

Chapter 2

Transmission and Distribution Systems and Design

2.1 Transmission Pipelines

2.1.1 Introduction

Once natural gas is first extracted from corresponding well, this is followed by gas treatment plant (downstream process), then via transmission pipeline to distribution network systems, and to the consumers. Through this transmission gas delivery, the concept of pipeline design is established through its location, the type of fluid being carried and its operating pressure and temperature are also of prime importance within this process. Unusual examples of severe location are the trans-Alaska pipeline where long sections are laid above ground to protect the permafrost and the Middle East, where long pipelines are laid both above and below ground and can be subjected to large temperature changes that bring complex design concepts. The operating pressure will determine the grade and wall thickness of the material, and temperature will also affect the requirements for pipe coatings, insulation, expansion joints, anchor blocks, etc. Gas pipelines require special attention over and above the normal design requirements for liquids because of the vast quantity of stored energy in the pipeline steel due to the compressibility of gas. The design should therefore take account of the probable consequences of failure and the parameters that can be adjusted to minimise the possibility of failure in pipeline systems. This chapter therefore attempts to provide the wide guidelines related to issues with the design and integrity of the transmission and distribution pipelines together with safety aspects of the systems.

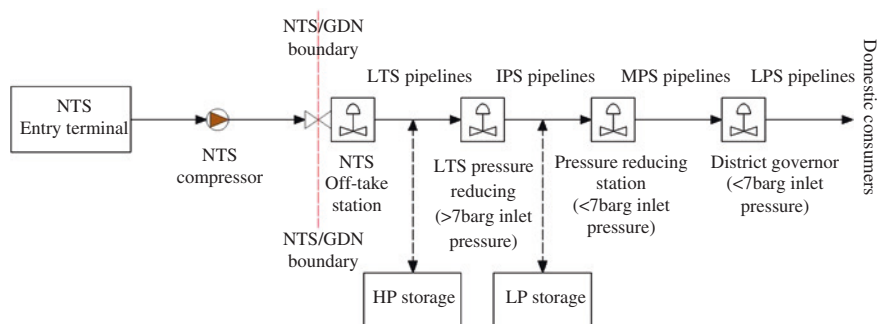


Fig. 2.1 Transmission and distribution system network [21]

2.1.2 Gas Transmission Pipeline Design

The design of gas transmission and distribution systems involves a series of tasks with their interdependencies to one another as shown in Fig. 2.1 below.

2.1.2.1 Design Criteria

Natural gas transmission systems design philosophy has survived revisions of guidelines that specify the detailed criteria for all components design. While standards used in different countries and regions differ, still there is wide overlap of the fundamental guides between them. The major criteria considered below include pressure and temperature ratings, gas specifications, gas velocity, pipeline sizing, stress analysis and location class.

Pressure and Temperature Ratings

Typically, new onshore and offshore gas transmission pipelines are designed and constructed to operate in the pressure range 40–94 barg, although IGM/TD 1—Edition 5 allows for a maximum operating pressure of 100 barg. The maximum operating pressure of existing onshore pipelines is limited based on a periodic risk assessment of proximity to buildings, crossings and pipe condition. Offshore subsea pipelines are operated at much higher pressures—typically 150 barg or higher—due to the lower consequential impacts of pipeline failure. Normal operating temperatures are relatively constant for buried pipelines, except in extreme conditions, and are generally taken to be 5 °C. IGM/TD/1 stipulates a design temperature of 0 °C, with some exceptions such as at the exit from

a pressure-reducing installation lower temperatures, at the exit from a compressor station—higher temperatures, at exposed bridge or other overhead pipeline crossings—lower or higher temperatures [1–3]. All pipeline materials should have adequate “fracture toughness” at or below the minimum design temperature. The pipeline must be designed for all possible operating temperatures; extreme examples are the above ground expansion/contraction loops on the trans-Alaska pipeline and similar loops incorporated into above ground desert pipelines in the Middle East. Exceptions to the normally assumed 5 °C operating temperature in the United Kingdom are:

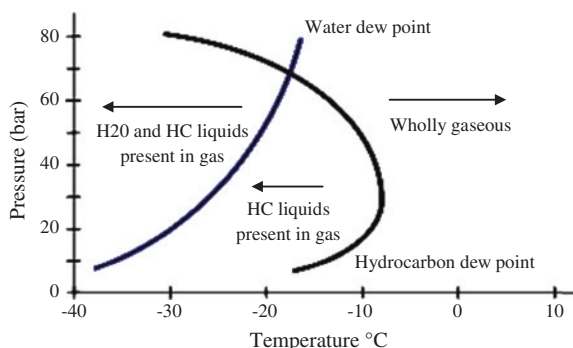
- Low temperatures on the outlet of pressure-reducing regulators
- Above ground pipework affected by ambient temperatures
- High temperatures on the outlet of compressor stations, which can persist for up to 50 km.

Gas Specifications

All pipeline materials should have adequate “fracture toughness” at or below the minimum design temperature. Although Fig. 2.2 has indicated the water dew point, in most cases, the gas that is conveyed in onshore gas transmission pipelines is dry, “sweet” methane, and the key gas quality parameters that are monitored and controlled are:

- Gross Calorific Value
- Relative Density
- Water Dew point
- Hydrocarbon Dew point
- Total Inerts
- Oxygen Content
- Hydrogen Sulphide
- Total Sulphur Content
- Impurities—dust, oil and contaminants

Fig. 2.2 Hydrocarbon dew pointing [21]



Gas Velocity

Theoretically, there is no velocity limit but dust, which is always present in pipeline gas, produces an abrasive effect when carried in the gas stream. A maximum velocity of about 20 m/s is therefore recommended to avoid erosion of the pipe. Particularly at bends, very high flow rates can induce “dust storms” and these are often induced during the commissioning of pipelines or equipment resulting in blockages and malfunctions of A.G.I. equipment. With appropriate control of gas quality and suitable gas-filtering arrangements at pipeline entry point, there is generally no need to limit the gas velocity. However, where dust is a particular problem, internal abrasion of the pipe can take place and velocities should be limited accordingly, typically up to 20 m/s. The fundamental equation involves [16] expressed as:

$$V_e = N \frac{c}{\sqrt{\rho}} \quad (2.1)$$

where V_e is the erosional velocity (m/s), N is 1.22 for metric system, c is a constant ranging between 100 and 250 [16], and d is the gas density (kg/m^3).

Pipeline Sizing

The required diameter will depend on economics as well as on the minimum pressures and required flow capacity. The requirement for compressors, which is of strategic and economic importance, will also affect the pipeline size. However, for basic sizing purposes, the steady state general flow equation can be used as described in Sect. 4.3 on Gas Flow in Pipelines. Consideration should always be given to transient analysis (unsteady state) to test the capability of the pipeline to meet emergency conditions and in the case of liquid pipelines to ensure that the pipeline is designed to meet surge conditions.

Pipeline Stress Analysis

Maximum Allowable Stress—Pressure and temperature as well as other operating conditions such as bending can create expansion and flexibility problems, and therefore, stress criteria are specified in all codes, limiting the level of combined stresses allowed in a pipeline. The design factor relates only to hoop stress if other stresses are significant, then these could contribute to the pipeline steel exceeding its yield stress. Design codes vary in the way they calculate the combined or equivalent stress but the following equation is typical:

$$\sigma_{eq} = \sqrt{\sigma_c^2 + \sigma_l^2 - \sigma_c \sigma_l + 3\tau^2} \quad (2.2)$$

where, σ_{eq} = von Mises (equivalent) stress, σ_c = circumferential stress, σ_l = longitudinal stress, τ = shear stress in plane of pipe cross.

Pipeline Fatigue

The fatigue life of a pipeline is usually defined in terms of the allowable pressure (stress) ranges and the associated numbers of pressure cycles. Normally, a 40-year life is assumed, but this could be longer or shorter depending on circumstances. Pressure cycling (i.e. hoop stress) can cause small weld defects to grow in time to a critical size and is therefore the major factor in determining the fatigue life of welded steel gas pipelines, particularly those pipelines that are designed to utilise line-pack storage. Fatigue life is not greatly influenced by temperature, providing that the fracture toughness properties are met, because temperature effects are small in comparison with those produced by hoop stress. When a new pipeline is high-level hydrostatically tested, any existing defects will grow under the influence of the high stress level and any that reach a critical length will fail resulting in pipe rupture. Normally, pipelines do not fail and any remaining defects are therefore non-critical. Pressure cycling, however, causes a gradual growth in the remaining defects such that one or more could become critical in time. Restrictions on pressure cycling are required to prevent this, particularly on pipelines operating under line-pack conditions. British Gas has determined that a pipeline life of 40 years, assuming 1 cycle/day, is equivalent to 15,000 cycles of 125 N/mm² magnitude. There are two common approaches:

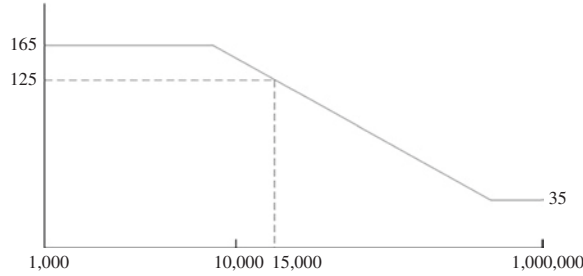
- **Constant daily pressure cycling** where the magnitude of daily pressure cycling is constant, the fatigue life should be determined from: $S_3 N = 2.93 \times 1,010$ where S = constant amplitude stress range (N/mm²), N = number of cycles.
- **Pressure cycling** where the magnitude of daily pressure cycling is not constant, the fatigue life is normally evaluated on the basis of converting the recorded variable cycles to an equivalent spectrum of constant amplitude stress cycles and the following condition for the damage fraction should be satisfied to obtain an acceptable fatigue life: $DF = \sum n_i \leq 1.0 N_i$

where n_i = the actual number of cycles accumulated at stress range S_i , DF = damage fraction, S_i = stress range (N_i and n_i), N_i = number of stress cycles allowed at stress range S_i . 15,000 cycles at 125 N/mm² has therefore been set as the maximum permissible fatigue life in IGE TD/1. According to Fig. 2.3, if any cycles are <125 N/mm², they are multiplied by a factor based on the number of stress cycles at the lower level, as shown in Fig. 2.3, which will be required to cause the same damage as 15,000 cycles at 125 N/mm².

Location class

For gaseous fuel such as natural gas in pipelines and other toxic and flammable gas pipelines, the design codes use a system of area classification in order to have an objective view for allocation of design factors and other elements such as minimum proximity. The rationale behind this type of classification is that concentration of people represents an increase in both risk to that population and also an

Fig. 2.3 Stress range versus number of cycles [21]



increased chance of third-party interference, i.e. digging up the pipeline, caused by that population. The manner in which the design codes perform this analysis is to establish a corridor centred on the pipeline. For a given length of corridor, the designer counts either the number of “people normally present” or “dwelling units” dependant on the code. The average number of people or dwellings is then calculated for the particular strip and the resultant design factor applied. The codes, however, make the highest classification subjective,—“central areas of towns and cities”—resulting in some confusion from time to time as to exactly what this constitutes.

It should be noted that only ASME B31.8 dictates a regarding of the pipeline on a continuous basis to take account of new developments built near to gas pipelines. Replacement of sections of the pipeline or restrictions in the MAOP can be necessary if a large development is built close to an existing pipeline. It is unlikely in the United Kingdom to occur due to the involvement of the HSE in planning application close to existing high-pressure gas pipelines. Other countries also have a form of building control within certain distances from hazardous installations or pipelines. Design codes BS 8010 and TD/1 also incorporate minimum distance requirements variable on MOP, pipe size, design factor and wall thickness, depicted on a graph.

The different ways of calculating area classification make direct comparison a little complicated; however, if an average of 3 persons/building is used (which is a common assumption used when counting people in the absence of detailed information), then a comparison can be made in the table below. There is a common trend. The general design factor for each area is also given in Table 2.1, to

Table 2.1 Design factor for various standards [16]

ASME B 31.8				ISO 13623		PD8010/IGE TD/1	
	No. of build- ings in area	No. of people/km (approx) 1 km ²	DF	No. of people/ km	DF	No. of people/ km	DF
1.1	<10	<46	0.8	0–1	0.83	1/R– <250	0.72
1.2	<10	<46	0.72	2– <50	0.77	1/R– <250	0.72
2	10–46	46–215	0.6	3–50 to 250	0.67	1/R– <250	0.72
3	>46	>215	0.5	4– >250	0.55	2/S– >250	0.3
4	Subjective	Subjective	0.4	5–Subjective	0.45	3/T–Subj	<16 bar

show the effect on design factor. There are often exceptions to particular features, e.g. schools and hospitals, which commonly down grade the area by one or more groups.

There are also specific design factors allocated to road, rail and river crossings and other such items. These are too numerous to list here, but are generally one classification lower than the adjacent pipeline.

Material grade

Material type considered as line pipe material specification until relatively recently was limited to American Petroleum Institute (API 5L). This specification provided the basic building blocks but was normally supplemented by additional company standards or specific project ones. In conjunction with the EN and ISO pipeline design codes, ISO line pipe specifications, ISO 3183, have also been issued, which have been incorporated into the EN system as EN 0208. The ISO and EN codes require use of their own line pipe specifications and requirements when the code is used (as well as a number of other “normative” codes listed in each code).

The ISO/EN line pipe specifications are split into three classes, A, B and C. A is essentially a rewrite of API 5L, B adds some general amendments varying such items as the under tolerance and offering numerous additional requirements subject to choice by the designers, and C is for sour service and special pipes. Class B is the one most anticipated to be used for pipelines. The specifications also round up the SMYS in terms of kN/m^2 varying the standard API SMYS ratings by a few per cent. The standard under tolerance for wall thickness for class 8 line pipe is reduced to 5 % from 10–12.5 % on the basic API 5L specification. Pipeline specifications list “standard” thicknesses of pipe that are usually used in order to gross up to the next available thickness. However, for pipelines longer than 50–60 km, there is a growing tendency to obtain pipe of exactly the required thickness at minimal additional cost. This is especially true for pipe of increased thickness where the standard sizes can be several mm apart. For long trunklines, several pipelines are now installed with the 0 D non-standard, with a constant ID, regardless of wall thickness. There are considerable savings to be made by this approach, but it needs to be looked at for each design and is not applicable for all projects, usually those where a fixed throughput is specified and where the distance is long (>100 km). Other non-standard items that have occurred include purchasing line pipe in 18 m lengths. The cost of non-standard trucks to transport them can outweigh the reduction in welds of 50 %. Logistics play an important part in this option as these loads are significantly longer than standard trailers. Line pipe grade is another area where changes in the “standard” have occurred in recent years. The most common grade of line pipe seen is now X60 or X65, certainly for larger diameter and higher pressure pipelines. Pipelines using X70, X80 and X100 are now being assessed or built. They do require greater care during welding, and there are issues related to the narrowing between SMYS and UTS. A minimum ratio of 90 % of UTS to SMYS is commonly applied.

Wall thickness

Wall Thickness (t)—Pipeline steels have standard values of nominal wall thickness with tolerances to allow for the manufacturing process. Acceptable tolerances vary depending on the requirements of the pipeline owner, but a typical tolerance for under thickness is 5 % for submerged arc welded (SAW) pipe. The nominal wall thickness therefore is not necessarily the actual wall thickness. In ANSI B31.8 pipelines can be designed using the nominal wall thickness but BS 8010 and IGE/TD/1 require the pipelines to be designed on the basis of “minimum wall thickness”, i.e. the nominal wall thickness less the maximum tolerance for under thickness. The minimum wall thickness should be equal to or greater than the design thickness t as in Eq. 2.3 where:

$$t = \frac{P \cdot d}{2fs} \quad (2.3)$$

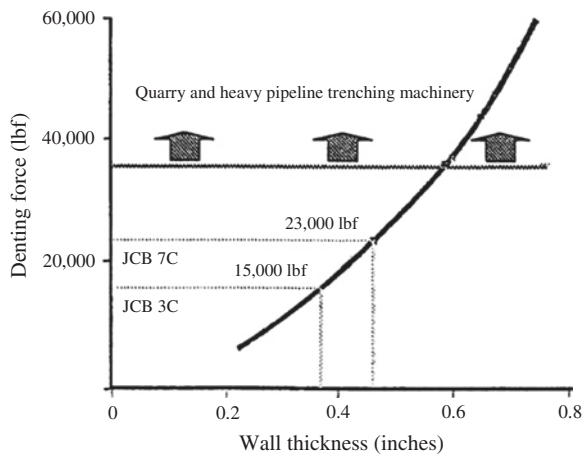
t = design thickness, d pipe diameter, p = internal pressure, S = specified minimum yield stress of the pipe material, f = design factor <1.0 .

From the Eq. 2.1, it is clear that the design thickness is dependent on other parameters that will be determined by the required operating conditions. The pressure and diameter will be determined by the required transmission capacity, and the design factor will be dependent on the pipeline route; therefore, it remains to select a material grade that will give a suitable design thickness or vice versa.

An important consideration in the selection of pipe wall thickness, particularly for gas pipelines, is to know what wall thickness is required to resist penetration by mechanical equipment and what depth of defect will result from the different types of machinery likely to be encountered.

Figure 2.4 shows the results of tests carried out by British Gas to find the force required to produce a 0.5 mm (0.2 inches) dent in X60 pipeline steel of different wall thicknesses. It will be observed that a wall thickness of 12.7 mm (0.5 inches)

Fig. 2.4 Denting force versus wall thickness [21]



will resist impact by the lighter types of machinery encountered in quarrying and pipeline trenching; however, during normal operations, it is unlikely that such equipment will be in use without the pipeline operator being aware of it. A wall thickness of 12.7 mm (0.5 inches) will resist impact by any of the commercially available excavators likely to be used during normal construction activities and is therefore suitable for use in high-risk areas, and a 9.52 mm (0.375 inch) wall thickness will resist an impact of 15,000 lb_f that makes it suitable for use in the more remote areas. The choice of material grade should therefore reflect the requirement for a wall thickness appropriate to the risk category of the pipeline route. Additionally, the requirement for thicker walled pipe should not be taken as an opportunity to reduce the material grade in any area below that being used on the remainder of the pipeline. High-risk areas require a combination of impact resistance and low operating stress level, which is provided by using a combination of appropriate wall thickness and grade of steel.

Material Properties of the pipe must have sufficient fracture toughness properties to prevent propagating brittle or ductile fractures at the minimum operating temperature of the pipeline. In the United Kingdom, the normal operating temperature is taken as 5 °C and it is required by IGE/TDI that fracture toughness properties are demonstrated at 0 °C to give a margin of safety. In the case of brittle fracture, the requirement is for a minimum of 75 % shear area when subject to a Drop Weight Tear Test (D.W.T.T), i.e. <25 % brittle fracture. However, if the pipeline is to operate permanently at a level below 30 % SMYS, then a D.W.T.T. is not required because propagating fractures do not occur below this level.

For existing pipelines operating above 30 % specified minimum yield stress (SMYS), the maximum design factor should be that corresponding to the Drop Weight Tear Test (D.W.T.T) transition temperature. As previously described, the arrest/propagate boundary is a function of the level of hoop stress and the transition temperature. Samples of the pipeline steel are therefore required for D.W.T. testing. Ductile fracture is avoided by ensuring that the pipeline steel has sufficient energy absorption properties to prevent fracture occurring. The Charpy V-notch impact test is used as previously described, and the energy level required will depend on the grade of steel and diameter of pipe (Fig. 2.5 and Table 2.2).

Fig. 2.5 Pipeline trenching system [21]

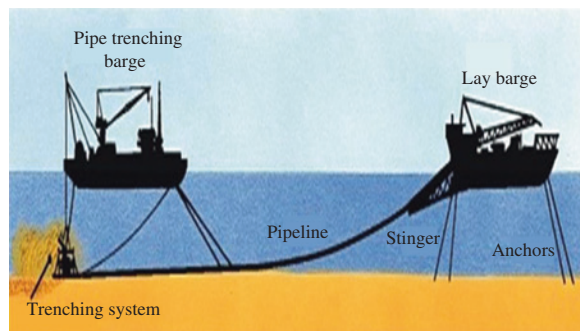


Table 2.2 Tabulated steel grades [19]

Steel grade (I.S. EN 10208–2)	Minimum yield strength (N/mm ²)	Corresponding steel grade (API 5L)
L 245	245	B
L 290	290	X42
L 360	360	X52
L 415	415	X60
L 450	450	X65
L 485	485	X70
L 555	555	X80

For existing pipelines operating above 30 % SMYS, the maximum design factor should be that corresponding to the D.W.T.T. transition temperature. As previously described, the arrest/propagate boundary is a function of the level of hoop stress and the transition temperature. Samples of the pipeline steel are therefore required for D.W.T. testing before Fig. 2.6 can be used.

High-Density Routes—the pipeline must use pipe with a minimum wall thickness of 11.91 mm, and the design factor must be <0.3. The thick-wall pipe should extend to a distance equal to the proximity distance on either side of the crossing, i.e. it is treated as though it were a type S area.

Other Routes—the pipeline must use a minimum of 9.52 mm wall thickness and have design factor of <0.3. In all locations where a pipe wall thickness of 19.1 mm or more is used, the design factor can be raised to 50 % SMYS because risk assessment has shown the risk of failure to negligible.

Parallel Routes—Pipeline routes parallel to traffic routes of any sort should be avoided. Any pipeline that is parallel and within the proximity distance (from the

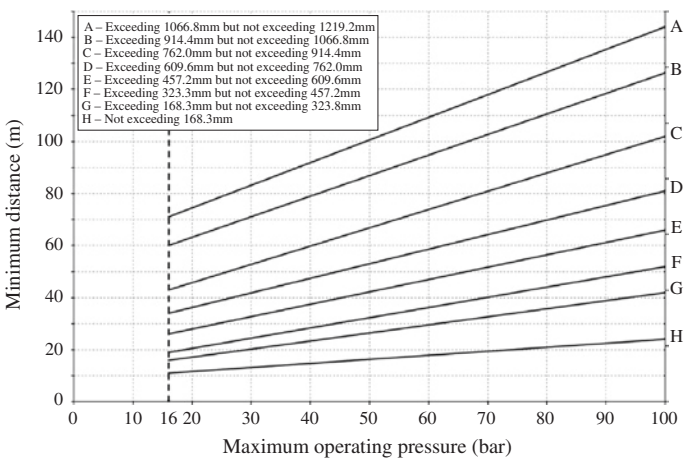


Fig. 2.6 Operating pressure versus minimum distance chart [21]

Table 2.3 Tabulated nominal thickness [19]

Outside diameter (mm)		Least nominal wall thickness (mm)
Exceeding	Not exceeding	
	168.3	4.78
168.3	457.2	6.35
457.2	608.6	7.92
609.6	914.4	9.52
914.4	1066.8	11.91
1066.8	1219.2	12.70

carriageway edge or rail running track) must conform to the traffic route requirements for the whole length of the infringement. Under-exemplified UK codes sleeves are avoided wherever possible, however, ANSI B31.8 still recommends sleeves at crossings as per Table 2.3.

The introduction of “thick-wall” pipe has considerably reduced the need for sleeves, and they should be avoided wherever possible, but may be needed for construction reasons in certain locations. In such cases, the pipeline design requirements should still conform to the appropriate crossing classification. Some existing pipelines were constructed using sleeves and therefore continue to operate under the original design conditions. Sleeves are classed according to their operational use:

Class 1—Sleeves required for (a) protection against external interference and (b) protect the public and property against a failure of the carrier pipe.

This applies where the carrier pipe is operating above 30 % SMYS or has a wall thickness <11.91 mm, i.e. a Class 1 sleeve must contain the line pressure in the event of a carrier pipe failure.

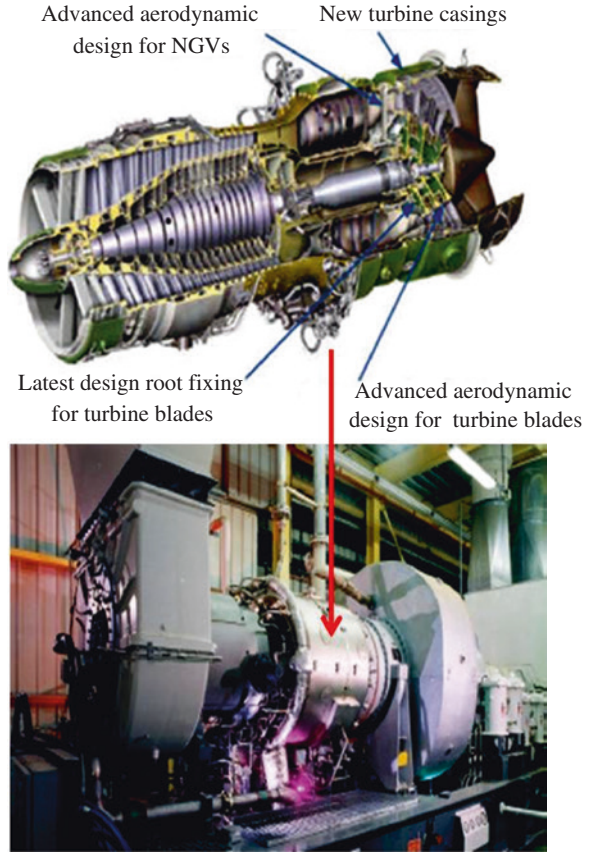
Class 2—Sleeves required for impact protection only, i.e. pipelines operating below 30 % SMYS but where the pipe wall is not thick enough to prevent serious impact damage

Class 3—Sleeves installed for construction purposes only. This class of sleeve can be (a) concrete (b) steel. If a construction sleeve is required, then concrete is better since concrete does not create a shield against CP currents.

2.1.3 Natural Gas Compression

Compressors are used to increase the flow capacity in the system between two points. They increase pressure to help overcome flow-related pressure losses but they also increase flow capacity by making the gas denser as shown in the cross section of Fig. 2.7; denser gas occupies less space and it moves with lower velocity so it loses less pressure along the way. Issues with legacy compressors are as follows: requirements of the industrial emission directive for emission limit values on NO_x and CO , best available technique (BAT), low-efficiency operation, NTS reconfiguration requirements for changing flow patterns. Electric variable speed

Fig. 2.7 Compressor units
[22]



motor drives and compressors are gradually replacing gas turbines and gas engines because of the following reasons: (i) There are no “local” air quality emissions, (ii) the electric motor has a high efficiency at its rated power, i.e. the full speed range of the compressor can be used without being compromised by adverse compressor drive issues, (iii) the GB transmission system operator has installed electric variable speed drive units on about six sites nationally.

2.1.4 Testing and Commissioning

Hydrostatic testing is carried out for all transmission pipelines operating at a design factor ≥ 0.3 , and the required test pressure is calculated from the expression in Eq. 2.3 and can be expressed as [3–6]:

$$P_t = 20t_n f_s D^{-1} \quad (2.4)$$

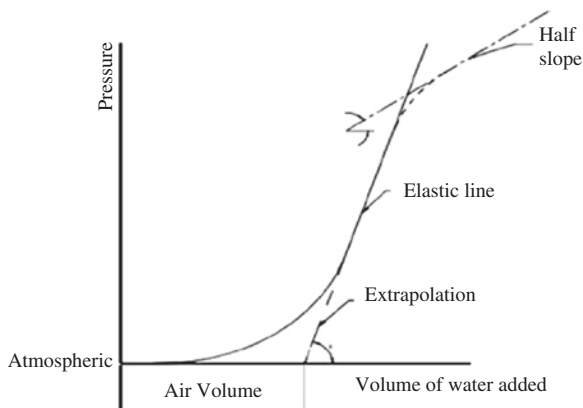
where P_t = test pressure (bar), t_n = nominal wall thickness (mm), s = specified minimum yield strength (N/mm^2), f = design factor, D = outside diameter of the pipe (mm)

In order to provide some test that the final completed pipeline with its various components and variations possible in materials, jointing, construction and back-filling are fit-for-purpose, a pressure test with or using a harmless fluid prior to commissioning is required in most design codes and safety legislation as being necessary. The accepted means is for a hydrostatic pressure test, whereby the pipeline is filled completely with water, pressurised up to a set pressure and the pressure held for a minimum period of time, commonly 24 h, but sometimes less. Some of the design codes allow pneumatic testing, but this is generally limited to low pressure and low design factors due to the vastly increased energy in a pneumatic test versus hydrostatic (>300 times) and the fact that any small leak takes much longer to be apparent on a pneumatic test versus hydrostatic.

Pressure testing is designed to achieve the following considerations: (i) demonstrate the integrity of the pipeline, (ii) locate the presence of small leaks and pinholes, (iii) remove defects, (iv) work-hardening small defects increasing fatigue life. The setting of the pressure test level needs to follow the methodology of the design code, but care also needs to be taken not to overstress the pipeline either at its lowest point or, when design calculations have used the empty weight of the pipe, as in gas pipes, and not the temporary weight of the hydrotest water. There have been occasions, often not publicised, where supports, pipe bridges and other spans have failed when a gas pipe is hydrostatically tested because insufficient thought had been given to the weight of the pipe when full of water instead of gas. The case for high-level or yield testing of pipelines relates to fracture mechanics, fatigue analysis and crack growth. The testing procedure normally recognises that if the pressure / volume graph for the water being used as the pressurising medium starts to get to a slope half of that found during the elastic portion of the test or that the pressure increase per unit volume is half that previously encountered, pressurisation should cease, regardless of the pressure as the pipeline has started to yield.

Acceptance criteria for pressure tests are normally blithely stated as “no pressure drop that cannot be accounted for by variations of temperature or other factor”. It is very rare for a pressure test to achieve the test pressure and to remain unchanged within the limits of accuracy of the test instruments. The pipeline temperature is critical to understanding and computing the variations in pressure that will occur. Temperature probes should be buried alongside the pipeline in at least three locations along the pipeline route. BS 8010 Sect. 8.6 and associated graphs provide a practical guide to computing the variations due to temperature. In the end, a decision is made based on observations, calculations and acceptance by one of the parties, usually the client or the testing company that the pipeline is free from defects. The pipeline is filled with water using pipeline “pigs” and pressurised to the required test pressure as a test of mechanical strength and integrity. The hydrostatic test also “work-hardens” and stress relieves the pipeline. A pressure–volume (PV) plot in Fig. 2.8, of the water added during the pressurisation process, is constructed, and this allows for the calculation of air content, which must be <0.2 % of the fill volume under test (or 0.5 % for short pipeline lengths).

Fig. 2.8 Typical PV representations



Commissioning of pipelines is carried out in the following order of preference:

- (i) Super-dry air/nitrogen followed by gas—an air-drying unit and compressors are used to propel foam pigs through the pipeline, which absorb liquid water and distribute residual water as a thin film on the internal pipe wall to facilitate faster evaporation.
- (ii) Vacuum drying followed by purging and gassing up—by reducing the pressure of air to 10 mbar, water will evaporate at 70 °C (the “saturation vapour temperature”) and the vapour is extracted via the vacuum. Methanol swabbing using a commissioning pig train is also conducted to ensure drying the pipe for water condensates, and it follows a sequence as outlined in Fig. 2.9 below.

In general, the key threats/risks to a gas transmission pipeline during its operating life arise from the following considerations (i) third-party interference, (ii) corrosion, (iii) ground movement, (iv) flooding, (v) internal/external stress corrosion cracking, (vi) fatigue and (vii) human error. A suitable, risk-based approach to Operations and Maintenance (O&M) is required to ensure that the pipeline has adequate integrity and remains fit-for-purpose. This involves assessing pipeline threats and risks and mitigating these risks through appropriate O&M and training [7].

- (i) **Third-party interference:** Typical O&M measures that are used to mitigate these risks include, pipeline surveillance in the form of dial-before-you-dig programmes, foot surveys, aerial surveys and landowner liaison, increased depth of cover

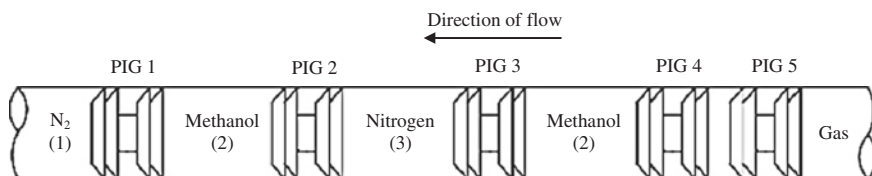


Fig. 2.9 Methanol swabbing process



Fig. 2.10 Typical third-party interferences [21]

This has historically been not only the most common loss of integrity as exemplified in Fig. 2.10, but also provides the largest loss of integrity and the highest level of damage. The root cause of many incidents is lack of knowledge of a pipeline's existence or depth. The most obvious place to start with in terms of information is visual markers on the ground. However, operating companies often find themselves in a dilemma as to whether increased knowledge of the location of the pipelines makes them vulnerable to deliberate attack and whether this outweighs the decrease in third-party activity. Marker posts also require constant maintenance to keep up to date telephone numbers, etc., and to repair damage. Marker tape below ground has been shown to be of little effect unless combined with some other form of protection. Regular contact and notification with the landowner and occupier usually reap large dividends in preventing damage. Many pipelines have a right to walk *I* inspect the pipeline annually, which affords time to contact each landowner. Loss of this right through inactivity and not keeping on up to date list of owners and occupiers has often been shown to be a false economy for the pipeline operator. A further means of preventing damage that has received much attention in the USA is the use of a “one-call” system whereby a contractor can phone one (free) number giving the location of where he is planning to excavate and a central record provides details on any pipeline or cable buried in the vicinity. This normally requires legislation to require all operators to provide the information and contribute towards the running costs. The incorporation in the United Kingdom of the New Roads and Street Works Act may perform a similar function, but the register of services is still limited and may take some time to build up to a comprehensive record. The majority of pipeline companies utilise an aerial observation of their pipelines, which can provide warning of works being undertaken on or close to the pipeline. The normal frequency adopted is bi-weekly, although this can have the effect of activities being kept on hold until the helicopter or plane has been over with the knowledge that there is two weeks grace before another inspection.

As in most activities, the hardest information to gather is near misses or in the case of pipelines dents or gouges. There is a human tendency not to report damage



Fig. 2.11 Ground movement [21]

to someone else's property if it is not apparent and forget about it. Pipelines are vulnerable to this type of damage, especially gouges that concentrate stress levels and accelerate corrosion at the locality. The only practical way to get information about these types of incidents is for the pipeline operator to accept that repair costs will not fall onto the person inflicting the damage. In the long run, this will produce effective results, but is sometimes difficult to accept.

(ii) **Ground movement**

The concept of ground movement as shown in Fig. 2.11 due to movement of ground occurring as a result of sand displacement due to ground movement

(iii) **Corrosion**

There are very few pipelines that are buried without some form of corrosion protection incorporated on them in the form of coating(s) and cathodic protection as shown in Fig. 2.12. The various types of coatings and their advantages are covered in depth elsewhere, but two main points can be highlighted.

The first is that the long-term success of a coating has been shown many times to be related to the surface preparation. There is no real substitute for grit blasting to an acceptable standard. The second is that a cathodic protection system needs regular inspection and monitoring to ensure its continued success. Too low a voltage does not provide protection and too high a voltage can damage coatings quite severely [8]. Internal corrosion can be prevented by the use of either the correct material to resist attack, internal coating or additives to prevent corrosion. Internal coatings have not had a good track record in the past, but advances in application technologies now mean that they should be at least as good as external coatings now are. Corrosion inhibitors have a good track record when used correctly, but require constant injection, albeit of concentrations in the order of 10 parts per

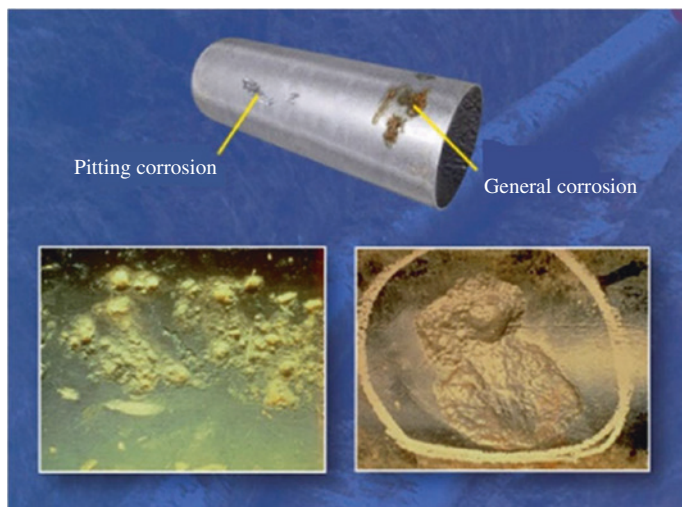


Fig. 2.12 Corrosion [21]

million. The inclusion of water within oil and product pipelines can cause considerable problems when a pipeline is left dormant for long periods of time when full or partly full of product. The only satisfactory way to mothball a pipeline is to clear the contents and replace them with an inert dry liquid or gas. This is, however, often not feasible for short durations, which over a period of a few years, can lead to substantial internal corrosion, commonly located about the 6 o'clock position.

(iv) **Flooding**

Flooding is one of the serious issues along the route of gas transmissions as shown in Fig. 2.13 typical scenario of flooding.

2.1.5 Safety in Pipelines Design and Operations

Safety is of paramount importance and in terms of protection of the asset a pipeline with a low risk also has a low probability of failure, thus keeping it in service for longer. Any design cannot make a pipeline absolutely safe and will not reduce the inherent risk involved in transporting a hazardous fluid. What it can do is make that risk sufficiently low so that it meets legal and project requirements. It also provides the basis for any assessment made as to the effort and cost involved in reducing a risk even further than the initial design. Most UK safety legislation and general practice world wide is for the risk to be to as low as reasonably practicable (ALARP). This means that items that would only contribute marginally to the overall risk level but cost a significant quantity of money to install (e.g.



Fig. 2.13 Typical Flooding in transmission pipeline [21]

block valves every 500 m) can be discounted in a rational and reasoned manner. Quantified risk assessments, structural reliability assessments and the data used to make such calculations are covered elsewhere in the text. Activities that design needs to cover includes (i) identification of all the possible failure modes and actions taken to eliminate or minimise their effect (HAZID), (ii) identification of hazards during construction (HAZCON), (iii) discussion of potential hazards and all modes of operating safely (HAZOP), (iv) compilation of potential hazards and reports relating to construction, operation and maintenance under the COM regulations [9], (v) production of the major accident prevention document (MAPD) required under the PSR 1996 regulations. Having introduced very briefly the environments in which gas pipes are laid, the materials and fittings used, the influence of pressure on the mode of failure, it is important now to consider how all of these elements can be drawn together to provide a general framework whereby safe operation of gas systems can be established. This has been done in Britain. The documents described as IGE/TD/1 and IGE/TD/3 are a result of lengthy deliberations on the assessment of safety with regard to operation of piping systems at pressures above and below 7 barg. Some of the steps, based on data presented so far and other items that describe the industry's experience, are now discussed in relation to distribution systems operating at pressures below 7 barg and will affirm the approach used in IGE/TD/3. Whichever guideline is being used, it must be seen to be logical and consistent with the objective of realising safe, cost effective, gas systems.

The separation between transmission and distribution is not just a division conveniently created for reasons of operational responsibility but because of the difference in the initial premise from which hazard is assessed. For transmission systems, it is implicit in IGE/TD/1 that the objective of transmission decisions

is to prevent incidents which involve the public. As the majority of transmission pipelines pass through environments with population densities of <2.5 persons/ha, this is a technically reasonable and economically realisable objective. This is not so for distribution pipes. The majority are in environments with population densities well above 50 persons/ha. Also, there is a difference in historical development. Many distribution systems have a long history, and it would seem unreasonable to develop standards for new pipes that did not take into account some of this heritage (like the patterns, loading, strain and consequences of failure). The first priority, therefore, is to establish from the history of these older mains a level of risk acceptable to the public.

Over the past 15 years, an average of 15 incidents/annum, involving damage to property or injury to people, occurred in Britain as a result of leaks from the distribution system. (Incidents are normally described as events that incur a severe explosion, i.e. fire, damage to property of an extent $>£100$, personal injury or death.) The incidents are not uniformly distributed. It is known that 80 % have occurred on 20 % of the older cast iron and PE system. Accordingly, the policy is now to give this section priority for replacement. The rest it has been determined, is operating at an acceptable level of safety. It is reasonable, therefore, to use this level as the base level for the design and construction of new pipelines operating at pressures below 7 barg.

At this stage, for the purposes of analysis, the distribution mains are divided into two sets: higher risk and lower (acceptable) risk. There is a variation in risk level within these sets but a useful general guide for comparison can be established by considering the difference in the average risk levels within these sets. As indicated, the more hazardous set comprising 20 % of mains covers 80 % of incidents, then conveniently the reverse is true of the rest of the mains that comprise the other set. This gives a difference in relative average risk between the sets of mains of 160. To continue this approach, it is now important to define a further set of attributes that help to resolve each of the above sets of mains into subsets. This will then enable the examination of the relative risks of these mains and, as a result of this information, to suggest the improvement in the performance of the materials, which is required to achieve a level of risk equivalent to the remaining 80 % of the cast-iron system.

2.2 Natural Gas Distribution Networks

The planning and design of gas distribution systems is an iterative process; there is no single absolute solution. The ideal design will minimise cost while at the same time retain sufficient flexibility to allow for future changes in the pattern of gas consumption. Figure 2.14 exemplifies the UK distribution system, although it varies from country to country around the world.

Systems should be designed to meet the maximum demands placed upon them. In low-pressure systems, experience has shown that this is likely to be the

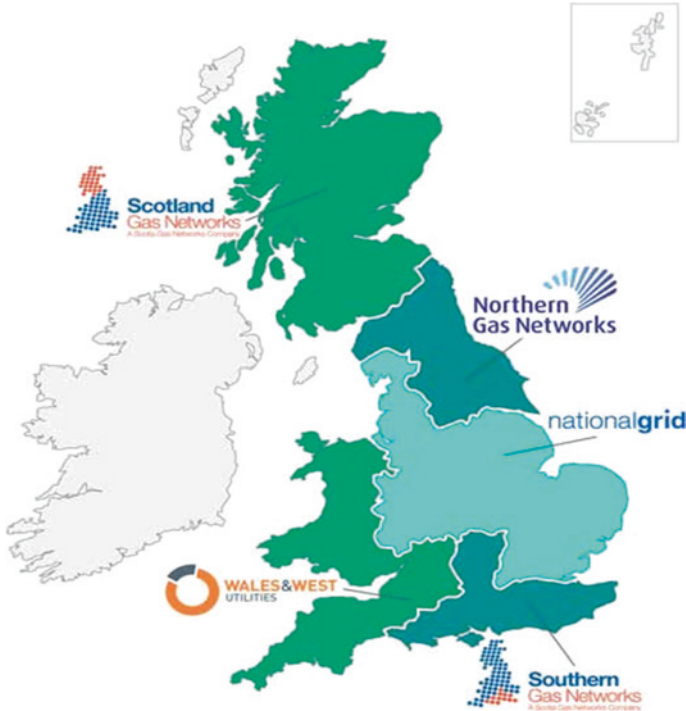


Fig. 2.14 UK distribution network [23]

maximum demand that will occur in any period of not <6 min, expressed as an hourly rate. However, it should be noted that flow rates may exceed this level for shorter durations and that instantaneous values could be up to 12.5 % higher. Where pressure differentials in excess of 25 mbar are to be used across a system; the design should be reassessed to ensure that, under peak instantaneous conditions, the minimum pressure in the system will ensure the continued safe operation of gas appliances.

For supplies to domestic estates, the design flow rate should be estimated from predicted and annual consumption. The estimate should be based upon the expected space-heating load and the rated load of any other appliances, taking into account the size and type of property. For supplies to groups of domestic consumers, diversity can be taken into account and diversity curves, which relate the peak flow for groups of consumers to the annual consumption of individual consumers within the group, are useful for this purpose. For supplies to individual industrial or commercial consumers, the design flow rate should be assessed. In the absence of specific information, it may be possible to estimate the design flow rate from the predicted annual consumption, appliance details or floor area. For supplies to groups of commercial and industrial premises and buildings and for the purposes of designing the overall system, allowance should be made for the

effects of diversity if such information is available. In the absence of information on diversity, it should be assumed that the maximum flow will occur at the peak of the system design flow rate. For systems where interruptible supplies are included, special consideration should be given to the effect of these supplies on the system design flow rate. Where a system contains a significant proportion of interruptible load, the maximum system demand may not occur under the peak 6-min conditions with interruptible supplies off, but rather at the point just prior to interruption when firm demands will be at a lower level. Under these circumstances, this higher demand level should be used as a basis for the system design flow rate. Any system designed using this revised criteria should be tested for robustness against the theoretical peak.

2.2.1 Distribution Network Design Consideration

The size of pipework and associated equipment should be determined, either by applying a suitable flow equation to a simple pipe system, or by using a sophisticated network analysis computer programme to model a more complex integrated system. Some computer programmes have cost functions, which allow the design to be optimised for least cost as well as capacity

2.2.1.1 Gas Demand

Gas demand will depend upon: (i) season (outside ambient temps); (ii) day of the week; (iii) time of day; and (iv) the nature of gas use (heating and/or cooking)—and must take into account “diversity of demand”. The peak gas demand for one consumer is always less than the aggregate of all consumers’ individual demands because as the number of consumers in a group increases, the probability of the coincident use of gas burning appliances decreases. In simple terms, diversity of demand (D) is defined as:

$$D = \frac{\text{Maximum potential gas demand}}{\text{Maximum actual gas demand}} \quad (2.5)$$

Historical design diversity curves have been developed for various categories of consumer for a maximum 6-min demand period [10].

2.2.1.2 Source Pressure

Systems should, generally, be designed to operate with the optimum pressure differential in order to make the best use of the available pressure without creating such a large pressure loss that the system is vulnerable to increases in gas demand. Where a suitable source of pressure is available, consideration should be given to

designing an intermediate-/medium-pressure supply system. In general, the same steps and principles apply as are used for low-pressure system design. Maximum use should be made of the pressure available, but due regard should be given to any effect on the upstream supply system. For example, its capacity to meet existing and future commitments (including interruptible loads), operating constraints, ongoing repair and maintenance requirements and possible abandonment as a result of a replacement policy [17, 18]. For demands taken from medium- and intermediate-pressure systems, source pressure will depend upon the available outlet pressure from the regulator supplying that part of the system concerned when operating at the system design flow rate. In such cases, the source pressure supplying a low-pressure system should not exceed the maximum normal operating pressure of the system. Source pressure should be based on the highest available pressure to optimise pipe sizing but subject to proximity and routing constraints. For discrete, new PE networks, the source pressure can be 75 mbar (or 2 barg for medium-pressure networks), however, where new PE networks are interconnected with older, leaking metallic pipes, the source pressure is normally limited to around 50 mbar or less [11].

2.2.1.3 System Pressure and Installations

The minimum design pressure for a gas distribution system should be that pressure, at the extremity of the system, which will provide the minimum pressure for the safe operation of customer appliances, allowing also for the pressure loss in the customer's plant pipework. This requirement also applies particularly to the operation of service pressure regulators. Supplies to consumers from a medium-pressure distribution main should provide adequate pressure to ensure proper control by the service regulator which should, normally, be located outside of any building. The pressure at which gas is supplied inside domestic buildings should not, normally, exceed 75 mbar but [12], where a higher pressure is considered, account should be taken of any risks involved. Where it is known that a gas compressor or booster is to be used, to increase pressure at a customer's premises, protection of the gas distribution system may be required by way of antifucltuators or valves. Pressure-regulating installations should normally be designed to pass the anticipated peak flow rate at the minimum expected inlet pressure and the maximum likely outlet pressure. The design should be based upon the peak flow rate likely to be experienced under normal supply conditions. However, the effects of any instantaneous flow rates that could be imposed by the downstream configuration should be considered. The design of installations should use a medium-term planning horizon, 10 years, based on network analysis predictions. Consideration should be given to any peculiarities of the system, for example the presence of interruptible consumers where the local load before interruption may be higher than at peak, or the effect of nearby non-domestic consumers on the normal load pattern. If any regulator installation is expected to provide security for another installation, adequate capacity should be provided within the installation.

Such additional capacity will, normally, be contained within the standby stream of a dual stream installation. The configuration of equipment within a regulator installation will affect the pressure loss across the station and therefore the capacity. Manufacturer’s data apply only to their individual items of equipment, it is the responsibility of the design engineer to ensure that combinations of equipment will still deliver the required quantities of gas.

2.2.1.4 Distribution Velocity

Gas Velocity should be limited to 20 m/s [20] in systems where there is a dust problem, particularly where the new network is interconnected to an older, metallic system. Otherwise, gas velocities up to 40 ms⁻¹ are acceptable. The velocity equations used for low-pressure and higher (than LP)-pressure pipelines are described in Sect. 4.1 [13].

2.2.1.5 Pipe Materials

Pipe material is invariably polyethylene (PE) for new pipelines and may be PE80 or PE100 grades of pipe. Long-term testing using linear regression analysis has established that PE pipes will have a lifetime of at least 50 years when subject to a constant hoop stress of 80 bar for PE80 and 100 bar for PE100 as shown typically in Fig. 2.15, at a constant temperature of 20 °C. PE100 pipes can operate at significantly higher operating pressures than PE80 pipes for the same wall thickness. Similar calculations are performed for other type of pipe materials.

The relationship between hoop stress and internal operating pressure is expressed in terms of hoop stress and thickness as

Hoop stress

(2.6)

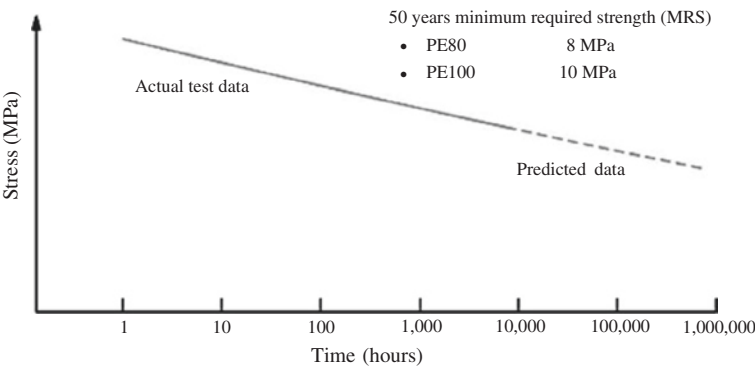


Fig. 2.15 Stress per hourly distribution [21]

The maximum operating pressure (MOP) for the PE pipe is then made on the basis that it does not exceed 10 barg and that the overall design coefficient (“C”) shall be greater than or equal to 2, such that [14, 15]:

$$C = \frac{20 \times \text{MRS}}{\text{MOP} \times (\text{SDR} - 1) \times D_f} \quad (2.7)$$

where MRS is the minimum required strength (long-term hydrostatic strength) and D_f is a de-rating factor to allow for the influence of increased operating temperatures—i.e. 1.1 at 30 °C and 1.3 at 40 °C. The MOP in GB has typically been limited to 4 barg for PE80 (5.5 barg for pipes of diameter ≤ 140 mm) and to 7 barg for PE100 within the temperature range. PE pipe has good “rapid crack propagation” (RCP). The critical RCP level is the pressure at which a crack can rapidly propagate through a pipeline (at a reference temp. of 0 °C). Sinusoidal crack at speed of sound over long distances.

Pipeline failure may result in catastrophic explosion of pipeline due to wrong pipe thickness or overpressure as shown in Fig. 2.16 for a typical failed section prior to pipe laying process (Fig. 2.17) from the stock PE pipes shown in Fig. 2.18.



Fig. 2.16 Typified pipeline failure in PE pipes [21]



Fig. 2.17 Typical PE pipeline used in construction [21]

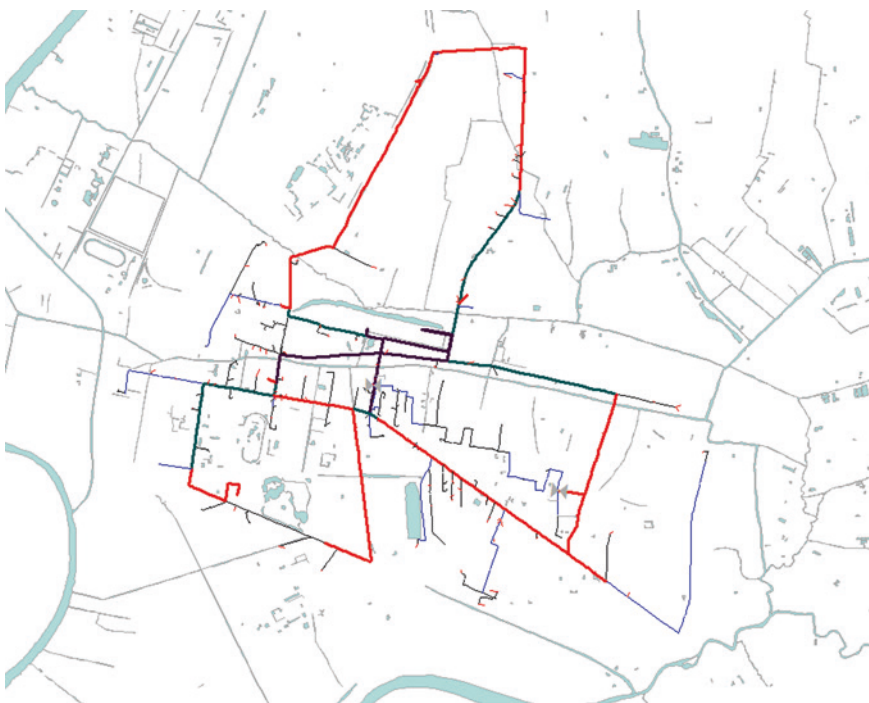


Fig. 2.18 Computer-aided network design [24]

2.2.2 Computer-Aided Design

There are a variety of computer programmes available that can be used to calculate pipe diameters for a specific pipe or system configuration. Any computer-aided system design should be checked by a competent person, before implementation, to ensure its practicability. In some cases, special features are incorporated, including, (i) fixing certain pipe sizes, for example to specify the route of distribution mains supplying a new housing development or industrial estate, (ii) restricting regulator and/or other source flows where one limited capacity is available, (iii) security runs to determine whether looping is necessary and/or to test the effect of regulator failure, and (iv) diversity runs, where the number of consumers supplied from each node is used in a diversity model to calculate the varying diversified flow throughout the system. Specifying pressures at particular points to allow for future extensions, further analysis of simulation-aided design is discussed in Sect. 4.2. Figure 2.18 shows a typical computer-aided network design.

Modern, sophisticated network design and modelling tools can develop a distribution network design very easily. They also allow simulation analysis and validation from actual pressure data in the field.

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