MANUAL

PIPELINE ENGINEERING

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DESIGN AND ENGINEERING PRACTICE

USED BY

COMPANIES OF THE ROYAL DUTCH/SHELL GROUP

PREFACE

DEP (Design and Engineering Practice) publications reflect the views, at the time of publication, of:

Shell International Oil Products B.V. (SIOP)
and
Shell International Exploration and Production B.V. (SIEP)
and
Shell International Chemicals B.V. (SIC)

The Hague, The Netherlands,

and other Service Companies.

They are based on the experience acquired during their involvement with the design, construction, operation and maintenance of processing units and facilities, and they are supplemented with the experience of Group Operating companies. Where appropriate they are based on, or reference is made to, national and international standards and codes of practice.

The objective is to set the recommended standard for good design and engineering practice applied by Group companies operating an oil refinery, gas handling installation, chemical plant, oil and gas production facility, or any other such facility, and thereby to achieve maximum technical and economic benefit from standardization.

The information set forth in these publications is provided to users for their consideration and decision to implement. This is of particular importance where DEPs may not cover every requirement or diversity of condition at each locality. The system of DEPs is expected to be sufficiently flexible to allow individual operating companies to adapt the information set forth in DEPs to their own environment and requirements.

When Contractors or Manufacturers/Suppliers use DEPs they shall be solely responsible for the quality of work and the attainment of the required design and engineering standards. In particular, for those requirements not specifically covered, the Principal will expect them to follow those design and engineering practices which will achieve the same level of integrity as reflected in the DEPs. If in doubt, the Contractor or Manufacturer/Supplier shall, without detracting from his own responsibility, consult the Principal or its technical advisor.

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All administrative queries should be directed to the DEP Administrator in SIOP.

NOTE: In addition to DEP publications there are Standard Specifications and Draft DEPs for Development (DDDs). DDDs generally introduce new procedures or techniques that will probably need updating as further experience develops during their use. The above requirements for distribution and use of DEPs are also applicable to Standard Specifications and DDDs. Standard Specifications and DDDs will gradually be replaced by DEPs.

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APPENDICES

1. INTRODUCTION

1.1 SCOPE

This is a new DEP which gives minimum technical requirements and recommended practices for the design, material procurement, construction and precommissioning of onshore and offshore pipelines used for the transport of hydrocarbons and other fluids commonly transported in the petroleum, natural gas and petrochemical industries. For some fluids, in particular those of an unstable or toxic nature, additional requirements not covered in this DEP may be appropriate.

This DEP supplements and amends ANSI/ASME B31.4 and B31.8, 1992 Editions. It is recognised that, in some countries, national regulations impose codes different than the ASME codes. In those situations, this DEP provides a baseline with regard to the recommended minimum Shell requirements for pipeline engineering.

Although this DEP is primarily concerned with metallic pipeline materials, the pipeline may also consist of non-metallic materials (e.g. glass reinforced plastics), a combination of steel and plastics (flexible pipes), or steel with polyethylene lining.

In this DEP, a pipeline is defined as a system of pipes for the transportation of fluids in the liquid or gaseous phase, or a combination of both phases, between (**but excluding**) wellhead facilities, production plants, pressure boosting stations, processing plants or storage facilities. A pipeline extends from pig trap to pig trap (including the pig traps and associated pipework and valves), or, if no pig trap is fitted, to the first isolation valve within the onshore plant or the offshore installation as applicable.

The sections of pipelines crossing major rivers and estuaries, which cannot be constructed using land pipeline methods, should be treated as offshore pipelines.

The transition point between the onshore and offshore sections of a pipeline crossing the sea shore or major rivers/estuaries shores is assumed to be at the highest water mark.

Onshore and offshore flowlines connecting off-plot wellhead areas or wellhead platforms to treatment facilities are considered pipelines and are therefore included in the scope of this DEP.

The design of pipelines in arctic areas is not specifically covered in this DEP. These pipelines require to address special considerations, e.g. environmental sensitivity and permafrost aspects; specialist advice should be obtained.

Finger type slugcatchers are included in the scope of this DEP.

Figure 1 provides a diagrammatic representation of pipeline scope boundaries.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

Unless otherwise authorised by SIPM, the distribution of this DEP is confined to companies forming part of the Royal Dutch/Shell Group or managed by a Group company, and to Contractors nominated by them (i.e. the distribution code is "C", as defined in DEP 00.00.05.05-Gen.).

This DEP is intended for use by all Functions in the Group that are involved in the design, material procurement and construction of pipelines.

If national and/or local regulations exist in which some of the requirements may be more stringent than in this DEP, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable as regards safety, environmental, economic and legal aspects. In all cases, the Contractor shall inform the Principal of any deviation from the requirements of this DEP which is considered to be necessary in order to comply with national and/or local regulations. The Principal may then negotiate with the Authorities concerned with the object of obtaining agreement to follow this DEP as closely as possible.

1.3 DEFINITIONS

1.3.1 General definitions

The **Contractor** is the party which carries out all or part of the design, procurement, construction, commissioning or management of a project or operation of a facility. The Principal may undertake all or part of the duties of the Contractor.

The **Manufacturer/Supplier** is the party which manufactures or supplies equipment and services to perform the duties supplied by the Contractor.

The **Principal** is the party which initiates the project and ultimately pays for its design and construction. The Principal will generally specify the technical requirements. The Principal may include an agent or consultant authorised to act for and on behalf of the Principal.

The word **shall** indicates a requirement.

The word **should** indicates a recommendation.

1.3.2 Specific definitions

Assembly	An arrangement of pipes and components such as a crossing, a pig trap, a block valve station or a riser.
Barred tee	Tee-piece provided with bars across the internal bore of the branch pipe to prevent entry of a pig.
Block valve	Valve for interrupting the flow or to shut-in a section of a pipeline. A block valve is normally either fully opened or fully closed.
Branch pipe	Pipe connected to a pipeline of equal or larger diameter, using a tee-piece.
Cold bend	A bend made from linepipe at ambient temperature, normally on the construction site, using a mechanical bending machine.
Commissioning	An activity where the fluid to be transported is initially introduced into a pipeline.
Consequence	The result of an event in terms of human safety, damage to the environment and economic loss.
Design factor	Ratio of the hoop stress created by the design pressure and the SMYS of the pipeline material.
Design pressure	The internal pipeline pressure used in the determination of the pipeline wall thickness requirements.
Emergency shutdown valve	Valve for isolating a pipeline from a plant in case of emergency situations within the plant.
Flammable fluid	A flammable fluid has a flash point lower than 100 °C, with reference to EP-55000 Section 40 Part 1.
Flowline	A pipeline transporting untreated hydrocarbons and other reservoir fluids.
Fluid	A substance which is transported through a pipeline in liquid or gaseous phase, or a combination of these.

Hot bend	A bend made under factory conditions by hot working billets, plates or pipes.
Incidental pressure	Pressure occurring in a pipeline with limited frequency and during limited periods of time. Incidental pressures include surge pressures, and thermal pressures if not occurring a significant portion of the time.
Injection line	A pipeline transporting gas, water or other fluids for injection into a well or a group of wells.
Isolation valve	Valve for isolating a pipeline from a plant connected to it.
Line pack	In a gas transmission system, the line pack is the quantity of gas in excess of the gas inventory in the system required to meet deliveries. The line pack is used to continue deliveries for some period following interruption of supply upstream.
Liquid hold-up	Quantity of liquids present in a two-phase pipeline.
Loading line	A pipeline between an onshore facility and an offshore loading facility, e.g. a single point mooring.
Maximum allowable incidental pressure	The maximum pressure that is allowed by ANSI/ASME B31.4/8 to occur in a pipeline with a limited frequency and during limited periods of time.
Maximum allowable operating pressure	The maximum pressure at which a pipeline is allowed to be operated under steady state process conditions, in accordance with ANSI/ASME B31.4/8.
Maximum operating temperature	The maximum temperature to which the pipeline or section of pipeline is expected to be exposed during normal operational activities, including start-up and shut-down operations, but excluding abnormal situations, e.g. fires.
Minimum operating temperature	The minimum temperature to which the pipeline or section of pipeline is expected to be exposed during normal operational activities, including start-up and shut-down operations, controlled blowdown, but excluding abnormal situations, e.g. pipeline ruptures.
Off-plot	A location outside designated plant boundaries.
Offtake line	A pipeline transporting fluid from a larger pipeline.
On-plot	A location inside designated plant boundaries.
Operating envelope	A defined set of key parameters or parameter ranges which must be adhered to during operation of the pipeline in order to prevent loss of technical integrity.
Overpressure protection valve	Valve intended to protect the pipeline against overpressure by preventing pressure from a source building up in the pipeline.
Pig	A device which can be propelled through a pipeline

	by fluid flow and normally used for cleaning, batching, inspection or other activities.
Pig trap	An ancillary item of pipeline equipment, with associated pipework and valves, for introducing a pig into a pipeline or removing a pig from a pipeline.
Pipeline	A system of pipes and other components used for the transportation of fluids, between (but excluding) plants. A pipeline extends from pig trap to pig trap (including the pig traps), or, if no pig trap is fitted, to the first isolation valve within the plant boundaries or a more inward valve is so nominated.
Pipeline code	An industry or national code written for the purpose of designing, constructing and operating pipelines.
Pipeline end manifold (PLEM)	An item of subsea equipment, comprising piping and valves, at the end of a pipeline, to which single point mooring hoses are connected.
Pipeline leak	An uncontrolled fluid release from a pipeline.
Plant	An installation, such as well-head, processing facility, pressure boosting station, storage tank, offshore platform, refinery, etc., with defined boundaries and which is not normally accessible to the public.
Pre-commissioning	A series of activities, including cleaning and possibly drying, executed to prepare the pipeline for commissioning.
Pressure equalisation line	Small bore pipe with valves to allow equalisation of pressure across a larger valve, avoiding damage to the seats of the larger valve.
Pressure relief safety valve	Valve for protecting a pipeline against overpressure by releasing fluid from the pipeline.
Remote vent line	A pipeline used for discharging light gaseous fluids to atmosphere.
Riser	A vertical, or near vertical, section in a pipeline.
Risk	The product of the probability of an event occurring and the consequences of the event when it has occurred.
Sectionalising block valve	Main valve for sectionalising a pipeline, in order to limit the release of line contents in case of pipeline leak or rupture.
Shore approach	That section of a pipeline which crosses the sea shore, or major river/estuary shores. The shore approach includes the area of breaking waves and extends to the highest water mark.
Single point mooring (SPM)	A device for mooring a ship and transferring fluid between a pipeline and that ship.
Slugcatcher	A device located at the downstream end of a two-

	phase pipeline, for the primary separation of the liquid and gas phases, and the temporary storage of liquids generated by pigging and transient flow conditions. There are two types of slug catchers: the vessel type and the finger type.
Specified minimum yield stress (SMYS)	The level of stress which produces 0.5 percent total strain (API definition). This stress is specified by the Principal and guaranteed by the Manufacturer/Supplier.
Sphere	A spherical shape pig, used for batching and liquid hold-up removal in two-phase pipelines.
Sphere tee	A jacketed tee-piece with a perforated inner pipe to prevent entry of a sphere into the branch pipe.
Spurline	A pipeline transporting fluid into a larger pipeline.
Stable fluid	With reference to EP-55000 Section 40 Part 1, a stable fluid has an NFPA reactivity grade number of zero.
Surface safety valve	Valve, part of the well-head assembly, applied as isolation valve between flowline and wellhead.
Surge pressure	Pressure due to mass flow velocity changes, caused by operational activities, e.g. valve closures, pump shut-down or start-up.
Technical integrity	Technical integrity of a facility is achieved when, under specified operating conditions, there is no foreseeable risk of failure endangering safety of personnel, environment or asset value.
Test pressure	The pressure at which the pipeline will be or has been tested for strength.
Thermal pressure	Pressure due to thermal effects on the fluid in the blocked-in pipeline or blocked-in pipeline sections.
Toxic fluid	With reference to EP-55000 Section 40 Part 1, toxic fluids include all fluids in the slightly toxic, toxic and highly toxic categories.
Trunkline	A main transmission pipeline to which spurlines and offtake lines may be connected.
Two-phase pipeline	Pipeline transporting fluids where both the liquid phase and the gas phase are present at pipeline pressure and temperature conditions.

1.4 ABBREVIATIONS

CP	Cathodic protection
DN	Diameter nominal
EIA	Environmental impact assessment
ESD	Emergency shutdown
GRP	Glass reinforced plastics
GRE	Glass reinforced epoxy
HIPS	High integrity protection system (against overpressure)
LPG	Liquefied petroleum gas

MAOP	Maximum allowable operating pressure
MESC	Materials and Equipment Standards and Code
NFPA	National Fire Protection Association
NGL	Natural gas liquids
PE	Polyethylene
PLEM	Pipeline end manifold
PSE	Shell Product Safety and Environmental Conservation Committee
QRA	Quantitative risk assessment
SMYS	Specified minimum yield stress

1.5 CROSS-REFERENCES

Where cross-references to other parts of this DEP are made, the referenced section number is shown in brackets. Other documents referenced by this DEP are listed in (8.).

2. APPLICATION OF CODES AND GROUP STANDARDS

2.1 ASME CODES

The fluid transported in the pipeline should be categorised in one of the following four groups, depending on its hazard potential:

- Category **A**: Non-flammable, stable and non-toxic fluids which are liquid at prevailing ambient temperature and atmospheric pressure plus 0.5 bar, i.e. the vapour pressure is lower than 1.5 bar (abs) at ambient temperature. Example: water, slurries.
- Category **B**: Flammable, or unstable or toxic fluids which are liquid at prevailing ambient temperature and atmospheric pressure plus 0.5 bar, i.e. the vapour pressure is lower than 1.5 bar (abs) at ambient temperature. Example: stabilised crude, gasoil.
- Category **C**: Non-flammable, stable and non-toxic fluids which are gases or a mixture of gas and liquid at prevailing ambient temperature and atmospheric pressure plus 0.5 bar, i.e. the vapour pressure is higher than 1.5 bar (abs) at ambient temperature. Example: nitrogen, carbon dioxide.
- Category **D**: Flammable, or unstable or toxic fluids which are gases or a mixture of gas and liquid at prevailing ambient temperature and atmospheric pressure plus 0.5 bar, i.e. the vapour pressure is higher than 1.5 bar (abs) at ambient temperature. Example: natural gas, liquid petroleum gas, ammonia.

Flammability, stability and toxicity are defined in (1.3.2).

Pipelines carrying category **A** and **B** fluids should be designed and constructed in accordance with ANSI/ASME **B31.4** and the additional requirements of this DEP.

Pipelines carrying category **C** and **D** fluids should be designed and constructed in accordance with ANSI/ASME **B31.8** and the additional requirements of this DEP.

NOTE: Liquid petroleum gas and anhydrous ammonia, which are covered by ANSI/ASME B31.4, fall under category D. Pipelines transporting these products therefore should be designed to ANSI/ASME B31.8.

2.2 SHELL GROUP STANDARDS

The Shell Group standards related to the design, material procurement, construction, and precommissioning of pipeline systems are referenced in this DEP (8.1). For topics which are not specifically covered in the Group standards, the Contractor may utilise the external standards referenced in ANSI/ASME B31.4 and B31.8, after consultation with, and approval by, the Principal.

Figure 2 shows the hierarchical organisation of existing and planned Group standards related to pipelines.

3. DESIGN

3.1 GENERAL CONSIDERATIONS

3.1.1 Introduction

The pipeline shall be designed in accordance with the relevant sections of ANSI/ASME B31.4/8, supplemented by this chapter (3).

The pipeline shall be designed taking into consideration the operating conditions and requirements over its entire projected life cycle including final abandonment, i.e. the maximum planned throughput and turn-down, the characteristics of the fluids to be transported, the pressure and temperature requirements, the mode of operations, the geographic location, and the environmental conditions.

3.1.2 Hydraulic design

In order to determine the possible range of operational parameters of the pipeline, a hydraulic analysis should be performed. For a given pipe size, fluid properties and flow rate, the hydraulic analysis should provide the pressure and temperature profiles along the pipeline for steady state and transient conditions. Full account shall be taken of possible changes in flowrates and operational modes, over the complete operational life of the pipeline.

The hydraulic analysis should provide data to address: surge pressure during shut-down of a liquid line, turn-down limitations and inhibition or insulation requirements to prevent wax or hydrates deposition, effect of flow conditions on the efficiency of corrosion inhibitors, liquid catching and slug control requirements at the downstream end of two phase lines.

The normal range of flow velocities is 1 to 2 m/s in liquid lines, and 5 to 10 m/s in gas lines. Continuous operations above 4 m/s for liquids and 20 m/s for gases should be avoided; lower units may apply to fluids containing solid particles, where maximum velocities will be dictated by the occurrence of erosive conditions.

NOTE: Liquid lines containing a separate water phase, even in small quantity (e.g. 1% water cut), should not be operated at too low velocities (typically below 1 m/s). This is to prevent water dropout which may lead to a corrosive situation.

For liquid lines, it is sometimes advantageous to adjust the design pressure along the route, depending on the patterns of the hydrostatic pressure and the friction pressure loss. Great care should be applied in the definition of the various sections and associated design pressures to determine whether, under any operations scenario, overpressurisation of one section is possible by the adjacent sections.

For gas pipelines, sections of decreasing design pressure are not recommended in general, because the slight cost benefit is unlikely to outweigh the lost advantage of line packing and thus loss of system availability.

3.1.3 Pipe material selection

The selection of the pipeline material type is a fundamental issue to be decided at the conceptual design stage of a pipeline project. The most frequently used pipeline materials are metallic. Non-metallic materials (e.g. GRP/GRE, flexible pipe) may be cost effective for specific applications, especially when the fluid is corrosive.

The occurrence and rate of internal corrosion is governed by a variety of process conditions which include:

- Corrosivity of the fluid, in particular due to the presence of water combined with hydrogen sulphide (sour corrosion), carbon dioxide (sweet corrosion), or oxygen. Temperature and pressure can have a great impact on the corrosion rates.
- Velocity of the fluid, which determines the flow regime in the pipeline. In pipelines transporting fluids containing water, too low velocities lead to settlement of water, which may lead to bottom of pipe internal corrosion; too high velocities can increase the overall corrosion rate and also destroy any protective scale or inhibitor films.
- Deposition of solids, which may prevent adequate protection by inhibitors, and can create anaerobic conditions for the growth of sulphate reducing bacteria.

The potential long-term impact of corrosion shall be considered during design (3.8), and it shall be demonstrated that the pipeline can remain fit-for-purpose throughout its lifetime.

When sour service conditions are foreseen, as specified in NACE MR0175, the linepipe material and other materials shall be specified to resist sour service, regardless of whether or not the fluid is to be dehydrated.

Carbon steel linepipe material may be used in "light" sweet corrosive conditions (typically where corrosion rates would not exceed 0.5 mm/year without inhibition), with appropriate corrosion allowance and inhibitor injection, regular high resolution intelligent pig monitoring, and under strictly controlled operating conditions. Corrosion allowances in excess of 3 mm shall not be considered without a detailed analysis by corrosion specialists. Materials able to resist sweet corrosion include duplex stainless steels and carbon steels with internal austenitic cladding.

Internal coatings cannot be relied on for complete prevention of corrosion. Internal lining (e.g. polyethylene) can be applied for internal corrosion protection (3.8.2).

Conditions which may cause pipewall erosion shall be avoided.

3.1.4 Operating philosophy

For the predicted life cycle conditions, the design shall take due account of operations, inspection and maintenance requirements, as well as established operating philosophy and practices, agreed in advance with the personnel responsible for the operation of the pipeline. These include manning levels for the operation, integrity monitoring and maintenance of the pipeline system, the requirements for telecommunications and remote operations, means of access to the onshore right of way, etc.

The design of pipelines which are continuously in operation should address the requirement for bypass at components which need regular maintenance.

General guidance on Operations Philosophies and Policies is presented in EP 87-1009.

3.2 PIPELINE RISKS

3.2.1 General

The risk associated with the pipeline, in terms of the safety of people, damage to the environment, and loss of income, depends on the expected failure frequency and the associated consequence, which is directly related to the type of fluids transported and the sensitivity of locations of the pipeline. In this context, pipeline failures are defined as loss of containment.

The potential pipeline failures, causes and their consequences, should be inventorised and taken into account in the design and the operating philosophy. The most common pipeline threats which may lead to the loss of technical integrity are given below.

- Internal corrosion and hydrogen induced cracking (HIC).
- Internal erosion.
- External corrosion and bi-carbonate stress corrosion cracking.
- Mechanical impact, external interference.
- Fatigue.
- Hydrodynamic forces.
- Geo-technical forces.
- Growth of material defects.
- Overpressurisation.
- Thermal expansion forces.

Notwithstanding the requirements of the ANSI/ASME B31.4/8 and this DEP, the factors which are critical to public safety and the protection of the environment should be analysed over the entire life of the pipeline, including abandonment. The risk should be reduced to as low as reasonably practicable, with the definite objective of preventing leaks. The level of risk may change with time, and it is likely to increase to some extent as the pipeline ages.

General safety design aspects are provided in EP 55000 Section 21.

3.2.2 Safety risk assessments

ONSHORE PIPELINES

A formal quantitative risk assessment (QRA) should be carried out in the following situations with the location classes as defined in (3.3.3):

• Fluid category B and C in location classes 3 and 4.
• Fluid category D in all location classes.

The assessment should confirm that the selected design factors (3.4.1) and proximity distances (3.3.4) are adequate.

OFFSHORE PIPELINES

A formal quantitative risk assessment (QRA) shall be carried out for pipelines connected to permanently manned offshore complexes, except for pipelines transporting category A fluids. The necessary riser protection and safety systems shall be derived from this assessment.

The risk depends firstly on the expected frequency of failure, due to internal and external corrosion, external loading (e.g. impacts, settlement differences, free spans), material or construction defects, and operational mishaps. Secondly, it depends on the consequences of the failure, based on the nature of the fluid in terms of flammability, stability, toxicity and polluting effect, the location of the pipeline in terms of ignition sources, population densities and proximity to occupied buildings, and the prevailing climatic conditions. The expected frequency of failure and the possible consequences may be time-dependent and should be analysed over the entire life of the pipeline.

Risks levels can be reduced by using lower design factors (e.g. higher wall thickness or stronger steel), rerouting, providing additional protection to the pipeline, application of facilities to minimise any released fluid volumes, and controlled methods of operation, maintenance and inspection.

NOTE: Pipelines with a wall thickness lower than 10 mm are susceptible to penetration, even by small mechanical excavators. External interference by third parties is a major cause of pipeline failures.

Specific precautions against this type of hazard should be addressed; this is particularly relevant to onshore pipelines transporting category C and D fluids.

A methodology for quantitative risk assessments is presented in EP 55000 Section 18.

3.2.3 Environmental impact assessments

An environmental impact assessment (EIA) shall be carried out for all pipelines or groups of pipelines. Guidance is presented in the Shell PSE EIA Guide.

EIA is a process for identifying the possible impact of a project on the environment, for determining the significance of those impacts, and for designing strategies and means to eliminate or minimise adverse impacts.

An EIA should consider the interaction between the pipeline and the environment during each stage of the pipeline life cycle. The characteristics of the environment may affect pipeline design, construction method, reinstatement techniques, and operations philosophy.

3.2.4 Economic risk

The economic risk is associated with deferment of income, cost of repair, and other costs such as liabilities to the public and clean-up costs. The economic risk should be evaluated for each phase of the pipeline operating life, and should be compatible with the overall objectives of the Principal.

3.3 PIPELINE ROUTING

3.3.1 Introduction

The selection of the route shall take full account of the associated risks (3.2), particularly safety and environmental risks, the accessibility for maintenance and inspection, as well as normal direct cost considerations.

3.3.2 Surveys

Detailed survey data should be available prior to finalising the pipeline route and carrying out detailed design. These data include:

ONSHORE PIPELINES	OFFSHORE PIPELINES
• Population and building densities for the establishment of location classes (3.3.3), location of inhabited buildings, taking into account any future land development plans. • Topographical data, location of rivers, roads and railways, including type and density of traffic. • Records of any existing special features which will need reinstatement after construction is completed. • Soil investigation for foundation design (burial and/or supports design), subsidence areas (e.g. due to mining activities). • Soil resistivity for cathodic protection design. • Environmental data (climatic, floods, earthquakes, landslides, currents at river crossings, vegetation, fauna).	• Seabed topographical data, location of rock/coral outcrops. • Soil investigation for foundation and on-bottom stability design. • Fishing, shipping (and other sea users) activity data. • Environmental data (climatic, currents, waves, bathymetry, earthquakes, landslides). • Third party facilities and concession areas.

3.3.3 Establishment of location classes for onshore pipelines

Based on the survey data, appropriate location classes shall be identified along the pipeline route for pipelines transporting category C and D fluids, in accordance with ANSI/ASME B31.8 Article 840.2. There is no specific requirement for pipelines transporting category A and B fluids, apart from access requirements during construction and for maintenance and emergency services during operations.

ANSI/ASME B31.8 identifies 4 location classes, ranging from location class 1 (sparsely populated areas) to location class 4 (densely populated areas).

Since location classes are used for the determination the design factor (3.4.1), the route selection shall take due regard for the cost impact on pipeline sections in location classes of higher category (e.g. class 3 and class 4).

3.3.4 Proximity to occupied buildings (onshore pipelines)

Compared to pipelines transporting category A and B fluids, pipelines transporting category C and D fluids constitute potentially higher hazards to people nearby. There are no provisions in ANSI/ASME B31.4/8 to cover this, apart from the location classes defined in (3.3.3) which only address population densities. For the purpose of initial routing, Appendix 1 provides guidance for establishing minimum distances of pipelines from occupied buildings depending on the type of the fluid, the pipeline diameter and its maximum operating pressure. Final routing should be established following the pipeline safety assessment (3.2.2).

3.3.5 Proximity to other facilities

For fluid categories B, C and D, the separation requirements between the pipeline (including pig traps) and other facilities within the plant fences or on the offshore platform should be in accordance with EP 55000 Section 21. For the definition of area classifications around the pipeline, refer to the Institute of Petroleum Model Code of Safe Practice Part 15.

3.3.6 Special routing considerations

In the derivation of the route, due consideration shall be given to the anticipated installation technique. This is particularly relevant to offshore pipelines.

ONSHORE PIPELINES

All pipelines shall have a permanent right of way with a width ranging from 4 m for DN150 and below, to 10 m for DN600 and above. The pipeline route should be centered on the right of way.

The radius of curvature of the pipeline foundation along route should not be less than 500xD, D being the pipeline diameter. Hot bends or field bends should be used when lower values are necessary.

When several pipelines are installed in the same trench, the separation between 2 adjacent pipelines shall be 0.3 m minimum.

The minimum distance for pipelines installed in a separate trench alongside an existing buried pipeline should range from 2 m for DN150 and below, to 5 m for DN900 and above.

The crossing of existing pipelines, cables, power lines, roads, railways and waterways should be at an angle between 60 and 90 degrees.

When installing a pipeline along power lines, the horizontal distance from any of the power cables and posts should be at least 10 m for power lines at 110 kv and above, and 4 m for power lines below 110 kv.

OFFSHORE PIPELINES

The radius of curvature of the pipeline along route should not be less than 2000xD, D being the pipeline diameter. When lower values are necessary, a detailed analysis of the pipeline lateral stability during laying should be carried out.

Pipelines close to offshore platforms should, as far as possible, be arranged in corridors to facilitate the anchoring of vessels for support and future construction activities at the platform. Straight lengths of pipe are normally necessary for start-up. Risers should be protected from the marine activity around the platform and, except for category A fluids, located away from the living quarters.

The crossing of existing pipelines and submarine cables should be at right angles. When this imposes excessive additional route length, lower crossing angles may be used, but not lower than 30 degrees.

The distance between parallel pipelines should not be less than 10 metres, or the value compatible with the installation equipment whichever is higher.

3.4 PIPELINE STRENGTH CONSIDERATIONS

3.4.1 Design factors (for hoop stress limitation)

The design factor applies to the nominal pipe wall thickness, excluding any corrosion allowance.

ONSHORE PIPELINES	OFFSHORE PIPELINES
The recommended design factors for the calculation of the nominal wall thickness are given in Table 1, derived from ANSI/ASME B31.8 Table 841.114B, but expanded.	The recommended design factors for the calculation of the nominal wall thickness are given in Table 2, derived from ANSI/ASME B31.8 Table A842.22, but expanded.

NOTE: Tables 1 and 2 provide recommended design factors for designs based on ANSI/ASME B31.4/8; they are not intended to replace the requirements included in National codes, which may impose different design factors and/or hoop stress calculations based on the minimum wall thickness (instead of nominal). These tables however highlight the critical areas, and National requirements should be assessed against the values provided. In any case, the Principal should be satisfied that the risk level at any point along the pipeline route remains within acceptable limits (3.2).

TABLE 1 DESIGN FACTORS FOR ONSHORE STEEL PIPELINES

FLUID CATEGORY	**A and B**	**C and D**			
APPLICABLE CODE	**B31.4 (Note 1)**	**B31.8**			
LOCATION CLASSES	**1, 2, 3 and 4**	**1**	**2**	**3**	**4**
Pipelines	0.72	0.72	0.60	0.50	0.40
Crossings (Note 2)					
Private roads	0.72	0.72	0.60	0.50	0.40
Unimproved public roads	0.60	0.60	0.60	0.50	0.40
Roads, highways, streets and railways	0.60	0.60	0.60	0.50	0.40
Rivers, dunes and beaches	0.60	0.60	0.60	0.50	0.40
Parallel encroachments (Note 3)					
Private roads	0.72	0.72	0.60	0.50	0.40
Unimproved public roads	0.72	0.60	0.60	0.50	0.40
Roads, highways, streets and railways	0.72	0.60	0.60	0.50	0.40
Fabricated assemblies (Note 4)	0.60	0.60	0.60	0.50	0.40
Pipelines on bridges	0.60	0.60	0.60	0.50	0.40
Near concentration of people	0.72	0.50 (Note 5)	0.50 (Note 5)	0.50	0.40
Pipelines, within plant fences, block valve stations and pig trap stations (Note 6)	0.60	0.60	0.60	0.50	0.5

NOTE 1: ANSI/ASME B31.4 does not use design factors other than 0.72, which is considered inappropriate at critical locations (e.g. crossings, within plant fences), and for fabricated assemblies. In these situations, design factors in line with ANSI/ASME B31.8 location Class 1 are recommended.

NOTE 2: ANSI/ASME B31.8 differentiates crossings with casings and without casings. Because of the poor experience of cased crossings (i.e. annular corrosion), the same design factor is recommended, whether a casing is used or not. Design factors for crossings of rivers, dunes and beaches, not included in ANSI/ASME B31.8, are provided.

NOTE 3: Parallel encroachments are defined as those sections of a pipeline running parallel to existing roads or railways, at a distance less than 50 metres.

NOTE 4: Fabricated assemblies include pig traps, valve stations, headers, finger type slugcatchers, etc.

NOTE 5: Concentrations of people are defined in ANSI/ASME B31.8 Article 840.3.

NOTE 6: This category, not specifically covered in ANSI/ASME B31.8, is added for increased safety.

TABLE 2 DESIGN FACTORS FOR OFFSHORE STEEL PIPELINES

FLUIDS	**A, B, C and D**
Pipelines	0.72
Sections of pipelines on the offshore platform	0.50
Risers (Note 1)	0.50
Fabricated assemblies (Note 2)	0.50
Shore approach sections	0.60

NOTE 1: Because of operational/construction activities, pipelines are more exposed close to platforms. Therefore, it is recommended to apply the riser design factor to a length of pipeline on the seabed next to the platform equivalent to the waterdepth.

NOTE 2: Fabricated assemblies include pig traps, valve assemblies, headers, finger type slugcatchers, subsea assemblies, etc., on the platform or at its immediate vicinity, e.g. within a distance equivalent to the waterdepth.

3.4.2 Steel quality

Pipelines are commonly constructed with linepipe in steel grades X42 to X65 as defined in API Spec 5L. Lower grades such as Grade B and higher grades may be appropriate in some cases. Experience within Shell is presently limited up to and including X70, and problems have been encountered in the industry for higher grades (hydrogen embrittlement caused by cathodic protection, weldability, required tensile to yield ratio). Use of grades X80 and above should at present be avoided.

Appropriate derating factors, in accordance with Table 841.116A of ANSI/ASME B31.8, should be used for pipelines operating at high temperatures.

NOTE: Table 841.116A applies to carbon steel materials (derating required above 120 °C). For duplex stainless steel, derating is generally required at lower temperatures (approximately 50 °C).

For the sections of pipelines in locations where they may be exposed to pool or jet fires, reducing the strength properties of high yield material, the material grade should not exceed X52. If higher grades are used, X52 yield strength should be assumed, unless measures are taken to protect the pipe section against exposure to (pool/jet) fire.

Attention shall be given to the fracture toughness properties of pipe material for gas pipelines to prevent the possibility of long running fractures. This is particularly critical when low temperatures are possible, e.g. downstream of pressure reduction stations and at exposed above ground locations.

3.4.3 Minimum wall thickness

The nominal pipe wall thickness shall not be less than 4.8 mm for all pipelines.

ONSHORE PIPELINES	OFFSHORE PIPELINES
The diameter to wall thickness ratio should not exceed 96, unless it can be demonstrated that higher values are not detrimental to the construction and in-situ integrity of the pipeline.	The diameter to wall thickness ratio should not exceed 60, unless it can be demonstrated that higher values are not detrimental to the construction and in-situ integrity of the pipeline.

3.4.4 Equivalent stresses

The wall thickness, initially derived from hoop stress considerations based on design factors (3.4.2), should be such that the longitudinal, shear, and equivalent stresses in the pipe wall under functional and environmental loads do not exceed certain values. This is covered in ANSI/ASME B31.4 Article 419.6 and of ANSI/ASME B31.8 Articles 833/A842.2. Because the requirements in these various articles differ from each other, it is recommended to use a single approach for all pipelines as detailed below.

- Two types of load shall be considered as defined in ANSI/ASME B31.8:
  a) Functional loads (defined in Article A841.32).
  b) Environmental loads (defined in Article A841.33).
- The equivalent stress is defined as follows:

  $S_{eq} = (S_h^2 + S_L^2 - S_h S_L + 3S_s^2)^{1/2}$ (Von Mises equation)

  S_{eq} = equivalent stress
  S_h = hoop stress (due to pressure)
  S_L = longitudinal stress (due to pressure, thermal expansion and bending)
  S_s = combined shear stress (due to torque and shear force)

  Formulae for S_h, S_L and S_s can be found in Appendix 2.
- The equivalent stress shall not exceed the values given in Table 3.

The stress calculations for the operational phase shall be carried out with the nominal wall thickness excluding the corrosion allowance.

Instead of an equivalent stress criterium as detailed above, a strain based criterium may be used if considered more appropriate (see 3.4.6).

Table 3 allowable equivalent stress

(percent of specified minimum yield stress)

	Functional plus environmental loads
Installation (Note 1, 2)	96
Hydrostatic test (Note 1)	100
Operation	90

NOTE 1: For the installation and hydrostatic test conditions, the environmental loads may be based on one-year return period.

NOTE 2: Not applicable to installation methods where yielding of the pipewall is an integral part of the method (e.g. reeled pipelines, risers installed in J-tubes).

3.4.5 External collapse of offshore pipelines

The pipeline wall thickness shall be such that the external pressure which would cause buckling under the expected bending and tension is higher than the actual net external pressure.

At locations where the calculated external pressure at which a buckle will propagate is lower than the actual net external pressure, the pipeline shall be fitted with buckle arrestors (typically every ten joints).

3.4.6 Strain based design

During pipeline construction, it is sometimes more appropriate to apply limitations to the maximum allowable strain of the pipe wall rather than to a maximum allowable stress. Examples during installation are field cold bending of onshore pipelines, offshore pipeline installation by reeling, and riser installation by J-tube pull or bending shoe. When the pipeline is plastically deformed, it shall be demonstrated that, after straining, the pipeline material still complies with the required specifications; this is particularly relevant to toughness, hardness and yield to tensile ratio properties. A maximum permanent bending strain of 2 percent resulting from installation is acceptable in general.

For pipelines in operation, the equivalent stress requirements (3.4.4) may lead in some situations to very high wall thicknesses and a strain based approach may be used instead. This is particularly relevant to pipelines transporting hot products (typically above 80 °C).

3.5 CROSSINGS

The design of crossings depends in general on the installation method.

ONSHORE PIPELINES

The use of casings for the crossing of roads or railways should be discouraged because of the difficulty in providing the pipeline with adequate protection against external corrosion. When casings are stipulated by local authorities, the cathodic protection of the pipeline section within the casing shall be carefully reviewed. Recommendations on pipeline crossings of roads and railways are contained in API RP 1102.

Directional drilling is particularly suitable for long crossings, e.g. rivers and waterways; the method can achieve large burial depths, and it is insensitive to current, river traffic, etc.

The recommended minimum covers at crossings are given in Table 4.

A minimum vertical separation of 0.3 m should be kept between the pipeline and any other buried structures, e.g. existing pipelines, cables, foundations, etc.

OFFSHORE PIPELINES

A minimum vertical separation of 0.3 m should be kept between the pipeline and any other underwater structures such as existing pipelines and submarine cables. Mats or equivalent means should be used for positive separation at crossing locations.

3.6 BURIAL PHILOSOPHY/PIPELINE PROTECTION

ONSHORE PIPELINES

Onshore pipelines should be buried to protect them from mechanical damage, fires and tampering. The recommended minimum covers are given in Table 4, based on ANSI/ASME B31.8 Article 841.142, but modified for increased safety margins.

In determining depth cover in agricultural areas, the depth of ploughing and of drain systems shall be considered. A cover of 1 m would be adequate in most cases. In grazing land, where fencing activities are common, a depth cover of 0.8 m is in general adequate.

The location of buried pipelines shall be clearly identified by markers. In areas where the risk of interference by mechanical excavators is high, a warning tape should be installed in the excavation above the pipeline to further lower the risk.

Any non-buried pipeline sections shall be justified on an individual basis, and shall be installed clear of the ground to avoid external corrosion. Pipe supports should be designed in accordance with DEP 31.38.01.29-Gen.

OFFSHORE PIPELINES

The section of pipeline within the shore approach should be buried to a depth to ensure that exposure due to erosion will not take place. There is otherwise no requirement to trench or bury offshore pipelines, unless necessary in order to achieve pipeline stability, mechanical protection or thermal insulation. It should be noted that protection against dragging anchors from large ships, particularly in soft soils, requires significant or even impracticable burial depths.

Pipelines of 16" and above, with high impact resistant concrete coating, can generally withstand the impact of fishing gear (e.g. trawl boards) and therefore need not be trenched. However, since several parameters, which may vary from case to case, are involved, this should be verified on an individual basis.

When the soil properties and the environmental conditions are suitable, the pipeline may self-bury within an acceptable period of time, removing the need for physical burial. The analysis of the self-burial process is complex and often based on local records/observations; therefore, specialised expertise should be sought.

Buried pipelines operating at high temperatures may be susceptible to upheaval buckling caused by high compressive loads. Upheaval buckling can be prevented either by expansion offsets regularly spaced along the pipeline, or a sufficient burial cover. The use of expansion bellows to accommodate thermal movement is not recommended.

TABLE 4 RECOMMENDED MINIMUM COVER FOR ONSHORE PIPELINES

Location	**Minimum cover (m) in Normal ground (Note 1)**	**Minimum cover (m) in Rock, requiring blasting**
Class 1	0.8	0.6
Class 2	1.0	0.8
Class 3 and 4	1.2	1.0
Public roads and railways crossings	1.5	1.2

NOTE 1: The cover refers to the undisturbed ground level.

3.7 STABILITY

All submerged pipelines, i.e. offshore pipelines and sections of onshore pipelines in swamps, floodable areas, high water table areas, river crossings, etc., should be stable under the combined action of hydrostatic and hydrodynamic forces. The on-bottom stability can be achieved by increasing the pipe wall thickness, by the application of concrete weight coating, by spaced anchor points, by trenching, or by burial.

Special considerations shall be given to pipelines installed in weak soils (e.g. peat), at dyke crossings, etc. where differential settlements may lead to pipeline loss of integrity.

The one year return wave and steady state current conditions should be used for the analysis of stability during the installation phase. The one hundred year environmental return conditions should be used for the analysis during the operation phase. The negative buoyancy should be sufficient to prevent unacceptable lateral pipeline displacements.

3.8 CORROSION PROTECTION AND MONITORING

3.8.1 External corrosion

ONSHORE PIPELINES

All metallic buried pipelines including duplex material pipelines, shall be coated externally by a suitable anti-corrosion coating, supplemented by cathodic protection. To ensure that adequate cathodic protection can be demonstrated at all times, pipelines shall be electrically isolated individually from the plants to which they are connected.

The design of cathodic protection systems for onshore pipelines shall be carried out in accordance with DEP 30.10.73.31-Gen.

Pipelines installed above ground should be coated or painted. The design of the pipeline supports should be such as to prevent pipeline corrosion at the support points.

NOTE: Short life pipelines (e.g. flowlines) may be installed above ground, without anti-corrosion coating, when experience can show that such arrangement does not lead to external corrosion (e.g. in dry climates).

OFFSHORE PIPELINES

All offshore pipelines, including duplex material pipelines, shall be coated externally by a suitable anti-corrosion coating, supplemented by cathodic protection for the part of the system below the water level. Impressed current for cathodic protection of offshore pipelines is not recommended.

To ensure that adequate cathodic protection can be demonstrated, pipelines should be electrically isolated individually from platforms. Alternatively, mathematical modelling may be used to achieve confidence that adequate cathodic protection can be achieved, in which case electrical isolation can be omitted.

The sections of the pipeline located at the air/water interface (e.g. splash and spray zones) are critical with regard to external corrosion, and special coatings or claddings should be used (e.g. vulcanised polychloroprene, external cupro-nickel cladding).

The sections of the pipeline that are externally insulated (either for thermal requirements or fire protection) should be designed to prevent ingress of water in the annulus between the pipeline and the insulation, and should be inspectable for external corrosion.

Apart from the field joint areas, factory applied linepipe coatings, as opposed to field applied coatings, should be used.

Cathodic overprotection in terms of differential potential shall be avoided. Duplex stainless steels and high grade carbon steels (above X60) are particularly sensitive to hydrogen embrittlement caused by excessive cathodic protection voltage.

Electrical isolation of pipelines from plants or platforms should be by means of monoblock isolating joints located above ground or above water. The joints, preferably to be installed in an inclined or vertical position, shall be capable of withstanding any mechanical loads resulting from the adjacent pipework configuration. When the transported fluid is conductive (e.g. high water cut), the length of the isolating joint required to achieve sufficient electrical isolation may be too large, and an internally coated isolating spool is preferred (refer to DEP 30.10.73.31-Gen.).

3.8.2 INTERNAL CORROSION

Linings may be used for internal corrosion protection, provided the lining material does not degrade following long-term exposure to the transported fluid, at the pipeline pressure and temperature conditions. Care is required to ensure continuity of the lining at the joints.

Polyethylene linings are susceptible to attack by aromatics, and to permeation of any dissolved gas in the transported fluid. To prevent lining collapse when the pipeline is depressurised, the permeated gas should be relieved from the annulus.

Internal coatings shall not be used for the purpose of preventing corrosion, because holidays in the coating cannot be completely avoided. In some situations, internal coatings may be applied for internal corrosion mitigation, when the expected leaks are deemed acceptable, following a review of the safety and environmental aspects.

Internal paint markings for individual pipe identification should not be used when corrosive conditions will be present in service.

3.8.3 Provisions for corrosion monitoring

For buried or submerged pipelines, the occurrence of coating damage is normally monitored by cathodic protection measurements (refer to DEP 30.10.73.31-Gen.).

If the pipeline is made of corrosion resistant material (e.g. duplex, GRP, cladsteel), there is normally no need to monitor for internal corrosion.

For carbon steel pipelines, the control of internal corrosion is normally by applying a tight control on the process parameters (e.g. water dewpoint in gas transmission systems, injection of corrosion inhibitor). Corrosion probes and corrosion coupons cannot be relied upon to provide a definite assessment of the pipeline condition, nor to demonstrate that internal corrosion is not occurring. Some indication of internal corrosion in the pipeline may be given by an analysis of debris recovered following a pigging operation; this technique is qualitative and is not able to provide any estimate of corrosion rates.

When corrosive conditions which may lead to significant corrosion damage are present, either internally or externally, a complete inspection of the pipeline should be carried out using intelligent pigging. Intelligent pigging should also be used when the criticality of the pipeline is such that proof of continued integrity is required.

3.9 INTERNAL COATINGS

Internal coatings, such as fusion bonded epoxy or two pack phenolic epoxy paint (flow coat), may be used in the following situations: to limit corrosion during transit and storage, to facilitate precommissioning, to reduce hydraulic friction losses, pig wear and the formation of pyrophoric dust.

Pyrophoric dust (FeS) may be produced in natural gas pipelines, when the gas contains H_2S (even in small quantities), under specific conditions. FeS will form when the gas is in contact with bare steel pipe over a sufficient period, and the water vapour content of the gas is in excess of 60 percent of the content corresponding to the water dew point. FeS may create operational problems, particularly at pressure reduction stations; it is a hazard when it comes in contact with air, e.g. when it is recovered at a pig receiver (self ignition). Finally, the dust can accumulate at isolating flanges and, since it is conductive, render them ineffective. When pyrophoric dust is expected, internal coating of the pipeline is strongly recommended (coating at the field welds, however, is not required).

3.10 PROVISION FOR PIGGING

3.10.1 General

All pipelines shall be suitable to pass pigs, even if pig traps are not permanently installed. Pigging should be used for the precommissioning, commissioning and decommissioning of pipelines, cleaning and corrosion control (removal of wax, debris and stagnant liquids, batch inhibition), the control of liquid hold-up in gas lines, inspection with intelligent pigs, and pipeline repairs if required. Permanent pigging facilities should be justified based on an analysis of pigging frequency and operational constraints. The maximum acceptable distance between pigging stations should be decided on the basis of anticipated pig wear and amount of collected solids.

The use of spheres should be limited to batch inhibition and to liquids removal in two-phase lines. Spheres may be considered when automatic launching is envisaged, or for pigging of branch lines, when the use of conventional pigs is not possible.

Permanent pig signallers should only be fitted when frequent pigging operations are anticipated. Otherwise, temporary strap-on pig signallers or pig location devices should be used.

Ancillary equipment should be flush mounted and barred tees should be used on main line sections of the pipeline. In the case of spheres, sphere tees should be used with drainage provision to prevent collection of debris and liquids which could cause corrosive conditions in the sphere tee annulus. Sphere tees should not be used subsea because of the difficulty in providing drainage.

Pig trap systems for pipelines shall be designed in accordance with DEP 31.40.10.13-Gen.

3.10.2 Double block and bleed

The isolation of the main stream and of the ancillary equipment on pig traps requires careful choice of valve type and configuration to allow safe operation, maintenance and repair without depressurising or decommissioning the pipeline. A double block and bleed system, consisting of two separate valves in series with a bleed point in between to allow diversion to a safe location of any fluid leaking through either valve, should be used in the following situations:

- Toxic fluids, any pressure class.
- Category C fluids, and non-toxic category B and D fluids, ANSI class 600 and above.

3.10.3 Intelligent Pigs

The following should be considered in the design of pipelines, based on the requirements for intelligent pigging:

- The internal diameter variations of main line sections should be limited. This may require the heavy wall sections of the pipeline (e.g. risers, road or railway crossings) to be specified based on the internal diameter, instead of the outside diameter normally used.
- Where sections of different internal diameter are connected together, the chamfer angle at the transition should not exceed 14 degrees, measured from the axis of the pipe (i.e. a taper of 1:4).
- The main line valves should be full bore, i.e. same internal diameter as the pipeline.
- All main line bends should have a sufficient radius to allow passage of intelligent pigs. Most intelligent pigs are able to pass 3-D bends for DN400 and above, 5-D bends for sizes between DN250 and DN400. For pipe sizes below DN250, the required bends depend on the pipe internal bore (7-D to 10-D). This is only indicative.

The Manufacturers/Suppliers of intelligent pigs should be contacted during the design stage, to ensure that the geometry of the pipeline, including the pig launcher and receiver, is adequate.

3.11 LINE SECTIONALISING AND EMERGENCY SHUT DOWN

3.11.1 General

This section (3.11) applies only to pipelines transporting category B, C and D fluids.

Pipeline block valves should be used to limit the release of line contents in the following situations:

- Leaks or pipeline ruptures outside plant boundaries. These valves are called "sectionalising block valves".
- Incidents within plant boundaries. The pipeline inventory needs to be isolated from the plant, in order to prevent escalation of the incident. These valves are called "emergency shutdown valves", and form part of the pipeline.

It may not always be possible to achieve complete leak tight isolation, but flow should in any case be severely limited so that the main objective is achieved, i.e. the fluid within the isolated sections is contained. Valves which are necessary for the routine operation of the pipeline, such as pig trap valves, are not considered as block valves. The use of fittings between block valves, such as flanges and instrument taps, should be minimised.

In some situations, e.g. at the downstream side of plants or major river crossings, a check valve may be used instead of a block valve, since it is simple, reliable and self-actuating. The valve will normally need to be piggable, either by using a piggable flapper or by allowing the flapper to be temporarily secured in the open position. Check valves shall not be used to provide isolation for maintenance of equipment.

3.11.2 Sectionalising block valves

ONSHORE PIPELINES	OFFSHORE PIPELINES
Notwithstanding the ANSI/ASME requirements (Articles 434.15.2/846.11), the spacing of sectionalising block valves should consider limiting the pipeline liquid contents between adjacent valves.	There is no requirement for sectionalising block valves in offshore pipelines.

3.11.3 Emergency shutdown valves

ONSHORE PIPELINES	OFFSHORE PIPELINES
ESD valves should be located at each end of the pipeline, and on the incoming and outgoing sections at any plant en route, such as compressor or pumping stations. The valves should be located in a non-hazardous area, e.g. close to the plant fences.	An ESD valve shall be located at the top of each riser connected to an offshore platform. It should be placed below the platform lower deck level for protection against topsides incidents. For pipelines connected to manned offshore complexes, and in addition to the top of riser ESD valve, a subsea ESD valve located on seabed close to the platform may be considered. Subsea valves should be justified by a quantitative risk assessment. The distance of the subsea ESD valve from the platform should be derived such that the combined risk associated with the platform activities and the pipeline fluid inventory between the valve and the platform is minimised.

ESD valves should not incorporate bypass arrangements. Pressure balancing, if required prior to valve opening, should be done using the operational valves located immediately upstream or downstream of the ESD valve.

3.11.4 Block valves actuation

Three methods of operating block valves can be considered: locally, remotely and automatically. The appropriate method shall be determined from a study of the likely effects of a leak and acceptable released volumes, based on the total time in which a leak can be detected, located and isolated. The closure time of the valves shall not create unacceptably high surge pressures.

Automatic valves can be activated by detection of low pressure, increased flow, rate of loss of pressure or a combination of these, or a signal from a leak detection system. Low pressure detection shall not be used if the control system is designed to maintain the pipeline pressure. Automatic valves shall be fail-safe.

ONSHORE PIPELINES	OFFSHORE PIPELINES
For pipelines transporting toxic category B fluids, and category C and D fluids, the installation of remotely operated sectionalising block valves is recommended to further reduce the extent of a leak. The emergency shutdown valves should be automatically actuated when an emergency shutdown condition occurs at the plant or facility.	The emergency shutdown valves should be automatically actuated when an emergency shutdown condition occurs on the platform.

3.11.5 Leak detection

The requirements for and type of leak detection systems should be derived from an evaluation of the criticality of the pipeline with regards to the consequence of a leak, depending on the transported product, the potential amount released, the sensitivity of the environment and, for onshore pipelines, the location class.

3.11.6 Blowdown

Facilities for operational and emergency pipeline depressurisation shall be available at one end of the pipeline and, for onshore pipelines transporting category C and D fluids, at each sectionalising valve location. The capacity of the blowdown system should be such that the pressure in the pipeline can be reduced as rapidly as practicable. For category C and D fluids, the material specified for the blowdown system should be compatible with the low temperatures encountered during blowdown.

3.12 OVERPRESSURE PROTECTION

3.12.1 Maximum allowable pipeline pressures

There are two governing levels of pressure in the safeguarding of pipelines against overpressurisation: the Maximum Allowable Operating Pressure (MAOP), which shall not be exceeded at any point along the pipeline during normal continuous operations, and the Maximum Allowable Incidental Pressure (MAIP), which shall not be exceeded at any point along the pipeline during upset conditions, i.e. conditions of limited frequency and duration.

MAOP and MAIP are related to each other, to the design pressure, to the pipeline test pressure and to SMYS, as specified in ANSI/ASME B31.4 Articles 402.2.3/4 and ANSI/ASME B31.8 Articles 841.322 and 845.411.

3.12.2 Overpressurisation by the upstream facility

When the pressure immediately upstream of the pipeline is in excess of the evacuation requirements, the pipeline may be designed to operate at lower pressures, in which case a pressure control system shall be installed to limit the pipeline inlet pressure. However, any type of pressure control system shall not be considered as an overpressure protection system.

When, following failure of the pressure control system, the maximum pressure which may be generated by the upstream facility is such that it results in pipeline pressures in excess of MAIP, an overpressure protection system shall be fitted between the upstream facility and the pipeline. Two methods can be considered:

- A system with pressure relief, consisting of mechanical safety/relief valves.
- An instrumented system with a high reliability for the isolation of the pressure source from the pipeline in case of overpressure (HIPS).

NOTE: Since it is not yet formally recognised in some countries, Authority approval may be required for the second method.

3.12.3 Surge Pressures

Pressure surges in pipelines are created by a change in momentum of the moving stream (e.g. valve closure). The occurrence of pressure surges should be determined by transient pressure analysis, using a specialised simulation computer program.

Surge pressures are particularly critical for pipelines transporting liquid fluids, because of the high density and lower compressibility compared to gaseous fluids. Although damping of the pressure wave initiated at the point of blockage occurs as it travels upstream, surge may in some cases result in the highest pipeline pressure at a location well upstream of the point of origin. This may occur in particular for liquid pipelines in hilly terrain.

The pipeline system shall be designed such that surge pressures cannot exceed MAIP at any point along the pipeline, and will not trigger the system for overpressure protection from the upstream facility if fitted.

Methods of preventing the generation of unacceptably high surge pressures including valve closure speed reduction or special fast-response pressure relief systems close to the point of surge initiation. If not sufficient, strict adherence to well formulated operating procedures should be implemented.

3.12.4 Thermal Effects

If a pipeline, or part of it, can be blocked-in while containing a medium with a low compressibility (e.g. liquid fluids), the effect of possible thermal expansion of the blocked-in fluid volume on the internal pressure of the pipe section (e.g. due to solar heating) should be investigated.

The pipeline system shall be designed such that pressures generated by thermal effects cannot exceed MAIP at any point along the pipeline, and will not trigger the system for overpressure protection from the upstream facility if fitted. When those pressures are part of the routine operation of the pipeline, i.e. they occur a significant portion of the time, they shall not exceed MAOP.

The protection against overpressure due to thermal effects may be effected by applying relief valves. Except on assemblies which can be isolated such as pig trap systems and slugcatchers, an isolation valve may be installed between the pipeline and the relief valve for maintenance purposes, provided that procedural controls are in place to ensure that the isolation valve remains normally in the open position, and that the pipeline is not shut in while the relief valve is out of service.

3.13 BRANCH CONNECTIONS AND FITTINGS

Threaded connections (pipe to pipe, fittings), slip-on flanges and mitred connections in excess of 3 degrees shall not be used in any part of the pipeline system. "Pup" pieces should not be less than 0.3 m or one pipe diameter whichever is more.

All branch connections (except for pressure relief systems, see 3.12) should be provided with a valve to permit isolation of the branch from the pipeline.

For mechanical strength reasons, there should be no branch or instrument connections smaller than DN50 on pipelines. For pipelines smaller than DN50, the branch connections shall have the same diameter as the pipeline. Weldolets larger than DN75 should not be used.

Piping materials should conform to DEP 31.38.01.15-Gen. for EP applications, and to DEP 31.38.01.12-Gen. for MF applications.

Gaskets for flanged connections should conform to the following:

- Raised face spiral round gaskets for flanges class 1500 and below, for onshore or above water.
- Ring type joints for subsea flanges, and for all flanges above class 1500.

The number of flanged connections in pipeline systems should be minimised, i.e. tie-in welds are preferred. In some situations (offshore pipeline tie-in to a PLEM or a pre-installed riser), a flanged connection may be used; one of the flanges should have a swivel ring for easy alignment. Subsea connections for large gas transmission systems should be realised by welding.

3.14 TELECOMMUNICATIONS

For any pipeline system, telecommunications should be provided to assist in the operational and maintenance activities (pipeline inspection, end to end communications for pigging operations, emergency situations, etc.). Pipeline monitoring from a central location and remote operations involving the use of telecommunications should be considered for all pipelines transporting toxic fluids.

3.15 RECORDS

A comprehensive set of design documents shall be produced and retained for the life of the pipeline. These documents should include all the design calculations and assessments which led to the technical choices during conception and design of the pipeline. They shall form part of the hand-over documentation (7.).

4. MATERIAL PROCUREMENT

4.1 GENERAL

All materials should be procured from Manufacturers/Suppliers approved by the Principal. The Principal shall specify if, and to what extent, he intends to perform surveillance inspection.

In specifying the level of Principal's inspection, the Principal should take into account:
- criticality of pipeline
- type of material
- past performance of Manufacturer/Supplier
- quality system of Manufacturer/Supplier

4.2 RE-USE OF MATERIALS

Materials from an abandoned pipeline may be used for a new project, provided that they can be certified as fully complying with the specifications required for the new application. Materials shall be inspected and tested to the level presently specified for new materials, i.e. by visual, destructive and non-destructive means. Considering deterioration in service and lower past standards, re-use of materials is not encouraged.

4.3 SPARE MATERIALS

Sufficient spare material should be ordered to cover for route deviations and possible pipeline damage during construction, and the set-up of a material contingency stock for pipeline emergencies during the operational phase. The quantity of spare materials depends on the pipeline length, its location and the likelihood of damage during transport, construction and operation. The following quantities are provided for guidance only.

- For each pipe size, spare linepipe material for testing, route deviations and construction damage should be available in accordance with the following:

Route length	**Spare linepipe**
up to 1 km	60 m
10 km	250 m
100 km	750 m
above 200 km	0.5 percent of route length

  For offshore pipelines, additional lengths corresponding to twice the waterdepth (to cover for wet buckles during installation) and one riser should be available.

- The contingency stock of linepipe material should consist, for each pipe size, of 60 m for onshore pipelines and 250 m for offshore pipelines.

4.4 LINEPIPE MATERIAL

Carbon steel linepipe shall be in accordance with the following Shell specifications, which are supplementary to the API Spec 5L specification:

L-2-2/3 Carbon Steel Linepipe for Non-Sour Service
L-3-2/3 Carbon Steel Linepipe for Sour Service

In addition, linepipe for sour service shall comply with MESC Spec. 74/125.

Linepipe material shall be procured from one of following manufacturing processes:

- Seamless (typically ranging from DN50 to DN450).
- High Frequency Induction, HFI (typically ranging from DN150 to DN500).
- Longitudinal Submerged Arc Welding, SAW (typically above DN400).

Spiral SAW and ERW (low frequency induction process) linepipe should not be used.

GRP linepipe and fittings shall be procured in accordance with DEP 31.40.10.31-Gen.

4.5 FITTINGS AND SPECIAL COMPONENTS

Fittings should be procured using the MESC system.

Components and fittings shall be compatible with the linepipe material in terms of weldability and also conform to the bevel geometry constraints detailed in the pipeline codes.

4.6 ANTICORROSION COATINGS

The following specifications apply:

L-4-1/2/3 Polyethylene/Polypropylene Coating of Linepipe
L-5-1/2/3 Fusion Bonded Epoxy Coating of Linepipe

4.7 CONCRETE COATING

The application of concrete coating for pipelines shall be carried out in accordance with DEP 31.40.30.30-Gen. Concrete thicknesses smaller than 25 mm are not recommended.

4.8 RECORDS

The material certificates and equipment vendors' data (including operating/maintenance instructions), to be included in the hand-over documentation, shall be kept for the life of the pipeline.

Each individual pipe should be allocated an identification number at the pipe mill, and the same number should be used for coating and construction records. For large pipeline projects, a computer-based system for recording and tracking each individual pipe joint from the pipe mill to the construction location should be considered.

5. CONSTRUCTION

5.1 GENERAL

Pipeline construction shall be performed in accordance with the relevant sections of the ANSI/ASME Codes, supplemented by this chapter, and shall comply with any additional criteria resulting from the design.

Construction activities close to existing facilities should be planned in coordination with the operations function, as shut-down of these facilities may be required.

The construction contractor shall provide all necessary calculations and procedures to ensure that the pipeline is installed in a safe and timely manner and with minimum impact on the environment. The procedures should include as a minimum:

ONSHORE PIPELINES	OFFSHORE PIPELINES
• Safety and Environment	• Safety and Environment
• Quality assurance	• Quality assurance
• Right of way and trenching	• Pipeline installation (laying initiation, normal laying, pipeline abandonment and recovery, post-installation survey)
• Stringing and cold bending	• Riser installation
• Welding and non-destructive testing	• Shore approach
• Field joint coating	• Pipeline trenching/burial
• Lowering-in, backfilling and site reinstatement	• Welding and non-destructive testing
• Roads, railways and river crossings	• Field joint coating
• Concrete coatings for river crossings	• Crossings
• Permanent markers and barriers	• Fabricated assemblies
• Fabricated assemblies	• Cathodic protection
• Cathodic protection	• Filling, cleaning and hydrostatic testing
• Filling, cleaning and hydrostatic testing	• Precommissioning
• Precommissioning	• Preparation of as-built records
• Preparation of as-built records	

The key equipment used by the construction contractor should be fully tested on mobilisation to prove that the requirements of the work can be met. Care shall be taken during construction that debris, muddy water etc., do not enter the pipeline.

5.2 PIPELINE INSTALLATION

ONSHORE PIPELINES

Onshore pipelines should normally be laid to ground contour, using one or several construction spreads travelling along a pre-established working strip. The working strip should be of adequate width for ease of construction; the recommended width ranges from 15 m to 30 m, depending on the type of terrain and the pipe diameter. The length of the construction spreads should be kept to a minimum. Where applicable, and prior to grading, the top soil and any existing special features should be removed from the working strip and stored for reinstatement on completion of the pipeline installation.

Care shall be taken that the external coating is not damaged during all phases of construction, particularly during lowering and trench backfilling. Backfill material should consist of fine grain materials. During construction and site reinstatement, the natural drainage of the surrounding landscape shall not be impeded.

Two methods may be considered for the installation of pipelines in swamps:

- The flotation method, where the pipeline is laid from a barge moving through a channel cut along the right of way.
- The push-pull method, where the ditch is dug by a lightweight track-driven machine and the pipeline, fitted with buoyancy tanks if necessary, is pulled along the ditch and sunk. This method is preferred in environmentally sensitive areas.

OFFSHORE PIPELINES

Several offshore installation methods can be envisaged, depending on the pipeline characteristics (diameter, length, waterdepth) and the availability of suitable equipment: conventional pipelaying (S-curve), reeling, towing following assembly onshore (on-bottom, off-bottom, mid-depth and surface), J-laying.

Conventional pipelay barges should have sufficient tensioner capacity to allow one tensioner to be kept on standby. Stingers should not be longer than 60 metres.

The equipment to be tested on mobilisation should include as a minimum the anchor winches, the pipe tensioners, the abandonment and recovery winches, the pipe straighteners, and all navigation/ positioning equipment, as applicable.

The field welding of carbon steel pipelines shall be in accordance with DEP 61.40.20.30-Gen.

All field welds shall be inspected by radiography or equivalent means, except for onshore pipelines transporting category A fluids. For this latter category of pipelines, the basic requirements of ANSI/ASME B31.4 apply.

Welding qualifications, for both the procedure and the welders, should be carried out under actual field conditions.

5.3 CONSTRUCTION HYDROTESTING

All new pipelines shall be tested after construction and burial (if applicable) to prove the strength and leak tightness, by means of a hydrostatic pressure test. Only water from approved sources should be used. Corrosion inhibitors, when required, should be selected on the basis of lowest environmental sensitivity.

Prior to testing, the pipeline shall be gauged, either by a gauge plate pig or an instrumented caliper pig, to ensure that no dents or buckles are left in the line.

Notwithstanding the ANSI/ASME requirements, the strength test pressure should be set to give at least a hoop stress level of 90% of the specified minimum yield stress, based on the minimum wall thickness. The pipeline sections with higher wall thicknesses and/or steel grades (e.g. risers, crossings), should be tested separately, prior to incorporation in the pipeline. The strength test pressure should be maintained for a duration of 4 hours minimum. Pressure fluctuations caused by thermal variations should be prevented by adding/removing suitable quantities of water from the pipeline.

Following the strength test, a leak tightness test shall be carried out on pipeline sections which cannot be inspected for leaks during the strength test. The leak tightness test pressure should be set initially at 80% of the strength test pressure, and allowed to fluctuate with temperature changes (i.e. there is no adding/removing of water from the pipeline). The leak tightness test pressure should be maintained for a duration of 24 hours minimum. There should be no leak, based on the correlation of pipeline pressure fluctuations and temperature changes.

A combined strength/leak tightness test may be performed at strength test pressure and without addition or removal of water if it can be ensured that the pipeline stresses will not exceed 100% SMYS at any location (accounting for pressure fluctuations caused by temperature variations).

Tie-in welds, i.e. welds which are not subject to the hydrostatic pressure test, shall be subjected to additional non-destructive testing (e.g. ultrasonic inspection).

The hydrostatic pressure testing of pipelines is covered in DEP 31.40.40.38-Gen.

5.4 RECORDS

A comprehensive set of as-built documents, to be included in the hand-over documentation, shall be produced during construction and retained for the life of the pipeline. These should include, as a minimum:

- Changes to original design, with reasons.
- Pipe tally giving the size, grade, wall thickness, identification number, coating details, and location of each pipe joint used during construction.
- Specifications used for field jointing (welding and coating).
- Non-conformance reports and remedial actions taken.
- Radiographs of the welds (radiographs need be retained for a period of five years only).
- Detailed survey of the as-laid position of the pipeline, including burial depth as applicable.
- Pigging records.
- Hydrotest certificates.

The design drawings shall be updated based on the as-built condition, before hand-over of the pipeline to the operations function.

5.5 SAFETY AND ENVIRONMENT

During all stages of the pipeline construction, the Contractor shall work to the highest achievable safety and environmental standards. The safety performance of all staff involved in the work shall be monitored and recorded. Regular safety inspection of the construction sites shall be carried out, to ensure compliance with the relevant procedures, as well as maintaining awareness of all staff regarding potential hazards.

The aspects related to the management of safety during the construction phase are covered in EP 55000 Sections 15 and 16.

6. PRE-COMMISSIONING

All pipelines shall be thoroughly cleaned to remove any remaining construction debris and loose scale. The collected material should be properly disposed of in an environmentally acceptable manner. Cleaning should be performed by successively pushing several cleaning pigs through the pipeline with water or air. The number of pig runs required will depend on the size and length of the pipeline, and the initial cleanliness of the pipeline. Clean linepipe and proper care during construction will minimise the cleaning effort.

The pipeline should be dewatered and, if necessary, be dried in a way compatible with the required service. Drying should be considered when the design of the pipeline is based on transporting dehydrated fluids, or when the dewatering operations are carried out long before commissioning. The appropriate drying technique should be derived from an analysis of product specification requirements (in terms of water content) and the risks of corrosion and hydrate formation following commissioning of the pipeline. Drying techniques include methanol or glycol swabbing, air or nitrogen drying and vacuum drying, or a combination of these techniques. Vacuum drying is normally used when high levels of dryness are required. Consideration should be given to voids in valves and fittings when planning a drying operation.

Whenever possible, in-line pipeline ball valves should be installed after the cleaning operations. This is to prevent the ingress of debris and dust in the valve bodies which may lead to damage of the valve seats and seals.

The precommissioning records, to be included in the hand-over documentation, should include the following:

- Number of runs, with type of pigs.
- Quantity and type of debris recovered during each run.
- Drying records, including certificate of dryness.

7. HAND-OVER DOCUMENTATION

The hand-over documentation shall include the design, materials, construction and precommissioning records, the Agreements, Permits and Authorisations related to the pipeline, plus a pipeline operating and maintenance manual to be prepared during the engineering phase of the project. The manual should cover the range of key operating conditions that can be envisaged for the entire life span, and the operating envelope for which the pipeline is designed, and should be compatible with the operational and maintenance practices already in place. The manual should include, as a minimum, the following information:

- A functional description of the pipeline, in the form of a process engineering flowscheme, showing all operational, safety and instrumentation features (pigtraps, valves, fitting, instruments, alarms and shut-down logics, pressure and flow controls).
- A physical description of the pipeline (route including major features along the route, linepipe characteristics including corrosion allowance, coatings, supports, burial details, crossings, cathodic protection, equipment drawings).
- A description of the key operating parameters (specification of the transported fluid, ranges of pressure, temperature and flow, design life, corrosion management including materials design philosophy, expected corrosion rates and inhibition requirements, design environmental conditions).
- The inspection and condition monitoring requirements of all parts of the pipeline (route surveys, external and internal corrosion surveys, valves and instrument checks, cathodic protection).
- Requirements for special operations such as start-up and shut-down, conditioning for prolonged shut-down, liquid hold-up control which may be required prior to pigging.
- Pigging requirements (type of pigs, frequency) for the foreseeable operating conditions, explaining the purpose, e.g. cleaning, corrosion control, liquid holdup control, including criteria for adjustment.
- Identification of the risks associated with the pipeline and the means taken to minimise them.
- Line leak/break detection and contingency plan, including roles and responsibilities of personnel, list of emergency equipment and contingency materials, and repair procedures of all parts of the pipeline.

The pipeline documentation should be structured in a manner such that all parties involved with the operation, maintenance and inspection of the pipeline system have ready access to all data required to control pipeline integrity.

8. REFERENCES

In this DEP, reference is made to the following publications:

NOTE: Unless specifically designated by date, the latest edition of each publication shall be used, together with any amendments/supplements/revisions thereto.

SHELL STANDARDS

Index to DEP publications and standard specifications	DEP 00.00.05.05-Gen.
Design of cathodic protection systems for onshore lines	DEP 30.10.73.31-Gen.
Piping classes - exploration and production	DEP 31.38.01.15-Gen.
Pipe Supports	DEP 31.38.01.29-Gen.
Design of pipeline pig trap systems	DEP 31.40.10.13-Gen.
GRP linepipe and fittings	DEP 31.40.10.31-Gen.
Concrete coating of linepipe	DEP 31.40.30.30-Gen.
Hydrostatic pressure testing of new pipelines	DEP 31.40.40.38-Gen.
Field welding of carbon steel pipelines	DEP 61.40.20.30-Gen.
Operations philosophies and policies	EP 87-1009
Management of contractor safety	EP 55000 Sect.15
Safety in projects	EP 55000 Sect.16
Quantitative Risk Assessment	EP 55000 Sect. 18
Safety engineering in facilities design	EP 55000 Sect. 21
Guidelines on the safe handling of chemicals (SHOC)	EP 55000 Sect. 40
Carbon steel linepipe for non-sour service	L-2-2/3
Carbon steel linepipe for sour service	L-3-2/3
Polyethylene/polypropylene coating of linepipe	L-4-1/2/3
Fusion bonded epoxy coating of linepipe	L-5-1/2/3
Hydrogen induced cracking sensitivity test	MESC Spec. 74/125
Environmental Impact Assessment Guide, 1988	Shell Product Safety and Environment Committee

AMERICAN STANDARDS

Liquid transportation systems for hydrocarbons, liquid petroleum gas, anhydrous ammonia, and alcohols, 1992 Edition	ANSI/ASME B31.4
Gas transmission and distribution piping systems,	ANSI/ASME B31.8

1992 Edition

Issued by:
The American Society of Mechanical Engineers
345 East 47th Street
New York, NY 10017
USA.

Recommended practice for liquid petroleum pipelines crossing railroads and highways	API RP 1102
Specification for Linepipe	API Spec 5L

Issued by:
American Petroleum Institute
1220 L Street Northwest
Washington, DC 20005
USA.

Sulphide stress cracking materials for oil field equipment	NACE MR0175

Issued by:
National Association of Corrosion Engineers
P.O. Box 218340
Houston, TX 77218
USA

BRITISH STANDARDS

Institute of Petroleum Model Code of Safe Practice Part 15, Area classification code for petroleum installations	IP 15

Issued by:
Institute of Petroleum
61 New Cavendish Street
London W1M 8AR
United Kingdom.

APPENDICES

APPENDIX 1 BUILDING PROXIMITY DISTANCES

For the purpose of initial pipeline routing, the following formulae provide the minimum distances between the pipeline and normally occupied buildings:

Pipelines having a design factor not exceeding 0.72:

$$d = Q\left[\frac{D^2}{32{,}000} + \frac{D}{160} + 11\right]\left[\frac{P}{32} + 1.4\right]$$

Pipelines having a design factor not exceeding 0.4:

$$d = Q\left[0.7 - \frac{t}{21}\right]\left[P + 82\right]$$

d : distance in metres

D : pipeline diameter in mm; if the pipeline diameter is less than 150 mm, D should be taken equal to 150 mm.

t : pipeline wall thickness in mm; if the wall thickness is less than 9.5 mm, t may be taken equal to 9.5 mm. If the wall thickness is larger than 13.5 mm, t shall be taken equal to 13.5 mm.

P : pipeline MAOP in bar (ga); for pipelines operating at less than 20 bar (ga), P should be taken equal to 20 bar (ga).

Q : fluid factor, as provided in the table below

Fluid Category	**Fluid Factor**
A and B	Q = 0, i.e. there is no minimum distance requirement except for access during construction and operations
C	Q = 0.3 for all fluids
D	Q = 0.5 for methane (Natural Gas) Q = 0.8 for ethylene Q = 1.0 for LPG Q = 1.25 for NGL Q = 0.45 for hydrogen Q = 2.5 for ammonia

Fluids not specifically mentioned above should be given the fluid factor most closely similar in hazard potential to those quoted.

It is stressed that the above methodology is for planning/guidance purposes only and that it does not replace a quantitative risk analysis.

APPENDIX 2 PIPELINE STRESSES

There are three types of stresses to be considered in the calculation of the equivalent stress: the hoop stress, the longitudinal stress and the combined shear stress.

Hoop stress:

$$S_h = \frac{PD}{2t}$$

Longitudinal stress:

Fully restrained pipeline:

$$S_L = \mu\,(S_h - P) - E\alpha\,(T_2 - T_1)$$

Fully unrestrained pipeline:

$$S_L = \frac{S_h}{2} + \frac{M_b}{Z}$$

Combined shear stress:

$$S_S = \frac{T}{2Z} + \frac{2\,F_S}{A}$$

P = pipeline internal pressure,

D = pipeline diameter,

t = wall thickness,

μ = Poisson's ratio,

E = modulus of elasticity,

α = linear coefficient of thermal expansion,

T_1 = pipeline installation temperature,

T_2 = pipeline operation temperature,

M_b = bending moment applied to the pipeline,

Z = pipe section modulus,

T = torque applied to the pipeline,

F_s = shear force applied to the pipeline,

A = pipe wall cross section area,

FIGURES

FIGURE 1 DIAGRAMMATIC REPRESENTATION OF PIPELINE SCOPE BOUNDARIES

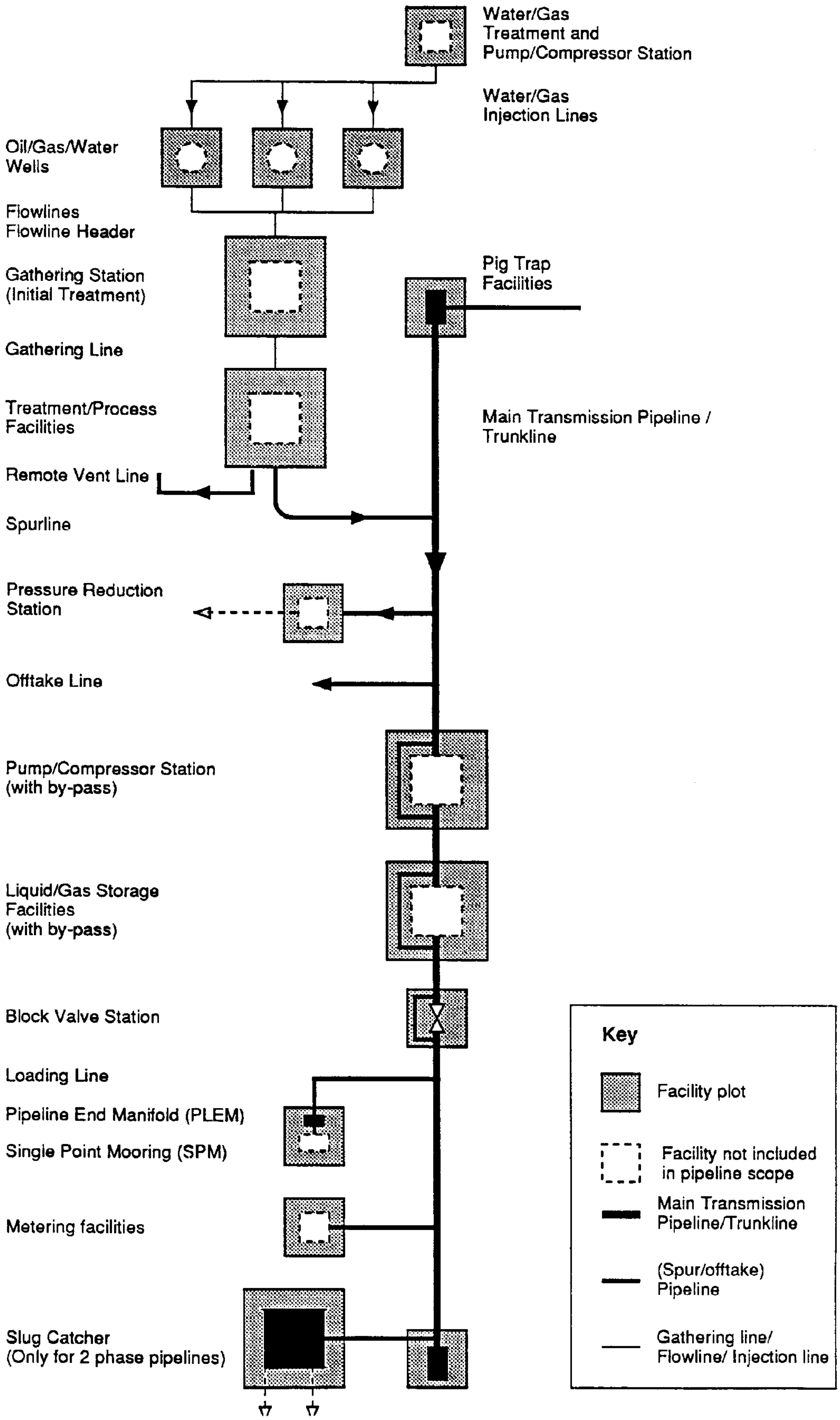
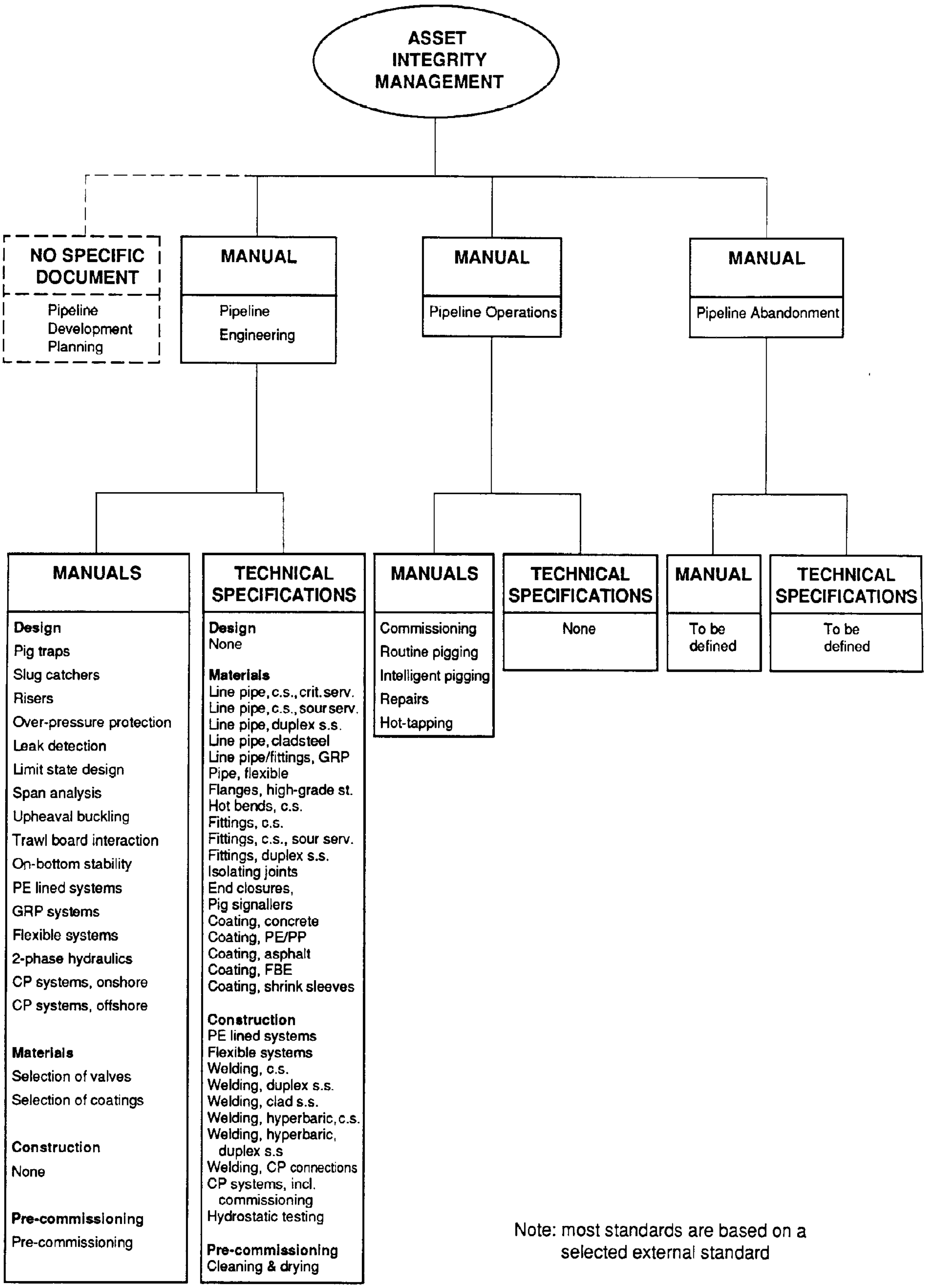

Water/Gas
Treatment and
Pump/Compressor Station
Water/Gas
Injection Lines
Oil/Gas/Water
Wells
Flowlines
Flowline Header
Gathering Station
(Initial Treatment)
Pig Trap
Facilities
Gathering Line
Treatment/Process
Facilities
Main Transmission Pipeline /
Trunkline
Remote Vent Line
Spurline
Pressure Reduction
Station
Offtake Line
Pump/Compressor Station
(with by-pass)
Liquid/Gas Storage
Facilities
(with by-pass)
Block Valve Station
Loading Line
Pipeline End Manifold (PLEM)
Single Point Mooring (SPM)
Metering facilities
Slug Catcher
(Only for 2 phase pipelines)
Key
Facility plot
Facility not included
in pipeline scope
Main Transmission
Pipeline/Trunkline
(Spur/offtake)
Pipeline
Gathering line/
Flowline/ Injection line

FIGURE 2 PIPELINE GROUP STANDARDS



Note: most standards are based on a selected external standard