum clearance of 12 in. (0.3 m) shall be provided between the outside of any buried pipe or component and the extremity of any other underground structures, except for drainage tile which shall have a minimum clearance of 2 in. (50 mm).

d) Ditching operations shall follow good pipeline practice and consideration of public safety. **API RP 1102** provides information on railroad and highway crossings.

2.9. Installation of Pipe in the Ditch

On pipelines operating at stresses of 20% or more of the specified minimum yield strength, it is important that stresses induced into the pipeline by construction be minimized. The pipe shall fit the ditch without the use of external force to hold it in place until the backfill is completed. When long sections of pipe that have been welded alongside the ditch are lowered in, care shall be exercised so as not to jerk the pipe or impose any strains that may kink or put a permanent bend in the pipe. Slack loops are not prohibited by this paragraph when laying conditions render their use advisable.

(Ref: ASME B 31.8 - 99)

2.10. Protection from Hazards

The Company must take all practicable steps to protect each pipeline from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.

Each aboveground line, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes either by placing it at a safe distance from the traffic or by installing barricades.

2.11. Underground Clearance

a) Each line must be installed with at least 12 inches (300 millimeters) of clearance from any other underground structure not associated with the gas line. If this clearance cannot be attained, the gas line must be protected from damage that might result from proximity to other structure.

b) Each line must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(Ref: U.S. Department of Transportation 191-192)

2.12. Backfilling

a) Backfilling shall be performed in a manner to provide firm support under the pipe.

b) If there are large rocks in the material to be used for backfill, care shall be taken to prevent damage to the coating by the use of rock shield material, or by making the initial fill with rock-free material sufficient to prevent damage.

c) Flooding as a method of trench consolidation is not allowed, unless the pipe is adequately anchored to stop it from floating.

COVER REQUIREMENTS

Buried pipeline shall be installed with a cover not less than that shown in the following table:

COVER

Location	Normal Excavation (In.)	Rock Excavation (In.)	
	All Sizes	Pipe Size NPS 20 and Smaller	Pipe Size Larger Than NPS 20
Class 1 & 2	30	12	18
Class 3 and 4	30	24	24
Drainage Ditch at: Public Roads	36	24	24
Highways	48	NA	NA
Railroad Crossings Uncased			
Primary Tracks	72	NA	NA
Industry Tracks	54	NA	NA
Railroad Crossing Cased	48	NA	NA
Waterways	48	18	18
Service lines-any location	18	12	NA

Notes:

- *Rock excavation is excavation that requires blasting.
- Where these cover provisions cannot be met or where external loads may be excessive, the pipeline shall be encased, bridged, or specially designed to withstand anticipated external load.
- Pipe passing through shallow waters (less than 12 feet or 3.7 m deep) must be installed with a minimum cover of 36 “(914 mm) in soil, or 18” (457 mm) in consolidated rock.

2.13. Steel Pipelines Crossing Railroads and Highways - Provision for Safety

The applicable regulations of federal, provincial, municipal, or other regulatory bodies having jurisdiction over the pipeline or facility to be crossed shall be observed for the installation of a crossing. Pipeline must cross the railroad or highway perpendicularly or as close perpendicularly as possible. Uncased crossings are preferred. Whether cased or uncased, there should be no void between the line (or the casing) and the soil. Installed casing must slope towards one end with a minimum slope of 1: 100. Table 6.1 gives the minimum wall thickness allowed for casing pipe and for uncased carrier pipe crossing highways and railways. Where the requirements of railways, highways, or the design calculations stipulate higher values, they must be used. Particular attention should be given to other governmental codes such as the Mineral Gas Safety Rules, 1960.

TABLE 2.1 – LEAST NOMINAL WALL THICKNESS FOR STEEL CASISNG AND CARRIER PIPE IN UNCASED CROSSING*

Pipe	Least Nominal Wall Thickness (in.)	
NPS	**Highways**	**Railways**
3	.125	.125
4	.125	.125
6	.188	.188
8	.188	.188
10	.188	.188
12	.188	.188
14	.188	.219
16	.188	.219
18	.188	.250
20	.188	.281
22	.220	.312
24	.250	.344
26	.250	.375
28	.250	.406
30	.250	.406
32	.250	.438
34	.250	.469
36	.250	.469
38	.312	.500
40	.312	.500
42	.312	.500
44	.312	.578
46	.312	.625
48	.326	.625
50	.344	.625

2.14. *Uncased Railway Crossings

It shall be permissible to install uncased steel pipelines under railways, provided that:

a) The pipe must be designed to sustain the loads.

b) For uncased crossings, the carrier pipe D/t ratio must not exceed the figures given in Table 6.2.

c) For steel pipe with a joint factor of 1.0, the hoop stress in the carrier pipe must not exceed 50% SMYS for primary track crossings.

d) For steel pipe with a joint factor, less than 1.0, hoop stress in the carrier pipe must not exceed 30% SMYS for primary track crossings.

e) For secondary and industrial track crossing, steel pipe with a joint factor less than 1.0, the SMYS in the carrier pipe must not exceed 50 %.

f) The pipe nominal wall thickness is not less than the minimum calculated from the design formula, or the minimum wall thickness given in tables 4.2 and 6.1.

TABLE 2.2 - MAXIMUM PIPE DIAMETER TO WALL THICKNESS (D/T) RATIO FOR UNCASED RAILWAY AND HIGHWAY CROSSINGS

	Maximum D/t ratio							
Maximum Operating Pressure (psi)	Steel pipe grade							
	35	42	46	52	56	60	65	70
2000	15	20	22	25	27	29	32	34
1900	16	21	23	26	29	31	33	36
1800	17	22	25	28	30	32	35	38
1700	18	24	26	30	32	34	37	40
1600	18	25	28	32	34	36	40	43
1500	19	27	30	34	36	39	42	45
1400	21	29	32	36	39	42	45	49
1300	22	31	34	39	42	45	49	53

	Maximum D/t ratio							
Maximum Operating Pressure (psi)	Steel pipe grade							
	35	42	46	52	56	60	65	70
1200	23	34	37	42	45	49	53	57
1100	25	37	41	46	50	53	58	62
1000	26	40	45	51	55	59	64	68
900	28	43	50	56	61	65	71	76
800	31	46	56	64	68	73	80	85
700	33	50	63	73	78	85	85	85
600	36	55	70	85	85	85	85	85
500	39	61	79	85	85	85	85	85
400	43	67	85	85	85	85	85	85
300	48	80	85	85	85	85	85	85
200	55	85	85	85	85	85	85	85
100	71	85	85	85	85	85	85	85

Notes:

1. For intermediate operating pressures, the D/t ratio may be interpolated.

2. D/t ratio means the OD divided by the nominal wall thickness.

3. Design conditions are the following:

3.1.1. 6’ (2.0 m) minimum depth of cover
3.1.2. 130 ^{0}F (55° C) temperature differential
3.1.3. Maximum hoop stress of 50% SMYS
3.1.4. Maximum combined circumferential stress of 72% SMYS
3.1.5. Maximum combined equivalent tensile stress of 90% SMYS
3.1.6. E-80 rail loading criteria with an impact factor of 1.4 at the surface, reducing linearly to 1.0 at 10’ (3.0m)
3.1.7. Fluctuating stress limitation of 10 psi (69 MPa) based upon 2,000,000 cycles; and
3.1.8. Maximum D/t ratio of 85

2.15. Approval for Crossings

Prior to the construction of a pipeline crossing, arrangement should be made with the pertinent authority in charge of the facility to be crossed.

2.16. Railroads and Highways Crossing Existing Pipelines

a) When an existing pipeline is to be crossed by a new road or railroad, the operating Company shall reanalyze the pipeline in the area to be crossed in terms of the new anticipated external loads. If the sum of the circumferential stresses caused by internal pressure and newly imposed external loads exceeds 0.8 SMYS (specified minimum yield strength) the operating Company shall install mechanical reinforcement, structural protection, or suitable pipe to reduce the stress, or redistribute the external loads acting on the pipeline. The line may also be considered for lowering or rerouting. API RP 1102 provides methods, which may be used to determine the total stress, caused by internal pressure and external loads.

b) Adjustments of existing pipelines in service at a proposed railroad or highway crossing shall conform to details contained in API RP 1102. If a casing is used, coated carrier pipe shall be independently supported at each end of the casing and insulated from the casing throughout the cased section. Casing ends shall be sealed using a durable, electrically nonconductive material.

2.17. Impact Factor

As carrier pipe at an uncased crossing will be subjected to both internal load from pressurization, and external load from earth forces (dead load) and train or highway traffic (live load), an impact factor should be applied to the live load in accordance with API RP 1102.

2.18. Cased Crossing

Suitable materials for casings are new or used line pipe, grade 35 or better. Where cased crossings are installed, the design shall be in accordance with the following requirements:

a) Carrier pipe shall be designed in accordance with the applicable requirements of Design Section, Section 4.

b) For carrier pipe smaller than NPS 6, the outside diameter of the casing pipe shall be at least 2” greater than the outside diameter of the carrier pipe. For carrier pipe NPS 6 or larger, the outside diameter of the casing pipe shall be at least 3” greater than the outside diameter of the carrier pipe.

c) Carrier pipe shall be held clear of the casing pipe by properly designed support, insulators, or centering devices, so installed as to minimize external loads transmitted to the carrier pipe.

d) The ends of the casings shall be suitably sealed to the outside of the carrier pipe. Venting of sealed casings is not mandatory; however, where vents are installed, they shall be protected from the weather to prevent water from entering the casing. Where casing seals of a type that will retain more than 5 psig pressure between the casing and the carrier pipe are installed, and vents are not used, provision shall be made to relieve the internal pressure before carrying out maintenance work.

e) Casing pipe under roads shall be of sufficient length to absorb all of the external loading from the roadbed at the point of crossing.

f) Casing pipe under railways shall extend to the greatest of the following distances, measured at right angles to the centerline of the track:

25’ each side from the centerline of the outside track

- 3’ beyond the toe of slope; and
- 3’ beyond the ditch line or area that may be affected by normal ditch cleaning operations.
- The nominal wall thickness for steel casing pipe shall be not less than the applicable least nominal wall thickness given in Table 6.1.

2.19. Casing Vents

If casing vents are provided, they shall extend 2’ from ground and shall be minimum NPS 2, one at each end of the casing. Vent pipes shall terminate with goosenecks, facing down. The vent pipe at the lower end of the casing shall be connected to the bottom of the casing, while the vent pipe at the higher end of the casing shall be connected to the top of the casing.

2.20. Inspection and Testing

Before installation, the section of carrier pipe used at the crossing should be inspected visually for defects. All girth welds should be inspected by radiographic or other nondestructive methods. After a cased crossing is installed, a test should be performed to determine that the carrier pipe is electrically isolated from the casing pipe.

2.21. Cathodic Protection

Cathodic protection systems at cased crossings should be reviewed carefully. Casing may reduce or eliminate the effectiveness of cathodic protection. The introduction of a casing creates a more complicated electrical system than would prevail for uncased crossings, so there may be difficulties in securing and interpreting cathodic protection measurement at cased crossings. Test stations with test leads attached to the carrier pipe and casing pipe should be provided at each cased crossing.

(Ref: API RP 1102 – 93)

2.22. Line Markers

(a) Line marker must be placed and maintained as close as practical over each buried line:

(b) At each crossing of a public highway, road and railroad

(c) Wherever necessary to identify the location of the gas line to reduce the possibility of damage or interference.

(d) At every turning point and at fence crossings.

(e) Line markers must be placed and maintained along each section of the line that is located above ground in an area accessible to the public.

(f) Line markers must be placed and maintained at every 1/3 mile (1/2 km approximately).

(g) Line markers must be placed and maintained at any other location where it is necessary as a warning for public safety.

(h) The following must be written legibly on a background of sharply contrasting color on each line marker.

- The world “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 1 inch (25 millimeters) high with ¼ inch (6.4 millimeters) stroke.
- The name of the Company and the telephone number (including area code), where the Company can be reached at all times.

Line markers are not required in location classes 3 and 4, where placement of a line marker would be impractical.

3. WELDING

3.1. Welding Techniques

This covers arc welding of butt, fillet, and socket welds in carbon and low-alloy steel piping used in the gas transmission systems. A shielded metal-arc welding, sub-merged arc welding using manual or semiautomatic technique may be used for the welding.

3.2. Equipment

Welding equipment shall be of a size and type suitable for the work, and it shall be maintained in a condition that ensures acceptable welds, continuity of operation and safety of personnel. Arc welding equipment shall be operated within the amperage and voltage ranges given in qualified welding procedures.

3.3. Materials

This applies to the welding of pipe and fittings that conform to the following specifications:

- API specification 5L
- Applicable ASTM specification

3.4. Filler Metal

All filler metals shall conform to one of the following specifications:

- AWS A5.1
- AWS A5.2
- AWS A5.5
- AWS A5.17
- AWS A5.18
- AWS A5.20
- AWS A5.28
- AWS A5.29

(Ref: API 1104 - 94)

3.5. Procedure Qualification

Before production welding is started, a detailed procedure specification shall be established and qualified to demonstrate that welds with suitable mechanical properties and soundness can be made by the procedure. The quality of the welds shall be determined by destructive testing. The details of each qualified procedure shall be recorded. The record shall be maintained as long as the procedure is in use.

(Ref: API 1104 - 94)

3.6. Procedure Specification

The procedure specification shall include the following information:

a) Process

The specific process or combination of processes used shall be identified. The use of a manual, semiautomatic or automatic welding process or any combination of these shall be specified.

b) Pipe and Fitting Materials

The material to which the procedures apply shall be identified.

c) Diameters and Wall Thickness

The ranges of diameters and wall thickness over which the procedure is applicable shall be identified.

d) Joint Design

The specification shall include a sketch or sketches of the joint that show the angle of bevel, the size of the root face, and the root opening or the space between abutting members. The shape and size of fillet welds shall be shown. If a backup is used, the type shall be designated.

e) Filler Metal and Number of Beads

The sizes and classification number of the filler metal and the minimum number and sequence of beads shall be designated.

f) Electrical Characteristics

The current and polarity shall be designated and the range of voltage and amperage for each electrode, rod, or wire shall be shown.

g) Position

The specification shall designate roll or position welding.

h) Direction of Welding

The specification shall designate whether the welding is to be performed in an uphill or downhill direction.

i) Time Between Passes

The maximum time between the completion of the root bead and the start of the second bead, as well as the maximum time between the completion of the second bead and the start of other beads, shall be designated.

j) Type and Removal of Lineup Clamp

The specification shall designate whether the lineup clamp is to be internal or external or if no clamp is required. If a clamp is used, the minimum percentage of root-bead welding that must be completed before the clamp is released shall be specified.

k) Cleaning and/or Grinding

The specification shall indicate whether power tools or hand tools are to be used for cleaning, grinding, or both.

l) Pre-and Post-Heat Treatment

The methods, temperature, temperature-control methods, and ambient temperature range for pre-and post-heat treatment shall be specified.

m) Speed of Travel

The range for speed of travel, in inches per minute, shall be specified for each pass.

(Ref: API 1104 - 94)

3.7. Essential Variables

A welding procedure must be reestablished as a new procedure specification, and it must be completely re-qualified when any of the essential variables listed below are changed.

(a) Welding Process

A change from the welding process or method of application established in the procedure specification constitutes an essential variable.

(b) Base Material

A change in base material constitutes and essential variable. For the purposes of this standard, all materials shall be grouped as follows:

- Specified minimum yield strength less than or equal to 42,000 pounds per square inch (290 MPa).

- Specified minimum yield strength greater than 42,000 pounds per square inch (290 MPa), but less than 65,000 pounds per square inch (448 MPa)

- For materials with specified minimum yield strength greater than or equal to 65,000 pounds per square inch (448 MPa), each grade shall receive a separate qualification test.

(c) Joint Design

A major change in joint design (for example, from V groove to U groove) constitutes an essential variable. Minor changes in the angle of bevel or the land of the welding groove are not essential variables.

(d) Position

A change in position from roll to fixed, or vice versa constitutes an essential variable.

(e) Wall Thickness

A change from one wall-thickness group to another wall-thickness group constitutes an essential variable, as mentioned under Qualification of Welders.

(f) Filler Material

Changes in filler metal constitute essential variables.

(g) Electrical Characteristics

A change from DC electrode positive to DC electrode negative or vice versa or a change in current from DC to AC or vice versa constitutes an essential variable.

(h) Time between Passes

An increase in the maximum time between completion of the root bead and the start of the second bead constitutes an essential variable.

(i) Direction of Welding

A change in the direction of welding from vertical downhill to vertical uphill, or vice versa, constitutes an essential variable.

(j) Speed of Travel

A change in the range for speed of travel constitutes an essential variable.

3.8. Qualification of Welders

The purpose of the welder's qualification test is to determine the ability of welders to make sound butt or fillet welds using previously qualified procedures. Before any production welding is performed, welders shall be qualified according to the applicable requirements.

A welder who has successfully completed the qualification test described in Section 3 of API 1104 (Latest Edition) shall be qualified within the limits of the essential variables described below. If any of the following essential variables are changed, the welder using the new procedure shall be re-qualified:

- A change from one welding process to another welding process or combination of processes.

- A change in the direction of welding from vertical uphill to vertical downhill or vice versa.

- A change of filler-metal classification.

- A change from one outside-diameter group to another.

  These groups are defined as follows:

  - Outside diameter less than 2 ⅜ inches (60.3 millimeters).

  - Outside diameter from 2 ⅜ inches (60.3 millimeters) through 12 ¾ (323.8 millimeters).

  - Outside diameter greater than 12 ¾ (323.8 millimeters).

- A change from one wall-thickness group to another. These groups are defined as follows:

  - Nominal pipe wall thickness less than 3/16 inch (4.78 millimeters).

  - Nominal pipe wall thickness from 3/16 inch (4.8 millimeters) through ¾ inch (19 millimeters).

  - Nominal pipe wall thickness greater than ¾ inch (19 millimeters).

- A change in position from that for which the welder has already qualified (for example, a change from rolled to fixed or a change from vertical to horizontal or vice versa). A welder who successfully passes a butt-weld qualification test in the fixed position with the axis inclined 45 degrees from the horizontal plane shall be qualified to do butt welds in all positions.

- A change in the joint design (for example, the use of a backing strip or a change from V bevel to U bevel).

(Ref: API 1104 - 94)

a) Basic Test

The test shall be made on NPS 12 or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8 inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

b) Additional Tests for Welders of Service Line Connections to Mains

A service line connection fitting shall be welded to a pipe section with the same diameter as a typical main. The weld is to be made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is to be tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

c) Periodic Tests for Welders of Small Service Lines:

Two samples of the welder's work, each about 8 inches (200 mm) long with the weld located approximately in the center, are to be cut from steel service line and tested as follows:

- One sample is centered in a guided bend testing machine, and bent to the contour of the die for a distance of 2 inches (50 mm) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.
- The ends of the second sample are flattened and the entire joint subjected to a tensile test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample also must pass the bending test per above paragraph.

(Ref: U.S. Department of Transportation 191-192)

3.9. Limitations of Welders

(a) No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) No welder may weld with a particular welding process unless, within the preceding 6 calendar months, he has been engaged in welding with that process.

(c) A qualified welder:

- May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding seven calendar months the welder has had one weld tested and found acceptable under API Standard 1104.

- May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with API Standard 1104.

(d) A qualified welder may not weld unless:

- within the preceding fifteen calendar months, but at least once each calendar year, the welder has re-qualified.

- within the preceding seven calendar months, but at least twice each calendar year, the welder has had---

  - a production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

  - for welders who work only on service lines NPS 2 inches (50 mm) or smaller in diameter, two sample welds tested and found acceptable.

(Ref: U.S. Department of Transportation 191-192)

3.10. Miter Joint

a) Except for miter joints of up to 3°, it is preferable to use other acceptable methods of change of direction, such as the use of welding elbows or induction bending.

b) A miter joint on steel pipe to be operating at a pressure less than 100 psig may not deflect the pipe more than 12.5° and must be at a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

c) Miter joints in excess of 3^0 angle on pipe with MAOP greater than 100 psig are not allowed.

3.11. Preparation of a Joint for Production Welding

Piping shall be welded by qualified welders using qualified procedures. The surfaces to be welded shall be smooth, uniform, and free from laminations, tears, scale, slag, grease, paint, and other deleterious material that might adversely affect the welding.

(a) Alignment

The alignment of the abutting ends shall minimize the offset between surfaces. For pipe ends of the same nominal wall thickness, the offset shall not exceed 1/16" (1.6 mm). If a larger offset is caused by dimensional variations, it shall be equally distributed around the circumference of the pipe. Hammering of the pipe to obtain proper lineup should be kept to a minimum.

(b) Use of Lineup Clamp for Butt Welds

Lineup clamps shall be used for butt welds in accordance with the procedure specification. When it is permissible to remove the lineup clamp before the root bead is completed, the completed part of the bead shall be in approximately equal segments spaced equally around the circumference of the joint. However, when an internal lineup clamp is used and conditions make it difficult to prevent movement of the pipe, or if the weld will be unduly stressed the root bead shall be completed before clamp tension is released. Root bead segments used in connection with external clamps shall be uniformly spaced around the circumference of the pipe and shall have an aggregate length of at least 50 percent of the pipe circumference before the clamp is removed.

(c) Mill Bevel

All mill bevels on pipe ends shall conform to the joint design used in the procedure specification.

(d) Field Bevel

Pipe ends should be field beveled by machine tool or machine oxygen cutting. If necessary, manual oxygen cutting may also be used. The beveled ends shall be reasonably smooth and uniform, and dimensions shall be in accordance with the procedure specification.

(e) Weather Conditions

Welding shall not be done when the quality of the completed weld would be impaired by the prevailing weather conditions, including but not limited to airborne moisture, blowing sands, or high winds. Windshields shall be used when necessary.

(f) Clearance

When the pipe is welded above ground, the working clearance around the pipe at the weld should not be less than 16 inches (40 millimeters). When the pipe is welded in a trench, the bell hole shall be large enough to provide the welder or welders with ready access to the joint.

(g) Cleaning Between Beads

Scale and slag shall be removed from each bead and groove. Power tools shall be used when called for in the procedure specification; otherwise, cleaning may be done by hand or by power tools. When automatic or semiautomatic welding is used, surface porosity clusters, bead starts, and high points shall be removed by grinding before weld metal is deposited over them.

(h) Position Welding

All position welds shall be made with the parts to be joined secured against movement and with adequate clearance around the joint, to allow the welder, or welders, space to work.

(i) Filler and Finish Beads

For position welding, the number of filler and finish beads shall be such that the completed weld attains a substantially uniform cross section around the entire circumference of the pipe. At no point shall crown surface be below the outside surface of the pipe, nor should it be raised above the parent metal by more than 1/16” (1.6 mm).
Two beads shall not be started at the same location. The face of the completed weld should be approximately 1/8” (3.2 mm) wider than the width of the original groove. The completed weld shall be thoroughly brushed and cleaned.

(j) Identification of Welds

Each welder shall identify his work in the manner prescribed by the procedure.

(k) Pre-And Post Heat Treatment

The procedure specification shall specify the pre-and post-heat treatment practices that are to be followed when materials or weather conditions make either or both treatments necessary.

(Ref: API 1104 - 94)

3.12. Inspection and Testing Of Production Welds

a) Visual inspection of welding must be conducted to ensure that:

- The welding is performed in accordance with the welding procedure.
- The weld is acceptable under Section 6 of API Standard 1104.

b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested on a percentage basis as given below under Nondestructive Testing.

3.13. Acceptance Standards for Nondestructive Testing

The acceptability of discontinuities located by radiographic, magnetic particle, liquid penetrant and ultrasonic test method is determined according to the Section 6 of API Standard 1104.

3.14. Nondestructive Testing for Lines with MAOP greater than 20% SMYS

a) Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.

b) Nondestructive testing of welds must be performed:

- In accordance with written procedures.
- By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld.

c) When nondestructive testing is required, the following percentages of each day's field butt welds, selected at random by the Company, must be nondestructively tested over their entire circumference:

- In Class 1 location at least 10 percent.
- In Class 2 locations at least 15 percent.
- In Class 3 and Class 4 locations, 100%, unless impracticable, in which case at least 90 percent at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings.
- At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when non-destructive testing is required.

f) When nondestructive testing is required, each Company must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

g) If any piece from a percentage sample fails, another percentage sample will be taken. If another sample fails, all the work from that welder shall be non destructively tested, and the welder be asked to take a re-qualification test before being allowed to weld on pressurized piping.

3.15. Non-Destructive Testing for Line Operating at Less Than 20% SMYS.

- A qualified welding inspector shall visually inspect all welds.
- At the discretion of the Company, a percentage of the production welds and all tie-in welds may be non-destructively tested.

3.16. Repair and Removal of Defects

a) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

b) Cracks in circumferential butt welds and in fillet welds shall be completely removed by cutting out cylinders containing such cracks except that it shall be permissible to repair such welds using a documented and proven crack repair procedure.

4. MATERIALS

4.1. Materials and Equipment:

All materials and equipment that will become a permanent part of any piping system shall be suitable and safe for the conditions under which they are to be used. This section prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

Materials for pipe and components must be:

- Able to maintain the structural integrity of the pipeline under its design conditions
- Chemically compatible with the fluid that is to be transported through it.

(Ref: U.S. Department of Transportation 191-192)

4.2. Steel Pipe

Steel pipe manufactured in accordance with the following standards may be used:

- API 5L Line Pipe
- ASTM A 53 Welded and Seamless Pipe
- ASTM A 106 Seamless Pipe
- ASTM A 134 Electric-Fusion (Arc)-Welded Pipe

- ASTM A 135 Electric-Resistance-Welded Pipe
- ASTM A 139 Electric-Fusion (Arc)-Welded Pipe
- ASTM A 333 Seamless and Welded pipe for Low-Temperature Service
- ASTM A 381 Metal-Arc-Welded Pipe
- ASTM A 671 Electric-Fusion-Welded Pipe
- ASTM A 672 Electric-Fusion-Welded Pipe
- CSA Z 245.1-98 Steel Line Pipe

4.3. Reuse of Steel Pipe

Removal of a portion of an existing steel line and reuse of the pipe in the same line, or in a line operating at the same or lower pressure, is permitted subject to the following restrictions:

Used steel pipe or, unidentified new steel pipe may be used for low-stress level (hoop stress less than 6,000 psi) service where no close coiling or close bending is to be done; provided careful visual examination indicates that it is in good condition and free from split seams or other defects that would cause leakage, and provided further that if the pipe is to be welded and is of unknown specification or its specification is ASTM A120, it shall satisfactorily pass weldability tests.

Minimum remaining wall thickness or the nominal thickness whichever is lower shall be used for determining the MAOP.

(Ref: ASME B 31.8 - 99)

4.4. Determination of Wall Thickness

Unless the nominal wall thickness is known with certainty, it shall be determined by measuring the thickness at quarter points on one end of each piece of pipe. If the lot pipe is known to be of uniform grade, size, and nominal thickness, measurement shall be made on not less than 10% of the individual length, but not less than 10 lengths; thickness of the other lengths may be verified by using a gage set to the minimum thickness. Following such measurement, the nominal wall thickness shall be taken as the next commercial wall thickness below the average of all the measurements taken, but in no case greater than 1.14 times the least measured thickness for all pipe under NPS 20, and no greater than 1.11 times the least measured thickness for all pipe NPS 20 and larger.

(Ref: ASME B 31.8 - 99)

4.5. Surface Defects

All pipes shall be examined for gouges, grooves and dents. All harmful defects of this nature must be eliminated or repaired.

4.6. S Value:

For pipe of unknown specification, the yield strength to be used as S in the formula:

***P= (2St/D) xFxExT,** in lieu of the specified minimum yield strength, shall be 24,000 psi, or determined as follows:

Determine the average value of all yield strength tests for a uniform lot. The value of S shall then be taken as the lesser of the following:

- 80% of the average value of the yield strength tests;
- The minimum value of any yield strength test, provided, however, that in no case shall S be taken as greater than 52,000 psi.

(Ref: ASME B 31.8 - 99)

WHERE

P = Design pressure in pounds per square inch gauge.

S = Yield strength in pounds per square inch gauge.

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches

F = Design factor.

E = Longitudinal joint factor.

4.7. Hydrostatic Test

New or used pipe of unknown specification and all used pipe the strength of which is impaired by corrosion or other deterioration, shall be retested hydrostatically either length by length in a mill type test or in the field after installation before being placed in service. The test pressure used shall establish the maximum allowable operating pressure.

The pipe must be tested at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1, and 2 locations and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 3 or 4 location. The test pressure must be maintained for at least 24 hours.

4.8. Bending Properties

For pipe NPS 2 and smaller, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion, and without opening the longitudinal weld. Pipe larger than NPS 2 must meet the requirements of the flattening tests set forth in Appendix H, ANSI B31.8-99.

4.9. Weldability

A welder who is qualified must make a girth weld. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than NPS 4, at least one test weld must be made for each 400 lengths of pipe. The weld must be destructively tested in accordance with API Standard 1104.

4.10. Inspection

The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects, which might impair the strength or tightness of the pipe.

4.11. Tensile Properties

If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 psi (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L.

(Ref: U.S. Department of Transportation 191-192)

4.12. Used Piping Components and Equipment

Used piping components such as fittings, elbows, bends, intersections, couplings, reducers, closures, flanges, valves, and equipment may be reused. Such components and equipment shall be cleaned and examined; reconditioned, if necessary, to insure that they meet all requirements for the intended service; and sound and free of defects.

In addition, reuse shall be contingent on identification of the specification under which the item was originally produced. Where the specification cannot be identified, use shall be restricted to a maximum allowable operating pressure based on yield strength of 24,000 psi (165 MPa) or less. However, such unidentified components may not be suitable for a particular transmission line application due to low stress restriction. (Allowed hoop stress less than 6000 psi.)

(Ref: ASME B 31.4 - 99)

4.13. Transportation of Pipe

For a pipeline that is to be operated at a hoop stress of 20 percent or more of SMYS, a Company may not use pipe having an outer diameter to wall thickness ratio of 70 to 1 or more, that is transported by railroad, unless the transportation is performed in accordance with **API RP 5L1.** (The recommendations provided herein apply to the transportation on railcars of API Specification 5L steel line pipe in sizes NPS 2 and larger, in lengths longer than single random. These recommendations cover coated or uncoated pipe, but they do not encompass loading practices designed to protect pipe coating from damage).

(Ref: U.S. Department of Transportation 191-192)

4.14. Marking of Materials

(a) Each valve, fitting, length of pipe, and other component must be marked:

- As prescribed in the specification or standard to which it was manufactured.
- To indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(Ref: U.S. Department of Transportation 191-192)

***Note*:**

All material and components, e.g., steel pipe, flanges, valves, gaskets, bolting, etc, must conform to the specifications listed in Appendix 4.1, which should not be taken as exhaustive. The Gas Company may at its own discretion, choose an equivalent or superior specification to suit the application.

Appendix 4.1

STANDARDS AND SPECIFICATIONS FOR VARIOUS FUNCTIONS

API – AMERICAN PETROLEUM INSTITUTE

a) API 5L – Line pipe

The Purpose of this specification is to provide the standards for pipe suitable for use in conveying gas, water, and oil in both the oil and natural gas industries. This specification covers seamless and welded steel line pipe. It includes plain-end, threaded-end, and belled-end pipe, as well as through the flow line (TFL) pipe and pipe with ends prepared for use with special couplings. Although the plain-end line pipe meeting this specification is primarily intended for field makeup by circumferential welding, the manufacturer will not assume responsibility for field welding.

b) API RP 5L1 - Recommended Practice for Railroad Transportation of Line Pipe

The recommendation provided herein apply to the transportation on railcars of API Specification 5L steel line pipe in sizes NPS2 and larger, in lengths longer than single random. These recommendations cover coated and uncoated pipe, but they do not encompass loading practices designed to protect pipe coating from damage.

c) API 1104 – Standard for Welding of Pipelines and Related Facilities

This standard covers the gas and arc welding of butt, fillet, and socket welds in carbon and low-alloy steel piping for transmission of crude petroleum, petroleum products, fuel gases, carbon dioxide, and nitrogen; and where applicable, covers welding on distribution systems. It applies to both new construction and in-service welding. This standard also covers the procedures for radiographic, magnetic particle, liquid penetrant, and ultrasonic testing, as well as the acceptance standards to be applied to production welds tested to destruction, or inspected by radiographic, magnetic particle, liquid penetrant, ultrasonic, and visual testing methods.

d) API 1107 - Recommended Pipeline Maintenance Welding Practices

This document covers recommended maintenance welding practices which may be used when making repairs to or installing appurtenances on piping system, which are, or have been in service in compression, pumping and transmission of crude petroleum, petroleum products or fuel gases, and where applicable, to distribution piping systems for these products.

e) API 6D - Piping Valves

This International Standard specifies requirements and gives recommendations for the design, manufacturing, testing and documentation of ball, check, gate and plug valves for application in pipeline systems. Valve for pressure ratings exceeding PN 420 (Class 2500) are not covered by this International Standard. App. A of Spec 6D provides guidelines to assist the purchaser with the selection of valve types and of specific requirements for ordering.

f) API 1102 - Steel pipelines Crossing Railroads and Highways

This gives primary emphasis to provisions for public safety. It covers the design, installation, inspection, and testing required ensuring safe crossings of steel pipelines under railroads and highways.

ASME - AMERICAN SOCIETY OF MECHANICAL ENGINEERS

a) ASME B 31.8 – Gas Transmission and Distribution Piping Systems

This Code covers the design, fabrication, installation, inspection, testing, and safety aspects of operation and maintenance of gas transmission and distribution systems, including gas pipelines, gas compressor stations, gas metering and regulation stations, gas mains, and service lines up to the outlet of the customers meter set assemblies. Included within the scope of this code are gas transmission and gathering pipelines and appurtenances that are installed offshore for the purpose of transporting gas from production facilities to onshore locations; gas storage equipment of the closed pipe type, fabricated or forged from pipe or fabricated from pipe and fittings and gas storage lines.

b) ASME B 16.5

Pipe flanges and flanged fittings

c) ASME B 16.20

Metallic Gaskets for Pipe Flanges: Ring Joint, Spiral Wound and Jacketed

d) ASME B 16.33

Manually Operated Metallic Gas Valves for Use in Gas Piping Systems Up To 125 Psig, Size 1/2-2

e) ASME B 16.34

Valves Flanged, Threaded and Welding End

ASTM – AMERICAN SOCIETY FOR TESTING AND MATERIALS

- A 53 Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless
- A 105 Forgings, Carbon Steel, for piping Components
- A 106 Seamless Carbon Steel Pipe for High-Temperature Service
- A 120 Pipe, Steel, Black and Hot-Dipped Zinc-Coated (Galvanized) Welded and Seamless for Ordinary Use
- A 134 Electric-Fusion (Arc)-Welded Steel Plate pipe (Sizes 16 in. and Over)
- A 135 Electric-Resistance-Welded Steel Pipe
- A 139 Electric-Fusion (Arc)-Welded Steel Plate Pipe (Sizes 4 in. and Over)

- A 193 Alloy-Steel and Stainless Steel Blots for High-Pressure and High-Temperature Service
- A 194 Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-temperature Service
- A 211 Spiral-Welded Steel or Iron Pipe
- A 307 Carbon Steel Externally Threaded Standard Fasteners
- A 320 Alloy Steel Bolting Materials for Low-Temperature Service
- A 333 Seamless and Welded Steel Pipe for Low-Temperature Service
- A 354 Quenched and Tempered Alloy Steel Bolts, Studs, and other Externally Threaded Fasteners
- A 372 Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels
- A 381 Metal-Arc-Welded Steel Pipe for Use with High pressure Transmission Systems
- A 395 Ferritic Ductile Iron Pressure-Retaining Castings for Use at Elevated Temperatures
- A 449 Quenched and Tempered Steel Bolts and Studs
- A 671 Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperature
- A 672 Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures

CSA – CANADIAN STANDARDS ASSOCIATION

- Z245.1 Steel Line Pipe

ISO – INTERNATIONAL ORGANIZATION FOR STANDARDIZATION

5. TESTING

5.1. New Construction and the Replacement of Existing Pipeline Facilities

The hydrostatic testing of newly constructed pipelines and replaced segments of existing pipeline facilities should be performed before placed in service in accordance with the requirements set forth in this document.

The qualification of existing piping systems for an operating pressure, higher than the previously established operating pressure, should be performed in accordance with requirements of ASME B31.8 and applicable governmental regulations, if any. A strength test as well as a leak test, which is to be done concurrently with the strength test, or after, is required. Fuel gas is not allowed for this test.

5.2. Test Medium

The hydrostatic test should be conducted with water.

5.3. Equipment for a Hydrostatic Test

Equipment for the hydrostatic test should suit the conditions, and be in good working order.

5.4. Test Plan and Procedure

A hydrostatic test plan and procedure diagram with explanatory notes and data should be prepared prior to testing, and it include the following details:

- The length and location of the test segment
- Test medium to be used
- Procedures for cleaning and filling the line
- Procedures for the pressurization of the test segment including the location of the injection points and the specified minimum and maximum test pressures
- Minimum test duration for test segment
- Procedures for removal and disposal of test medium
- Safety precautions and procedures.

A specified test pressure is defined as the minimum test pressure, which should be applied to the most elevated point in the test segment. A detailed analysis of the profile to determine static and dynamic pressures while the pipeline is being tested should be performed so that the pipeline will not be over-pressured at points, which are at low elevations.

5.5. Conducting Hydrostatic Test

5.6. Pressurization

Personnel conducting the test should maintain continuous surveillance over the operation and ensure that it is carefully controlled. The test segment should be pressurized at a moderate and constant rate. When approximately 70 percent of the specified test pressure is reached, the pumping rate should be regulated to minimize pressure variations and to ensure that increments of no greater than 100 kpa (14.5 psi) may be accurately read and recorded. A pressure-recording gauge should be installed in parallel with a deadweight tester, and it should be checked at regular intervals throughout the testing period by the deadweight tester. The bourdon tube type pressure gauge is used only for approximation of pressure and its readings need not be recorded. Pipe connections should be periodically checked for leaks during pressurization.

(Ref: API RP 1110)

5.7. Hydrostatic Test Record

Each Company shall record test information, and will retain it for the useful life of the pipeline. The record must contain at least the following information:

- The name of the company and the employee responsible for making the test, and the name of any testing company used
- Test medium used.
- Test pressure.
- Test duration.
- Pressure recording charts, or other record of pressure readings.
- Elevation variations, whenever significant for the particular test.
- Leaks and failures noted and their disposition.
- Ambient and ground temperatures at start & end of test.

5.8. Displacement of Test Medium

Water should be displaced with spheres, squeegees and/or other pigging devices. Water should be disposed off at approved locations in a manner that will cause minimal environmental effects.

(Ref: API RP 1110)

5.9. Pressure Test for Lines with MAOP Producing Greater Than 20% SMYS

(a) Strength Test

Medium	Location Class	Pressure (Min)	Duration (Hrs.)	Remarks
Water	1,2	1.25 MAOP	24	Limit stress to 90% SMYS during test
Water	3,4	1.4 MAOP	24	-Do-
Air or Inert Gas	Any	1.1 MAOP	24	Limit stress during test to: 40% SMYS-for class 4 50% SMYS-for class 3 57% SMYS – for class 1 & 2

(b) Leak Test

If air on inert gas is used for strength test, a separate leak test is not required providing all exposed joints and field welds are checked for leaks. Otherwise a separate leak test using air or inert gas must be used for the leak test, at a minimum pressure of 150 psig or at 110% MAOP whichever is greater. Duration of test shall be 24 hours.

5.10. Field Pressure Test for Lines with MAOP of 100 PSIG to 20% SMYS

(a) Strength Test

Same conditions as for above 20% SMYS stress level pipe apply, except that natural gas may also be used, in which case the following limitations would apply:

- Limit test pressure to 1.1 MAOP
- Limit stress level to 20% SMYS during test.

(b) Leak Test

If a gaseous medium is used for strength test, a separate leak test is not required, providing all exposed joints and field welds are checked for leaks, using leak detection liquid and / or instrument. Otherwise, a separate leak test using air, inert gas or natural gas must be performed for the leak test at a minimum pressure of 150 psig or one that produces a stress level of 20% SMYS, whichever is greater. Test duration shall be 8 hours.

5.11. Safety during Test

All testing of pipelines and mains after construction shall be done with due regard for the safety of employees and the public during the test. When air or gas is used, suitable steps shall be taken to keep persons not working on the testing operations out of the testing area during the period in which the hoop stress is first raised from 50% of the specified minimum yield strength to the maximum test stress, and until the pressure is reduced to the maximum operating pressure.

6. CORROSION

6.1. Corrosion Control

This section prescribes minimum requirements and procedures for the protection of metallic pipelines and components from external, internal and atmospheric corrosion for new and existing piping system.

a) External and internal corrosion shall be controlled in a manner consistent with the condition of the piping system and the environment in which the system is located.

b) Each operating Company shall establish procedures to implement its corrosion control program to achieve the desired objectives.

c) NACE RP-01-69/NACE RP-06-75, NACE RP–02-75 may be referred for guidance.

6.2. External Corrosion Control for Buried or Submerged Pipelines

6.3. NEW INSTALLATIONS

All new pipelines and service lines, and pipe-type and bottle-type holders shall be externally coated and cathodically protected unless it can be demonstrated by test and experience that the materials are resistant to corrosion in the environment in which they are installed. However, within twelve months after installation, the operating Company shall electrically inspect the buried or submerged system. If the electrical inspection indicates that a corrosive condition exists, the piping system shall be cathodically protected. If cathodic protection is not installed, the piping system shall be electrically inspected at intervals not exceeding five years, and the system shall be cathodically protected if electrical inspection indicates that a corrosive condition exists.

(Ref: ASME B 31.8. - 99)

6.4. Coating System

The performance of the coating system is dependent on surface preparation, coating material, application methods and testing methods. Factory applied coating is preferred for all pipeline components to ensure adequate surface preparation and coating application under controlled condition. Pipe coating shall be inspected, both visually and by an electric holiday detector just prior to lowering pipe into ditch. Any holiday or other damage to the coating shall be repaired and re-inspected. The backfilling operation shall be inspected for quality, compaction and placement of material to prevent damage to pipe coating.

6.5. Protective Coatings and Surface Preparation

(a) External protective coating, applied for the purpose of external corrosion control must:

- have surface preparation compatible with the coating to be applied. The pipe surface shall be free of deleterious materials such as rust, scale, moisture, dirt, oils, lacquers, and varnish. The surface shall be inspected for irregularities, which could protrude through the coating. Any such irregularities shall be removed. Further information can be obtained from NACE RP-02-75, (Application of Organic Coatings to the External Surface of Steel Pipe for Underground Service).

- have sufficient adhesion to the metal surface to effectively resist under film migration of moisture

- is sufficiently ductile to resist cracking

- have sufficient strength to resist damage due to handling and soil stress

- have properties compatible with any supplemental cathodic protection.

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

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

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

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

The integrity of the coating shall be visually checked immediately after the pipe is lowered in the trench. Defects found in coating shall be repaired using approved procedures and materials.

(Ref: U.S. Department of Transportation 191-192)

6.6. Cathodic Protection System

The objective of using cathodic protection is to control the corrosion of metallic surfaces in contact with electrolyte.

a) A cathodic protection system provided by a galvanic anode or impressed current anode system shall be installed that will mitigate corrosion and contain a method of determining the degree of cathodic protection achieved on the buried or submerged piping system.

b) A cathodic protection system shall preferably be installed at the same time as the construction but no later than one year after completion of construction.

c) Cathodic protection shall be controlled so as not to damage the protective coating, pipe, or components.

d) Owners of known underground structures that may be affected by installation of a cathodic protection system shall be notified of, and where necessary, parties involved shall conduct joint-bonding surveys.

e) Electrical installations shall be made in accordance with the U.S. National Electrical Code, ANSI/NFPA 70, API RP 500C.

f) The cathodic protection system shall be compatible with coating used on the pipeline.

(ASME B 31.4 – 99)

6.7. Criteria for Cathodic Protection for Steel Structures

(a) A negative (cathodic) voltage of at least 0.85 volt as measured between the structure surface and a saturated copper-copper-sulfate reference electrode contacting the electrolyte. Determination of this voltage is to be made with the protective current applied.

(b) A minimum negative (cathodic) voltage shift of 300 millivolts, produced by the application of protective current. The voltage shift is measured between the structure surface and a saturated copper-copper-sulfate reference electrode contacting the electrolyte. The criterion of voltage shift applies to structures not in contact with dissimilar metals.

(c) A minimum negative (cathodic) polarization voltage shift of 100 millivolts measured between the structure surface and a saturated copper-copper sulfate reference electrode contacting the electrolyte. This polarization voltage shift is to be determined by interrupting the protective current and measuring the polarizing decay. When the current is initially interrupted, an immediate voltage shift will occur. The voltage reading after the immediate shift shall be used as the base reading from which to measure polarization decay.

(d) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

(Ref: ASME B 31.8 99)

6.8. Electrical Isolation

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

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

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

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

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

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

(Ref: U.S. Department of Transportation 191-192)

6.9. Test Stations

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

6.10. Test Leads

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

(b) Each test lead wire must be attached to the pipeline in a manner that minimizes stress concentration on the pipe.

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

6.11. Interference Currents

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

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

(Ref: U.S. Department of Transportation 191-192)

6.12. Existing Piping System

The operating Company shall establish procedures for determining the external condition of its existing buried or submerged piping systems, and take action appropriate for the conditions found, including, but not limited to the following:

(a) Examine and study records available from previous inspections and conduct additional inspections where the need for additional information is indicated. The type, location, number, and frequency of such factors as knowledge of the condition of the piping system, environment, and public or employee safety in the events of leakage shall be considered.

(b) Install cathodic protection on all buried or submerged piping systems that are coated with an effective external surface coating material. All buried or submerged piping at compressor stations, and terminals shall be electrically inspected, and cathodic protection installed or augmented where necessary.

(c) Operating pressures on bare piping systems shall not be increased until they are electrically inspected and other appropriate actions are taken regarding condition of pipe and components.

(Ref: ASME B 31.4 – 99)

6.13. Monitoring

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected four times each calendar year, but with intervals not exceeding 3.5 months, to ensure that it is operating.

(c) Each reverse current switch, each diode and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance four (4) times each calendar year, but with intervals not exceeding 3.5 months.

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

(e) Each Company shall, at intervals not exceeding five (5) years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this section, in areas in which active corrosion is found. The Company shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

(Ref: U.S. Department of Transportation 191-192)

6.14. Corrective Measures

(a) If corrosion exits, which, unless controlled, could result in a condition that is detrimental to public or employee safety, appropriate corrective measures shall be taken to mitigate further corrosion on the piping system. Corrective measures shall maintain a safe operating system. Appropriate corrective measures may include the following:

- Provisions for proper and continuous operation of cathodic protection facilities
- Application of protective coating
- Installation of galvanic anode
- Application of impressed current
- Electrical isolation
- Stray current control
- Other effective measures
- Any combination of the above.

(Ref: ASME B 31.8 – 99)

6.15. Atmospheric Protection

6.16. New Installation

Pipe and components that are exposed to the atmosphere shall be protected from external corrosion by use of corrosion resistant steel, or application of protective coating, or paint, unless the operating Company can demonstrate by test, investigation, or experience in area of application that a corrosive atmosphere does not exist. Protective coating or paint shall be applied to a clean surface and shall be suitable material to provide adequate protection from the environment.

6.17. Existing Piping System

Pipe and components in existing piping system that are exposed to the atmosphere shall be inspected in accordance with a planned schedule and corrective measures shall be taken.

6.18. Monitoring

Protective coating or paint used to prevent corrosion of pipe and components exposed to the atmosphere shall be maintained in a serviceable condition, and such protective coating or paint, as well as bare pipe and components, not coated or painted, shall be inspected at intervals not exceeding 18 months, but at least once every calendar year.

6.19. Internal Corrosion

The interior surface of a pipeline conveying a corrosive or potentially corrosive fluid shall be protected against corrosion.
Corrosion inhibitors and biocides or internal lining are some of the possible remedies to mitigate internal corrosion. The operating Company shall establish procedures for determining the corrosive effect of the gas and the internal condition of its existing piping system and take appropriate action for the condition found.

(Ref: U.S. Department of Transportation 191-192)

6.20. Corrective Measures

(a) In the case of external corrosion of buried or submerged piping, cathodic protection shall be installed or augmented to mitigate the external corrosion.

(b) In the case of internal corrosion of piping, steps shall be taken or augmented to mitigate the internal corrosion.

(c) In the case of external corrosion of piping exposed to the atmosphere, protective coating or paint shall be repaired or applied to mitigate the external corrosion.

(d) Pipe that is replaced because of external corrosion shall be replaced with coated pipe if buried or submerged, and with corrosion resistant steel pipe or coated or painted pipe, if exposed to the atmosphere.

(e) If a portion of the piping system is repaired, reconditioned, or replaced, or operating pressure is reduced because of external or internal corrosion, the need for protection of that portion from deterioration shall be considered, and steps indicated shall be taken to control the corrosion.

6.21. Records

(a) Records and maps showing the location of cathodically protected piping, cathodic protection facilities, and neighboring structures affected by or affecting the cathodic protection system shall be maintained and retained for as long as the piping system remains in service.

(b) Results of tests, surveys, and inspections required to indicate the adequacy of corrosion control measures shall also be maintained for the service life of the piping systems, as well as records relating to routine or unusual inspections such as internal or external line conditions, when cutting line or hot tapping, shall be retained for at least 5 years.

7. LEAK DETECTION AND ODORIZATION

7.1. Foot Patrol

Lines that are installed in locations where abnormal physical movements or abnormal external loadings could cause failure or leakage shall be patrolled periodically, with the patrol frequencies determined by the severity of the conditions that could cause failure or leakage, and the consequent hazards to public and property.

7.2. Leakage Survey Frequency

The operating Company shall establish in its operating and maintenance procedure, provision for regular surveys for detecting leaks. Suitable combinations of methods such as gas detection surveys, corrosion surveys, vegetation surveys, bar hole surveys or surface detection surveys may be employed.

Leaks located by leakage surveys, detected by smell, or reported by public shall be investigated promptly, but no later than 24 hours. Repair record shall be kept for the life of the line.

Where repaired or abandoned piping is reactivated, it shall be tested to confirm that it is gas-tight.

(a) Each Company shall conduct periodic leakage surveys in accordance with this section.

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

- A leakage survey with leak detection equipment must be conducted in location class 3 and 4, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and side walks, and at other locations providing an opportunity for finding gas leaks at intervals not exceeding 7 1/2 months, but at least twice every year.

- Leakage survey in location class 1 and 2 must be conducted at intervals not exceeding 30 months, but at least once every two years.

- In addition to all above requirements, every service line must be visually inspected for signs of leakage, such as dead vegetation and gas smell in the air from buried pipe or above ground piping at the meter at the time of every meter reading by the Meter Reader. All suspected leaks shall be reported to the Company the same day.

7.3. Methods and Equipment

There are a variety of leakage survey and test methods to be carried out in the field that are used singly or in combination, depending on the circumstances. (History, location, etc.) These types include the following:

(a) Surface Gas Detection Survey

This type of survey entails continued sampling of the atmosphere at or near ground level with a gas detector. This is the most widely used survey in the gas pipeline network. The equipment used for this type of survey may be portable or may be vehicle mounted.

(b) Foot Survey

In this survey, a gas company representative walks over the gas line, and uses his eyes, ears and sense of smell to detect unusual conditions and gas leaks. In areas with vegetation, a vegetation survey is a quick visual method to detect possible gas leaks.

(c) Sub – Surface Gas Detection Survey

A sub-surface survey is used in conjunction with a surface detection survey to pinpoint the source of escaping gas in soil. This procedure involves the sampling of the atmosphere below ground level using Combustible Gas Indicator (GCI) or any other device capable of reading 0.5% gas in air. To pinpoint the leak, bar holes over the pipeline area are tested for gas level readings. The locations of the bar holes are adjusted to identify the source of leak as accurately as possible.

(d) Pressure Drop Survey

This type of survey is performed on isolated section of piping to determine any pressure losses due to leakage. Test pressures and durations are defined by various operating modes. The amount of pressure drop is dependent upon the volume of the line under test, the temperature stabilization of the test medium and the sensitivity of the instrument.

(e) Aerial Inspection

This type of survey is quite useful for transmission lines. During aerial inspections, other aspects relating to right of way can also be noted beside leakages. Useful information such as nearby construction activity, flooding, soil erosion, heaving or subsidence, encroachments and change of location class should also be observed.

(f) Inline Inspection

For this purpose, a pig is used to determine the condition of the pipeline. A "smart pig" can be used to check the integrity of an existing pipeline. A magnetic flux is setup in the pipe being inspected as the pig traverses the test section while being propelled by fluid pressure. The flux covers the 360^0 circumference and it can be disturbed by the anomalies in the pipe wall. Corrosion pits, hard spots, stress corrosion cracking and welds, etc., can cause these anomalies. The pig is able to record the anomalies.

(g) Soap Test

Above ground fittings, valves and exposed piping can be tested for leaks with a leak detection fluid (usually soap/water mixture.) Leaks are indicated by the formation of bubbles. This test may be performed on all leak repairs and all tie-in points.

(h) Vegetation Survey

A visual examination of the vegetation above or adjacent to a buried gas line for indication of dead or dying vegetation is called a vegetation survey. A gas leak near vegetation would deprive the plants of necessary oxygen and moisture, causing the plant to wilt and die.

(i) Ultrasonic Leakage Test

The testing of exposed piping facilities is carried out with an instrument capable of detecting the ultrasonic energy generated by escaping gas. The instrument used should be suitable for the pressure involved. The ultrasonic test may be used for the testing of exposed piping facilities. However, if the ultrasonic background level produces a full-scale meter reading when the gain is set at mid-range, the facility should be tested by some other survey method.

(Ref: ASME B 31.8 - 1999)

7.4. Odorization

Odorization of gas in transmission pipeline system is generally not required. Where odorization is required for safety consideration, location class or per customer's need, odorize with a suitable gas odorant in sufficient continuous quantity to make the gas detectable by the sense of smell at gas concentration of 20% lower explosive limit (20% LEL).

Only odorization equipment designed for the type and injection rate of odorant shall be used. Each operating Company, for the gas supplied through its facilities, which requires odorization, shall conduct odorant concentration tests. Test points shall be remotely located from the odorizing equipment so as to provide data representative of gas at all points of the system. In the concentrations in which an odorant is used in the gas, it must comply with the following:

The odorant shall not be deleterious to persons, materials, or pipe.

(a) The products of combustion from the odorant shall not be toxic when breathed, nor corrosive or harmful to those materials, which will be exposed to it.

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

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

(d) Each Company shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant is present in accordance with this section.

8. OPERATION AND MAINTENANCE

8.1. Procedural Manual for Operations, Maintenance and Emergencies

Each Company shall prepare and follow for each pipeline, a manual of written procedures for conducting operations, maintenance and repair activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the Company at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operation of a pipeline system commences. This manual must be kept at locations where operations and maintenance activities are conducted, and it should be made available to appropriate engineering and operating staff. This manual or manuals must include at least all the topics covered in this Standard, with particular emphasis on:

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

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

(c) For transmission lines, the manual must include procedures for the following to provide safety when operating design limits have been exceeded.

(d) Responding to, investigating, and correcting the causes of unintended closure of valves or shutdowns.

(e) Increase or decrease in pressure or flow rate outside normal operating limits.

(f) Loss of communications.

(g) Operation of any safety device.

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

(i) Controlling corrosion in accordance with the operations and maintenance requirements of this standard.

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

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

(l) Checking variations from normal operation, at sufficient critical locations in the system, to determine continued integrity and safe operation, after an abnormal operation occurs.

8.2. Emergency Plans

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

- Receiving, identifying, and classifying notices of events, which require immediate response by the Company.

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

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

    - Gas detected inside or near a building.

    - Fire located near or directly involving a pipeline facility.

    - Explosion occurring near or directly involving a pipeline facility.

    - Natural disaster.

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

- Actions directed towards protecting people first and then property.

- Emergency shutdown and pressure reduction in any section of the Company pipeline system necessary to minimize hazards to life and property.

- Making safe any actual or potential hazard to life or property.

- 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.

- Safely restoring any service outage.

- Beginning action if applicable, as soon after the end of the emergency as possible.

(b) Each Company shall:

- 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 (1) of this section as necessary for compliance with those procedures.

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

- Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each Company shall establish and maintain liaison with the appropriate fire, police, and other public officials, and

- Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency.

- Acquaint the officials with the Company's ability in responding to a gas pipeline emergency.

- Identify the types of gas pipeline emergencies of which the Company notifies the officials.

- Plan how the Company and officials can engage in mutual assistance to minimize hazards to life or property.

8.3. Public Education

Each Company 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 Company or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the Company transports gas. The program must be conducted in English/Urdu and in other regional languages commonly understood by a significant number and concentration of the non-English acquainted population.

8.4. Purging Lines

(a) When a pipeline is being purged of air by use of gas, the natural gas must be introduced into one end of the line in a moderately rapid and continuous flow. If natural 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 ahead of natural gas.

(b) When a pipeline is being purged of gas by use of air, the air must be injected 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 ahead of air.

8.5. Patrolling

(a) Each Company 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) Pipelines in locations where anticipated physical movement or external loading could cause failure or leakage must be patrolled at intervals to be determined by the Company.

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

(d) The frequency of patrols is determined by the size of the line, the operating pressures, the location class, terrain, weather and other relevant factors, but intervals between patrols may not be longer than prescribed in Table 8.1.

TABLE 8.1 – MAXIMUM INTERVALS BETWEEN PATROLS FOR TRANSMISSION LINES

Location Class	Highways And Rail Crossings	All Other Places
1 & 2	Seven and a half (7 ½) months, but at least twice each calendar year.	Fifteen (15) months, but at least once each calendar year.
3	Four and half (4 ½) months, but at least four times each calendar year.	Seven and a half (7 ½) months, but at least twice each calendar year.
4	Four and half (4 ½) months, but at least four times each calendar year.	Four and half (4 ½) months, but at least four times each calendar year.

8.6. Leakage Survey

Each Company shall conduct periodic leakage surveys in accordance with this section. The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the requirements given in Section 11, Leak Detection and Odorization.

8.7. Crossing of Existing Pipelines

Where existing pipelines are to be crossed by roads or railways, the pipelines in such locations shall be either upgraded to meet the applicable design requirement, or subjected to a detailed engineering analysis to satisfy its safety, considering all expected loads to be imposed on the pipeline during construction and operation of the crossing, and the resulting combined stresses in the pipeline. Any such crossing must also meet the requirements of Mineral Gas Safety Rules.

8.8. General Requirements for Repair Procedures

Each Company shall take immediate temporary measures to protect the public whenever a leak, imperfection, or damage that impairs its serviceability is found in the gas pipeline system. If it is not feasible to make a permanent repair at the time of discovery, temporary repairs shall be done promptly, which then are to be followed by permanent repairs within a reasonable time.

8.9. Evaluation of Imperfections and Repair of Piping Containing Defects

(a) Where imperfections are found in steel piping, evaluations shall be made in order to determine the suitability of such piping for continued service. Where considered appropriate, evaluations of imperfections shall include methods capable of finding cracks.

(b) Where practicable, operating Companies shall maintain materials, equipment, and spare parts in adequate quantities and at suitable locations for use in emergency repairs.

(c) Excavation of piping suspected of containing defects, and if required, the subsequent temporary or permanent repair of such piping shall be performed after the piping is depressurized as necessary to an operating pressure that is considered safe for the proposed work. Caution shall be exercised when excavating to avoid contacting other buried structures or facilities.

(d) After repair operation, pipe shall be cleaned and coating applied as per these Standards.

(e) Where piping is not suitable for continued service at the established operating pressure due to the presence of defects, either the piping shall be operated at pressures that are determined by engineering assessment to be acceptable, or the affected piping shall be repaired in accordance with these Standards.

(f) Disturbed areas shall be restored, as nearly as practical, to their original conditions. Surface restoration and stabilization measures shall be taken where required.

8.10. Corrosion Imperfections

Corroded areas on the external surface of the pipe shall be thoroughly cleaned to remove corrosion products so that their dimensions can be measured accurately. For the assessment of internal corrosions imperfections, it shall not be necessary to consider the portions of such imperfections that are within the material present as a corrosion or erosion allowance.

Exclusively internal corrosion imperfections and exclusively external corrosion imperfections shall be permissible regardless of the length of the corroded area, provided that a maximum depth of such imperfections is 10% or less of the nominal wall thickness of the pipe. Areas that have coincident internal and external corrosion imperfections shall be permitted regardless of the longest length of the corroded area, provided that the sum of the maximum internal depth and the maximum external depth is less than 10% of the nominal wall thickness of the pipe.

Corroded areas that have a depth greater than 10%, up to and including 80% of the nominal wall thickness of the pipe shall be permitted, provided that the longitudinal length of the corroded area does not exceed L, as determined by the following equation:

$$L = 0.441\ B\ (Dt)^{0.5}$$

L = Maximum allowable longitudinal length of the corroded area in inches.

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches.

B = A value equal to 4 for maximum depths greater than 10 %, up to and including 17.5 % of the nominal wall thickness. For depth of corrosion pit greater than 17.5 % of the nominal wall thickness,

$$B = \{[(c/t)/\ (1.1\ c/t) - 0.15)]^{2} - 1\}^{0.5}$$

c = the maximum depth of corrosion for areas that are exclusively internal, or exclusively external corrosion imperfections, or the sum of the maximum internal and the maximum external corrosion imperfections.

Corroded areas that exceed the depth or length limits specified above shall be considered defects, which shall be repaired using one or more of the repair methods given in Table 12.2. Corroded areas in close proximity to each other shall be considered as continuous if the distance between them as measured along the longitudinal axis of the pipe is less than the longitudinal length of the smallest area in that cluster of corrosion pits.

8.11. Gouges, Grooves and Arc Burns

Gouges, groves and arc burns shall be considered as defects and shall be repaired in accordance with Table 12.2.

8.12. Dents

The following dents shall be considered as defects.

Dents that contain stress concentrators, such as gouges, grooves, arc burns or cracks.
Dents that exceed a depth of 0.25” for pipe sizes up to and including NPS 4 and those that are deeper than 6% of the OD, for pipe sizes larger than NPS 4.

8.13. Pipe Body Surface Cracks

Pipe body surface cracks shall be considered as defects and shall be repaired in accordance with Table 8.2.

8.14. Weld Imperfection in Circumferential Welds

Field circumferential welds that are found to contain unacceptable defects shall be repaired in accordance with Table 8.2.

8.15. Imperfections in Mill Seam Welds and Mill Circumferential Welds

Pipe containing welds that are found to be unacceptable shall be repaired in accordance with Table 8.2.

8.16. Permanent Field Repair Methods General

Where flammable mixtures are present, pipeline cuts shall be made with mechanical cutters. Appropriate bonding and grounding procedures shall be employed in order to eliminate sources of ignition caused by impressed currents, or the removal of pipe sections. Considerations shall be given to turning off adjacent cathodic protection rectifiers.

8.17. Grinding Repairs

Grinding of cracks, arc burns, gouges and grooves is an acceptable method of permanent repair, provided the length and depth of metal loss is in accordance with the formula given below. For arc burns, confirmation of complete removal of altered metallurgical structures by etching the ground area with a 10% solution of ammonium persulfate or a 5% solution of nital is recommended. For gouges, grooves and cracks, confirming complete removal of the defects by using dye penetrant or magnetic particle inspection and measuring the remaining wall thickness using a mechanical or ultrasonic technique is recommended.

Areas to be repaired by grinding shall be thoroughly cleaned before grinding is initiated. Grinding shall be performed to produce a smooth transition between the surface contour of the repaired area and the surrounding pipe surface. External metal loss resulting from grinding to a depth of 40% of the nominal wall thickness of the pipe is permitted, provided that the longitudinal length of the ground area does not exceed length L as determined by the following formula:

$$L = 0.441\ B1\ (Dt)^{0.5}$$

Where

L = maximum allowable longitudinal length of the metal loss area resulting from a grinding repair, inches.

D = nominal outside diameter of pipe, inches.

T = nominal wall thickness of pipe, inch.

B1 = a value equal to 4 for maximum depths up to and including 13% of the nominal wall thickness.

= a value determined from the following equation for maximum depths greater than 13% of the nominal wall thickness up to and including 40% of the of the nominal wall thickness:

$$B1 = \{[(c/t)/\ (1.1\ c/t) - 0.11)]^{2} - 1\}^{0.5}$$

c = maximum depth of the ground area, inches.

Pipe with areas of external metal loss that do not exceed the length or depth limits given by the above formula may be permitted for continued service. Areas of external metal loss resulting from grinding beyond the depth or length limits shall be considered to be grind defects, and they shall be repaired in accordance with the Table 12.2.

8.18. Piping Replacements

It is a permissible method for all pipe defects repairs to cut out cylindrical pieces of pipe and components containing the defects, and replacing them with pretested piping that meets the applicable design criteria. The minimum length of the replacement pipe shall be as follows:

Pipe Size, (NPS).	Minimum Replacement Length (in.)
< 6	6
6 to 24	2 x OD of pipe
> 24	48

8.19. Repair Sleeves

Refer to Table 8.2 for conditions for usage of repair sleeves. Reinforcement repair sleeves and pressure containment repair sleeves shall be permissible as permanent repairs, provided that:

Repair sleeves extend longitudinally at least 2” beyond the ends of the defects, and consideration is given to the following:

- Concentration of bending stresses in the pipe at the ends of repair sleeves and between closely spaced repair sleeves.
- Design compatibility of repair sleeves and piping materials.
- Adequate support of the repair sleeves during installation and operation.
- Present and future operating and pressure testing conditions.

8.20. Steel Reinforcement and Steel Pressure Containment Repair Sleeves

In addition to the foregoing, the steel repair sleeves shall meet the following requirements:

(a) Repair sleeves shall have a nominal load carrying capacity at least equal to that of the originally installed pipe.

(b) Welding shall be performed in accordance with the requirements for welding given in the Welding Section.

(c) Destructive testing and nondestructive inspection shall be used to demonstrate freedom from cracking in the weld and parent material of test welds.

(d) Electrical continuity shall be ensured between the pipe and the steel reinforcement repair sleeve.

(e) Steel reinforcement repair sleeves, not welded to the pipe, shall meet the following supplementary requirements:

  - Measure shall be taken to seal the circumferential ends of steel reinforcement repair sleeves in order to prevent migration of water between pipe and sleeve.
  - Steel reinforcement repair sleeves that do not utilize grouting material to fill the annulus between the sleeve and the pipe shall be accurately fitted to the pipe, and the damaged area shall be filled with an appropriate material to provide the required mechanical support.

8.21. Fiberglass Reinforcement Repair Sleeves

Refer to Table 12.2 for allowed application of fiberglass repair sleeves. Only approved fiberglass repair sleeves shall be used on steel gas lines. The following limitations shall be observed.

Only trained and certified personnel shall perform installation of sleeves. Sleeves shall not be used to repair:

- Leaks.
- Defects where metal loss exceeds 80% of nominal wall thickness.
- Dent.
- Gouges, grooves, arc burns or cracks that have not been removed by grinding.

8.22. Temporary Repair Methods

Where it is not practicable to perform permanent repairs immediately, it shall be permissible to repair piping containing leaks or defects in the form of gouges, grooves, dents, arc burns, corrosion pits or cracks, using temporary repair methods. Patching, puddle welding, and lace welding shall not be permitted. Approved mechanical leak clamps and bolt-on split sleeves are permitted for temporary repairs, where so required. After temporary repairs are completed, it may be necessary to operate the line at reduced pressures until permanent repairs are completed.

TABLE 8.2 - ACCEPTABLE PERMANENT REPAIR METHODS

	Type Of Defect	Grinding Repair	Pressure Sleeve	Reinforce-ment Sleeve	Fiber-Glass Sleeve	Welding Repair
1	**Corrosion Defects**					
	External	Not acceptable	0	0	1	Not acceptable
	Internal	Not acceptable	0	0	1	Not acceptable
2	**Gouge. Groove or Arc Burn**		0			
	On pipe body or mill seam weld, not in a dent	0	0	0	1, 2	Not acceptable

	Type Of Defect	Grinding Repair	Pressure Sleeve	Reinforce-ment Sleeve	Fiber-Glass Sleeve	Welding Repair
	On a circumferential weld, not in a dent	0	0	2	1, 2	Not acceptable
3	**Dent Defect**		0			
	With stress concentrator, not on a circumferential weld	3	0	2	Not acceptable	Not acceptable
	With stress concentrator, on a circumferential weld	3	0	2	Not acceptable	Not acceptable
	Without stress concentrator, on pipe body	Not acceptable	0	0	Not acceptable	Not acceptable
	Without stress concentrator on a mill seam weld	Not acceptable	0	Not acceptable	Not acceptable	Not acceptable
	Without stress concentrator on a circumferential weld	Not acceptable	0	Not acceptable	Not acceptable	Not acceptable
4	**Pipe Body Crack**					
	Not in dent	0	0	2	1, 2	Not acceptable
5	**Weld Defect**					
	In a circumferential weld	0	0	Not acceptable	Not acceptable	0
	In a mill seam weld	0	0	Not acceptable	Not acceptable	Not acceptable
6	**Grind Defect**	Not acceptable	0	0	1	Not acceptable
	Leak	Not acceptable	0	Not acceptable	Not acceptable	Not acceptable

For explanation of numbers, continue reading.

0 - There is no limitation.
1 – This repair method is not acceptable for defects with metal loss in excess of 80% of the nominal wall thickness.
2 –The stress concentrator (gouge, groove, arc burn or crack) shall be removed by grinding prior to application of the sleeve.

3 –The stress concentrator (gouger, groove, arc burn or crack) shall be removed by grinding prior to the dent being assessed for acceptability.

Note: Cutting out a cylindrical length of pipe containing any type of defect, and replacing the cutout with a similar quality pretested pipe is an available method of repair.

(Modified from CSA Standard Z662-99)

8.23. Valve Maintenance

Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

8.24. Vault Maintenance

(a) Each vault housing a pipeline valve, pressure regulating or pressure limiting equipment, and with internal volume of 200 cubic feet (6 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, ensuring it is in good physical condition and is adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

8.25. Prevention of Accidental Ignition

Where the presence of gas constitutes a hazard of fire or explosion, the Company shall take steps including the following in order to minimize the danger of accidental ignition of gas in any structure or area.

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting must not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Posting of warning signs, where appropriate.

8.26. Abandonment or Deactivation of Facilities

a) Each Company shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

b) Each pipeline abandoned in place must be disconnected from all sources of gas.

c) Except for service lines, each inactive pipeline that is not being maintained must be disconnected from all sources of gas.

d) Whenever service to a customer is discontinued, one of the following must be compiled with:

- The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the Company.
- A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
- The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

e) If air is used for purging, the Company shall insure that a combustible mixture is not present after purging.

f) Each abandoned vault must be filled with a suitable compacted material.

8.27. Record Keeping

Each Company shall maintain the following records for gas lines:

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

(b) A record of each patrol, survey, inspection must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

(Ref: U.S. Department of Transportation 191-192)

8.28. Customer Meter and Regulator Station Installations

(Consumers tapped directly from transmission line)

8.29. Location for Customers' Meter and Regulator Station Installations

(a) On service lines supplying large industrial customers or installations where gas is utilized at higher than standard service pressure, specially designed regulating and metering stations suitable for high pressure gas measurement shall be installed at readily accessible and safe locations.

(b) Customers' meters and regulator may be located either inside or outside of buildings, depending upon local conditions.

(c) When outside meters and service regulators are installed in locations that do not afford reasonable protection from accidental damage, such protection shall be provided.

(d) All regulator and relief vents where required, shall terminate in the outside air in rain and insect-resistant fittings. The open end of the vents shall be located where, if a regulator failure resulting in the release of gas occurs, the gas can escape freely into the atmosphere and away from any opening into the buildings or sources of ignition.

(e) Industrial or commercial customers' regulating facilities off the transmission line shall not be installed in underground pits or vaults that can submerge in water due to rain or flooding.

8.30. Protection of Customer's Meter and Regulator Installations from Damage

(a) Pressure control and measurement equipment shall not be located where rapid deterioration from corrosion or other causes is likely to occur.

(b) A suitable protective device, such as back-pressure regulator or a check valve shall be installed downstream of the station as required under the following conditions:

- If the nature of the utilization equipment is such that it may induce a vacuum at the meter, a backpressure regulator shall be installed downstream of the station.

- A check valve, or equivalent, shall be installed if:
  - the utilization equipment might induce a back-pressure

  - the gas utilization equipment is connected to a source of oxygen or compressed air

  - Liquefied petroleum gas or other supplementary gas is used as standby and might flow back into the meter station. A three-way valve installed to admit the standby supply and at the same time shutting off the regulator supply may be substituted for a check valve if desired.

8.31. Avoidance of Overstress at Customers' Meters and Regulators

All meters and regulators shall be installed in such a manner as to prevent undue stresses upon the connecting piping or the meter. Connections made of material that can be easily damaged, shall not be used. The use of standard-weight close nipples is prohibited.

SD/ -

BRIG. (RETD.) TARIQ MAHMUD,

Secretary,

Oil and Gas Regulatory Authority

REGISTERED No. M - 302
L - 7646

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PART II

Statutory Notifications (S. R. O.)

GOVERNMENT OF PAKISTAN

OIL AND GAS REGULATORY AUTHORITY

NOTIFICAT ION

Islamabad, the 4th February, 2008

SRO No. 116(I)/2008:—In exercise of the powers conferred by Section 42 of the Oil and Gas Regulatory Authority Ordinance, 2002 (Ordinance XVII of 2002) the Oil and Gas Regulatory Authority is pleased to make the following amendment in the Natural Gas Transmission (Technical Standards) Regulations 2004: -

In the aforesaid regulations, in regulation 4.2, for the words, "*Steel pipe manufactured in accordance with the following standards may be used*" shall be substituted namely: -

"Steel pipe manufactured under internationally recognized accreditation in accordance with the following standards shall be used"

BRIG. (RETD.) TARIQ MAHMUD,
Secretary,

[2116(2008)/Ex./Gaz.]

REGISTERED No. M - 302
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ISLAMABAD, WEDNESDAY, JULY 23, 2008

PART II

Statutory Notifications (S. R. O.)

GOVERNMENT OF PAKISTAN

OIL AND GAS REGULATORY AUTHORITY

NOTIFICAT ION

Islamabad, the 23rd July, 2008

SRO No. 773(I)/2008:—In exercise of powers conferred by Section 42 of the Oil and Gas Regulatory Authority Ordinance, 2002 (Ordinance XVII of 2002), the Oil and Gas Regulatory Authority is pleased to notify that S.R.O. 138(1)/2008 dated 4th February, 2008 shall take effect 1st January, 2009.

BRIG. (RETD.) TARIQ MAHMUD,
Secretary,

[2797(2008)/Ex./Gaz.]