



GUIDE FOR BUILDING AND CLASSING

SUBSEA PIPELINE SYSTEMS

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**American Bureau of Shipping
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the State of New York 1862**

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Foreword

This Guide applies to classification of design, construction and installation of offshore pipelines made of metallic materials, as well as the periodic surveys required for maintenance of classification. Serviceability of pipelines is also addressed, but only to the extent that proper functioning of the pipe and its components affects safety. This Guide may also be used for certification or verification of design, construction and installation of pipelines. ABS will certify or verify design, construction and installation of offshore pipelines when requested by the Owner or mandated by government regulations to verify compliance with this Guide, a set of specific requirements, national standards or other applicable industry standards. If ABS certification or verification is in accordance with this Guide and covers design, construction and installation, then the pipeline is also eligible for ABS classification.

This Guide has been written for worldwide application, and as such, the satisfaction of individual requirements may require comprehensive data, analyses and plans to demonstrate adequacy. This especially applies for pipelines located in frontier areas, such as those characterized by relatively great water depth or areas with little or no previous operating experience. Conversely, many provisions of this Guide often can be satisfied merely on a comparative basis of local conditions or past successful practices. ABS acknowledges that a wide latitude exists as to the extent and type of documentation which is required for submission to satisfy this Guide. It is not the intention of this Guide to impose requirements or practices in addition to those that have previously proven satisfactory in similar situations.

Where available, design requirements in this Guide have been posed in terms of existing methodologies and their attendant safety factors, load factors or permissible stresses that are deemed to provide an adequate level of safety. Primarily, ABS's use of such methods and limits in this Guide reflects what is considered to be the current state of practice in offshore pipeline design. At the same time, it is acknowledged that methods of design, construction and installation are constantly evolving. In recognition of these facts, the Guide specifically allows for such innovations and the Appendices are intended to reflect this. The application of this Guide by ABS will not seek to inhibit the use of any technological approach that can be shown to produce an acceptable level of safety.

This ABS Guide is effective 1 May 2006 and supersedes the edition published in May 2005.

Changes to Conditions of Classification (1 January 2008)

For the 2008 edition, Chapter 1, "Scope and Conditions of Classification" was consolidated into a generic booklet, entitled *Rules for Conditions of Classification – Offshore Units and Structures (Part 1)* for all units, installations, vessels or systems in offshore service. The purpose of this consolidation was to emphasize the common applicability of the classification requirements in "Chapter 1" to ABS-classed offshore units, pipelines, risers, and other offshore structures, and thereby make "Conditions of Classification" more readily a common Rule of the various ABS Rules and Guides, as appropriate.

Thus, Chapter 1 of this Guide specifies only the unique requirements applicable to subsea pipeline systems. These supplemental requirements are always to be used with the aforementioned *Rules for Conditions of Classification – Offshore Units and Structures (Part 1)*.



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CHAPTER 1 Scope and Conditions of Classification (Supplement to the ABS Rules for Conditions of Classification – Offshore Units and Structures)

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CHAPTER 1 Scope and Conditions of Classification

SECTION 1 Applicability (1 January 2008)

The intention of this Guide is to serve as technical documentation for design, fabrication, installation and maintenance of offshore production, transfer and export pipelines made of metallic materials. The principal objectives are to specify the minimum requirements for classing, continuance of classing, certification and verification by ABS.

In addition to the requirements of this Guide, the design of a marine system requires consideration of all relevant factors related to its functional requirements and long term integrity, such as:

- Compliance with local Laws, Acts and Regulations
- Functional requirements
- Physical site information
- Operational requirements

1 Classification (1 January 2008)

The requirements for conditions of classification are contained in the separate, generic *ABS Rules for Conditions of Classification – Offshore Units and Structures (Part I)*.

Additional requirements specific to subsea pipeline systems are contained in the following Sections.



CHAPTER 1 Scope and Conditions of Classification

SECTION 2 Classification Symbols and Notations (1 January 2008)

A listing of Classification Symbols and Notations available to the Owners of vessels, offshore drilling and production units and other marine structures and systems, “List of ABS Notations and Symbols” is available from the ABS website “<http://www.eagle.org/absdownloads/index.cfm>”.

The following notations are specific to subsea pipeline systems.

1 Pipelines Built under Survey

Pipelines which have been built, installed, tested and commissioned to the satisfaction of the ABS Surveyors to the full requirements of this Guide or to its equivalent, where approved by the Committee, will be classed and distinguished in the *Record* by:

⊠ A1 Offshore Installation – Offshore Pipelines

3 Pipelines not Built under Survey

Pipelines which have not been built, installed, tested and commissioned under ABS survey, but which are submitted for classification, will be subjected to a special classification survey. Where found satisfactory, and thereafter approved by the Committee, they will be classed and distinguished in the *Record* in the manner as described in 1-2/1, but the mark ⊠ signifying survey during construction will be omitted.

5 Classification Data

Data on the pipeline will be published in the *Record* as to the latitude and longitude of its location, type, dimensions and depth of water at the site.



CHAPTER 1 Scope and Conditions of Classification

SECTION 3 Rules for Classification (1 January 2008)

1 Application

These requirements are applicable to those features that are permanent in nature and can be verified by plan review, calculation, physical survey or other appropriate means. Any statement in the Guide regarding other features is to be considered as guidance to the designer, builder, Owner, et al.

3 Risk Evaluations for Alternative Arrangements and Novel Features

Risk assessment techniques may be used to demonstrate that alternatives and novel features provide acceptable levels of safety in line with current offshore and marine industry practice. The *ABS Guide for Risk Evaluations for the Classification of Marine-Related Facilities* provides guidance on how to prepare a risk evaluation to demonstrate equivalency or acceptability for a proposed design.

Risk evaluations for the justification of alternative arrangements or novel features may be applicable either to the installation as a whole, or to individual systems, subsystems or components. ABS will consider the application of risk evaluations for alternative arrangements and novel features for subsea pipeline systems.

Portions of the subsea pipeline system or any of its components thereof not explicitly included in the risk evaluation submitted to ABS are to comply with any applicable part of the ABS Rules and Guides. If any proposed alternative arrangement or novel feature affects any applicable requirements of Flag and Coastal State, it is the responsibility of the Owner to discuss with the applicable authorities the acceptance of alternatives based on risk evaluations.

For new or novel concepts, i.e. applications or processes that have no previous experience in the environment being proposed, the guidance encompassed in the class Rules may not be directly applicable to them. The *ABS Guidance Notes on Review and Approval of Novel Concepts* offer ABS clients a methodology for requesting classification of a novel concept. The process described in this guidance document draws upon engineering, testing and risk assessments in order to determine if the concept provides acceptable levels of safety in line with current industry practices.



CHAPTER 1 Scope and Conditions of Classification

SECTION 4 Documents to be Submitted

1 General

For classing pipelines according to this Guide, the documentation submitted to ABS is to include reports, calculations, drawings and other documentation necessary to demonstrate the adequacy of the design of the pipelines. Specifically, required documentation is to include the items listed in this Chapter.

3 Plans and Specifications

Plans and specifications depicting or describing the arrangements and details of the major items of pipelines are to be submitted for review or approval in a timely manner. These include:

- Site plan indicating bathymetric features along the proposed route, the location of obstructions to be removed, the location of permanent man-made structures, the portions of the pipe to be buried and other important features related to the characteristics of the sea floor
- Structural plans and specifications for pipelines, their supports and coating
- Schedules of nondestructive testing and quality control procedures
- Flow diagram indicating temperature and pressure profiles
- Specifications and plans for instrumentation and control systems and safety devices

When requested by the Owner, the Owner and ABS may jointly establish a schedule for information submittal and plan approval. This schedule, to which ABS will adhere as far as reasonably possible, is to reflect the fabrication and construction schedule and the complexity of the pipeline systems as they affect the time required for review of the submitted data.

5 Information Memorandum

An information memorandum on pipelines is to be prepared and submitted to ABS. ABS will review the contents of the memorandum to establish consistency with other data submitted for the purpose of obtaining classification or certification.

An information memorandum is to contain, as appropriate to the pipelines, the following:

- A site plan indicating the general features at the site and the field location of the pipelines
- Environmental design criteria, including the recurrence interval used to assess environmental phenomena
- Plans showing the general arrangement of the pipelines
- Description of the safety and protective systems provided
- Listing of governmental authorities having authority over the pipelines
- Brief description of any monitoring proposed for use on the pipelines
- Description of manufacturing, transportation and installation procedures

7 Site-specific Conditions

An environmental condition report is to be submitted, describing anticipated environmental conditions during pipe laying, as well as environmental conditions associated with normal operating conditions and the design environmental condition. Items to be assessed are to include, as appropriate, waves, current, temperature, tide, marine growth, chemical components of air and water, ice conditions, earthquakes and other pertinent phenomena.

A route investigation report is to be submitted, addressing with respect to the proposed route of the pipeline system the topics of seafloor topography and geotechnical properties. In the bathymetric survey, the width of the survey along the proposed pipeline route is to be based on consideration of the expected variation in the final route in comparison with its planned position, and the accuracy of positioning devices used on the vessels employed in the survey and in the pipe laying operation. The survey is to identify, in addition to bottom slopes, the presence of any rocks or other obstructions that might require removal, gullies, ledges, unstable slopes and permanent obstructions, such as existing man-made structures. The geotechnical properties of the soil are to be established to determine the adequacy of its bearing capacity and stability along the route. The methods of determining the necessary properties are to include a suitable combination of in-situ testing, seismic survey, and boring and sampling techniques. As appropriate, soil testing procedures are to adequately assess sea floor instability, scour or erosion and the possibility that soil properties may be altered due to the presence of the pipe, including reductions in soil strength induced by cyclic soil loading or liquefaction. The feasibility of performing various operations relative to the burial and covering of the pipe is to be assessed with respect to the established soil properties.

Where appropriate, data established for a previous installation in the vicinity of the pipeline proposed for classification may be utilized, if acceptable to ABS.

9 Material Specifications

Documentation for all materials of the major components of pipelines is to indicate that the materials satisfy the requirements of the pertinent specification.

For linepipes, specifications are to identify the standard with which the product is in complete compliance, the size and weight designations, material grade and class, process of manufacture, heat number and joint number. Where applicable, procedures for storage and transportation of the linepipes from the fabrication and coating yards to the offshore destination are to be given.

Material tests, if required, are to be performed to the satisfaction of ABS.

11 Design Data and Calculations

Information is to be submitted for the pipelines that describe the material data, models and variability, long-term degradation data and models, methods of material system selection, analysis and design that were employed in establishing the design. The estimated design life of the pipelines is to be stated. Where model testing is used as the basis for a design, the applicability of the test results will depend on the demonstration of the adequacy of the methods employed, including enumeration of possible sources of error, limits of applicability and methods of extrapolation to full scale data. It is preferable that the procedures be reviewed and agreed upon before material and component model testing is performed.

Calculations are to be submitted to demonstrate the adequacy of the proposed design and are to be presented in a logical and well-referenced fashion, employing a consistent system of units. Where suitable, at least the following calculations are to be performed:

11.1 Structural Strength and On-bottom Stability Analysis

Calculations are to be performed to demonstrate that, with respect to the established loads and other influences, the pipelines, support structures and surrounding soil possess sufficient strength and on-bottom stability with regard to failure due to the following:

- Excessive stresses and deflections
- Fracture
- Fatigue
- Buckling
- Collapse
- Foundation movements

Additional calculations may be required to demonstrate the adequacy of the proposed design. Such calculations are to include those performed for unusual conditions and arrangements, as well as for the corrosion protection system.

11.3 Installation Analysis

With regard to the installation procedures, installation analyses, including trenching effects, are to be submitted for review. These calculations demonstrate that the anticipated loading from the selected installation procedures does not jeopardize the strength and integrity of the pipelines.

11.5 Safety Devices

An analysis of the pipeline safety system is to be submitted to demonstrate compliance with API RP 14G. As a recommended minimum, the following safety devices are to be part of the pipelines:

- For departing pipelines, a high-low pressure sensor is required on the floater or platform to shut down the wells, and a check valve is required to avoid backflow.
- For incoming pipelines an automatic shutdown valve is to be connected to the floater or platform's emergency shutdown system, and a check valve is required to avoid backflow.
- For bi-directional pipelines, a high-low pressure sensor is required on the floater or platform to shut down the wells, and an automatic shutdown valve is to be connected to the floater or platform's emergency shutdown system.

Shortly after the pipelines are installed, all safety systems are to be checked in order to verify that each device has been properly installed and calibrated and is operational and performing as prescribed.

In the post-installation phase, the safety devices are to be tested at specified regular intervals and periodically operated so that they do not become fixed by remaining in the same position for extended periods of time.

13 Installation Manual

A manual is to be submitted describing procedures to be employed during the installation of pipelines and is as a minimum to include:

- List of the tolerable limits of the environmental conditions under which pipe laying may proceed
- Procedures and methods to evaluate impact and installation damage tolerance
- Procedures to be followed should abandonment and retrieval be necessary
- Repair procedures to be followed should any component of pipelines be damaged during installation
- Contingency plan

An installation manual is to be prepared to demonstrate that the methods and equipment used by the contractor meet the specified requirements. As a minimum, the qualification of the installation manual is to include procedures related to:

- Quality assurance plan and procedures
- Welding procedures and standards
- Welder qualification
- Nondestructive testing procedures
- Repair procedures for field joints, internal and external coating repair, as well as repair of weld defects, including precautions to be taken during repairs to prevent overstressing the repair joints
- Qualification of pipe-lay facilities, such as tensioner and winch
- Start and finish procedure
- Laying and tensioning procedures
- Abandonment and retrieval procedures
- Subsea tie-in procedures
- Intervention procedures for crossing design, specification and construction, bagging, permanent and temporary support design, specification and construction, etc.
- Trenching procedures
- Burying procedures
- Field joint coating and testing procedures
- Drying procedures
- System pressure test procedures and acceptance criteria

Full details of the lay vessel, including all cranes, abandonment and recovery winches, stinger capacities and angles, welding and nondestructive testing gear, firing line layout and capacity and vessel motion data are to be provided, together with general arrangement drawings showing plans, elevations and diagrams of the pipeline assembly, welding, nondestructive testing, joint coating and lay operations. Full details of any trenching and burying equipment is to be provided.

15 Pressure Test Report

A report including procedures for and records of the testing of each pipeline system is to be submitted. The test records are, as a minimum, to include an accurate description of the facility being tested, the pressure gauge readings, the recording gauge charts, the dead weight pressure data and the reasons for and disposition of any failures during a test. A profile of the pipeline that shows the elevation and test sites over the entire length of the test section is to be included. Records of pressure tests are also to contain the names of the Owner and the test contractor, the date, time and test duration, the test medium and its temperature, the weather conditions and sea water and air temperatures during the test period. Plans for the disposal of test medium together with discharge permits may be required to be submitted to ABS.

17 Operations Manual

An operations manual is to be prepared to provide a detailed description of the operating procedures to be followed for expected conditions. The operations manual is to include procedures to be followed during start-up, operations, shutdown conditions and anticipated emergency conditions. This manual is to be submitted to ABS for record and file.

19 Maintenance Manual

A maintenance manual providing detailed procedures for how to ensure the continued operating suitability of the pipeline system is to be submitted to ABS for approval.

The manual is, as a minimum, to include provisions for the performance of the following items:

- Visual inspection of non-buried parts of pipelines to verify that no damage has occurred to the systems and that the systems are not being corroded
- Evaluation of the cathodic protection system performance by potential measurements
- Detection of dents and buckles by caliper pigging
- Inspection and testing of safety and control devices

Additionally, ABS may require gauging of pipe thickness should it be ascertained that pipelines are undergoing erosion or corrosion.

Complete records of inspections, maintenance and repairs of pipelines are to be provided for ABS.

21 As-built Documents

The results of surveys and inspections of the pipelines are to be given in a report which, as a minimum, is to include the following details:

- Plot of the final pipeline position, superimposed on the proposed route including pipeline spans and crossings
- Description and location of any major damage to the pipelines alongside information regarding how such damage was repaired
- Description of the effectiveness of burial operations (if applicable for pipelines)

As appropriate, results of additional inspections, which may include those for the proper operation of corrosion control systems, fiber-optic and/or damage sensors, buckle detection by caliper pig or other suitable means and the testing of alarms, instrumentation and safety and emergency shutdown systems, are to be included.



CHAPTER 1 Scope and Conditions of Classification

SECTION 5 Survey, Inspection and Testing (1 January 2008)

1 General

1.1 Scope

This Section pertains to inspection and survey of pipelines at different phases, including:

- Fabrication
- Installation
- Testing after installation

The phases of fabrication and construction covered by this Section include pipe and coating manufacture, fabrication, assembly and linepipe pressure test. The phases of installation include route survey of the pipelines, preparation, transportation, field installation, construction, system pressure test and survey of the as-built installation. The post-installation phase includes survey for continuance of classification, accounting for damage, failure and repair.

1.3 Quality Control and Assurance Program

A quality control and assurance program compatible with the type, size and intended functions of pipelines is to be developed and submitted to ABS for review. ABS will review, approve and, as necessary, request modification of this program. The Contractor is to work with ABS to establish the required hold points on the quality control program to form the basis for all future inspections at the fabrication yard and surveys of the pipeline. As a minimum, the items enumerated in the various applicable Subsections below are to be covered by the quality control program. If required, Surveyors may be assigned to monitor the fabrication of pipelines and assure that competent personnel are carrying out all tests and inspections specified in the quality control program. It is to be noted that the monitoring provided by ABS is a supplement to and not a replacement for inspections to be carried out by the Constructor or Operator.

The quality control program, as appropriate, is to include the following items:

- Material quality and test requirements
- Linepipe manufacturing procedure specification and qualification
- Welder qualification and records
- Pre-welding inspection
- Welding procedure specifications and qualifications
- Weld inspection
- Tolerances and alignments
- Corrosion control systems
- Concrete weight coating
- Nondestructive testing

- Inspection and survey during pipe laying
- Final inspection and system pressure testing
- Pigging operations and tests
- Final as-built condition survey and acceptance

1.5 Access and Notification

During fabrication and construction, ABS representatives are to have access to pipelines at all reasonable times. ABS is to be notified as to when and where linepipe, pipeline and pipeline components may be examined. If ABS finds occasion to recommend repairs or further inspection, notice will be made to the Contractor or his representatives.

1.7 Identification of Materials

The Contractor is to maintain a data system of material for linepipe, pipeline components, joints, anodes and coatings. Data concerning place of origin and results of relevant material tests are to be retained and made readily available during all stages of construction.

3 Inspection and Testing in Fabrication Phase

Specifications for quality control programs of inspection during fabrication of linepipe and pipeline components are given in this Subsection. Qualification tests are to be conducted to document that the requirements of the specifications are satisfied.

3.1 Material Quality

The physical properties of the linepipe material and welding are to be consistent with the specific application and operational requirements of pipelines. Suitable allowances are to be added for possible degradation of the physical properties in the subsequent installation and operation activities. Verification of the material quality is to be done by the Surveyor at the manufacturing plant, in accordance with Chapter 2 of this Guide. Alternatively, materials manufactured to the recognized standards or proprietary specifications may be accepted by ABS, provided such standards give acceptable equivalence with the requirements of this Guide.

3.3 Manufacturing Procedure Specification and Qualification

A manufacturing specification and qualification procedure is to be submitted for acceptance before production start. The manufacturing procedure specification is to state the type and extent of testing, the applicable acceptance criteria for verifying the properties of the materials and the extent and type of documentation, record and certificate. All main manufacturing steps from control of received raw material to shipment of finished linepipe, including all examination and checkpoints, are to be described. ABS will survey formed linepipe, pipeline, pipeline components such as bends, tees, valves, etc., for their compliance with the dimensional tolerances, chemical composition and mechanical properties required by the design.

3.5 Welder Qualification and Records

Welders who are to work on pipelines are to be qualified in accordance with the welder qualification tests specified in a recognized code, such as API STD 1104 and Section IX of the ASME "Boiler and Pressure Vessel Code". Certificates of qualification are to be prepared to record evidence of the qualification of each welder qualified by an approved standard/code. In the event that welders have been previously qualified, in accordance with the requirements of a recognized code, and provided that the period of effectiveness of previous testing has not lapsed, these welder qualification tests may be accepted.

3.7 Pre-Welding Inspection

Prior to welding, each pipe is to be inspected for dimensional tolerance, physical damage, coating integrity, interior cleanliness, metallurgical flaws and proper fit-up and edge preparation.

3.9 Welding Procedure Specifications and Qualifications

Welding procedures are to conform to the provisions of a recognized code, such as API STD 1104, or Owner's specifications. A written description of all procedures previously qualified may be employed in the construction, provided it is included in the quality control program and made available to ABS. When it is necessary to qualify a welding procedure, this is to be accomplished by employing the methods specified in the recognized code. All welding is to be based on welding consumables and welding techniques proven to be suitable for the types of material, pipe and fabrication in question. As a minimum, the welding procedure specification is to contain the following items:

- Base metal and thickness range
- Types of electrodes
- Joint design
- Weld consumable and welding process
- Welding parameters and technique
- Welding position
- Preheating
- Interpass temperatures and post weld heat treatment

For underwater welding, additional information is to be specified, if applicable, including water depth, pressure and temperature, product composition inside the chamber and the welding umbilical and equipment.

3.11 Weld Inspection

As part of the quality control program, a detailed plan for the inspection and testing of welds is to be prepared.

The physical conditions under which welding is to proceed, such as weather conditions, protection and the condition of welding surfaces are to be noted. Alterations in the physical conditions may be required should it be determined that satisfactory welding cannot be obtained.

Where weld defects exceed the acceptability criteria, they are to be completely removed and repaired. Defect acceptance criteria may be project-specific, as dictated by welding process, nondestructive testing resolution and results of fatigue crack growth analysis. The repaired weld is to be reexamined using acceptable nondestructive methods.

3.13 Tolerances and Alignments

The dimensional tolerance criteria are to be specified in developing the linepipe manufacturing specification. Inspections and examinations are to be carried out to ensure that the dimensional tolerance criteria are being met. Particular attention is to be paid to the out-of-roundness of pipes for which buckling is an anticipated failure mode. Structural alignment and fit-up prior to welding are to be monitored to ensure the consistent production of quality welds.

3.15 Corrosion Control Systems

The details of any corrosion control system employed for pipelines are to be submitted for review. Installation and testing of the corrosion control systems are to be carried out in accordance with the approved plans and procedures.

Where employed, the application and resultant quality of corrosion control coatings (external and internal) are to be inspected to ensure that specified methods of application are followed and that the finished coating meets specified values for thickness, lack of holidays (small parts of the structural surfaces unintentionally left without coating), hardness, etc. Visual inspection, micrometer measurement, electric holiday detection or other suitable means are to be employed in the inspection.

3.17 Concrete Weight Coatings

Weight coatings applied when onshore or, if applicable, when on the lay vessel are to be inspected for compliance with the specified requirements for bonding, strength and hardness, weight control and any necessary special design features. Production tests are to be carried out at regular intervals to prove compliance with the specifications.

3.19 Nondestructive Testing

A system of nondestructive testing is to be included in the fabrication and construction specification of pipelines. The minimum extent of nondestructive testing is to be in accordance with this Guide or a recognized design Code. All nondestructive testing records are to be reviewed and approved by ABS. Additional nondestructive testing may be requested if the quality of fabrication or construction is not in accordance with industry standards.

3.21 Fabrication Records

A data book of the record of fabrication activities is to be developed and maintained so as to compile as complete a record as is practicable. The pertinent records are to be adequately prepared and indexed in order to assure their usefulness, and they are to be stored in a manner that is easily recoverable.

As a minimum, the fabrication record is to include, as applicable, the following:

- Manufacturing specification and qualification procedures records
- Material trace records (including mill certificates)
- Welding procedure specification and qualification records
- Welder qualification
- Nondestructive testing procedures and operator's certificates
- Weld and nondestructive testing maps
- Shop welding practices
- Welding inspection records
- Fabrication specifications
- Structural dimension check records
- Nondestructive testing records
- Records of completion of items identified in the quality control program
- Assembly records
- Pressure testing records
- Coating material records
- Batch No., etc.
- Concrete weight coating mix details, cube test, etc.

The compilation of these records is a condition of certifying pipelines.

After fabrication and assembly, these records are to be retained by the Operator or Fabricator for future reference. The minimum time for record retention is not to be less than the greatest of the following:

- Warranty period
- Time specified in fabrication and construction agreements
- Time required by statute or governmental regulations

5 Inspection and Testing during Installation

This Subsection gives the specifications and requirements for the installation phase, covering route survey of pipelines prior to installation, installation manual, installation procedures, contingency procedures, as-laid survey, system pressure test, final testing and preparation for operation.

5.1 Specifications and Drawings for Installation

The specifications and drawings for installation are to be detailed and prepared giving the descriptions of and requirements for the installation procedures to be employed. The requirements are to be available in the design premise, covering the final design, verification and acceptance criteria for installation and system pressure test, records and integrity of pipelines. The drawings are to be detailed enough to demonstrate the installation procedures step-by-step. The final installation results are to be included in the drawings.

5.3 Installation Manual

Qualification of installation manual is specified in [1-4/13](#) of this Guide.

5.5 Inspection and Survey During Pipe Laying

Representatives from ABS are to witness the installation of pipelines to ensure that it proceeds according to approved procedures.

5.7 Final Inspection and Pressure Testing

A final inspection of the installed pipeline is to be completed to verify that it satisfies the approved specifications used in its fabrication and the requirements of this Guide. If the pipeline is to be buried, inspection will normally be required both before and after burial operations. As appropriate, additional inspections, which may include those for the proper operation of corrosion control systems, buckle detection by caliper pig or other suitable means, the testing of alarms, instrumentation, safety systems and emergency shutdown systems, are to be performed.

5.9 Inspection for Special Cases

Areas of pipelines may require inspection after one of the following occurrences:

- Environmental events of major significance
- Significant contact from surface or underwater craft, dropped objects or floating debris
- Any evidence of unexpected movement
- Any other conditions which might adversely affect the stability, structural integrity or safety of pipelines

Damage that affects or may affect the integrity of pipelines is to be reported at the first opportunity by the Operator for examination by ABS. All repairs deemed necessary by ABS are to be carried out to their satisfaction.

5.11 Notification

The Operator is to notify ABS on all occasions when parts of pipelines not ordinarily accessible are to be examined. If at any visit a Surveyor should find occasion to recommend repairs or further examination, this is to be made known to the Operator immediately in order that appropriate action may be taken.

7 In-service Inspection and Survey

The phases of operation include operation preparation, inspection, survey, maintenance and repair. During the operation condition, in-service inspections and surveys are to be conducted for pipelines. In-service inspections and surveys are to be planned to identify the actual conditions of pipelines for the purpose of integrity assessment. In-service inspection can be planned based on the following:

- At each Annual Survey, the records of maintenance are to be reviewed for compliance with the approved maintenance plan. The function of the safety protective devices is to be proven in order.
- Any subsea maintenance inspection carried out internally or externally of the pipeline is to be verified and reported by an ABS attending Surveyor.
- At each five (5) year interval, the complete maintenance records are to be reviewed and any major inspections, in accordance with the approved maintenance plans, are to be witnessed and reported by an ABS attending Surveyor.

9 Inspection for Extension of Use

Existing pipelines to be used at the same location for an extended period of time beyond the original design life are to be subject to additional structural inspection in order to identify the actual condition of the pipelines. The extent of the inspection will depend on the completeness of the existing inspection documents. Any alterations, repairs, replacements or installation of equipment since installation are to be included in the records.

The inspection schedule of the pipelines can be planned based on the requalification or reassessment of the systems applying, e.g., structural reliability methodology and incorporating past inspection records.



CHAPTER 1 Scope and Conditions of Classification

SECTION 6 Definitions

1 Classification

The term *Classification*, as used herein, indicates that an offshore installation has been designed, constructed, installed and surveyed in compliance with accepted Rules and Guides.

3 Constructor or Contractor

A *Constructor* or *Contractor* is any person or organization having the responsibility to perform any or all of the following: analysis, design, fabrication, inspection, testing, load-out, transportation and installation.

5 Extension of Use

An existing pipeline used at the same location beyond its original design life.

7 Maximum Allowable Operating Pressure

The *Maximum Allowable Operating Pressure* is defined as the design pressure less the positive tolerance of the pressure regulation system.

9 Offshore

Offshore is the area seaward of the established coastline that is in direct contact with the open sea.

11 Operator

An *Operator* is any person or organization empowered to conduct commissioning and operations on behalf of the Owners of pipelines.

13 Owner

An *Owner* is any person or organization who owns pipelines.

15 Pipeline

A *Pipeline* is a primarily horizontal pipe lying on, near or beneath the seabed, normally used for the transportation of hydrocarbon products between offshore production facilities or between a platform and a shore facility.

17 Pipeline System

A *Pipeline System* is an integrated set of subsea pipelines and flowlines, including pertinent instrumentation, foundations, coatings, anchors, etc.

19 Recurrence Period or Return Period

The *Recurrence Period* or *Return Period* is a specified period of time that is used to establish extreme values of random parameters, such as wave height, for design of pipelines.



CHAPTER 2 Materials and Welding

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CHAPTER 2 Materials and Welding

SECTION 1 Metallic Pipe

1 General

This Chapter specifies the linepipe material requirements, including steel pipes and other special metallic pipes used for pipeline applications. Material and dimensional standards for metallic pipe are to be in accordance with this Guide with respect to chemical composition, material manufacture, tolerances, strength and testing requirements. A specification is to be prepared stating the requirements for materials and for manufacture, fabrication and testing of linepipes, including their mechanical properties.

3 Selection of Materials

The linepipe materials used under this Guide are to be carbon steels, alloy steels or other special materials, such as titanium, manufactured according to a recognized standard. The materials are to be able to maintain the structural integrity of pipelines for hydrocarbon transportation under the effects of service temperature and anticipated loading conditions. Materials in near vicinity are to be qualified in accordance with applicable specifications for chemical compatibility.

The following aspects are to be considered in the selection of material grades:

- Mechanical properties
- Internal fluid properties and service temperature
- Resistance to corrosion effects
- Environmental and loading conditions
- Installation methods and procedure
- Weight requirement
- Weldability
- Fatigue and fracture resistance

Documentation for items such as formability, welding procedure, hardness, toughness, fatigue, fracture and corrosion characteristics is to be submitted for ABS review to substantiate the applicability of the proposed materials.

5 Steel Linepipe

The material, dimensional standards and manufacturing process of steel pipe are to be in accordance with API SPEC 5L, ISO 3183-1~3 or other recognized standards. Approval by ABS is required for the intended application with respect to chemical composition, material manufacture, tolerances, strength and testing requirements.

5.1 Chemical Composition

The chemical composition of linepipes, as determined by heat analysis, is to conform to the applicable requirements of the grade and type of steel material. However, the requirements of chemical composition may be agreed upon between the Operator and the linepipe manufacturer.

5.3 Weldability

The carbon equivalent (C_{eq}) and the cold cracking susceptibility (P_{cm}) for evaluating the weldability of steel pipes may be calculated from the ladle analysis, in accordance with the following equations (percentage of weight):

$$C_{eq} = C + \frac{Mn}{6} + \frac{Cr + Mo + V}{5} + \frac{Ni + Cu}{15}$$

$$P_{cm} = C + \frac{Si}{30} + \frac{Mn + Cu + Cr}{20} + \frac{Ni}{60} + \frac{Mo}{15} + \frac{V}{10} + 5B$$

Selection of C_{eq} and P_{cm} , as well as their maximum values, is to be agreed between the Operator and the steel mill when the steel is ordered to ensure weldability. When low carbon content is used for sour service, the value of the cold cracking susceptibility (P_{cm}) is to be limited. However, the behavior of steel pipe during and after welding is dependent on the steel, the filler metals used and the conditions of the welding process. Unless it can be documented otherwise, a testing program is to be performed to qualify candidate linepipe materials and filler metals.

5.5 Pipe Manufacturing Procedure

During the initial stages of manufacture of each item (after this called “first day production”), certain supplementary tests and qualification of manufacturing and testing facilities will be required in addition to the testing and inspection required during production of pipe. This testing and qualification is also to be done if there are any alterations in the manufacturing, testing or inspection procedures that might result in a detrimental change in pipe quality. No pipe will be accepted until first day production tools and qualifications are accepted.

The fabrication procedures are to comply with an approved standard pertinent to the type of pipe being manufactured. All nondestructive testing operations referred to in this Chapter are to be conducted by nondestructive testing personnel qualified and certified in accordance with standards such as ASNT SNT-TC-1A, ISO 9712 or other applicable codes.

The manufacturer is to prepare a manufacturing procedure specification for review by ABS. The manufacturing procedure specification is to document the forming techniques and procedures, welding procedures and welding testing, material identification, mill pressure testing, dimensional tolerances, surface conditions and properties to be achieved and verified. Pipes are to be selected from initial production for manufacturing procedure qualification through mechanical, corrosion and nondestructive testing.

Deepwater service requires the manufacture, inspection, testing and shipping of linepipes with minimum requirements as follows:

- The steel is to be fully killed and fine-grain.
- Plate is to be manufactured to a well-known and documented practice. All heat-treating facilities are to be equipped with instrumentation such that all temperatures can be controlled and recorded.
- All production welding is to be automatic.
- Pipe may be either non-expanded or cold expanded. Cold expanded pipe is not to exceed 2.0 percent maximum expansion, nor is it to exceed the amount of expansion used during first day production tests by more than 0.2 percent.
- Pipe may be cold compressed. Cold compressed pipe is not to exceed 2.0 percent maximum compression, nor is it to exceed the amount of compression used during first day production tests.
- The plates and/or pipe from each heat are to remain segregated during the entire manufacturing, testing, inspection and shipping process, as is practical.

5.7 Fabrication Tolerance

The fabrication tolerance may be agreed upon between the operator and the linepipe manufacturer, but is to be consistent with the design requirements. The pipes may be sized to their final dimensions by expansion and straightening. The pipes are to be delivered to the dimensions specified in the manufacturing procedure.

5.9 Fracture Arrest Toughness

Fracture toughness values for crack arrest given in ISO codes and API RP are adequate for design factors up to 72% and are given mainly for land-based pipelines. The acceptance criteria for fracture arrest toughness of offshore pipelines are to be agreed upon between the operator and linepipe manufacturer.

5.11 Mill Pressure Test

The mill test pressure and duration may be agreed upon between the Operator and the linepipe manufacturer, but it is to be consistent with the design requirements. The mill pressure test is to be conducted after final pipe expansion and straightening.

7 Linepipe Materials for Special Applications

This Subsection defines the minimum requirements for linepipe materials such as carbon steel, stainless steel, duplex, clad carbon steel and titanium alloy for extreme temperatures, sour service or other special applications.

7.1 Sour Service

Linepipe materials for sour (H_2S -containing) service are to satisfy the criteria of NACE MR0175 for resistance to sulfide stress cracking (SSC) and hydrogen-induced cracking (HIC) failures. Materials that are not listed in NACE MR0175 are to be tested according to procedures NACE TM0177 and NACE TM0284 for both materials and welds. The acceptance criteria are to be agreed upon between the Operator and the linepipe manufacturer based on the intended service condition

7.3 Stainless, Duplex and Super Duplex Stainless Steel Pipes

The chemical composition and the manufacturing of stainless steel pipes are to follow standards such as ASTM A790. The manufacturer is to establish the manufacturing procedure for the pipes, which is to contain relevant information about steel manufacturing, pipe manufacturing, welding and control methods which are to follow recognized standards such as API SPEC 5LC. Mechanical tests are to be performed after heat treatment, expansion and final shaping. Specific tests may be required to meet project requirements.

7.5 Clad Pipe

Clad pipes are to be compatible with the functional requirements and service conditions as specified for the project. Material dimensional standards and manufacturing process of clad steel pipe are to be in accordance with API SPEC 5LD or equivalent recognized standards.

7.7 Titanium Pipe

Specific compositional limits and tensile property minimums for titanium alloy tubular products may be produced in accordance with ASTM B861 and ASTM B862 specifications. Titanium alloys are highly corrosion-resistant to produced well fluid, including all hydrocarbons, acidic gases (CO_2 and H_2S), elemental sulfur and sweet and sour chloride brines at elevated temperatures. Titanium alloys are also generally resistant to well, drilling and completion fluids.

9 Marking, Documentation and Transportation

Pipes are to be properly marked for identification by the manufacturer. The marks are to identify the standard with which the product is in complete compliance, the size and weight designations, material grade and class, process of manufacture, heat number and joint number.

Pipe storage arrangements are to preclude possible damage, such as indentations of the surface and edges of pipes. Materials are to be adequately protected from deleterious influences during storage. The temperature and humidity conditions for storing weld filler material and coating are to be in compliance with those specified in their controlling material specification or manufacturer-supplied information.

Documentation for all materials of the major components of pipelines is to indicate that the materials satisfy the requirements of the pertinent specification. Material tests are to be performed to the satisfaction of ABS. Procedure for the transportation of the linepipes from the fabrication and coating yards to the offshore destination is to be established. Transportation of the pipes is to follow the guidelines of API RP 5L1 and API RP 5LW.



CHAPTER 2 Materials and Welding

SECTION 2 Pipe Components and Pipe Coating

1 General

The design of the pipeline includes various piping components. Specifications for each piping component and coating material used on a pipeline system are to be identified. The specifications are to be submitted to ABS for approval if the components have special service conditions or deviate from the standards indicated in this Guide or other comparable codes.

For valves, fittings, connectors and joints, if the wall thickness and yield strength between the adjoining ends are different, the joint design for welding is to be made in accordance with ASME B31.4, Figure 434.8.6(a)-(2), for liquid pipelines, or ASME B31.8, Appendix I, Figure I5, for gas pipelines.

The internal diameter of pipeline components is to be equal to that of the connecting pipeline sections. Consideration is to be given to effects of erosion at locations where the flow changes direction.

Seal design for valves, fittings and connectors is to take into account external hydrostatic pressure.

3 Piping Components

The piping components are to be suitable for the pipeline design conditions and be compatible with the linepipes in material, corrosion and welding.

3.1 Flanges

Pipe flanges used for offshore pipelines vary depending on the connection requirement subsea and at the surface to the platforms. Typical flange materials and dimensions are to follow ASME B16.5, API SPEC 17D, and MSS SP-44, where applicable. The flange design may be determined by calculations in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code.

3.3 Pipe Fittings

Pipe fittings are to match the design of the linepipes and flanges. Typical materials and dimensions are to follow ASME B16.9, B16.11, B16.25, MSS SP-75, and API SPEC 17D, where applicable.

3.5 Gaskets

Gaskets are to match the design of the flanges. Typical materials and dimensions are to follow ASME B16.20 and API SPEC 6A, where applicable.

3.7 Bolting

The bolting is to match the design of the flanges. Typical materials, dimensions and bolting torque are to follow ASME B16.5 and API SPEC 6A, where applicable.

3.9 Valves

The valves are to match the linepipes and flanges. Typical materials and dimensions are to follow ASME B16.34, API STD 600 and API SPEC 6D, ISO 14313 or equivalent codes or standards.

3.11 Subsea Tees

Subsea tees are to be of the extruded outlet, integral reinforcement type. The design is to be in accordance with ASME B 31.4, ASME B31.8 or equivalent codes or standards.

3.13 Y-pieces

Y-pieces and tees where the axis of the outlet is not perpendicular to the axis of the run are to be designed by finite element analysis.

3.15 Bends

Mitered bends are not permitted in offshore liquid and gas pipeline systems. Pipe that has been cold-worked solely for the purpose of increasing the yield strength to meet specified minimum yield strength is not allowed in offshore pipeline systems. Bends are to be made in such a manner as to preserve the cross-sectional shape of the pipe, and are to be free from buckling, cracks or other evidence of mechanical damage. The pipe diameter is not to be reduced at any point by more than 2.5% of the nominal diameter, and the completed bend is to be able to pass the specified sizing pig.

3.17 Piping Supports and Foundations

Piping support and foundation design is to follow the appropriate criteria of ASME B31.4 and API RP 2A-WSD.

Supporting elements, such as supports, braces and anchors for pipelines are to be designed in accordance with ASME B31.4 for liquid pipelines and ASME B31.8 for gas pipelines. No supporting elements are allowed to be welded directly to the pipeline except clamps, which are to fully encircle the pipe and be welded to the pipe by a full encirclement weld.

5 Pipe Coating

Specifications for corrosion protection coatings and concrete weight coating are to be submitted to ABS for approval if special service conditions exist. The weight coating specification is as a minimum to include:

- Chemical composition
- Physical and strength properties
- Quality control procedures and verifying tests for manufacturing or production

5.1 Corrosion Protection Coating

Corrosion protection coating materials are to be suitable for the intended use and consideration is to be given to:

- Corrosion protective properties
- Temperature resistance
- Adhesion and disbonding properties in conjunction with cathodic protection
- Mechanical properties
- Impact resistance
- Durability
- Shear strength
- Tensile strength
- Sea water resistance
- Water absorption
- Dielectric resistance

- Compatibility with cathodic protection system
- Resistance to chemical, biological and microbiological effects
- Aging, brittleness and cracking
- Variation of properties with temperature and time
- Health and safety information and instruction according to national regulations

The coating procedure is to be in compliance with appropriate standards and is to include the details of the pipe surface preparation, production parameters, material specifications, application and testing methods, including acceptance criteria, and details of cutback lengths and coating termination.

Before and after the coating application, inspection and testing are to be conducted by means of holiday detection to identify discontinuities or other defects that may impair its performance.

5.3 Weight Coating

Weight coating is, when applicable, to be applied to ensure vertical and horizontal on-bottom stability by providing negative buoyancy to the pipeline. The weight coating specification is to include:

- Mechanical properties, including strength, density, durability, etc.
- Cement materials or equivalent
- Reinforcement, including type, amount and grade
- Concrete coating method to achieve homogeneous and adequately consolidated coating
- Curing method compatible with coating application
- Repairs of uncured or hardened defective concrete coatings
- Storage, handling and transportation of coated pipe

Inspection and testing are to be carried out at regular intervals during weight coating application, and consideration is to be given to:

- Mix proportions and water-cement ratio
- Concrete density and compressive strength
- Weight before and after concrete application
- Outer diameter of coated pipe
- Water absorption
- Compatibility with corrosion protection coating

Stress concentration in the pipeline due to the weight coating is to be examined to avoid local damage in the form of buckling or fracture during handling and laying operations.

5.5 Insulation Coating

Thermal insulation coatings may be required for pipelines, spools, pipe-in-pipe systems and pipeline bundle systems to ensure flow assurance, in which case, a design and qualification program is to be submitted to ABS for review.

The thermal insulation design is to consider the coating material properties, including:

- Thermal conductivity
- Density
- Adhesion to base material
- Abrasion resistance

- Service pressure and temperature
- Impact resistance
- Creep
- Durability against chemical, physical or biological effects
- Water absorption
- Degradation during service

Inspection is to be conducted both during surface preparation and after coating application.

5.7 Field Joint Coating

Field joint coating is to be placed on the pipe joint after completion of the welding and weld testing. Installation, inspection and testing procedures for the field joint are to be developed and submitted to ABS.



CHAPTER 2 Materials and Welding

SECTION 3 Welding of Pipes and Piping Components

The welding of metallic pipes is to be performed in accordance with approved welding procedures that have been qualified to produce sound, ductile welds of adequate strength and toughness. Welding standards comparable to API STD 1104 and Section IX of the ASME Boiler and Pressure Vessel Code are to be employed in association with this Guide. For special pipe materials, the applicability of the API STD 1104 is to be examined and verified at all stages of welding, and any alternative methods are to be submitted for review.

Welders are to be tested in accordance with the welder qualification tests specified in recognized national codes, such as API STD 1104. Certificates of qualification are to be prepared to cover each welder when they are qualified by standards other than those of ABS, and such certificates are to be available for the reference of the Surveyors.

Before construction begins, details of the welding procedures and sequences are to be submitted for review. The details are to include:

- Base metal and thickness range
- Types of electrodes
- Edge preparation
- Electrical characteristics
- Welding technique
- Proposed position and speed
- Preheating and post-weld heat treatment practices

Welding procedures conforming to the provisions of an acceptable code may be qualified in the presence of the Surveyor, in accordance with the pertinent code. A written description of all pre-qualified procedures employed in the pipeline's construction is to be prepared and made available to the Surveyors.

When it is necessary to qualify a welding procedure, this is to be accomplished by employing the methods specified in an acceptable code, and in the presence of the Surveyor.



CHAPTER 2 Materials and Welding

SECTION 4 Corrosion Control

1 General

A corrosion control system analysis is to be performed to determine necessary protection measures and to provide in-service performance criteria and procedure for maintaining the system. The analysis is to be submitted to ABS for review and approval.

This Section recommends guidelines for the establishment of corrosion mitigation procedures for offshore pipelines. The following publications are incorporated by reference for the detection and mitigation of external and internal corrosion:

- ASME B31.4, Chapter VIII
- ASME B31.8, Chapter VI

3 Corrosion Control

3.1 External Corrosion Control

Adequate anti-corrosion coating and cathodic protection are to be provided for protection against external corrosion and may include a galvanic anode system, an impressed current system or both. Design considerations are to be given to:

- Pipe surface area
- Environmental conditions
- Suitability of galvanic anode systems under given marine environment
- Design life of galvanic anode systems
- How to minimize potential damage to the cathodic protection system during the lifecycle
- Interference of electrical currents from nearby structures
- Necessity of insulating joints for electrical isolation of portions of the system
- Inspection requirements for rectifiers or other impressed current sources

3.3 Internal Corrosion Control

Adequate measures are to be taken against internal corrosion. Proper selection of pipe material, internal coating, injection of a corrosion inhibitor or a combination of such options are to be considered.

When necessary, internal corrosion may be mitigated by the following:

- Running scrapers
- Dehydration
- Injection of corrosion inhibitors

- Use of bactericides
- Use of oxygen scavengers
- Use of internal coating compatible to the contents
- Use of corrosion resistant alloys

3.5 Corrosion Allowance

The selected pipe wall thickness is to include a corrosion allowance to account for internal and external corrosion during the service life of the pipe. Determination of the amounts of corrosion allowances is to take into account corrosion protection methods applied, corrosion-resistant properties of the linepipe material, the fluid corrosivity inside the pipe, chemical compositions of seawater, location of the pipeline, etc. The values of the allowances are to be submitted and agreed upon between the Designer/Owner and ABS. Guidance for estimating corrosion rates and allowances is given in Appendix 2.

The net thickness, which means that the thickness of the corrosion allowance is deducted from the nominal wall thickness ($t_{nominal} = t_{net} + \text{Corrosion Allowance}$), is to be used for the checks of hoop stress and hydrostatic collapse, as specified in Chapter 3, Section 5. For all other load cases involving longitudinal and radial stresses, the nominal wall thickness is to be used.

3.7 Monitoring and Maintenance of Corrosion Control Systems

Corrosion rate and the effect of anti-corrosion systems are to be evaluated by applying a monitoring program. Remedial actions are to be taken based on the evaluation results.



CHAPTER 3 Design

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CHAPTER 3 Design

SECTION 1 Design Requirements and Loads

1 General

This Section pertains to the identification, definition and determination of loads that are to be considered in the design of pipelines. Loads generally acting on pipelines are categorized into load classes and followed by more detailed descriptions in subsequent Sections, together with acceptance criteria for the utilization of the pipe strength. The criteria cover only the plane pipe, and for flanges and other connectors, other recognized standards such as the ASME Boiler and Pressure Vessel Code are to be used.

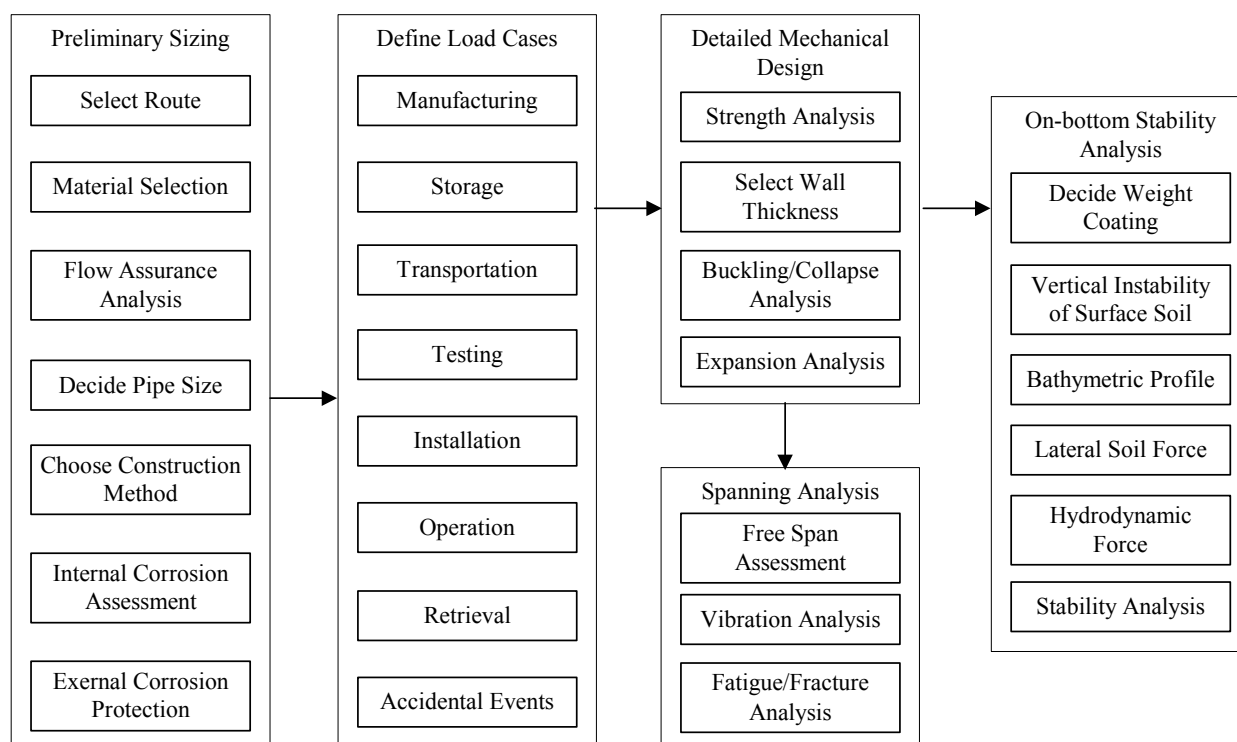
On commencement of the detailed engineering phase, a comprehensive quality plan is to be prepared, detailing the controls that will be implemented in the course of the design.

The quality plan is to set down the structure and responsibilities of the design team and outline procedures governing the assignment of design tasks, checking of work, document issues and tracking.

The design process is to be fully documented and supported by comprehensive calculations in which all assumptions are fully justified. A Design Report is to be prepared in which all data analysis, calculations and recommendations are clearly laid out. Document control procedures are to ensure the traceability of all documentation, drawings, correspondence and certification.

The design steps involved are illustrated in the design flowchart in 3-1/Figure 1.

FIGURE 1
Pipeline Design Flowchart



1.1 Regulations, Codes and Standards

International codes and standards pertinent to the design, manufacture, coating, welding and inspection of pipelines and ancillary flanges and fittings are listed in Appendix 4.

The Design Basis is the document that defines all of the data and conditions that are required for the design of the pipeline system. The document defines all codes and standards, Owner requirements, design criteria, environmental conditions, loads and safety factors.

1.3 Mechanical Design

The objective of mechanical design is to determine the wall thickness and material grade for the pipeline system, determined by application of flow assurance criteria. The governing codes are to be:

- ANSI B31.4 for production and water injection pipelines
- ANSI B31.8 for gas injection and gas export lines
- API RP 1111 “Design Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines”

The mechanical design of all subsea pipelines requires compliance with API 5L standard wall thickness criteria. Mechanical design is also to ensure the on-bottom stability of each pipeline under installed and operational conditions.

For each subsea pipeline, it is to be verified that the pipeline, as designed, is capable of withstanding all loads that may be reasonably anticipated over its specified design life. Imposed loads are to be classified as functional, environmental or constructional and may be continuous or incidental, unidirectional or cyclic in nature. Accidental loads are to be considered separately following review of risk factors for the particular development and are to be applied under agreed combinations with functional and environmental loads.

All potential external and internal loads are to be identified and load combinations developed to represent superposition that may occur within defined degrees of probability. In preparing load cases, the probable duration of an event (e.g., pipeline installation) is to be taken into account in the selection of concurrent environmental conditions. Extreme environmental events are unlikely to coincide, and therefore, the design process is to take caution to exclude unrealistic load combinations.

Pipelines are to be designed for the load combination that yields the most unfavorable conditions in terms of overall stress utilization. Usage factors are to be determined from referenced design codes. Usage factors are to differentiate between equivalent stresses stemming from the imposition of functional and environmental loading and those derived under installation or hydrotest conditions. Should the designated code make individual provision for conveyed fluid categorization, this is to be factored into the design equation. Due consideration is to be given to the potential effect of residual loads. Such loads are to be established, where feasible, from installation logbooks. Where an estimate of residual loading is necessary, this is to be done conservatively.

1.5 Load Case Definition

The subsea pipeline is to be designed to satisfy its functional requirements under loading conditions corresponding to the internal environment, external environment, system requirements and design service life.

All load cases for the pipeline are to include manufacturing, storage, transportation, testing, installation, operation, retrieval and accidental events.

The design of the pipeline is to be based on design load cases, which are to be defined in a project-specific Design Basis document. For a general definition of load cases, load combinations and load effects, refer to Subsection 3-1/5 or recognized codes and standards.

All of the load combinations and conditions are to be approved by ABS.

1.7 Wall Thickness Selection

Pipeline design pressures are to be as defined in the design basis. Design pressures are to be calculated from flow assurance and reservoir data. The following pressures are to be considered in the design as a minimum.

- Design wellhead shut-in pressure
- Design pressure
- Local design pressure
- Hydrotest pressure (at sea level)
- Leak test pressure (at sea level)
- Maximum allowable operating pressure (MAOP)
- Maximum incidental pressure
- Maximum allowable incidental pressure
- Mill test pressure

Pipeline wall thickness is to be determined on the basis of the local design pressure, defined as the internal pressure at any point in the pipeline system for the corresponding design pressure. The local pressure is to be taken as the design pressure at the reference height plus the static head of the transported medium due to the difference between the reference height and the height of the section being considered. The required pipeline wall thickness is also a function of pipeline material grade, diameter, water depth and installation methods.

1.9 Expansion Analysis

Analysis is to be performed to model and predict the effect of combined internal pressure and thermal gradient on the longitudinal expansion of the pipeline. Expansion analysis is to consider the most onerous load combinations to determine the greatest potential linear strain of the pipeline. Analysis is to model the surrounding soil properties, derive a representative seabed friction factor and assume a depth of burial based on the bearing properties of the soil.

The ability of a pipeline to accommodate the effects of pipeline expansion is a function of the pipeline length and the virtual anchor points at which expansion forces are balanced by mobilized soil friction. Where insufficient pipeline length is available along which to mobilize frictional resistance against expansion (such as in a short, high-temperature production line), a mechanical means of absorbing pipeline movement is to be designed, such as an expansion loop or offset.

Expansion offsets are to be modeled to accurately represent the physical boundary conditions including the resistance against movement mobilized by the soil. Both pipeline and riser growth are to be modeled, unless they are decoupled by the interposition of an interface structure. A finite element model is the preferred analytical method. Alternative methods may be considered upon presentation of a detailed justification of the technique proposed. Analysis of the spool piece is to consider the temperature profile along the pipeline and the pressure effects on expansion.

Design of a spool-piece or offset is to consider the implications of installation. Where an alternative means of introducing pipeline flexibility is feasible, this is to be explored, such that over-complexity of the subsea pipeline system is avoided.

1.11 Buckle Analysis

Subsea pipelines are susceptible to cross-section instability and collapse under a combination of bending moment and external pressure. A buckle initiated by mechanical damage or external pressure may propagate along the pipeline if the external pressure is greater than the propagation pressure for the pipeline. The pipeline is to be designed to withstand local buckling under the most severe conditions of combined external pressure and bending moment that is specified for installation and operation.

A buckling analysis is to be performed to determine the wall thickness of the pipeline that will be required to resist collapse. The analysis is to determine the collapse and buckling propagation pressures in accordance with 3-5/7, 3-5/9 and 3-5/11 of this Guide. The analysis is to consider the following key parameters:

- Pipeline diameter
- Wall thickness
- Linepipe ovality
- Material grade and yield strength
- Reduction in hoop compressive yield stress (caused by the manufacturing process)
- Maximum allowable bending strain (during installation and operation)

Where necessary, limitations on ovality may be specified to increase the pipeline's resistance to buckling.

The effects of plastic strains that may be imposed on the pipeline from reeled installation or from the stinger overbend during S-Lay are to be evaluated and considered in the analysis.

1.13 Buckle Arrestor Design

If the analysis demonstrates that the external pressure exceeds the pipeline propagation pressure, buckle arrestors are to be designed to arrest propagating buckles. A clear rationale for arrestor design is to be outlined, indicating required steps in the design and assumptions made. The use of any empirical correlations is to be fully documented and justified, indicating the limitations in validity of the data.

The economics of buckle arresting is to be considered in the design to arrive at a recommended buckle arrestor spacing. Determination of arrestor spacing is to compare the consequences of failure (replacement of the buckled section of pipe plus loss of use of the line) and the cost of manufacture and installation of buckle arrestors.

1.15 Fracture Analysis

All pipelines are to have inherent resistance against the initiation and propagation of brittle and ductile fracture. Safety against brittle fracture is to be governed principally by material conformance requirements, as detailed in industry-recognized standards.

1.17 On-Bottom Stability

The mechanical design of subsea pipelines is to ensure the stability of the pipeline on the seabed under extreme environmental loading conditions over the design life of the system. The pipeline is to be designed such that no movement from its installed location occurs, except by those defined limits covering lateral and vertical movement, thermal expansion and settlement. Permissible movements are to be determined, as defined under industry-recognized standards. It is to be adequately demonstrated that permissible movements will not adversely affect pipeline integrity, neither in the short nor long term. The following aspects are to be considered in the stability analysis:

- Hydrodynamic forces due to steady-state currents, loop currents, extreme wave action, turbidity currents, river plume effects, etc.
- Lateral soil forces
- Potential slope instability of the seabed due to geotechnical or geo-seismic mechanisms
- Vertical instability of the surface soil layers

All pipelines are to be negatively buoyant with a submerged weight sufficient to resist vertical uplift and to mobilize friction against lateral sliding. In the conduct of the design, it is to be recognized that permissible movements may vary along the length of the pipeline. The design is to adequately delineate any such zones and clearly state the assumptions made with regard to a particular portion of a pipeline's length. A dynamic method of analysis is to be used to define pipeline movements. The analysis is to use the most adverse combination of environmental conditions. Analysis is to consider directionality and a realistic variation in force incidence along the length of the pipeline. Stability analysis is to consider the pipeline under installation, testing and operational conditions.

Buried pipelines are to be constructed with adequate vertical stability such that sinking or floatation will be prevented or within a limit such that strength and stability criteria specified in Chapter 3, Sections 5 and 6 are not exceeded. The soil liquefaction potential may be assessed if anticipated along the route. The trenching and naturally backfilled soft clay soil may have the tendency to liquefy due to wave action on the seabed, and therefore, special attention is to be given.

Environmental criteria are to be defined according to the duration of a given condition. Assessment of stability under installation conditions (including hydrotest) is to be based on a 1-year return period. Stability verification for operational conditions is to be based on 100-year return period data.

Adequate soil investigation is to be carried out to enable accurate determination of lateral and longitudinal friction coefficients. Geotechnical investigation is to establish soil characteristics such as soil type, specific weight, particle size distribution and shear strength. Additional information is to be derived from geohazard evaluation, including a probabilistic seismic assessment and mass gravity flow assessment. Interpretation of geotechnical conditions along the proposed pipeline is to identify all significant changes in characteristics liable to influence the stability assessment of the pipeline.

In some cases, the use of concrete coating as a stability enhancement may not be appropriate. Should the potential for pipeline instability be identified in these cases, the following methods are to be considered:

- Increased pipe wall thickness
- Piled anchors
- Concrete saddles/gravity anchors
- Flexible concrete or artificial seaweed mattresses
- Grout bags
- Rock placement

Other methods may be proposed, provided they can be demonstrated to be feasible and cost-effective alternatives. Recommendations are to be presented for approval in the course of the detailed design before the design is finalized.

A full and detailed analysis of the proposed stability enhancement method is to be performed. In determining the degree of restraint, the following factors are to be considered.

- Method of load transfer between lateral restraint and pipeline
- Potential for flow-induced vibration between the restraint devices

1.19 Free Span Analysis

Seabed bathymetry profiles are to be used to perform a series of free span analyses. Assuming a uniform residual pipelay tension in combination with a representative bottom roughness profile, an estimate is to be made of the magnitude and potential distribution of free spans along the pipeline route. End support conditions are to be idealized and end slope conditions are to be taken into account in the free span analysis. Spans identified through this analysis are to be tabulated, characterized by span length, support separation, maximum span clearance and static stress levels.

In the water depth considered, vortex shedding will be considered to derive only from current effects. Assessment of free span under installation (including hydrotest) and operating conditions is to be based on 1-year return period and 100-year return period events, respectively.

A maximum allowable span length is to be determined by application of static and dynamic criteria. In performing static analysis, it is to be permissible to consider either allowable stress or strain criteria. A maximum static stress level is to be determined by calculation such that sufficient margin is made available under the operating condition to allow for dynamic excitation.

1.21 Vortex-Induced Vibration and Fatigue

Vortex shedding may be set up in a pipeline free span due to fluid flow effects around the pipe structure, resulting in potentially severe oscillation. The aim of the design is either to prevent oscillations or to demonstrate that those oscillations are acceptable in terms of the general serviceability of the pipeline, allowable stress levels and fatigue considerations. Analysis is to calculate critical current velocities for both cross-flow and in-line motion.

The natural frequency of the pipeline span is a function of the pipe stiffness, end conditions, length and effective mass. Using these parameters, the natural frequency of the pipe span is to be calculated. Calculations are to fully document the logic process used to model end pipe conditions, added mass factors, reduced velocity and stability parameter. A critical span length is to be calculated for each pipeline and the results are to be tabulated to show the limiting span in each case.

Critical span lengths are to be calculated based on the avoidance of in-line motion for the imposed design bottom current. It is to be demonstrated also that, with the selected limiting span length, cross-flow motion will not occur.

Fatigue evaluation is based on a Palmgren-Miner fatigue model, and the fatigue life of the pipeline is to be at least 10 times the specified service life. Prior to undertaking the fatigue analysis, an appropriate S-N curve may be proposed and utilized, provided a strong rationale for its application is given.

1.23 External Corrosion Protection Design

The subsea pipeline external corrosion is to be prevented by a combination of external anti-corrosion coating and the installation of sacrificial anodes. Sacrificial anodes are designed in accordance with the recognized codes.

3 Design Basis

The Design Basis is the document that defines all of the data and conditions that are required for the design of the subsea pipeline. The Design Basis defines all codes and standards, Owner's requirements, design criteria, environmental conditions, loads and safety factors that will be used for the design.

Design data is to be defined in the Design Premise/Design Basis Document. The Design Premise is to contain results of conceptual studies, environmental conditions, regulatory requirements and applicable codes and standards. Whenever possible, the input data (and any assumptions made where data is lacking) is to be agreed with the Owner or Designer, and any ambiguous or conflicting requirements are to be resolved prior to the design and initiation of engineering work.

As a minimum, the design is to be based on the parameters specified in 3-1/Tables 1 to 3. The list is to be expanded with any additional specific parameters which may impact the design.

Environmental data is to be related to months of the year or seasons. Loop current information is to be obtained for pipeline applications in areas subject to such events.

TABLE 1
Design Information for Pipelines

<i>Parameters</i>	<i>Comments</i>
Internal fluid parameters	All relevant internal fluid parameters are to be specified, including parameters in 3-1/Table 2. Internal pressure Temperature Fluid composition Service definition Fluid/flow description Flow rate parameters Thermal parameters
External environment	All relevant external parameters are to be specified, including parameters in 3-1/Table 3.
System description	Defined by Owner or Designer
Service life	Defined by Owner or Designer
Design load case definition	Defined by Owner or Designer
Design criteria	Defined by Owner or Designer
Analysis parameters	Defined by Owner or Designer

TABLE 2
Internal Fluid Parameters

<i>Parameters</i>	<i>Comments</i>
Internal pressure	Operating pressure or pressure profile through service life Maximum design pressure Minimum design pressure Maximum allowable operating pressure
Temperature	Operating temperature or temperature profile through service life Maximum design temperature Minimum design temperature
Fluid composition	All parameters that define service conditions Corrosive agents including organic acids, chlorides, etc. Injected chemical products including corrosion, hydrate and scale inhibitors and wax solvents
Service definition	Including partial pressure of CO ₂ and H ₂ S, and water content
Fluid/flow description	Fluid type and flow regime
Flow rate parameters	Flow rates, fluid density, viscosity
Thermal parameters	Fluid heat capacity

TABLE 3
Environment Parameters

<i>Parameter</i>	<i>Comment</i>
Location	
Water depth	Design water depth, water depth variations
Seawater data	Density, pH value, electronic resistance, salinity, minimum and maximum temperatures
Air temperature	Minimum, maximum and mean temperatures
Soil data	Description, shear strength, friction coefficients, densities
Marine growth	Maximum values and variations, marine growth density
Current data	Current as a function of water depth, direction and return period
Wave data	Significant and maximum waves, associated periods, wave spectra, scatter diagram, as a function of direction and return period
Tide Level	Highest/lowest astronomical tide, storm surge
Hydrodynamic Coefficients	For pipelines on the seabed or open trench

5 Definitions of Design Loads

Loads acting on pipelines can be divided into environmental, functional and accidental loads.

5.1 Environmental Loads

Environmental loads are defined as loads imposed directly or indirectly by environmental phenomena such as waves, current, ice and snow. In general, the environmental loads vary with time and include both static and dynamic components. The characteristic parameters defining environmental loads are to be appropriate to the operational phases, such as transportation, storage, installation, testing and operation. Environmental loads and load effects are further described in Chapter 3, Sections 3 and 6.

5.3 Functional Loads

Functional loads are defined by dead, live and deformation loads occurring during transportation, storage, installation, testing, operation and general use.

- *Dead loads* are loads due to the weight in air of principal structures (e.g., pipes, coating, anodes, etc.), fixed/attached parts and loads due to external hydrostatic pressure and buoyancy calculated on the basis of the still water level.
- *Live loads* are loads that may change during operation, excluding environmental loads which are categorized separately. Live loads will typically be loads due to the flow, weight, pressure and temperature of containment.
- *Deformation loads* are loads due to deformations imposed on pipelines through boundary conditions such as reel, stinger, rock berms, tie-ins, seabed contours, etc.

The functional loads are to be determined for each specific operation expected to occur during the pipeline life cycle and are to include the dynamic effects of such loads, as necessary. Load and load effects are further described in Chapter 3, Sections 3 and 6. In addition, extreme values of temperatures expressed in terms of recurrence periods and associated highest and lowest values are to be used in the evaluation of pipe materials.

5.5 Accidental Loads

Accidental loads are defined as loads that occur accidentally due to abnormal operating conditions, technical failure and human error. Examples are soil sliding, earthquakes, impacts from dropped objects, trawl board or collision. It is normally not necessary to combine these loads with other environmental loads unless site-specific conditions indicate such requirement. Dynamic effects are to be properly considered when applying accidental loads to the design. Risk-based analysis and past experience may be used to identify the frequency and magnitude of accidental loads. Accidental loads and load effects are further described in Chapter 3, Section 6.

Typical design loads may be categorized in accordance with 3-1/Table 4.

TABLE 4
Categorization of Design Loads for Pipelines

<i>Environmental Loads</i>	<i>Functional Loads</i>	<i>Accidental Loads</i>
Waves	Weight in air of:	Impacts from:
Current	- Pipe	- Dropped objects
Tides	- Coating	- Trawl board
Surge	- Anodes	- Collision
Marine growth	- Attachments	Soil sliding
Subsidence	- Etc.	Loss of floating installation station
Scours	Buoyancy	
Seafloor instability	Towing	
Seismic	External hydrostatic pressure	
Sea ice	Internal pressures:	
Soil liquefaction	- Mill pressure test	
Hygrothermal aging	- Installation	
	- Storage, Empty/water filled	
	- In-place pressure test	
	- Operation	
	Installation tension (pipes)	
	Installation bending (pipes)	
	Makeup (connectors)	
	Boundary conditions:	
	- Reel	
	- Stinger	
	- Tie ins	
	- Rock berms	
	- Seabed contours	
	- Etc.	
	Soil interaction	
	Loads due to containment:	
	- Weight	
	- Pressure	
	- Temperature	
	- Fluid flow, surge and slug	
	- Fluid absorption	
	Inertia	
	Pigging and run tools	



CHAPTER 3 Design

SECTION 2 Geotechnical Conditions

1 General

The seabed stiffness and soil friction definition where the contact pressure between pipes and seabed governs the friction force can generally describe the interaction between the seabed and the pipeline. The geotechnical conditions are an important part of establishing the pipe/soil interaction model for in-place analysis, which is further discussed in Chapter 3, Section 6.

3 Pipe Penetration in Soil

The penetration of a statically loaded pipe into soil can be calculated as a function of pipe diameter, vertical contact pressure, the undrained shear strength and submerged soil density. The circular form of pipelines leads to a combined effect of friction and bearing capacity resisting soil penetration.

In order to represent the soft nature of the seabed, a pressure/penetration relationship can be used to specify the pipeline's penetration as a function of the ground pressure (force per unit length of the pipeline).

5 Soil Friction

Bi-axial soil friction data are, when applicable, to be used for in-place analysis. Both pipeline penetration of the seabed and build up of loose sediments due to lateral movement may lead to extra lateral soil resistance. The degree of penetration/build up is dependent on the soil type and stiffness and is to be considered in the friction model.

7 Breakout Force

The breakout force is the maximum force needed to move a pipe from its stable position on the seabed. This force can be significantly higher than the force needed to maintain the movement after breakout, depending on the soil type and degree of penetration. Reasonable breakout forces are to be used in in-place analyses.

9 Soil Surveys

Seabed soil is to be sampled at appropriate intervals and locations along with the bathymetrical surveys. Normally, only the upper two meters are of interest for pipelines, with special attention paid to the top 10 cm, where accurate data will improve the stability evaluation.



CHAPTER 3 Design

SECTION 3 Environmental Effects

1 General

Design environmental conditions are to be defined by the operator, together with oceanographic specialists, and approved by ABS. All foreseeable environmental phenomena that may influence the pipeline integrity are to be described in terms of their characteristic parameters relevant to operational and strength evaluations.

Field and model-generated data are to be analyzed by statistical and mathematical models to establish the range of pertinent variations of environmental conditions to be employed in the design. Methods employed in developing available data into design criteria are to be described and submitted in accordance with [Chapter 1, Section 4](#). Probabilistic methods for short-term, long-term and extreme-value predictions employing statistical distributions are to be evidenced by relevant statistical tests, confidence limits and other measures of statistical significance. Hindcasting methods and models are to be fully documented. Due to the uncertainty associated with the definition of some environmental processes, studies based on a parametric approach may be helpful in the development of design criteria.

Generally, suitable environmental data and analyses will be accepted as the basis for designs when fully documented with sources, date and estimated reliability noted. For pipelines in areas where published design standards and data exist, such standards and data may be cited as reference.

3 Current

Current may be a major contributor to both static and dynamic loading on pipelines installed at any depth. The current velocity and direction profile at a given location may have several contributions, of which the most common are:

- Oceanic scale circulation patterns
- Lunar/astronomical tides
- Wind and pressure differential generated storm surge
- River outflow

The vector sum of all current components at specified elevations from the seafloor to the water surface describes the current velocity and direction profile for the given location. The current profile might be seasonally dependent, in which case, this is to be accounted for in the design.

For pipelines, it will be enough to know the current profile associated with extreme waves at a level near the seafloor. Normally, the current velocity and direction do not change rapidly with time and may be treated as time invariant for each sea state.

Onsite data collection may be required for previously unstudied areas and/or areas expected to have unusual or severe current conditions. If the current profile is not known from on-location measurements, but is judged not to be severe for the design, the current velocity at a given depth may be established using a velocity profile formulation. Current velocity profiles are to be based on site-specific data or recognized empirical relationships, and the worst design direction is to be assumed.

5 Waves

Waves are a major source of dynamic loads acting on pipelines located in shallow waters (normally less than 150 meters), and their description is therefore of high importance. Statistical site-specific wave data, from which design parameters are to be determined, are normally to include the frequency of occurrence for various wave height groups and associated wave periods and directions. For areas where prior knowledge of oceanographic conditions is insufficient, the development of wave-dependent design parameters is to be performed in cooperation with experienced specialists in the fields of meteorology, oceanography and hydrodynamics.

For a fully-developed sea, waves may be represented using the Bretschneider spectrum, while the JONSWAP spectrum normally will be applicable for less developed seas. In the calculation of spectrum moments, a proper cut-off frequency based on a project-defined confidence level is to be applied. Wave scatter diagrams can be applied to describe the joint probability of occurrence of the significant wave height and the mean zero-crossing period. Where appropriate, alternative traditional regular wave approaches may be used.

When dealing with extreme response estimations, the regular design wave heights are to be based on the maximum wave height of a given return period, e.g., 1, 10 or 100 years, found from long-term wave statistics. The estimation of the corresponding extreme wave period is, in general, more uncertain due to lack of reliable data, and it is consequently recommended that the wave period be varied over a realistic interval in order to ensure that all extreme wave cases have been considered. For systems with obvious unfavorable wavelengths and periods due to geometry or eigen-frequencies, the design wave period can be identified based on such criteria, while the wave height follows from breaking wave criteria or statistical considerations.

Long-term response statistics are to be applied in fatigue damage assessment whereby a scatter diagram of the joint probability of the sea state vector and the wave spectrum represents the wave climate defined by significant wave height, peak period and main wave direction. A simplified representation of the long-term distribution for the response may be based on the frequency domain method consisting of:

- Establishing an approximate long-term response distribution based on stochastic dynamic analyses
- Calculation of an approximate lifetime extreme response
- Identification of the design storm
- Estimation of lifetime maximum response based on time domain simulations

In analysis, a sufficient range of realistic wave periods and wave crest positions relative to pipelines are to be investigated to ensure an accurate determination of the maximum wave loads. Consideration is also to be given to other wave-induced effects such as wave impact loads, dynamic amplification and fatigue. The need for analysis of these effects is to be assessed on the basis of the configuration and behavioral characteristics of pipelines, the wave climate and past experience.

7 Combinations of Current and Waves

The worst combination of current and waves is to be addressed in the design. When current and waves are superimposed, the current velocity and direction are to be added as vectors to the wave-induced particle velocity and direction prior to computation of the total force, and where appropriate, flutter and dynamic amplification due to vortex shedding are to be taken into account.

For pipelines having small diameters compared to the wave lengths being considered, semi-empirical formulations such as Morison's equation are considered to be an acceptable basis for determining the hydrodynamic force acting on a pipe:

$$F = F_D + F_i$$

where

- | | | |
|-------|---|---|
| F | = | in-line component of hydrodynamic force per unit length along pipes |
| F_D | = | hydrodynamic drag force per unit length |
| F_i | = | hydrodynamic inertia force per unit length |

The drag force for a stationary pipe is given by:

$$F_D = \frac{1}{2} \rho \cdot OD \cdot C_D \cdot u_n \cdot |u_n|$$

where

- ρ = density of water
- OD = total external diameter of pipe, including coating, etc.
- C_D = drag coefficient
- u_n = component of the total fluid velocity vector normal to the axis of pipes

The inertia force for a stationary pipe is given by:

$$F_i = \rho \cdot \left(\frac{\pi \cdot OD^2}{4} \right) \cdot C_M \cdot a_n$$

where

- C_M = inertia coefficient based on the displaced mass of fluid per unit length
- a_n = component of the total fluid acceleration vector normal to the axis of pipes

The lift force for a stationary pipe located on or close to the seabed is given by:

$$F_L = \frac{1}{2} \rho \cdot C_L \cdot u_n^2 \cdot OD$$

where

- F_L = lift force per unit length
- C_L = lift coefficient

For pipelines located on or close to the seabed, the hydrodynamic force coefficients C_D , C_M and C_L will vary as a function of the gap.

9 Tides

Tides, when relevant, are to be considered in the design of pipelines. Tides may be classified as lunar or astronomical tides, wind tides and pressure differential tides. The combination of the latter two is defined as “storm surge” and the combination of all three as “storm tide”. The water depth at any location consists of the mean depth, defined as the vertical distance between the seabed and an appropriate near-surface datum, and a fluctuating component due to astronomical tides and storm surges. The highest and the lowest astronomical tide bound the astronomical tide variation. Still-water level is to be taken as the sum of the highest astronomical level plus the storm surge. Storm surge is to be estimated from available statistics or by mathematical storm surge modeling.

11 Marine Growth

Marine growth may accumulate and is to be considered in the design of pipelines. The highest concentrations of marine growth will generally be seen near the mean water level with an upper bound given by the variation of the daily astronomical tide and a lower bound, dependent on location. Estimates of the rate and extent of marine growth may be based on past experience and available field data. Particular attention is to be paid to increases in hydrodynamic loading due to the change of:

- External pipe diameter
- Surface roughness
- Inertial mass
- Added weight

Consideration is also to be given to the fouling effects likely on corrosion protection coatings.

13 Subsidence

The effects of seafloor subsidence are to be considered in the overall design when pipelines are installed in areas where unique geological conditions exist. This will be an area where, for example, significant seafloor subsidence could be expected to occur as a result of depletion of the subsurface reservoir. The magnitude and time scale of subsidence are in such cases to be estimated based on geologic studies.

15 Scours

The seafloor contours in installation areas may change considerably over time due to scour erosion, which is removal of soil due to current and waves caused either by natural geological processes or by structural elements interrupting the flow regime near the seafloor. When applicable, the magnitude and time scale of scour erosion is to be estimated based on geologic studies and its impact on design appropriately accounted for. When the magnitude of scour erosion makes it difficult to account for in design, a proper survey program and routines for evaluating observed seafloor changes is to be established.

17 Seafloor Instability

Seafloor instability may be seen under negligible slope angles in areas with weak, under-consolidated sediments. Movements of the seafloor may be activated as a result of loads imposed on the soil due to pipeline installation, change in pipeline operating conditions, wave pressure, soil self weight, earthquakes or combinations of these phenomena. When applicable, such areas are to be localized by proper surveys and precautions such as rerouting taken in the design.

19 Seismic

The seismic activity level for the pipeline installation area is to be evaluated based on previous records or detailed geological investigations. For pipelines located in areas that are considered seismically active, the effects of earthquakes are to be considered in the design. An earthquake of magnitude that has a reasonable likelihood of not being exceeded during the design life is to be used to determine the risk of damage, and a rare intense earthquake is to be used to evaluate the risk of structural failure. These earthquake events are referred to as Strength Level and Ductility Level earthquakes, respectively. The magnitudes of the parameters characterizing these earthquakes, having recurrence periods appropriate to the design life of the pipelines, are to be determined. The effects of earthquakes are to be accounted for in the design, but generally need not be taken in combination with other environmental factors.

The strength level and ductility level earthquake-induced ground motions are to be determined on the basis of seismic data applicable to the installation location. Earthquake ground motions are to be described by either applicable ground motion records or response spectra consistent with the recurrence period appropriate to the design life of pipelines. Available standardized spectra applicable to the region of the installation site are acceptable, provided such spectra reflect site-specific conditions affecting frequency content, energy distribution and duration. These conditions include the type of active faults in the region, the proximity to the potential source faults, the attenuation or amplification of ground motion and the soil conditions.

The ground motion description used in design is to consist of three components corresponding to two orthogonal horizontal directions and the vertical direction. All three components are to be applied to pipelines simultaneously.

As appropriate, effects of soil liquefaction, shear failure of soft mud and loads due to acceleration of the hydrodynamic added mass by the earthquake, mud slide, tsunami waves and earthquake-generated acoustic shock waves are to be accounted for in the design.

21 Sea Ice

Arctic pipelines in shallow water can be damaged by grounded ice which drags along the seabed and cuts gouges that can be several meters deep. The intensity of gouging depends on the interaction between the ice climate, wind, water depth, the local topography of the bottom and the seabed geotechnics. Severe deformation of the seabed extends below the bottom of the gouge so that a pipeline can be damaged even though the ice passes above it.

More details about conditions that are to be addressed in design and construction for arctic and sub-arctic offshore regions can be found in API RP 2N.

23 Environmental Design Conditions

In this Guide, the combination of environmental factors producing the most unfavorable effects on pipelines as a whole, and as defined by the parameters given above, is referred to as the Environmental Design Conditions.

The combination and severity of environmental conditions for use in design are to be appropriate to the pipelines and consistent with the probability of simultaneous occurrence of the environmental phenomena. It is to be assumed that environmental phenomena may approach pipelines from any direction unless reliable site-specific data indicate otherwise. The direction, or combination of directions, which produces the most unfavorable effects on pipelines is to be accounted for in the design, unless there is a reliable correlation between directionality and environmental phenomena.

When applicable, it is recommended that at least the following environmental conditions be covered by pipeline analyses.

23.1 Normal Operating Condition with Pipeline in the Normal Intact Status

- i) Worst combination of 1-year wind, wave, current and tide
- ii) Environmental condition of 100-year return waves plus 10-year return current
- iii) Environmental condition of 10-year return waves plus 100-year-return current
- iv) Realistic values for marine growth
- v) Realistic values for loads due to sea ice
- vi) Realistic values for earthquakes

23.3 Temporary Condition

The following are to be checked as temporary conditions:

- i) *Transportation condition*
Geometrical imperfections, such as dents and out-of-roundness introduced by loads applied during transportation, are to be considered.
- ii) *Installation/retrieval condition*
Varying amount deployed
Filled with air or water
Environmental condition of 1-year wave and current or reliable weather forecasts
- iii) *System pressure test*
Loads (especially pressure loads) during system pressure test.
- iv) *Shut-down and start-up*
The fatigue evaluation is to include loads induced by shutdown and startup.
- v) *Pigging condition*
Loads induced by pigging operations are to be considered.

23.5 Abnormal/Accidental Operating Condition

Impacts and soil sliding conditions are to be checked, when applicable.

23.7 Fatigue

Adequate loading conditions are to be used for fatigue load effect analysis, including:

- i)* Significant wave
- ii)* Vortex-induced vibrations
- iii)* Cyclic loading induced during installation and operation
- iv)* Thermal stresses induced during processing and operation



CHAPTER 3 Design

SECTION 4 Flow Assurance Analysis

1 General

Flow assurance analysis is not subjected to ABS review. However, reports for a full thermal-hydraulic analysis may be required by ABS as supporting documents. The thermal-hydraulic analysis is to determine the optimum size of the subsea pipelines and to predict pipeline temperature and pressure profiles, flow regimes and liquid holdups in steady state and transient conditions.

3 Pipeline Sizing/Steady State Analysis

Sizing of subsea pipelines is to be carried out with the aid of hydraulic analysis. Initial sizing may be performed using hand calculations or a suitable computer program, but a validated computer program appropriate to the type of fluid flow and conditions being considered is always to confirm final sizing.

Although hydraulic considerations usually decide the size of a pipeline and associated connected systems, a number of non-hydraulic criteria may have an effect and are to be considered. Some of the criteria are:

- Riser design (the requirement for constant inner diameter)
- Standard pipe sizes
- Fluid velocity control
- Piggability

5 Fluid Phase Definition

Fluid phase behavior is to be determined from the flow analysis and phase envelopes are to be developed for the produced fluids. The information is to be used for hydrate and wax deposition analyses.

7 Pressure and Temperature Profile

Pressure and temperature profiles are to be established for the single phase (gas or liquid) and multi-phase risers. The prediction of flow rate and pressure drop in multi-phase pipelines is not as accurate as for the single-phase lines and the same applies to the prediction of liquid holdup and slug sizes. The sensitivity of the pipeline diameter selection is to be investigated, and consideration is to be given to selection of a smaller or larger diameter to accommodate the uncertainties in the calculations.

9 Transient Analysis

A variety of transient thermal-hydraulic analyses may be needed for the complete design and optimization of a production system. These include:

- Riser and pipeline warm-up and cool-down
- Startup and shutdown fluid flow rates and flow stabilization time
- Pigging
- Slugging

11 Surge Analysis

A surge analysis may be required to predict the behavior of the flowing fluids if slugs are present in the line and during emergency shutdowns.

13 Heat Transfer/Insulation Design

The subsea pipeline will require flow path insulation to retain fluid temperature and/or to increase cool-down times during short-term shut-in conditions. The insulation may be solid material, foam or syntactic foam. The insulation material properties are to be reviewed against hydrostatic collapse.

The heat transfer calculations are to take into consideration reduction of insulating properties due to reduction of insulating layer thickness (caused by hydrostatic pressure, installation loads, etc.), absorption of water and aging.

15 Hydrate Mitigation

Hydrate formation is a potential problem in pipelines that contain gas and free water. System design has to ensure that the conditions in the riser cannot lead to hydrate formation. This is normally achieved by either keeping the pipeline warm and/or by injecting methanol or glycol in the riser/pipeline system. The design is also to cater for shutdown conditions when considering hydrate formation.

17 Wax Deposition

Some crude oils contain significant proportions of paraffin compounds which will start to crystallize if the temperature of the oil drops sufficiently. This can result in wax deposition on the walls of the pipeline and may result in restricted flow or blockage. System design is to ensure that the required throughput of the pipeline system can be maintained and that it can be restarted after a shutdown. Several methods of wax deposit mitigation must be considered, including:

- Insulation and/or burial to maintain higher temperature
- Use of chemical additives to reduce wax deposition or pressure loss in the pipeline system



CHAPTER 3 Design

SECTION 5 Strength and Stability Criteria

1 General

This Section defines strength and stability criteria which are to be applied as limits for the design of subsea metallic pipelines. The criteria are applicable for wall-thickness design as well as installation and in-place analyses. Alternative strength criteria based on recognized codes/standards, mechanical tests or advanced analysis methods such as listed in the Appendices may be applied in the design based on approval by ABS. If alternative strength criteria are applied in the design, consistency is to be maintained.

The strength criteria listed in this Section follow a working stress design approach and cover the following failure modes:

- Yielding
- Local buckling
- Global buckling
- Fatigue
- Cross sectional out-of-roundness

3 Stress Criteria for Metallic Gas Transportation Pipelines

3.1 Hoop Stress Criteria

In selecting the wall-thickness of gas transportation pipe, consideration is to be given to pipe structural integrity and stability during installation and operation, including pressure containment, local buckling/collapse, global buckling, on-bottom stability, protection against impact loads and free span fatigue, as well as high temperature and uneven seabed-induced loads.

The internal pressure containment requirements often used as a basis for wall-thickness design are:

$$\sigma_h \leq \eta_h \cdot SMYS \cdot k_T$$

where

- | | | |
|------------|---|---|
| σ_h | = | hoop stress |
| $SMYS$ | = | Specified Minimum Yield Strength of the material |
| k_T | = | temperature dependent material strength de-rating factor, as specified in Table 841.116A of ASME B31.8. |
| η_h | = | 0.72, hoop stress usage factor |

The hoop stress σ_h for pipes is to be determined by:

$$\sigma_h = \frac{(p_i - p_e) \cdot (D - t)}{2 \cdot t}$$

where

- p_i = internal design pressure
- p_e = external design pressure
- D = nominal outside steel diameter of pipe
- t = net wall thickness, as specified in 2-4/3.5

For thick walled pipes with a $D/t < 20$, the above hoop stress criteria may be adjusted based on BSI BS 8010-3, for example.

3.3 Longitudinal Stress

To ensure structural integrity against longitudinal forces, the following longitudinal stress criteria are to be satisfied:

$$\sigma_\ell \leq \eta_\ell \cdot SMYS$$

where

- σ_ℓ = longitudinal stress
- $SMYS$ = Specified Minimum Yield Strength of the material
- η_ℓ = 0.8, longitudinal stress usage factor

3.5 Von Mises Combined Stress

The von Mises combined stress, also referred to as the stress intensity, is at any point in the pipe to satisfy the following:

$$\sigma_e = \sqrt{\sigma_\ell^2 + \sigma_h^2 - \sigma_\ell \cdot \sigma_h + 3 \cdot \sigma_{\ell h}^2} \leq \eta_e \cdot SMYS$$

where

- σ_e = Von Mises combined stress
- σ_ℓ = longitudinal normal stress
- σ_h = hoop stress (normal stress circumference direction)
- $\sigma_{\ell h}$ = shear stress due to shear force and torsional moment
- η_e = 0.9, usage factor for combined stress

Note: Nominal pipe wall thickness, as specified in 2-4/3.5, is to be used in the calculations of the principal stresses σ_ℓ , σ_h , and $\sigma_{\ell h}$.

5 Stress Criteria for Metallic Liquid Transportation Pipelines

5.1 Hoop Stress Criteria

In selecting the wall-thickness of liquid transportation pipe, consideration is to be given to pipe structural integrity and stability during installation and operation, including pressure containment, local buckling/collapse, global buckling, on-bottom stability, protection against impact loads and free span fatigue, as well as high temperature and uneven seabed induced loads.

The internal pressure containment requirements often used as a basis for wall-thickness design are:

$$\sigma_h \leq \eta_h \cdot SMYS$$

where

- σ_h = hoop stress
- $SMYS$ = Specified Minimum Yield Strength of the material
- η_h = 0.72, hoop stress usage factor

The hoop stress σ_h for pipes is to be determined by:

$$\sigma_h = \frac{(p_i - p_e) \cdot (D - t)}{2 \cdot t}$$

where

- p_i = internal or external design pressure
- p_e = external design pressure
- D = nominal outside steel diameter of pipe
- t = net wall thickness, as specified in 2-4/3.5

For thick walled pipes with a $D/t < 20$, the above hoop stress criteria may be adjusted based on, e.g., BSI BS 8010-3.

5.3 Longitudinal Stress

To ensure structural integrity against longitudinal forces, the following longitudinal stress criteria are to be satisfied:

$$\sigma_\ell \leq \eta_\ell \cdot SMYS$$

where

- σ_ℓ = longitudinal stress
- $SMYS$ = Specified Minimum Yield Strength of the material
- η_ℓ = 0.8, longitudinal stress usage factor

5.5 Von Mises Combined Stress

The combined stress, also referred to as the stress intensity, is at any point in the pipe to satisfy the following:

$$\sigma_e = \sqrt{\sigma_\ell^2 + \sigma_h^2 - \sigma_\ell \cdot \sigma_h + 3 \cdot \sigma_{\ell h}^2} \leq \eta_e \cdot SMYS$$

where

- σ_e = Von Mises combined stress
- σ_ℓ = longitudinal normal stress
- σ_h = hoop stress (normal stress circumference direction)
- $\sigma_{\ell h}$ = shear stress due to shear force and torsional moment
- η_e = 0.9, usage factor for combined stress

Note: Nominal pipe wall thickness, as specified in 2-4/3.5, is to be used in the calculations of the principal stresses σ_ℓ , σ_h , and $\sigma_{\ell h}$.

7 Global Buckling

Internal overpressure and increased operating temperatures may aggravate build up of compressive forces in a pipeline, which after start-up or after repeated start-up/shut-down cycles, may lead to global buckling of the pipeline. This effect is to be explicitly dealt with in the design, either by advanced analysis predicting the position and amplification of buckles or by demonstrating that the build-up of compressive force is less than the force needed to initiate global buckling.

9 Local Buckling/Collapse for Metallic Pipelines

9.1 Collapse Under External Pressure

The characteristic buckling pressure can be calculated based on:

$$p_c = \frac{p_{el} p_p}{\sqrt{p_{el}^2 + p_p^2}}$$

where

$$p_{el} = \frac{2 \cdot E}{1 - \nu^2} \cdot \left(\frac{t}{D} \right)^3 \quad \text{elastic buckling pressure}$$

$$p_p = SMYS \cdot \frac{2 \cdot t}{D} \quad \text{yield pressure at collapse}$$

$SMYS$ = Specified Minimum Yield Strength

E = Young's Modulus

ν = Poisson's ratio, 0.3 for steel pipelines

In the calculation of elastic buckling pressure (p_{el}), the wall thickness is to be the net thickness of the pipe wall, as specified in 2-4/3.5.

The pipeline is not considered to collapse if the minimum differential pressure on the pipe satisfies the following:

$$(p_e - p_i) \leq \eta_b p_c$$

where

p_e = external pressure

p_i = internal pressure

η_b = buckling usage factor

0.7 for seamless or ERW pipe

0.6 for cold expanded pipe

9.3 Local Buckling/Collapse under External Pressure and Bending

For installation and temporary conditions where the pipe may be subjected to external overpressure, cross sectional instability in the form of local buckling/collapse is to be checked. For pipes with a D/t less than 50 and subjected to external overpressure combined with bending, the following strain check is to be applied:

$$\frac{\varepsilon}{\varepsilon_b} + \frac{p_e - p_i}{p_c} \leq g(f_0)$$

where

ε = bending strain in the pipe

ε_b = $\frac{t}{2D}$, buckling strain under pure bending

p_e = external pressure

p_i = internal pressure

f_0 = out-of-roundness, $(D_{\max} - D_{\min})/D$, not to be taken less than 0.5%

$g(f_0)$ = $(1 + 10f_0)^{-1}$, out-of-roundness reduction factor

An out-of-roundness higher than 3% is not allowed in the pipe without further analysis considering collapse under combined loads, propagating buckling and serviceability of the pipe.

11 Propagating Buckles

During installation or, in rare situations, shutdown of pipelines, local buckles/collapse may start propagating along the pipe with extreme speed driven by the hydrostatic pressure of seawater. Buckle arrestors may be used to stop such propagating buckles by confining a buckle/collapse failure to the interval between arrestors. Buckle arrestors may be designed as devices attached to or welded to the pipe or they may be joints of thicker pipe. Buckle arrestors will normally be spaced at suitable intervals along the pipeline for water depths where the external pressure exceeds the propagating pressure level.

Buckle arrestors are to be used when:

$$p_e - p_i \geq 0.72 \cdot p_{pr}$$

where

$$p_{pr} = 6 \cdot SMYS \cdot \left(\frac{2 \cdot t}{D} \right)^{2.5} \quad \text{buckle propagation pressure}$$

When required, buckle arrestors are to be designed according to recognized codes, such as API RP 1111.

13 Fatigue for Metallic Pipelines

Pipelines may be subjected to fatigue damage throughout their entire life cycle. The main causes of fatigue failure are normally effects of:

- Installation
- Startup and shutdown cycles
- Wave and current conditions

The fatigue life may be predicted using an S-N curve approach and Palmgren-Miner's rule. The fatigue life is not to be less than ten (10) times the service life for the pipeline, as specified in Section 4 of *ABS Guide for Fatigue Assessment of Offshore Structures*. This implies for the fatigue equations listed in this Guide that the maximum allowable damage ratio η is not to be taken higher than 0.1. A value higher than 0.1 may be accepted if documentation for inspection, improvement in welding, workmanship is provided and accepted by ABS.

Typical steps required for fatigue analysis using the S-N approach are outlined below.

- i) Estimate long-term stress range distribution
- ii) Select appropriate S-N curve
- iii) Determine stress concentration factor
- iv) Estimate accumulated fatigue damage using Palmgren-Miner's rule

$$D_{fat} = \sum_{i=1}^{M_c} \frac{n_i}{N_i} \leq \eta$$

where

$$\begin{aligned} D_{fat} &= \text{accumulated fatigue damage} \\ \eta &= \text{usage factor for allowable damage ratio} \\ N_i &= \text{number of cycles to failure at the } i\text{-th stress range defined by the S-N curve} \\ n_i &= \text{number of stress cycles with stress range in block } i \end{aligned}$$

The maximum allowable damage ratio may be relaxed if detailed analysis based on fracture mechanics or reliability-based calibration demonstrates that the target safety level is fulfilled with a higher allowable damage ratio. Also, documentation demonstrating detailed fatigue inspection and planning may lead to the acceptance of a higher allowable damage ratio. The use of and documentation for using a higher allowable damage ratio is to be submitted to and approved by ABS.

ABS-(A) offshore S-N curves defined in Section 3, Figure 1 of the *ABS Guide for the Fatigue Assessment of Offshore Structures* are to be applied using only the parameters “A”, “m” and “C” for all cycles. Appendix 1 of the *ABS Guide for the Fatigue Assessment of Offshore Structures* is to be used for the selection of the different structural welding details.

Fatigue assessment may be based on nominal stress or hot-spot stress. When the hot spot stress approach is selected, stress concentration factors due to misalignment (for example), are to be estimated using appropriate stress analysis or stress concentration factor equations.

15 Out-of-roundness

Out-of-roundness in this Guide is defined as $(D_{\max} - D_{\min})/D$. Out-of-roundness may occur in the manufacturing phase, during transportation, storage, installation and operation. Out-of-roundness may aggravate local buckling or complicate pigging and is to be considered. If excessive cyclic loads is expected during installation and operation, it is recommended that out-of-roundness due to through-life cyclic loads be simulated, if applicable.

17 Allowable Stresses for Supports and Restraints

Maximum allowable shear and bearing stresses in structural supports and restraints are to follow applicable ABS Rules, AISC ASD Manual of Steel Construction, API RP 2A-WSD or alternatively recognized Rules or standards.

19 Installation

During installation when the pipe is fully supported on the lay vessel, relaxed criteria in the form of maximum allowable strain, e.g., may be applied when documentation for the criteria is submitted and approved by ABS.



CHAPTER 3 Design

SECTION 6 Pipeline Rectification and Intervention Design

1 General

This Section covers on-bottom stability and global buckling requirements for seabed intervention design related to pipes. The basic seabed intervention design may be performed using simple design equations, while more challenging design scenarios often will require a more advanced approach, such as the finite element method.

3 In-place Analysis

The in-place model is to be able to analyze the in-situ behavior of a pipeline over the through-life load history. The through-life load history consists of several sequential load cases, such as:

- Installation
- Testing (water filling and system pressure test)
- Operation (content filling, design pressure and temperature)
- Shut down and cool down cycles
- Storage

3.1 Parameters and Procedures for In-place Analysis

When performing in-place analyses, static and dynamic loads are to be applied, as applicable.

Static analyses are to be performed, when applicable, to handle nonlinearity from large-displacement effects, material nonlinearity and boundary nonlinearity, such as contact, sliding and friction (pipe/seabed interaction).

Dynamic analyses may be used in the study of nonlinear dynamic responses of pipes. General nonlinear dynamic analysis uses implicit integration of the entire model to calculate the transient dynamic response of the system. Implicit time integration is to be applied where a set of simultaneous nonlinear dynamic equilibrium equations is to be solved at each time increment.

When applicable, geometrical nonlinearity is to be accounted for in the model. The instantaneous (deformed) state of the structure is to be updated through the analysis. This is especially important when performing dynamic analysis of pipes subjected to wave loading. By including geometrical nonlinearity in the calculation, a finite element program will use the instantaneous coordinates (instead of the initial) of the load integration points on the pipe elements when calculating water particle velocity and acceleration. This ensures that even if some parts of the pipeline undergo extreme lateral displacements, the correct drag and inertia forces will be calculated on each of the individual pipe elements that make up the pipeline.

3.3 Modal Analysis

The aim of the modal analysis is to calculate the natural frequencies and corresponding mode shapes.

In order to obtain natural frequencies, modal shapes and associated normalized stress ranges for the possible modes of vibrations, a dedicated finite element program is to be used, and as a minimum, the following aspects are to be considered:

- i) Flexural behavior of the pipeline is modeled, considering the bending stiffness and the effect of axial force.
- ii) Effective axial force that governs the bending behavior of the span is to be taken into account.
- iii) Interaction between a spanning pipe section and pipe lying on the seabed adjacent to the span is to be considered.

Due consideration to points *i)* and *ii)* above is to be given in both single-span and multiple-span modal analyses.

The axial effective force, i.e., the sum of the external forces acting on the pipe, is also to be accounted for. It is noted that the effective force may change considerably during the various phases of the design life.

It is important to ensure that a realistic load history is modeled prior to performing the modal analyses.

3.5 Location Fixity

The pipeline is to be designed with a specified tolerance of movement from its as-installed position. An analysis to determine that the anchoring arrangements, soil strength and friction coefficient will limit the pipeline movement to the specified tolerance is to be performed.

The types of pipeline movements to be considered include horizontal movement caused by current and wave forces, vertical movement caused by hydrodynamic lift on the pipeline, either positive or negative vertical movements caused by loss of strength of the supporting or overburden soil and earthquake-induced effects.

3.7 High Pressure/High Temperature

Design of high pressure/high temperature pipes is to consider global buckling due to thermal and internal pressure induced expansion.

5 On-bottom Stability

Unless accounted for in the design, pipelines resting on the seabed, trenched or buried, are not to move from their as-installed position under even extreme environmental loads. The lateral stability of pipelines may be assessed in design using two-dimensional static or three-dimensional dynamic analysis methods.

The submerged weight of the pipe is to be established based on the on-bottom stability calculations, which will have a direct impact on the required pipe-lay tensions, installation stresses and pipe configuration on the sea-bottom.

Properly performed stability analysis, performed in accordance with, e.g., AGA L51698, will in general be acceptable to ABS.

5.1 Static Stability Criteria

Lateral stability criteria employ a simplified stability analysis based on a quasi-static balance of forces acting on the pipe. The lateral stability analysis method may be defined as below:

$$\gamma(F_D - F_i) \leq \mu(W_{sub} - F_L)$$

where

F_D	=	hydrodynamic drag force per unit length
F_i	=	hydrodynamic inertia force per unit length
F_L	=	hydrodynamic lift force per unit length
W_{sub}	=	submerged pipe weight per unit length
μ	=	lateral solid friction coefficient
γ	=	safety factor, equal to or larger than 1.1

The effect of seabed contours is, if applicable, to be included in the analysis.

Buried pipes are to have adequate safety against sinking or flotation. Sinking is to be checked, assuming that the pipe is water filled, and flotation is to be checked, assuming that the pipe is gas or air filled. If the pipe is installed in soils having low shear strength, the soil bearing capacity is to be evaluated.

Axial stability due to thermal and pressure effects is to be checked through simplified methods or a detailed in-place analysis. The axial stability criteria may be defined as those for lateral stability criteria. The anodes are to be acceptable to sustain the anticipated axial friction force. Axial stability is to be evaluated using suitable soil/pipe interaction models.

For weight calculations of corroded pipelines, the expected average weight reduction due to metal loss is to be deducted. Reduction of soil shear strength, e.g., due to hydrodynamic loads, is to be considered in the on-bottom stability design.

5.3 Dynamic Stability Analysis

Dynamic analysis involves full dynamic simulation of the pipeline resting on the seabed, including modeling of soil resistance, hydrodynamic forces, boundary conditions and dynamic response. It may be used for detailed analysis of critical areas along a pipeline, such as pipeline crossings, etc., where a high level of detail is required.

The acceptance criteria for dynamic analysis are defined based on strength criteria, deterioration/wear of coating, geometrical limitations of supports and distance from other structures, etc.

The allowable lateral displacement of pipelines is to be based on factors such as:

- Distance from platform or other constraint
- Seabed obstructions
- Width of surveyed corridor
- Significant damage to external coating or anodes due to movement
- Interference with other pipelines or subsea installations due to movement
- Change in load condition due to movement
- Change in seabed features in adjacent areas

7 Free Spanning Pipeline

This Subsection gives acceptance criteria for vortex-induced vibrations of free spanning pipes and describes a methodology applicable for design of pipeline systems.

7.1 General

Free spans may form as a result of the seabed topography or may be formed subsequently as a result of soil erosion and transportation. Where geotechnical and bottom-profiling survey techniques identify areas prone to erosion/deposition action, such areas are to be flagged as regions of potential pipeline span formation. The development of a free-span rectification methodology is to take into account the local soil bearing strengths. For regions of low bearing strength, a mattress-type foundation may be appropriate.

Alignment sheets are to be prepared indicating bathymetry, route corridor and pipeline details. A centerline profile is to be developed to show bathymetry along with core sample locations and corresponding interpreted geological cross-section. Scales and contour intervals are to be specified and alignment sheets are to indicate all existing facilities, pipelines, cables, wrecks, major obstructions, debris and all other pertinent features, natural or man-made.

Seabed bathymetry profiles are to be used to perform a series of free span analyses. Assuming a uniform residual pipelay tension in combination with a representative bottom roughness profile, an estimate is to be made of the magnitude and potential distribution of free spans along the pipeline route. End support conditions are to be idealized and end slope conditions are to be taken into account in the free span analysis. Spans identified through this analysis are to be tabulated, characterized by span length, support separation, maximum span clearance and static stress levels

A maximum allowable span length is to be determined by application of static and dynamic criteria. In performing static analysis, it may be permissible to consider either allowable stress or strain criteria. A maximum static stress level is to be determined by calculations such that sufficient margin is made available under the operating condition to allow for dynamic excitation.

Vortex shedding may be set up in a pipeline free span due to fluid flow effects around the pipe structure, resulting in potentially severe oscillation. The aim of the design is to be either to prevent oscillations or to demonstrate that oscillations are acceptable in terms of the general serviceability of the pipeline, allowable stress levels and fatigue considerations. Analysis is to obtain critical velocities for both cross-flow and in-line motion.

Design criteria applicable to different environmental conditions may be defined as follows:

- i) Peak stresses or strain under extreme loading conditions are to satisfy the strength criteria given in Chapter 3, Section 5.
- ii) Cyclic stress ranges smaller than the cut-off stress may be ignored in fatigue analyses.
- iii) The allowable fatigue damage (see Chapter 3, Section 5) is not to be exceeded.

7.3 Evaluation of Free Spanning Pipelines

When applicable, single span analysis is to be performed in order to assess the onset of in-line and cross-flow vortex-induced vibrations (VIV), as well as to calculate fatigue damage.

For a cylindrical pipe in water, vortex-shedding frequency can be calculated as:

$$f_s = \frac{St \cdot u_n}{D}$$

where

- f_s = vortex-shedding frequency
- u_n = velocity of water normal to the pipelines
- D = outside diameter of pipe
- St = Strouhal number, varies from 0.2 to 0.4 in most practical cases, but it is also a function of the Reynolds number

The natural frequency of the pipeline span is a function of the pipe stiffness, end conditions, length and added and effective mass. The natural frequency of the pipe span is to be calculated using these parameters. Calculations are to fully document the logic process used to model end pipe conditions, added mass factors, reduced velocity and stability parameter. A critical span length is to be calculated for each pipeline and the results tabulated to show the limiting span in each case.

A modal analysis of a single span with appropriate boundary conditions may be conducted to calculate the natural frequencies and modes for vortex-induced vibration assessment. Different boundary conditions are to be analyzed together with a range of axial forces.

The natural frequency of the span may be calculated as:

$$f_n = \frac{CK^2}{2\pi L^2} \sqrt{\frac{EI}{m} \left(1 + \frac{P}{P_E} \right)}$$

where

- f_n = natural frequency, in cycles per second
- C = coefficient, 0.7 for pipes in water and 1.0 for pipes in air
- K = end-fixity condition constant,
 - 3.14 for hinged-hinged condition
 - 3.92 for fixed-hinged condition
 - 4.73 for fixed-fixed condition

I	=	moment of inertia of pipe taking into account weight coating, etc.
L	=	span length
P	=	the effective axial force (tension positive)
P_E	=	the Euler buckling force
		$\pi^2 EI/L^2$ for hinged-hinged condition
		$2\pi^2 EI/L^2$ for fixed-hinged condition
		$4\pi^2 EI/L^2$ for fixed-fixed condition
m	=	mass per unit length of pipe plus mass of water displaced by pipe, internal fluid and weight coating, etc.

For a large range of current velocities, vortex-shedding frequency is locked-in at the natural frequency of the pipe. Large amplitude vibrations may occur unless the natural frequency is sufficiently greater than the vortex-shedding frequency.

A multiple span analysis may be conducted to take into account the interaction between adjacent vertical spans, i.e., several spans may respond as a system. The multiple span approach may be necessary for the vertical mode of vibration where the seabed between adjacent spans form a fixed point about which the pipeline pivots during the vibration. Alternative methods, such as finite element analysis coupled with computational fluid dynamics (CFD), can be employed to accurately estimate structural response due to vortex shedding.

For pipes installed in shallow waters, wave-induced in-line fatigue is to be evaluated. The in-line motion for a free spanning pipe subjected to wave forces represented by the Morison force, damping forces and axial forces may be determined using nonlinear partial differential equations. The pipe motion as a function of time and position may be obtained by solving the equation of in-line motion using modal analysis.

7.5 Span Correction

Critical span lengths are to be calculated based on the avoidance of in-line motion for the imposed design bottom current. It is also to be demonstrated that, with the selected limiting span length, large amplitude cross-flow motion will not occur. A free span is to be corrected by appropriate means whenever the strength and fatigue criteria specified in Chapter 3, Section 5 are not met.

A span rectification plan is to be established for correcting pipeline spans. Spans are to be supported at the midpoint, where possible, or along an extended portion of the span. A detailed design is to be prepared for span supports that may be used on a range of span clearances. The support is to ensure the stability of the pipeline and to incorporate sufficient flexibility in its design to enable it to be modified in the field to suit the requirements of each span. Alternatively, techniques including sandbags, grout bags, mattresses, trenching, rock dump or combinations of different methods may be used for span correction.

9 Upheaval and Lateral Buckling

Pressure and temperature from flow contents may cause expansion in the pipe length and the pipe may buckle to a new equilibrium position. Examples of expansion are:

- Vertical downwards in a free span, up-lift on a free span shoulder and upheaval buckling for buried lines
- Horizontal snaking and/or lateral buckling on the seabed

The following may accelerate global buckling:

- Uneven seabed
- Local reduction in friction resistance
- Fishing gear impact, pull-over and hooking loads

Pipes under internal/external pressure and seabed friction may be modeled as compressive beam-columns subject to an “effective force”. The seabed friction factors are to be properly modeled in the analysis.

9.1 Upheaval Buckling

In the case of an upheaval buckling resulting in limited plastic bending strains, pipelines may continue operating, provided that the operating parameters are kept within a range that prevents the accumulation of low-cycle high strain fatigue damage in the buckled section and that local buckling will not occur. When applicable, local buckling, out-of-roundness and fatigue damage analyses are to be conducted and submitted for approval by ABS.

9.3 Lateral Buckling

Allowing lateral buckling may be an effective way of designing high pressure/high temperature pipelines, provided that the pipeline is not at risk of local buckling or at risk of colliding with another pipeline or installation. In such situations, cyclic and dynamic behavior of the pipes is to be documented through simulation of in-situ behavior. When applicable, local buckling, out-of-roundness and fatigue damage analyses are to be conducted and submitted for approval by ABS.

11 Design for Impact Loads

For unburied pipelines and buried pipelines where scour conditions could remove the overburden, accidental impact loading from such activities as anchoring, fishing operations, etc., is to be considered. The energy absorption properties of the pipeline are to be determined and correlated with the probable accidental loading.

Pipeline design is to consider impact loads, such as:

- Fishing gear impact, pull-over and hooking loads (when applicable)
- Dropped objects
- Anchoring

11.1 Fishing Gear Loads

When it is necessary to design for fishing gear loads, the weight and sizing (length and breadth) of the fishing gear and trawl velocity for the route where pipelines are to be installed are to be investigated to form a design basis. Due consideration is to be given to the future developments or changes in equipment within the lifetime of the pipelines.

11.3 Dropped Objects

Design for dropped objects is to be conducted accounting for falling frequency, weight and velocity of the dropped objects. The methods of analysis and acceptance criteria may be similar to those defined for fishing gear impact.

11.5 Anchoring

Design for anchoring is to be conducted, accounting for falling frequency, weight, velocity of the dropped objects and different scenarios causing anchor drop/drag on the unburied pipelines. The methods of analysis and acceptance criteria may be similar to those defined for fishing gear hooking loads.



CHAPTER 3 Design

SECTION 7 Routing, Installation and Construction

1 Route Selection

When selecting the pipeline route, consideration is to be given to the safety of all parties, environmental protection and the likelihood of damage to the pipe or other facilities. Any future activities in the immediate region of the pipeline are to be accounted for when selecting the route.

In selecting a satisfactory route for an offshore pipeline, a field hazards survey may be performed to identify potential hazards, such as sunken vessels, pilings, wells, geologic and manmade structures and other pipelines. Appropriate regulations are to be applied for minimum requirements for conducting hazard surveys.

The selection of the route is to account for applicable installation methods and is to minimize the resulting in-place stresses.

The pipelines will run from a pipeline end manifold base or Pipe Line End Manifold (PLEM) structure beneath the Floating Production Installation (FPI) to an unspecified destination. The pipeline corridor is to be selected based on hydrographic survey data. Hydrographic survey is to identify seabed topography bathymetry, seabed features, wrecks and debris. Geotechnical and geophysical survey is to be performed to determine surface and subsurface strata characteristics.

The soil bearing capacity of surface and subsurface soil layers is to be assessed. Significant soil weakness or instability may necessitate routing realignment or design measures to enhance pipeline stability. Export line route selection is to endeavor to minimize deviation since additional length may escalate cost. A seismic study, if applicable, is to highlight the geohazard potential of unstable features.

In the route selection process, it is to be recognized that factors such as safety and functional integrity are to take precedence. A more direct and cost-effective route may be selected, even though a shorter routing may place the pipeline at a higher level of risk from external factors. In such a case, appropriate measures are to be taken within the design of the system to mitigate possible adverse effects.

All physical constraints, both natural and man-made, should be identified along the pipeline corridor. Current and planned development, both along the pipeline corridor and in the immediate vicinity, is to be identified. A distance of 100 m is to be observed between the pipeline and an existing subsea facility. A separation distance of 30 m is to be maintained in between any existing or planned pipelines unless the pipeline is to be crossed or the pipeline approaches the platform, in which case, the spacing may be gradually reduced to that of the riser facing of the platform.

Special route surveys may be required at landfalls to determine:

- Environmental conditions caused by adjacent coastal features
- Location of the landfall to facilitate installation
- Location to minimize environmental impact

1.1 Route Survey

The route survey covers survey for design purposes, survey for pre-installation and as-laid survey. Issues related to the seabed intervention are discussed in Chapter 3, Section 6.

1.1.1 Route Survey for Design

A detailed route survey is to be performed for the planned pipeline route to provide sufficient data for the design. The width of the survey corridor is to be wide enough to cover the installation tolerance. Detailed and more accurate surveys are required, especially for uneven seabed topography, obstructions, near installations or templates, existing pipeline or cable crossings, subsurface conditions, large boulders, etc.

Seabed bathymetry and soil data properties are to be investigated and provided based on the route survey results. Seabed properties, including different soil layers, are to be included in the route survey maps. As a minimum, the soil stiffness and seabed soil friction coefficients in both axial and lateral directions are to be provided.

1.1.2 Route Survey for Pre-Installation

Prior to installation, the route is to be surveyed for the following cases:

- New installations along the route
- Changes of installation (e.g., templates) location
- Change of seabed conditions due to heavy marine activities
- New requirements due to seabed intervention design or installation engineering

1.1.3 As-Laid Survey

After installation, an as-laid survey is to be conducted. As a minimum, the following is to be included in the as-laid survey:

- Position (coordinates) and water depth profile for the pipeline systems
- Coordinates identifying starting and ending point
- Identification and quantification of any spans, crossings, structures and large obstructions
- Reporting of any damages to the pipeline systems, including pipes, cathodic protection system, weight coating, supports, appurtenances, in-line structures, etc.

If necessary, an integrity assessment of the pipeline system based on the as-laid survey is to be performed.

1.1.4 As-Built Survey

After the final testing of the pipeline system, an as-built survey is to be conducted. This survey may be limited to key locations defined during the as-laid survey, such as identified spans, crossings, subsea structures and areas with special features. As a minimum, the following is to be included in the as-built survey:

- Positions (coordinates) and water depth profile, including tangential points, out-of-straightness measures, etc.
- Quantification of spans, crossings, trench, burial, scour, erosion
- Reporting of any damages to the pipeline systems, including pipes, cathodic protection system, weight coating, supports, appurtenances, in-line structures, etc.

1.3 In-Field Pipelines

The in-field area is subject to detailed geotechnical and geophysical survey to determine soil and sub-structural characteristics, local surface irregularities and obstructions.

In-field pipeline routing is to consider vessel mooring patterns and temporary anchor locations of Mobile Offshore Drilling Units (MODUs). The potential of interference between mooring lines and risers/pipelines under extreme vessel motion is to be assessed. In developing pipeline layouts, the selected minimum route curvature radius is to be verified such that it is sufficient to maintain the pipeline from moving when the lay barge executes a route turn. Bending capacity of the pipe, as described in Chapter 3, Section 5, is also to be taken into account for the selection of minimum route curvature radius. The soil lateral friction can maintain the curvature of radius R during installation, if:

$$R \geq \frac{T}{\mu \cdot W_s}$$

where

R	=	route curvature radius along the route
T	=	on-bottom lay tension
μ	=	soil lateral friction coefficient
W_s	=	submerged weight of the pipe

Pipeline installation sequence and construction method are to be reviewed to determine the influence on pipeline layout in the field area. The feasibility of all proposed pipeline layouts and installation/tie-in methods is to be confirmed.

3 Installation Analysis

An analysis of the pipe-laying operation is to be performed, taking into account the geometrical restraints of the anticipated laying method and lay vessel, as well as the most unfavorable environmental condition under which laying will proceed. The analysis is to include conditions of starting and terminating the operation, normal laying, abandonment and retrieval operation, and pipeline burial. The analysis is to ensure that excessive strain, fracture, local buckling or damage to coatings will not occur under the conditions anticipated during the pipe-laying operation.

Strength analysis is to be performed for the pipeline during laying and burial operations. The strength analysis is to account for the combined action of the applied tension, external pressure, and bending and dynamic stresses due to laying motions, when applicable.

3.1 S-Lay Installation

For S-lay installation, the pipe is laid from a near-horizontal position using a combination of horizontal tensioner and a stinger controlling the curvature at over-bend. The lay-vessel can be a ship, barge or a semi-submersible vessel. The required lay tension is to be determined based on the water depth, the submerged weight of the pipeline, the allowable radius of curvature at over-bend, departure angle and the allowable curvature at the sag-bend. The stinger limitations for minimum and maximum radius of curvature and the pipeline departure angle are to be satisfied.

Strain concentrations due to increased stiffness of in-line valves are to be accounted for. The in-line valve is to be designed for strength and leakage protection to ensure the integrity of the in-line valve after installation.

Due to local increased stiffness by external coatings and buckle arrestors, for example, strain in girth welds may be higher than in the rest of the pipe, and strain concentration factors are to be calculated based on strain level and coating thickness or wall-thickness of buckle arrestors.

Installation procedures are to safeguard the pipe with coatings, protection system, valves and other features that may be attached. A criterion for handling the pipe during installation is to consider the installation technique, minimum pipe-bending radii, differential pressure and pipe tension.

3.3 J-Lay Installation

For J-Lay (near-vertical pipe-lay), the pipe is laid from an elevated tower on a lay vessel using longitudinal tensioner. In this way, over-bend at the sea surface is avoided. In general, J-Lay follows the same procedure as S-Lay (see 3-7/3.1).

3.5 Reel Lay Installation

For reel lay, the pipe is spooled onto a large radius reel aboard a reel lay vessel. The reel-off at location will normally occur under tension and involve pipe straightening through reverse bending on the lay vessel. The straightener is to be qualified to ensure that the specified straightness is achieved.

Anodes are, in general, to be installed after the pipe has passed through the straightener and tensioner.

Filler metals are to be selected to ensure that their properties after deformation and aging match those of the base material.

Fracture mechanics assessment may be conducted to assess ductile crack growth and potential unstable fracture during laying and in service. The allowable maximum size of weld defects may be determined based on fracture mechanics and plastic collapse analysis.

3.7 Installation by Towing

The pipe is transported from a remote assembly location to the installation site by towing either on the water surface, at a controlled depth below the surface or on the sea bottom.

The submerged weight of the towed pipeline (e.g., bundles) is to be designed to maintain control during tow. The bundles may be designed to have sufficient buoyancy by encasing the bundled pipelines, control lines and umbilical inside a carrier pipe. Ballast chains may be attached to the carrier pipe at regular intervals along the pipeline length to overcome the buoyancy and provide the desired submerged weight.

In the case of bottom tow installation, the route is to be surveyed carefully, and the pipe must have an abrasion-resistant coating that can stand up to dragging across the seabed.

5 Construction

Pipelines are to be constructed in accordance with written specifications that are consistent with this Guide. The lay methods described in 3-7/3 and other construction techniques are acceptable, provided the pipeline meets all of the criteria defined in this Guide. Plans and specifications are to be prepared to describe alignment of the pipeline, its design water depth and trenching depth and other parameters.

5.1 Construction Procedures

The installation system is to be designed, implemented and monitored to ensure the integrity of the pipeline system. A written construction procedure is to be prepared, including the following basic installation variables:

- Water depth during normal lay operations and contingency situations
- Pipe tension
- Pipe departure angle
- Retrieval
- Termination activities

The construction procedure is to reflect the allowable limits of normal installation operations and contingency situation.

5.3 Buckle Detection

Detections of dents, excessive ovality or buckles in the pipeline are to be performed during pipe laying. Whenever possible, the detection is to be accomplished by passing a buckle detector through the pipe section. Alternative methods capable of detecting changes in pipe diameter may be used upon agreement with ABS.

5.5 Weld Repair

For weld repair carried out at weld repair stations, weld repair analysis is to be performed to ensure that the length and depth of cut combination does not produce combined stresses that exceed the allowable stress during pipe laying.

5.7 Trenching

In the event that on-bottom stability of the pipeline cannot be achieved with a means of shielding the pipeline from the effects of current, the impact on the pipeline of trenching is to be determined. Pipeline trenching may require lifting of the pipeline to allow clearance for plowshares to excavate a trench. The pipeline minimum allowable curvature for trenching is to be determined and the pipeline vertical curvature of the as-installed pipeline is to be as large as possible to control the pipeline stresses within allowable limits during operational phase. If required, the design is to include stress analysis of this configuration to ensure that stresses remain within allowable limits.

The standard depth of trenching for pipelines is the depth that will provide 0.9 meter (3 feet) of elevation differential between the top of the pipe and the average sea bottom. The hazards are to be evaluated to determine the total depth of trenching in those situations where additional protection is necessary or mandated.

A post-trenching survey is to be conducted to determine if the required depth has been achieved.

5.9 Gravel Dumping

Gravel dumping is to be controlled such that the required gravel is dumped over and under the pipeline and subsea structures and over the adjacent seabed. During the gravel dumping operations, inspection is to be carried out to determine the performance of the dumping. Measures are to be taken to avoid damaging the pipeline and coating during the dumping process. Upon completion of the gravel dumping, a survey is to be conducted to confirm the compliance with the specified requirements.

5.11 Pipeline Cover

Pipeline cover is normally installed where more protection is required. Pipeline and coating are to be protected from damage in areas where backfill is specified, or where pipeline-padding material is specified.

5.13 Pipeline Crossings

In deepwater locations, pipeline crossing is not normally required. In-field pipeline layouts are to ensure that crossing is avoided where feasible and export lines are to be deviated such that the potential for interference is avoided. Where crossings cannot be avoided, a crossing design is to be developed that takes into account the accuracy with which pipelines can be installed in extreme depths. Vertical separation at crossings between new and existing pipelines is to be at least one (1) foot, as required in ASME 31.4. The pipeline crossing profile is to be checked for in-place stresses for hydrotest, operational and environmental loads. The stability of supports is to be checked for sliding and overturning moments. Crossing design is also to take into account soil bearing strength and the requirement for additional support to minimize or avoid the creation of an unsupported span.

5.15 Protection of Valves and Manifolds

Valves, manifolds and other subsea structures installed on an offshore pipeline are to be protected from fishing gear and anchor lines. Protective measures are to be applied to prevent damage to the valves and manifolds. Such measures are not to obstruct trawling or other offshore operations.

5.17 Shore Pull

Shore pull is a process in which a pipe string is pulled either from a vessel to shore or vice versa. Installation procedures are to be prepared, including installation of pulling head, tension control, twisting control and other applicable items.

Cables and pulling heads are to be dimensioned for the loads to be applied, accounting for overloading, friction and dynamic effects. Winches are to have adequate pulling force, and are to be equipped with wire tension and length indicators.

Buoyancy aids are to be used if required to keep pulling tension within acceptable limits. Buoyed pipeline sections' lateral stability is to be analyzed for installation phase.

5.19 Tie-in

Tie-in procedures are to be prepared for the lifting of the pipeline section, control of configuration and alignment, as well as mechanical connector installation. Alignment and position of the tie-in ends are to be within specified tolerances prior to the tie-in operation.

5.21 Shore Approaches

The choice of shore crossing location, design and construction technique is to take into account the following factors:

- i)* Changing nature of the shorelines
- ii)* Environmental importance of shorelines
- iii)* Complexity of sea/land interface
- iv)* Existing pipelines, cables and outfalls in the area

Adequate site investigation and knowledge of environmental conditions are to be obtained in planning shore approaches. Marine survey is to be carried out to determine the shore profile, the ocean and tidal currents and the seabed bathymetry, which determines local wave refraction. Geotechnical site investigation is to be carried out to determine the geotechnical description and strength properties of the seabed material.



CHAPTER 3 Design

SECTION 8 Special Considerations for Pipe-in-Pipe Design

1 General

This Section defines the design criteria that are specifically applied to pipe-in-pipe systems. Relevant failure modes for pipelines, described in Chapter 3, Section 5, are to be considered in the design of pipe-in-pipe systems.

3 Design Criteria

3.1 Strength Criteria

The design of pipe-in-pipe systems is, in general, to follow the strength criteria given in Chapter 3, Section 5. For high temperature/pressure systems, an equivalent strain criterion may be applied as:

$$\varepsilon_p = \sqrt{2(\varepsilon_{p\ell}^2 + \varepsilon_{ph}^2 + \varepsilon_{pr}^2)/3}$$

where

$$\begin{aligned}\varepsilon_{p\ell} &= \text{longitudinal plastic strain} \\ \varepsilon_{ph} &= \text{plastic hoop strain} \\ \varepsilon_{pr} &= \text{radial plastic strain}\end{aligned}$$

The maximum allowable accumulation of plastic strain is to be based on refined fracture calculations and is to be submitted for approval by ABS.

The inner pipe burst capacity of the pipe-in-pipe system is determined based on the internal pressure, and local buckling capacity is evaluated based on the outer pipe subjected to the full external pressure.

3.3 Global Buckling

In terms of structural behavior, a pipe-in-pipe system may be categorized as being either compliant or non-compliant, depending on the method of load transfer between the inner and outer pipes. In compliant systems, the load transfer between the inner and outer pipes is continuous along the length of the pipeline, and no relative displacement occurs between the pipes, whereas in non-compliant systems, force transfer occurs at discrete locations. Due to effective axial force and the presence of out-of-straightness (vertically and horizontally) in the seabed profile, pipe-in-pipe systems are subjected to global buckling, namely, upheaval buckling and lateral buckling. In contrast to upheaval buckling, lateral buckling may be accepted if it does not result in unacceptable stresses and strains. In case global buckling may occur, a detailed finite element analysis is recommended to further investigate the buckling behavior.

3.5 Pipe-in-Pipe Appurtenances Design

Design of pipe-in-pipe appurtenances is to be based on their functional and installation requirements:

- Field joint design
- Bulkhead design
- Spacers
- Water stops/intermediate bulkheads to prevent water intrusion at the field joints
- Insulation



CHAPTER 3 Design

SECTION 9 Special Considerations for Pipeline Bundle Design

1 General

This Section defines the design criteria that are specifically applied to pipeline bundle systems. Relevant failure modes described in Chapter 3, Section 5, are to be considered in the design of pipeline bundle system.

3 Functional Requirements

Pipeline bundle systems may be used in applications when the same end points have to be connected by more than one pipeline or where pipe insulation is required to avoid hydrate and wax formation. A bundle can be open, with the individual pipes and cables strapped together, or closed, with all of them contained in an outer carrier pipe. The following functional requirements are to be considered:

3.1 Design Temperature/Pressure

Design temperature and pressure are to be based on hydraulic analyses. Significant temperature drops along the bundle system are to be avoided.

3.3 Pigging Requirements

If the bundle system is designed for pigging, the geometric requirement is to be fulfilled. The minimum bend radius is usually five (5) times the nominal internal diameter of the pipe to be pigged.

3.5 Settlement/Embedment

Settlement/embedment of the pipeline bundle system is to be taken into account, where appropriate.

3.7 System Thermal Requirements

The insulation value is to be determined based on thermal conduction, convection and hydraulic analysis considering:

- Maximum/minimum operating temperature
- Cool down time
- Heat-up time
- Heat-up system volume
- Bundle configuration and the relative positions of the components
- Bundle length
- Heating medium temperature
- Heating medium flow rate
- Properties of the fluid contained inside the pipelines

5 Design Criteria for Bundle Systems

The design of bundle systems is to ensure that the system satisfies the functional requirements, and that adequate structural integrity is maintained against all of the failure modes.

Design of the carrier pipelines, heat-up lines and service line is to be in accordance with Chapter 3, Section 5. The design criteria are to be applicable for installation, system pressure test and operation.

5.1 Carrier Pipe Design

Carrier pipe stresses are to be checked during the carrier selection and are to be reviewed in light of the stresses determined from the expansion analysis.

The weight of all of the bundle component parts is to be determined. The displacement of external anodes, clamps and valves is to be accounted for by using a submerged weight for these items in the weight calculations.

5.3 Wall Thickness Design Criteria

Pipelines are to be sized according to processing data. The wall thickness of the pipelines depends on the internal pressure containment and the pressure in the annulus. For high temperature applications, thermal loading is to be considered in pipeline sizing and selection of material properties that will apply at elevated temperatures.

The wall thickness design of pipes within the bundle system is to take into account the following:

5.3.1 Hoop Stress

The hoop stress criterion in Chapter 3, Section 5 is applicable for bundle systems.

5.3.2 Collapse due to External Hydrostatic Pressure

The wall thickness of the carrier pipe is to be designed to avoid pipe collapse due to external hydrostatic pressure.

5.3.3 Local Buckling

The pipelines, carrier and sleeve pipe are to be designed to withstand local buckling due to the most unfavorable combination of external pressure, axial force and bending.

5.3.4 Installation Stress

The wall thickness is to be adequate to withstand both static and dynamic loads imposed by installation operations.

5.3.5 System Pressure Test and Operational Stresses

The wall thickness is to be adequate to ensure the integrity of carrier and sleeve pipe under the action of all combinations of functional and environmental loads experienced during system pressure test and operation.

5.5 On-Bottom Stability Design

The bundle system is to be stable on the seabed under all environmental conditions encountered during installation, testing and throughout the design life. The bundle is to be designed with sufficient submerged weight to maintain its installed position, or to limit movement such that the integrity of the bundle system is not adversely affected. The bundle may be considered stable when actual submerged weight is greater than the minimum required multiplied a factor of 1.1.

On-bottom stability is to be verified in accordance with 3-6/5.

5.7 Free Spans Design

Maximum allowable span length for the bundle system is to be calculated for both static and dynamic loading conditions. Analyses are to consider all phases of the bundle design life, including installation, testing and operation.

5.9 Bundle Expansion Design

The design is to take into account expansion and/or contraction of the bundle as a result of pressure and/or temperature variation. The bundle expansion analysis includes determination of external and internal forces acting on the system, calculation of axial strain of the system and integration of the axial strain of unanchored bundle to determine the expansion. Design pressure and the maximum design temperature are to be used in bundle expansion analysis. The presence of the sleeve pipe is to be taken into account. Bundle expansion movement is to be accommodated by the tie-in spools.

5.11 Bundle Protection Design

The bundle system is to be designed against impact loads in areas where fishing activities are frequent. The pipelines are to be protected against dropped objects around the installations (see 3-6/11). Carrier pipe and bundle towheads are to offer sufficient protection against the dropped objects.

5.13 Corrosion Protection Design

Cathodic protection design is to be performed according to relevant codes, e.g., NACE RP0176. Cathodic protection together with an appropriate protective coating system is to be considered for protection of the external steel surfaces from the effects of corrosion.

The sleeve pipe is to be protected from corrosion using chemical inhibitors within the carrier annulus fluid. Pipelines within the sleeve pipe are to be maintained in a dry environment, and a cathodic protection system will therefore not be required.

5.15 Bulkheads and Towhead Structure Design

The bulkheads will form an integral part of the towhead assemblies. The towhead structure is to remain stable during all temporary and operational phases. Stability is to be addressed with respect to sliding and overturning with combinations of dead weight, maximum environmental and accidental loads applied. The design of towhead structure is to be in accordance with relevant structural design code.

5.17 Bundle Appurtenances Design

Design of bundle appurtenances is to be based on their functional requirements:

- Spacer
- Filling, flood and vent valves
- Transponder supports
- Chain attachment straps
- Tie-in spools



CHAPTER 4 Testing, Inspection and Maintenance

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CHAPTER 4 Testing, Inspection and Maintenance

SECTION 1 Testing, Drying and Commissioning

1 General

This Section describes the minimum functional requirements to be met during hydrostatic test and commissioning of a pipeline system composed generically of a subsea pipeline and all connected interface components. The purpose of the commissioning is to prepare the pipeline system for the acceptance of production hydrocarbons, lift gas and injection water.

For an oil pipeline system, commissioning is mainly dewatering. For the gas pipelines, drying is normally required before introduction of the hydrocarbons into the pipeline system. Project-specific commissioning procedures are to be developed.

The minimum functional requirements include the following:

- Cleaning, gauging and line filling
- Hydrostatic pressure test
- Leak test
- Post-testing and rectification requirements
- Pigging requirements
- Dewatering
- Drying requirements.

Hydrostatic pressure test is to be performed on the completed system and on all components not tested with the pipeline system or components requiring a higher test pressure than the remainder of the pipeline. If leaks occur during tests, the leaking pipeline section or component is to be repaired or replaced and retested in accordance with this Guide.

Detailed procedures for the hydrostatic testing and commissioning of the pipeline system are to be developed. The procedures are to be such that they do not jeopardize the pipeline system's fitness for purpose, e.g., by overstressing the whole pipeline system or parts of it. In addition, the procedures are not to impose additional requirements over and above specified operational conditions on mechanical design of the pipeline.

1.1 Testing of Short Sections of Pipe and Fabricated Components

Short sections of pipe and fabricated components such as scraper traps and manifolds may be tested separately from the pipeline. Where separate tests are used, these components are to be tested to pressures equal to or greater than those used to test the pipeline system.

1.3 Testing After New Construction

1.3.1 Testing of Systems or Parts of Systems

Pipelines designed according to this Guide are to be system pressure-tested after completion of trenching, gravel dumping, covering and crossing. The test is to be performed after installation and before operation.

It is to be ensured that excessive pressure is not applied to valves, fittings and other equipment. The valve position and any differential pressure across the valve seat are to be specifically defined in the test procedures.

1.3.2 Testing of Tie-ins

Because it is sometimes necessary to divide a pipeline system into test sections and install weld caps, connecting piping and other test appurtenances, it is not required to test tie-in welds. However, tie-in welds that have not been subjected to a pressure test are to be radiographically inspected or subjected to other accepted nondestructive methods. After weld inspection, field joints are to be coated and inspected. Mechanical coupling devices used for tie-in are to be installed and tested in accordance with the manufacturer's recommendations.

3 Cleaning, Gauging and Line Filling

Prior to pressure testing, the pipeline system is to be cleaned and gauged to ensure removal of construction debris and loose scale and to check that the pipeline system is free of deformations and/or obstructions. Prior to using water for the cleaning operation, all pipeline spans have to be inspected to ensure that the unsupported spans do not exceed the allowable span value for hydrostatic test conditions. Filling the pipeline for hydrostatic testing normally takes place as part of the gauging operation. The water used may be fresh water or filtered seawater, depending on the project-specific requirements.

It is recommended that the air content in the system during the pressure test does not exceed 0.2% of the volume of the system being tested.

3.1 Cleaning

The first pig driven through the cleaning section is to be of a bi-directional type. The position of the pig should be monitored. All debris received with the pig is to be disposed of in an authorized manner.

3.3 Gauging

The test section is to be gauged after cleaning. A bi-directional pig is to be fitted with one or two aluminum gauging plates. The diameter of the gauging pig is recommended to be 95% of the inner drift diameter of the pipe. A record is to be taken of the condition of each gauging plate before and after use. Any damage noted by the gauging pig is to be located and repaired.

3.5 Line Filling

Necessary measures are to be taken to remove air from the line during filling. The filling speed should be specified prior to the filling operation. In most cases, the filling pig speed is to be approximately 2 ft/s and is not to exceed 6 ft/s. In order to assist in controlling the line filling and water treating, the following measurements and records are to be taken:

- Inlet flowrate
- Inlet pressure
- Inlet temperature
- Chemical injection rate (if carried out)
- Dye injection rate (if carried out).

Precautions are to be taken during freezing conditions.

3.7 Temperature Stabilization

The temperature of the line-fill water should be stable before testing commences. The calculation of the temperature stabilization period is to be detailed in the test procedure. Pressures and temperatures, including ambient, are to be recorded regularly during the stabilization period.

3.9 Pressurization

The Owner is to provide the ABS Surveyor with a chart that shows a graph of pressure versus added volume (P/V plot) using measurement of volume added either by pump strokes or flow meter and instrument reading of pressure gauge and a dead weight tester.

The rate of pressurization should be constant and not exceed 1 bar per minute until a pressure of 35 bar or 50% of the test pressure, whichever is lesser, has been reached. During this period, volume and pressure readings should be recorded at regular intervals.

When the pressure of 35 bar or 50% of the test pressure, whichever is lesser, has been reached, the air content in the test line is to be determined.

When the air content is within the maximum allowable limit of 0.2% of the test section volume, the pressurization should continue.

The pressures and added volumes should be continuously plotted until the specified test pressure has been reached

5 Hydrostatic Pressure Testing

After installation and before operation, all parts of an offshore pipeline designed according to this Guide are to be subjected to hydrostatic test. API RP 1110 and API RP 1111 may be used as guidance on the hydrostatic test. The system pressure test is not to result in hoop stress and combined stress exceeding the capacity given in Chapter 3, Section 5. Precautions are to be taken to ensure safety of personnel during the entire test procedure.

The test medium is to be fresh water or seawater unless freezing may happen. Corrosion inhibitor and biocide additives are to be added to the test medium in case the water is to remain in the pipeline for an extended period. Effects of temperature changes are to be taken into account when interpretations are made of recorded test pressures. Plans for the disposal of test medium together with discharge permits are to be acceptable to the local authorities.

The purpose of the hydrostatic pressure test of the pipeline system is to ensure its mechanical strength after completion of construction and to verify that the system is leak free.

The pressure and the duration of the test are to be in accordance with requirements specified in 4-1/5.3.

For the purpose of this functional requirement, it is assumed that the hydrostatic pressure test is to fulfill the requirements of ASME B31.8 (gas pipeline system) and ASME B31.4 (liquid pipeline system) as a minimum.

A detailed hydrostatic pressure test procedure is to be developed for the purpose of testing the pipeline system.

5.1 Assumptions and Sequence of Operations

The hydrostatic test of the pipeline system is performed after completion of all installation and construction work and before operation.

The extent of the test is to be based on actual project configuration and it is to include the entire pipeline and installed interface components as a minimum.

Depending on the offshore installation scenarios, some components of the pipeline system, such as risers, may be subject to a local hydrostatic leak test prior to the hydrostatic test of the whole pipeline system. It is recommended that the connected components and pipeline system be tested as a unit.

The sequence of pressure testing operations of the pipeline system is to be as follows:

- i)* Filling
- ii)* Cleaning and gauging
- iii)* Hydrotesting, including: temperature stabilization, pressurization, air contents check and hydrostatic test/holding period
- iv)* Post-testing, including depressurization and documentation
- v)* Rectification activities (if required), including leak location during test, dewatering for rectification and rectification of defects
- vi)* Final/repeat hydrotesting
- vii)* Testing, certificates witness signature

5.3 Hydrostatic Test Pressure and Duration

Hydrostatic pressures both internally and externally are to be taken into account. Guidance on the work procedure can be found in API RP 1111 and API RP1110. The minimum duration of the hydrostatic pressure test is to be a strength test at the test pressure for at least eight (8) continuous hours. The assembly testing is to be comprised of a four-hour strength test followed by visual examination at the leak tightness test pressure. A leak tightness test may be combined with strength test or be commenced immediately after strength test has been completed satisfactorily.

The test pressure at any point of the test section is not to be less than 1.25 times of the maximum allowed operating pressure (MAOP) and at least be equal to the test pressure required in the ANSI/ASME B31.4 or B31.8, or to the pressure creating a hoop stress of 90% SMYS of the linepipe material, based on the minimum wall thickness, whichever is higher.

During the hydrostatic pressure test, the combined stress is not to exceed 100% SMYS of linepipe material based on minimum wall thickness.

The margin between the hoop stress of 90% SMYS and the combined stress of 100% SMYS allows for elevation differences in the test section and/or longitudinal stresses, e.g., due to bending. However, the elevation differences in each test section are to be limited to a value corresponding to 5% of SMYS of the linepipe material or to 50 m or as specified in the scope of work.

It is to be confirmed that the calculated test pressure does not exceed the design pressure of the fittings specified for the pipeline.

The combined stress for the hydrostatic pressure test condition is to be calculated in accordance with Chapter 3, Section 5 of this Guide. The calculation is to include major residual stresses from construction, e.g., from towing or lay barge operations and longitudinal stresses due to axial and bending loads, e.g., at unsupported pipeline spans. The combined stress during the hydrostatic pressure test is to be limited to 100% of SMYS based on the minimum wall thickness. If the calculated combined stress is higher than 100% of SMYS, special measures are to be taken to reduce the longitudinal stresses in the test section.

The pressure is to be maintained during the strength test at test pressure ± 1 bar by bleeding or adding water as required. The volumes of water added or removed are to be measured and recorded.

The test section temperature and the ambient temperature against time plot created for the stabilization period is to be maintained.

5.5 Leak Tightness Test

The leak tightness test may be commenced immediately after the strength test has been completed satisfactorily or combined with strength test. No water is to be added or removed during the tightness test. The test is intended to demonstrate that there is no leak in the pipeline. To allow for pressure variations caused by temperature fluctuations during the test duration, the leak test pressure is to be set to a level of 80% of the hydrostatic test pressure if they are carried out separately.

If it can be ensured that the pressure variations due to temperature fluctuations are within the specified limits, a combined strength/leak tightness test at the strength test pressure, without water addition or removal, is to be carried out.

5.7 Acceptance Criteria

The pressure variation is not to exceed $\pm 0.2\%$ of the test pressure during the test period. Due to temperature changes, a pressure variation of up to $\pm 0.4\%$ of the test pressure may be acceptable. The pressure test is only acceptable when both the above pressure variation criteria are met and no leakage is observed. To determine whether any pressure variation is a result of temperature changes or whether a leak is present, the pressure and or temperature changes are to be calculated from an appropriate pressure and temperature equation formula for an unrestrained test section.

5.9 Pipeline End Manifold (PLEM) Hydrotest Considerations

The PLEM's pipe-work will be subjected to a separate hydrostatic test prior to the offshore leak tightness test. PLEM can be treated as an assembly/fabricated item. During the offshore test, care is to be exercised to ensure that excessive pressure is not applied to valves, fittings and other components.

7 Post-test and Rectification Requirements

After the satisfactory completion of the hydrostatic pressure test, the pipeline system is to be depressurized. The depressurization should be performed at a steady and controlled rate. The manufacturer of the connected components defines the maximum depressurization rate.

If a leak is suspected, the pressure is to be reduced to less than 80% of the test pressure before carrying out a visual examination.

If it is not possible to locate the suspected leak by visual examination, a method is to be used such that the locating of leaks can be done at test pressure without endangering the personnel carrying out the work. When the leak has been found, the test section is to be repaired.

7.1 Dewatering for Rectification

To rectify any defects, it may be necessary to partially or completely dewater the test section. Prior to dewatering, it is to be confirmed that all block valves, if installed, are in the fully open position. The disposal of line-fill water is to be done in accordance with accepted procedures.

The test section is not to be left in the partially or completely dewatered condition longer than one week without any further internal corrosion protection. Depending on the post-dewatering period and the line-fill water quality, it may be required to purge nitrogen or swab the test section with fresh water and/or inhibition slugs to avoid internal corrosion in the test section.

7.3 Rectification of Damage

Damage and/or defects detected during cleaning, filling, gauging and pressure test operations are to be located and repaired or replaced in accordance with the appropriate pipeline construction specification. The proposed repair and/or replacement procedure is to be verified and approved when the actual site conditions are known. Following the completion of repairs, the activity, which has been interrupted for the repair works, should be repeated until the failed activity has been successfully completed.

9 Pigging Requirements

Pigging operations are to comply with the activity-specific requirements specified in the offshore installation procedures.

9.1 Pig Selection

Cleaning pigs with steel brushes or brush-coated foam pigs are to be used in uncoated carbon steel pipelines. Only polyurethane plates, disc pigs, spiral wound or criss-cross polyurethane coated foam pigs are to be used for cleaning of internally flow coated pipelines.

Pigs are to be suitable to pass through pipelines with minimum bore and minimum bend radius, as specified in the scope of work.

Foam pigs are to be oversized as required for their duty.

Brush or abrasive coated foam pigs should replace bare foam pigs if inspection after pigging reveals pig deterioration to the extent that they may disintegrate during pigging and/or become inefficient for dewatering.

9.3 Planning Pigging Operations

Pipeline elevation, density of fluid in the pipeline and back-pressure at the receiving end are to be taken into account when calculating the required inlet flows and pressures for the driving medium.

Prior to any pigging operations, it is to be verified that:

- i) All valves have been correctly positioned and are functioning
- ii) All main line valves are to be in the fully open position
- iii) Discharge and/or storage facilities have been connected and are in good working order

Pigs should be removed from the pig receiver immediately upon arrival and then inspected.

9.5 Pig Train Monitoring

During all pigging operations, the location of the pig trains should be predicted by calculations and measurement of the volume of the driving medium. Launching and arrival of pigs at pig traps are to be monitored by pig signalers fitted to the pig traps or by measuring signals from pig location devices fitted to the last pig of the pig train.

When glycol or other chemicals are part of the pig train or used as the driving medium, the location of pig trains should be monitored during the pigging operations. Location monitoring should be done by measuring the signals from pig location devices or by predictions based on the volumes of the discharged fluids measured in the discharge pipe work.

All pigging operations are to be recorded in a pig data register with the following data as a minimum:

- i) Number of the pig runs
- ii) Type(s) of pig
- iii) Volumes and pressures of the driving media
- iv) Time of launching and receiving
- v) Condition of pigs before launching and upon arrival
- vi) Volume(s) and nature(s) of material and substances arriving in front of the pig at the receiving end

11 Dewatering

The pipeline system is to be dewatered with appropriate medium. The dewatering pigs are to be driven by nitrogen or by produced fluid, whenever practicable. The entrance of air/oxygen into the pipeline is to be avoided during the dewatering. The pipeline is not to be left dewatered with air for more than two (2) weeks unless otherwise permitted in the scope of work. Adequate size dump lines at the receiving end are to be provided, with regard to safety and legislation over control of pollution. The following are to be measured and recorded:

- i) Details of test water disposed from the receiving end
- ii) For each dewatering run the quantities, pressure and flowrate records of the driving medium
- iii) Dew point records of the air

13 Drying of Gas Pipelines

The pipeline system is to be dried to a level that is specified for the intended service. One of the major factors determining the drying method is the dryness criterion. This dryness is based on the value that is required to avoid the formation of hydrates.

The general requirements for drying are:

- i) Drying is to follow immediately after dewatering.
- ii) The period between drying and commissioning is to be kept as short as possible.
- iii) Only nitrogen is to be used as drying medium. Use of hydrocarbon gas as a drying medium should be avoided.
- iv) If vacuum drying is going to be undertaken, it is important to verify if all the pipeline system components including PLEM valves and any risers, or other installed components are capable of vacuum service.
- v) Methanol/Glycol swabbing should be used when there may be a risk of a hydrate forming in the pipeline system.
- vi) Production gas drying can be used if the water content in the pipeline system following dewatering is sufficiently low to avoid the possibility of hydrate formation.

The records of critical parameters (dew point, temperature, pressure at inlet and outlet of the pipeline system, flowrate, total volume of drying medium, etc.) for each activity included in the drying process are to be provided for ABS review.



CHAPTER 4 Testing, Inspection and Maintenance

SECTION 2 Inspection, Maintenance and Repair

1 Inspection

1.1 Inspection and Monitoring Philosophy

An inspection and monitoring philosophy is to be established, and this is to form the basis for the detailed inspection and monitoring program.

Inspection and monitoring are to be carried out to ensure safe and reliable operation of the pipeline system.

1.3 Inspection by Intelligent Pigging

The types and frequency of intelligent pig inspection are to be determined based on the Operator's inspection philosophy and the operational risks of the pipe system. The inherent limitations of each inspection tool are to be examined.

1.3.1 Metal Loss Inspection Techniques

Several techniques are applicable, for example:

- Magnetic flux leakage
- Ultrasonic
- High frequency eddy current
- Remote field eddy current

1.3.2 Intelligent Pigs for Purposes Other than Metal Loss Detection

Pipe inspection by intelligent pigging can be categorized into the following five groups of inspection capability:

- Crack detection
- Calipering
- Route surveying
- Free-span detection
- Leak detection

1.5 Monitoring and Control

Control systems such as these listed below are to be provided to ensure operational safety.

1.5.1 Emergency Shutdown

A means of shutting down the pipe system is to be provided at each of its initial and terminal points. The response time of an emergency shut down valve is to be appropriate to the fluid in the pipe (type and volume) and the operating conditions.

1.5.2 Pressure Protection

The pipe system is to be operated in a way that ensures the operating pressure is not exceeded. Primary overpressure protection devices which shut-in the production facilities (wells, pumps, compressors, etc.) are in no case to exceed the maximum allowable operating pressure. Secondary overpressure protection may be set above the maximum allowable operating pressure, but is not to exceed 90% of System Test Pressure. Such primary and secondary protection will protect the pipeline and allow for the orderly shut-in of the production facilities in case of an emergency or abnormal operating conditions. In some cases, other overpressure protection device settings for subsea well pipelines may be allowed since in the case of an emergency the well(s) will be shut-in at the host facility by the emergency shutdown system.

Instrumentation is to be provided to register the pressure, temperature and rate of flow in the pipeline. Any variation outside of the allowable transients is to activate an alarm in the control center.

1.5.3 Pressure, Temperature and Flow Control

To ensure protection of the pipe system against overpressurization and excessively high temperatures, automatic primary and secondary trips are to be installed. Details, including high/low pressure/temperature settings, are to be documented in the Operations Manual.

1.5.4 Relief Systems

Relief systems, such as relief valves, are typically required to ensure that the maximum pressure of the pipe system does not exceed a certain value. Relief valves are to be correctly sized, redundancy provided, and they are to discharge in a manner that will not cause fire, health risk or environmental pollution.

3 Maintenance

The principle function of maintenance is to ensure that the pipelines continue to fulfill their intended purpose in a safe and reliable way. Their functions and associated standards of performance are to be the basis for the maintenance objectives.

Maintenance is to be carried out on all pipeline systems, including associated equipment (e.g., valves, actuators, pig traps, pig signalers and other attachments). Maintenance procedures and routines may be developed, accounting for previous equipment history and performance.

5 Pipeline Damage and Repair

In the event of pipe damage threatening the safe continuous transportation of hydrocarbons, inspection, reassessment, maintenance and repair actions are to be promptly taken, as illustrated below:

- Identify possible cause of damage
- Identify type of encountered damage
- Define pipeline zone criticality and damage categorization
- Identify damage location and assessment techniques
- Outline repair techniques which may be applied to specific damage scenarios

5.1 Categorization of Damage

The causes of pipeline damage may be categorized as below:

5.1.1 Internal Damage

Internal corrosion damage occurring as a result of the corrosivity of the transported product and flow conditions in combination with inadequate use of inhibitors. Corrosion damage tends to take place in low points, bends and fittings.

Internal erosion damage occurs through abrasion by the product transported, typically at bends, trees, valves, etc. Erosion may cause deterioration of the inside wall and become a primary target for corrosion.

5.1.2 External Damage

Dropped objects due to, for example, activities on or surrounding a platform

Abrasion between cable or chain and the pipe

In form of a direct hit or dragging due to anchoring

Damage caused by construction operations, shipping operations, fishing operations

5.1.3 Environmental Damage

Severe storms and excessive hydrodynamic loads

Earthquake

Seabed movement and instability

Seabed liquefaction

Icebergs and marine growth

5.1.4 Types of Pipeline Damage

Damage to pipe wall

Overstressing or fatigue damages

Corrosion coating and weight coating damage

5.3 Damage Assessment

For damaged pipes, ASME B31.4 and B31.8 may be applied to determine whether a damage assessment and repair will be necessary. If a severe damage can not be repaired immediately, strength assessment of pipes with damages such as dents, corrosion defects and weld cracks may be performed, as defined in Appendix 2 of this Guide.

7 Pipeline Repair Methods

7.1 Conventional Repair Methods

Non-critical intervention work such as free-span correction, retrofitting of anode sleds and rock dumping can usually be considered as planned preventive measures. For the localized repair of non-leaking minor and intermediate pipeline damage, repair clamps may be utilized without the necessity of an emergency shutdown to the pipeline system. For major pipeline damage resulting in or likely to result in product leakage, immediate production shutdown and depressurization is invariably required, allowing the damaged pipe section to be retreated and replaced.

7.3 Maintenance Repair

Non-critical repairs that in the short term will not jeopardize the safety of the pipeline can form part of a planned maintenance program. Examples are:

- Corrosion coating repair
- Submerged weight rectification
- Cathodic protection repair
- Span rectification procedures
- Installation of an engineered backfill (rock dumping)



CHAPTER 4 Testing, Inspection and Maintenance

SECTION 3 Extension of Use

1 General

This Section pertains to obtaining and continuance of classification/certification of existing pipelines beyond the design life. The classification/certification requires special considerations with respect to the review, surveys and strength analyses in order to verify the adequacy of the pipeline for its intended services.

3 Extension of Use

To establish if an existing pipeline is suitable for extended service, the following are to be considered:

- Review original design documentation, plans, structural modification records and survey reports
- Survey pipeline and structures to establish condition
- Review the results of the in-place analysis utilizing results of survey, original plans, specialized geotechnical and oceanographic reports and proposed modifications which affect the dead, live, environmental and earthquake loads, if applicable, on the pipeline
- Re-survey the pipeline utilizing results from strength analysis. Make any alterations necessary for extending the service of the pipeline
- Review a program of continuing surveys to assure the continued adequacy of the pipeline

The first two items are to assess the pipeline to determine the possibility of continued use. In-place analyses may be utilized to identify the areas most critical for inspection at the re-survey.

Fatigue life is sensitive to the waves encountered during the past service and future prediction, and long-term environmental data is to be properly represented. Should any area be found to be deficient, then these areas require strengthening in order to achieve the required fatigue life. Otherwise, inspection programs are to be developed in order to monitor these areas on a periodical basis.

Fatigue analysis will not be required if the following conditions are satisfied:

- The original fatigue analysis indicates that the fatigue lives of all joints are sufficient to cover the extension of use.
- The fatigue environmental data used in the original fatigue analysis remain valid or are deemed to be more conservative.
- Cracks are not found during the re-survey, or damaged joints and members are being repaired.
- Marine growth and corrosion is found to be within the allowable design limits.

Surveys, as described in [Section 1-1-8 of the ABS Rules for Conditions of Classification – Offshore Units and Structures \(Part 1\)](#) and [Chapter 1, Section 5 of this Guide](#), are to be undertaken on a periodic basis to ascertain the satisfactory condition of the pipeline. Additional surveys may be required for pipe systems having unique features.

3.1 Review of Design Documents

Pipeline design information is to be collected to allow an engineering assessment of a pipeline's overall structural integrity. It is essential to have the original design reports, documents and as-built plans and specifications and survey records during fabrication, installation and past service. The Operator is to ensure that any assumptions made are reasonable and that information gathered is both accurate and representative of actual conditions at the time of the assessment. If the information cannot be provided, an assumption of lower design criteria, actual measurements or testing is to be carried out to establish a reasonable and conservative assumption.

3.3 Inspection

Inspection of an existing pipeline, witnessed and monitored by an ABS Surveyor, is necessary to determine a base condition upon which justification of continued service can be made. Reports of previous inspection and maintenance will be reviewed, an inspection procedure developed and a complete underwater inspection required to assure that an accurate assessment of the pipeline's condition is obtained.

The corrosion protection system is to be reevaluated to ensure that existing anodes are capable of serving the extended design life of the pipe system. If found necessary, replacement of the existing anodes or installation of additional new anodes is to be carried out. If the increase in hydrodynamic loads due to the addition of new anodes is significant, this additional load is to be taken into account in the strength analysis.

3.5 Strength Analyses

The strength analyses of an existing pipeline are to incorporate the results of the survey and any structural modifications and damages. The original fabrication materials and fit-up details are to be established such that proper material characteristics are used in the analysis and any stress concentrations are accounted for. For areas where the design is controlled by earthquake or ice conditions, the analyses for such conditions are also to be carried out. The results of the analyses are considered to be an indicator of areas needing inspection. Effects of alterations of structures or seabed to allow continued use are to be evaluated by analysis. Free spans where strength criteria are violated may be improved by seabed intervention. The results of these load reductions on the structure are to be evaluated to determine whether the repairs/alterations are needed.

3.7 Implementing Repairs/Re-inspection

The initial condition survey, in conjunction with structural analysis, will form the basis for determining the extent of repairs/alterations which will be necessary to class the pipeline for continued operation.

A second survey may be necessary to inspect areas which the analysis results indicate as being the more highly-stressed regions of the structure. Areas found overstressed are to be strengthened. Welds with low fatigue lives may be improved either by strengthening or grinding. If grinding is used, the details of the grinding are to be submitted to ABS for review and approval. Intervals of future periodic surveys shall be determined based on the remaining fatigue lives of these welds.



APPENDIX 1 Limit State Design Criteria

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APPENDIX 1 Limit State Design Criteria

SECTION 1 Limit State Design Principles

1 Limit State Design

1.1 Strength Requirements

The strength requirements for pipeline design will normally be satisfied if the following limit states are fulfilled:

- Bursting
- Local buckling and collapse
- Fracture
- Fatigue
- Ratcheting/Out-of-roundness

1.3 Limit States

The limit states are given in the form of maximum allowable limits such as strain, stress and bending moments and are to be checked for the following design scenarios:

- Installation
- Empty condition
- Water filled condition
- Pressure test condition
- Operational conditions

1.5 Maximum Allowable Limits

The maximum allowable limits are based on equations predicting the ultimate strength to which reduction factors are applied to address uncertainties in strength estimation and consequences related to failure:

- Statistical values for design equations
- Statistical values for material properties
- Complexity of conditions to be modeled
- Location zone



APPENDIX 1 Limit State Design Criteria

SECTION 2 Classification of Containment, Location, Material Quality and Safety

This Appendix recommends limit state design factors reflecting appropriate safety levels, containment hazard levels, consequences of failure related to life, environment and business, together with uncertainties related to material resistance and loads acting on the pipe. The recommended factors will be applicable for most pipeline designs, but where this Appendix is deemed inadequate, the establishment of alternative safety factors is to be verified by ABS.

1 Classification of Containment

The containment being transported is to be identified and categorized according to A1-2/Table 1.

TABLE 1
Classification of Containment

<i>Category</i>	<i>Description</i>
A	Contents in the form of gases and/or liquids that at ambient temperature and atmospheric pressure are nonflammable and nontoxic. <i>Examples:</i> water, water-based fluids, nitrogen, carbon dioxide, argon and air.
B	Contents in the form of gases and/or liquids that at ambient temperature and atmospheric pressure are flammable, toxic and/or could lead to environmental pollution if released. <i>Examples:</i> oil, petroleum products, toxic liquids, hydrogen, natural gas, ethane, ethylene, ammonia, chlorine, liquefied petroleum gas (such as propane and butane), natural gas liquids, etc.

If the containment being carried is not among the gases or liquids mentioned in A1-2/Table 1, it is to be classified in the category containing substances most similar in hazard potential to those quoted. If any doubt arises as to the contents being transported, hazardous classification B is to be assumed.

3 Classification of Location

The pipeline system is to be classified into location classes, as defined in A1-2/Table 2.

TABLE 2
Classification of Location

<i>Zone</i>	<i>Description</i>
1	Areas where infrequent human activity is anticipated (to be documented).
2	Areas adjacent to manned platforms and areas where frequent human activity is anticipated.

5 Classification of Material Quality

The material quality used for linepipes designed based on the format given in this Appendix is to meet the requirements of chemical composition and mechanical properties as defined by ISO 3183 1~3. The material quality is to be classified as A, B or C, as given by A1-2/Table 3.

TABLE 3
Classification of Material Quality

<i>Material Quality</i>	<i>Description</i>
Class A	A basic quality level corresponding to that specified in the main part of API SPEC 5L or ISO 3183-1.
Class B	For transmission pipelines, overall enhanced requirements (e.g., concerning toughness and nondestructive testing) are addressed, as specified by ISO 3183-2
Class C	For particularly demanding applications where very stringent requirements (e.g., concerning sour service, fracture arrest properties, plastic deformation) on quality and testing are imposed, ISO 3183-3.

The tensile and Charpy V-notch impact properties are to be in accordance with relevant specifications, such as API SPEC 5L or ISO 3183 1~3. Tensile properties of the linepipe are to be tested in both transverse and longitudinal directions, while Charpy V-notch samples are to be tested only in the transverse direction.

Materials are to exhibit fracture toughness that is satisfactory for the intended application, as supported by previous satisfactory service experience or appropriate toughness tests. Where the presence of ice is judged as a significant environmental factor, material selection may require special consideration.

The following requirements with respect to the definition of Specified Minimum Yield Strength and Specified Minimum Tensile Strength in the circumferential direction are to be fulfilled:

SMYS < (mean – 2*Standard Deviations) of yield stress

SMTS < (mean – 3*Standard Deviations) of tensile stress

The material yield stress and tensile stress are to be obtained through testing at relevant temperatures and test results submitted to ABS.

Material anisotropy is defined by the ratio between material properties in the transverse direction and those in the longitudinal direction, and is, where appropriate, to be accounted for in the strength calculations.

For pipelines or sections of these to be operated at temperatures above 50°C (120°F), appropriate material resistance de-rating factors are to be established and applied to the specified minimum yield and tensile strength.

For linepipes manufactured by the UO or UOE method, the influence of the manufacturing process on the yield stress is to be accounted for in the design. If the material's specified minimum yield stress is less than 70 ksi, the values given in 3-4/7 may be used, otherwise, the influence of the manufacturing process is to be based on testing.

7 Classification of Safety

The definition of safety classes used in this Appendix is in accordance with A1-2/Table 4.

TABLE 4
Definition of Safety Classes

<i>Safety Class</i>	<i>Description</i>
Low	Failure implies no risk to human safety and only limited environmental damage and economic losses.
Normal	Failure implies negligible risk to human safety and only minor damage to the environment, but may imply certain economic losses.
High	Failure implies risk to the total safety of the system as to human safety and environmental pollution. High economic losses may apply.

For normal use, the safety classes in A1-2/Table 5 and A1-2/Table 6 apply. Other safety classification may be justified based on the design target reliability level of the pipeline, but are in such cases to be submitted for approval by ABS.

TABLE 5
Classification of Safety Classes Pipelines

<i>Load Condition</i>	<i>Content Category A</i>		<i>Content Category B</i>	
	<i>Location Zone 1</i>	<i>Location Zone 2</i>	<i>Location Zone 1</i>	<i>Location Zone 2</i>
Temporary	Low	Low	Low	Low
Operational	Low	Normal	Normal	High
Abnormal	Low	Normal	Low	Normal

TABLE 6
Classification of Safety Classes for Bundles

<i>Pipes</i>	<i>Launch & Installation</i>	<i>Operation</i>
Flowlines	Low	Normal
Heat-Up Lines	Low	Low
Carrier pipe and Sleeve	Normal	Low



APPENDIX 1 Limit State Design Criteria

SECTION 3 Limit State for Bursting

1 Hoop Stress Criteria

The hoop stress is not to exceed the following:

$$(p_i - p_e) \frac{D - t}{2 \cdot t} \leq \eta_s \cdot \min[1.00 \cdot SMYS, 0.87 \cdot SMTS]$$

where

- p_i = internal pressure
- p_e = external pressure
- D = nominal outside steel diameter of pipe
- t = minimum wall thickness
- $SMYS$ = Specified Minimum Yield Strength at design temperature
- $SMTS$ = Specified Minimum Tensile Strength at design temperature

De-rating of material resistance is, where applicable, to be accounted for in the definition of Specified Minimum Yield Strength and Specified Minimum Tensile Strength at elevated design temperatures.

For thick walled pipes with a $D/t < 20$, the above hoop stress criteria may be adjusted based on, e.g., BS 8010-3.

The usage factors for hoop stress criteria are given in A1-3/Table 1.

TABLE 1
Usage Factors for Hoop Stress Criteria

<i>Material Quality</i>	<i>Usage Factor</i>	<i>Safety Class</i>		
		<i>Low</i>	<i>Normal</i>	<i>High</i>
Class B, C	η_s	0.85	0.80	0.70
Class A	η_s	0.83	0.77	0.67

3 System Pressure Test

The pipeline system is to be subjected to a system pressure test after installation in accordance with Chapter 4, Section 1.



APPENDIX 1 Limit State Design Criteria

SECTION 4 Limit State for Local Buckling

Local buckling may occur due to excessive bending combined pressure and longitudinal force. The failure mode will be a combination of local yielding and flattening/local buckling and mainly depends on the diameter to wall thickness ratio, load condition and local imperfections in material and geometry. Initial out-of-roundness is the only local imperfection accounted for in the equations presented in this Appendix. The formulas in this Section are applicable to diameter to thickness ratios between 10 and 60. For pipes of larger D/t ratio, the use of the moment criterion is subject to ABS approval. The criteria will be applicable to steel pipes, but may be applied to titanium pipes, provided that an equivalent $SMYS$ is defined as the minimum of $SMYS$ and $SMTS/1.3$.

1 Maximum Allowable Moment

The maximum allowable bending moment, M_{All} , ensuring structural strength against local buckling may be found by:

$$M_{All} = \frac{\eta_{RM}}{\gamma_c} M_\ell \cdot \sqrt{1 - (1 - \alpha^2) \cdot \left(\frac{p}{\eta_{RP} p_\ell} \right)^2} \cdot \cos \left[\frac{\pi}{2} \cdot \frac{\frac{\gamma_c F}{\eta_{RF} F_\ell} - \alpha \cdot \frac{p}{\mu_{RP} p_\ell}}{\sqrt{1 - (1 - \alpha^2) \cdot \left(\frac{p}{\eta_{RP} p_\ell} \right)^2}} \right]$$

where

- p = pressure acting on the pipe ($p_i - p_e$)
- F = true longitudinal force acting on the pipe
- γ_c = condition load factor
- η_R = strength usage factors

The moment M_ℓ , which is the moment capacity in pure bending, may be calculated as:

$$M_\ell = \left(1.05 - 0.0015 \cdot \frac{D}{t} \right) \cdot SMYS \cdot D^2 \cdot t$$

where

- $SMYS$ = Specified Minimum Yield Strength in longitudinal direction at design temperature
- D = average diameter
- t = wall thickness

The longitudinal force, F_ℓ , may be estimated as:

$$F_\ell = 0.5(SMYS + SMTS)A$$

where

- A = cross sectional area, which may be calculated as $\pi \times D \times t$
- $SMYS$ = Specified Minimum Yield Strength in longitudinal direction at design temperature
- $SMTS$ = Specified Minimum Tensile Strength in longitudinal direction at design temperature

The pressure, p_ℓ , is for external overpressure conditions equal to the pipe collapse pressure and may be calculated based on:

$$p_\ell^3 - p_{el} \cdot p_\ell^2 - \left(p_p^2 + p_{el} \cdot p_p \cdot f_0 \cdot \frac{D}{t} \right) \cdot p_\ell + p_{el} \cdot p_p^2 = 0$$

where

$$p_{el} = \frac{2 \cdot E}{(1 - \nu^2)} \cdot \left(\frac{t}{D} \right)^3$$

$$p_p = k_{fab} \cdot SMYS \cdot \frac{2 \cdot t}{D}$$

$$D = \text{average diameter}$$

$$t = \text{wall thickness}$$

$$f_0 = \text{initial out-of-roundness } (D_{\max} - D_{\min})/D, \text{ not to be taken less than } 0.5\%$$

Note: Out-of-roundness caused during the construction phase is to be included but not flattening due to external water pressure or bending in as-laid position. Increased out-of-roundness due to installation and cyclic operating loads may aggravate local buckling and is to be considered. It is recommended that out-of-roundness due to through-life cyclic loads be simulated, if applicable.

$$SMYS = \text{Specified Minimum Yield Strength in hoop direction at design temperature}$$

$$E = \text{Young's Modulus at design temperature}$$

$$\nu = \text{Poisson's ratio}$$

$$k_{fab} = \text{material resistance de-rating factor due to fabrication}$$

For internal overpressure conditions, the pressure, p_ℓ , is equal to the burst pressure, which may be found as:

$$p_\ell = 0.5 \cdot (SMTS + SMYS) \cdot \frac{2 \cdot t}{D - t}$$

where

$$SMYS = \text{Specified Minimum Yield Strength in hoop direction at design temperature}$$

$$SMTS = \text{Specified Minimum Tensile Strength in hoop direction at design temperature}$$

$$D = \text{average diameter}$$

$$t = \text{wall thickness}$$

The strength anisotropy factor, α , may be calculated as:

$$\alpha = \frac{\pi \cdot D^2}{4} \cdot \left| \frac{p_c}{F_\ell} \right| \quad \text{for external overpressure}$$

$$\alpha = \frac{\pi \cdot D^2}{4} \cdot \left| \frac{p_b}{F_\ell} \right| \quad \text{for internal overpressure}$$

3 Effects of Manufacturing Process

The material strength in the hoop direction will be influenced by the manufacturing process, and if no test data are available for the hoop strength, the following reduction factor, k_{fab} , is to be used.

$$k_{fab} = \begin{cases} 1.00 & \text{Seamless and annealed pipes} \\ 0.93 & \text{Welded pipes not expanded, e.g., UO pipes} \\ 0.85 & \text{Welded and expanded pipes, e.g., UOE pipes} \end{cases}$$

5 Usage Factors

Usage factors, η_R , are listed in A1-4/Table 1.

TABLE 1
Usage Factors

<i>Usage Factors</i>	η_{RP}	η_{RF}	η_{RM}
Low	0.95	0.90	0.80
Normal	0.93	0.85	0.73
High	0.90	0.80	0.65

7 Condition Load Factors

To account for uncertainties related to the modeling of certain load conditions, condition load factors are introduced in accordance with A1-4/Table 2.

TABLE 2
Condition Load Factors for Limit State Design

<i>Load Condition</i>	<i>Condition Load Factor, γ_c</i>
Uneven seabed	1.06
Continuously stiff supported	0.85
System pressure test	0.94
Otherwise	1.0



APPENDIX 1 Limit State Design Criteria

SECTION 5 Limit State for Fracture of Girth Weld Crack-like Defects

Fracture in welds due to tensile strain is normally evaluated in accordance with a recognized assessment method based on the failure assessment diagram, which combines the two potential failure modes, brittle fracture and plastic collapse. This Section may be applied to define acceptance criteria for inspection of girth welds.

1 Possible Cracks in Girth Weld

Various types of imperfections are known to occur in girth welds. The most damaging types are cracks, inadequate penetration of the root bead and lack of fusion. The imperfections are particularly damaging if they occur in a weld that significantly under-matches the yield strength of the base material.

When evaluating the risk of fracture failure for girth welds, assumptions are to be made regarding types, dimensions and locations of weld defects. The most frequently seen type of planar/crack-like defect in one-sided Shielded Metal Arc Welding is lack-of-fusion defects. Such defects can be located near the surface, at the root of the weld toe or they can be surface-breaking and may have gone undetected when following nondestructive testing procedures according to API STD 1104.

Maximum weld flaws are to be used as the basic input for the assessment. The flaw may be assumed as maximum allowable defect due to lack of fusion between passes. Surface flaw is chosen as the worst case scenario from acceptable flaws specified in the welding procedure specifications. The defect sizes to be used in the fracture assessment are to be based on the welding methods used and the accuracy of the nondestructive testing during construction. If no detailed information is available, the defects and material may be taken as below:

Type:	Surface flaw due to lack of fusion
Depth (a):	Minimum of 3 mm (0.118 inch) and nominal wall-thickness divided by number of welding passes
Length ($2c$):	$2c < \min [2t, 250 \text{ mm (1.97 inch)}]$
CTOD:	0.075 mm (0.003 inch) or as given by welding specifications
Material:	As for parent material
D =	average diameter
t =	wall thickness

The fracture failure of welds is highly dependent on the weld matching and on the ratio of yield to tensile strength. An adequate strain concentration factor is to be established, accounting for the stiffness of coatings and buckle arrestors.

3 Fracture of Cracked Girth Welds

Defects in girth welds can be assessed on one of three levels, depending upon the quality of the affected welds, the availability of relevant material data and difficulties related to repairs. Level 1 is to be mandatory, where acceptance levels are graded according to criticality of application. Level 2 is to be a conservative initial assessment. Level 3 is to be applied to details that fail in Level 2.

3.1 Level 1 Assessment – Workmanship Standards

Pipeline welding codes establish minimum weld quality standards based on inspection of welder's workmanship, and the flaw acceptance criteria are evolved through industry experience. Hence, most workmanship standards are similar, though not identical, in terms of allowable imperfection types and sizes.

The workmanship standards may be based on API STD 1104 or standards such as ASME Boiler and Pressure Vessel Code, CSA Z662 and BS 4515.

3.3 Level 2 Assessment – Alternative Acceptance Standards

Alternative acceptance standards have been developed to facilitate acceptance of flaws that do not meet workmanship standards. Incentives for alternative standards are usually economic, arising due to the inaccessibility or quantity of welds that would otherwise be repaired. Alternative standards recognize that the true severity of a flaw is dependent on material toughness and applied stress levels, and can only be determined using fracture mechanics principles.

CTOD is established from destructive tests performed on weldments. If the pipeline is yet to be constructed, CTOD tests can be performed as part of the weld procedure qualification. If the pipeline is already in service and CTOD data are not available, the welding procedures, consumable and base materials used in construction may be used to duplicate welds for the purpose of conducting CTOD tests. If any of these elements is no longer available, it will be necessary to obtain a representative weld for testing. Alternatively, a lower-bound CTOD of 0.075 mm (0.003 inch) may be assumed in lieu of tests.

Alternative criteria are given in codes and standards, such as in Appendix to API STD 1104, Appendix K to CSA Z662, BSI 7910 and the EPRG Guidelines on assessment of defects in transmission pipeline girth welds.

3.5 Level 3 Assessment – Detailed Analysis

A more detailed analysis is to use FADs and tearing stability analysis from BS 7910, API RP 579 or equivalent.

BS 7910 Level 2 provides three possible FADs:

- i) Generalized curve for low work hardening materials
- ii) Generalized curve for low and high work hardening materials
- iii) Material specific curve

Level 3 in BS 7910 covers tearing instability analysis.

In the assessment of the fracture failure capacity of the weld due to longitudinal strain of the pipe, surface breaking flaws may be idealized as semi-elliptical surface weld defects of depth, a , and total length, $2c$. a and c are to be based on nondestructive test measurements with a minimum of not less than the minimum detectable crack size by the applied nondestructive test method. Parametric solutions for K are available in codes such as API RP 579 and BS 7910.

The critical stress levels with respect to failure (e.g., fracture, plastic collapse of remaining ligament) can be obtained from Failure Assessment Diagram analysis, for the different pipelines as a function of the degree of corrosion wall-thickness reduction. The corresponding critical strain level is estimated using the Ramberg-Osgood curve for the stress-strain relationship.

5 Fatigue Crack Propagation

The fatigue crack propagation rate may be obtained following the procedure described in A1-6/5 or refer to basic fracture mechanics methodology as per BS 7910, API RP 579 or equivalent.

Use actual da/dN versus ΔK and ΔK data wherever possible. Fit Paris' equation over the entire range of data or fit alternative crack growth law (e.g., Forman equation, see API RP 579 for others). Alternatively, fit Paris' equation in piecewise linear manner. The latter may be the most effective for crack growth in seawater with/without cathodic protection. In the absence of specific da/dN data, use upper bound relationships in BS 7910, API RP 579 or equivalent.

Fatigue life versus crack depth may be predicted by integrating da/dN versus ΔK relationship using weight average ΔK or cycle-by-cycle approach if interaction effects are negligible.



APPENDIX 1 Limit State Design Criteria

SECTION 6 Limit State for Fatigue

Unsupported pipeline spans, welds, J-lay collars and buckle arrestors are to be assessed for fatigue. Potential cyclic loading that can cause fatigue damage includes vortex-induced vibrations, wave-induced hydrodynamic loads, floating installation movements and cyclic pressure and thermal expansion loads. The fatigue life is defined as the time it takes to develop a through-wall-thickness crack.

Fatigue analysis and design can be conducted using:

- i) S-N approach for high cycle fatigue (and low cycle fatigue of girth welds may be checked based on $\Delta\epsilon$ -N curves.)
- ii) Fracture mechanics approach
- iii) Hybrid approach (Combination of S-N and fracture mechanics approaches)

It is recommended that the S-N approach be prioritized for design purposes. The fracture mechanics approach is recommended for assessments or reassessments and establishment of inspection criteria. It should be noted that the S-N approach and fracture mechanics approach should produce very similar results. Different acceptance criteria could be applied for the different approaches. In general, design life criteria should be adopted when using the S-N approach, while through-thickness crack criteria are to be applied for the fracture mechanics approach. In order to achieve a consistent safety level, it might be necessary to calibrate the initial crack size in the fracture mechanics approach against the S-N approach.

1 Fatigue Assessment Based on S-N Curves

For assessment of high cycle fatigue, fatigue strength is to be calculated based on laboratory tests (S-N curves) or fracture mechanics. In the limit state based fatigue analysis, appropriate partial safety factors are to be defined and applied to loads and material strength prior to the estimation of the accumulated fatigue damage.

Typical steps required for fatigue analysis using the S-N approach are outlined below.

- i) Estimate long-term stress range distribution
- ii) Select appropriate S-N curve
- iii) Determine stress concentration factor
- iv) Estimate accumulated fatigue damage using Palmgren-Miner's rule

The S-N curves to be used for fatigue life calculation may be defined by the following formula:

$$\log N - \log a - m \cdot \log \Delta\sigma$$

where

- N = allowable stress cycle numbers
- a, m = parameters defining the curves, which are dependant on the material and structural detail
- $\Delta\sigma$ = stress range, including the effect of stress concentration

Multiple linear S-N curves in logarithmic scale may be applicable. Each linear curve may then be expressed as the above equation.

The fatigue damage may be based on the accumulation law by Palmgren-Miner:

$$D_{fat} = \sum_{i=1}^{M_c} \frac{n_i}{N_i} \leq \eta$$

where

- D_{fat} = accumulated fatigue damage
- η = allowable damage ratio, to be taken in accordance to 3-4/11
- N_i = number of cycles to failure at the i^{th} stress range defined by the S-N curve
- n_i = number of stress cycles with stress range in block i

3 Fatigue Assessment Based on $\Delta\varepsilon$ - N Curves

The number of strain cycles to failure may be assessed according to the American Welding Society (AWS) Standards $\Delta\varepsilon$ - N curves, where N is a function of the range of cyclic bending strains $\Delta\varepsilon$.

The strain range $\Delta\varepsilon$ is the total amplitude of strain variations, i.e., the maximum less the minimum strains occurring in the pipe body near the weld during steady cyclic bending loads.

5 Fatigue Assessment Based on Fracture Mechanics

In the fracture mechanics approach, the crack growth is calculated using Paris' equation and the final fracture found in accordance with recognized failure assessment diagrams. It may be applied to develop cracked S-N curves for pipes containing initial defects. If a crack growth analysis is performed by the fracture mechanics method, the design criterion for fatigue life is to be at least 10 times the service life for all components. The initial flaw size is to be the maximum acceptable flaw specified for the nondestructive testing during manufacture of the component in question.

Typical steps required for fatigue analysis using the fracture mechanics approach are outlined below:

- i) Estimate long-term stress range distribution
- ii) Determine stress concentration factor
- iii) Select appropriate material parameter to be used in Paris' equation
- iv) Determine initial crack size and crack initiation time
- v) Determine the critical crack size
- vi) Determine geometry function for stress intensity factor
- vii) Integrate Paris' equation to estimate fatigue life



APPENDIX 1 Limit State Design Criteria

SECTION 7 Limit State for Ratcheting/Out-of-roundness

The pipeline out-of-roundness is related to the maximum and minimum pipe diameters (D_{\max} and D_{\min}) measured from different positions around the sectional circumference according to:

$$f_0 = \frac{D_{\max} - D_{\min}}{D}$$

Out-of-roundness introduced during manufacturing, storage and transportation is generally not to exceed 0.75%. For design, the initial out-of-roundness is not to be assumed less than 0.50%.

The out-of-roundness of the pipe may increase where the pipe is subject to reverse bending and the effect of this on subsequent straining is to be considered. For a typical pipeline, the following scenarios will influence the out-of-roundness:

- i) Reverse inelastic bending during installation
- ii) Cyclic bending due to shutdowns in operation if global buckling is allowed to relieve temperature- and pressure-induced compressive forces

Critical point loads may arise at free-span shoulders, artificial supports and support settlement.

Out-of-roundness accumulative through the life cycle is, if applicable, to be found from ratcheting analysis. Out-of-roundness is not to exceed 2% unless:

- i) Effect of out-of-roundness on moment capacity and strain criteria is included
- ii) Requirements for pigging and other pipe run tools are met

Ratcheting is described in general terms as signifying incremental plastic deformation under cyclic loads in pipelines subject to high pressure and high temperatures. The effect of ratcheting on out-of-roundness and local buckling is to be considered.

A simplified code check of ratcheting is that the equivalent plastic strain is not to exceed 0.1%, as defined based on elastic-perfectly-plastic material and assuming that the reference state for zero strain is the as-built state after mill pressure testing.

The finite element method may be applied to quantify the amount of deformation induced by ratcheting during the life cycle of a pipeline.



APPENDIX 1 Limit State Design Criteria

SECTION 8 Finite Element Analysis of Local Strength

If adequate documentation is presented, alternative methods for estimating the strength capacity of pipes subjected to combined loads may be accepted for installation and seabed intervention design. An important tool is the finite element method, which allows the designer to model the geometry, material properties and imperfections such as out-of-roundness, field joints, attachments and corrosion defects and thereafter estimate the maximum strength for a given load scenario. Another important issue is the effect of cyclic loads. Cyclic loads may aggravate/increase imperfections and fatigue damage, which may end up reducing the design life.

1 Modeling of Geometry and Boundary Conditions

When applicable, the size of a finite element model may be reduced by introducing symmetry boundary conditions. For this approach to be valid, material, geometry and loads are to be symmetrically distributed around the same symmetry line. This approach may reduce finite element models to one half or less of the pipe section.

It is important that the modeled pipe section includes all features and attachments relevant for the stress distribution in the pipe and that the model is sufficiently long to catch relevant failure modes.

Imperfections such as out-of-roundness, weld defects/misalignment and corrosion defects may reduce the strength of the pipe considerably, and the largest realistic imperfections are to be included in the model. Imperfections that might be insignificant for some load conditions will be catastrophic for others. An example is out-of-roundness, which has negligible influence on the burst strength while it might reduce the collapse strength due to considerable external overpressure. If different imperfections are combined, their mutual orientation might influence the pipe strength. An example is combined out-of-roundness and corrosion defects. Here, the worst orientation of the out-of-roundness with regard to pipe strength might change with the increasing size of a corrosion defect.

3 Mesh Density

The mesh density generally depends on the selected element definition and detail level of the analysis. Selection of element definition and mesh density/distribution is generally to be based on engineering experience, but it is recommended that sensitivity studies be performed to demonstrate the adequacy of the chosen mesh. This exercise will normally be a part of the verification procedure for the model.

5 Material

The material input to Finite Element Software is to be based on the software used and the problem to be solved. For pure elastic analysis, it will normally be enough to describe the material characteristic in the form of the modulus of elasticity and Poisson's ratio, while for analysis, including material nonlinearity, it will be necessary to include a description of the material's plastic behavior. Here, it is important to notice that finite element programs might use either a true stress-strain or engineering stress-strain relationship.

It is important to consider if residual stresses in the material are to be included in the model. For pipelines, residual stresses in both longitudinal and hoop directions might be introduced through the forming process or by seam welding. Effects of these residual stresses are, in general, considered negligible for pipeline analysis, but practice has demonstrated that this is not always the case.

When cyclic inelastic loading is to be modeled, a nonlinear combined isotropic and kinematic material model may be applied. This material model will also be applicable for low cycle fatigue studies.

7 Loads and Load Sequence

The sequence of applied loads may influence the result, and if the sequence is not known, several tests are to be performed to make sure that the results represent the worst case. As an example, a pipe subjected first to axial tension and then pressure might burst at a higher pressure than for the pure pressure condition, and visa versa.

9 Validation

Finite element models and other analysis models, in general, are to be validated against appropriate mechanical tests and the validation approved by ABS before they are used in design.



APPENDIX 2 Assessment of Corrosion, Dent and Crack-like Defects

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APPENDIX 2 Assessment of Corrosion, Dent and Crack-like Defects

SECTION 1 Corrosion Defect Assessment

This Appendix defines strength criteria that may be used for corrosion allowance design and assessment of corroded and dented pipes and girth weld defects.

1 Scope of the Assessment

The scope of the assessment includes:

- i) Proper characterization of defects by thickness profile measurements
- ii) An initial screening phase to decide whether detailed analysis is required or whether fitness for service is to be considered
- iii) Detailed assessment phase:
 - Check burst limit state (allowable versus maximum internal service pressure).
 - Check collapse limit state (allowable versus maximum external service pressure, bending moment and axial load).
 - Check adequacy of residual corrosion allowance for remaining service life.
 - Other checks, e.g., residual fatigue life, particularly if cracks are detected within defects.
- iv) Updated inspection and maintenance program

3 Corrosion Defect Inspection

The pipe is to be inspected, if applicable, for defects due to corrosion, and consideration is to be given to the uncertainties in corrosion rate and measurement accuracy. These uncertainties may be modeled by a probabilistic method.

Initially, inspection intervals may be set as three (3) years for oil and water lines and six (6) years for dry gas lines. However, the optimum inspection intervals may be selected using reliability-based inspection planning techniques. The reliability-based inspection planning procedure is to estimate the corrosion rate in the line and identify all of the defects that would fail the strength requirements before the next inspection.

5 Corrosion Defect Measurements

The actual size and shape of the corrosion defect is to be defined by an adequate number of measured thickness profiles. These measurements are to be performed in accordance with Section 5.3 of API RP 579 or equivalent.

The assessment of a single isolated defect is to be based on a critical profile defined by the largest measured characteristic dimensions of the defect (e.g., depth, width, length) and properly calibrated safety/uncertainty factors in order to account for uncertainties in the assessment and thickness measurements. See API RP 579 Section 4.3 for guidance on extracting the critical profile from measured thickness profiles.

If several corrosion defects inside a relatively small area have been detected during an inspection, appropriate determination of defect interaction is to be conducted, accounting for the following factors:

- Angular position of each defect around circumference of the pipe
- Axial spacing between adjacent defects
- Internal or external defects
- Length of individual defects
- Depth of defects
- Width of defects

A distance equivalent to the nominal pipe wall thickness may be used as a simple criterion of separation for colonies of longitudinally-oriented pits separated by a longitudinal distance or parallel longitudinal pits separated by a circumferential distance.

For longitudinal grooves inclined to pipe axis:

- If the distance x , between two longitudinal grooves of length L_1 and L_2 , is greater than either of L_1 or L_2 , then the length of corrosion defect L is L_1 or L_2 , whichever is greater. It can be assumed that there is no interaction between the two defects.
- If the distance x , between two longitudinal grooves of length L_1 and L_2 , is less either of L_1 and L_2 , it is to be assumed that the two defects are fully interacted and the length of the corrosion defect L is to be taken as $L = L_1 + L_2 + x$.

7 Corrosion Defect Growth

The corrosion defect depth, d , after the time of operation, T , may be estimated using an average corrosion rate V_{cr} :

$$d = d_0 + V_{cr} \cdot T$$

where d_0 is defect depth at the present time.

The defect length may be assumed to grow in proportion with the depth, hence:

$$L = L_0 \left(1 + \frac{V_{cr} \cdot T}{d_0} \right)$$

where L and L_0 are defect lengths at the present time and the time T later.

The corrosion rate is to be based on relevant service data or laboratory tests.

9 CO₂ Corrosion Rate Estimate

CO₂ corrosion rates in pipelines made of carbon steel may be evaluated using industry-accepted equations that preferably combine contributions from flow independent kinetics of the corrosion reaction at the metal surface, with the contribution from flow dependent mass transfer of dissolved CO₂.

The corrosion rate V_{cr} , in mm/year, can be predicted by:

$$V_{cr} = \frac{1}{\frac{1}{V_r} + \frac{1}{V_m}}$$

where

- V_r = flow independent contribution, denoted the reaction rate
- V_m = flow dependent contribution, denoted the mass transfer rate

The reaction rate V_r can be approximated by:

$$\log(V_r) = 4.93 - \frac{1119}{T_{mp} + 273} + 0.58 \cdot \log(p\text{CO}_2)$$

where

- T_{mp} = temperature, in °C
- $p\text{CO}_2$ = partial pressure of CO_2 , in bar
- = $n\text{CO}_2 \cdot p_{opr}$
- $n\text{CO}_2$ = fraction of CO_2 in the gas phase
- p_{opr} = operating pressure, in bar

The mass transfer rate V_m is approximated by:

$$V_m = 2.45 \cdot \frac{U^{0.8}}{d^{0.2}} \cdot p\text{CO}_2$$

where

- U = liquid flow velocity, in m/s
- d = inner diameter in meters

11 Maximum Allowable Operating Pressure for Corroded Pipes

All defects deeper than 0.8 times the wall thickness are to be repaired. For less severe defect depths, ASME B31G or the following criteria may be applied to estimate the maximum allowable operating pressure for pipelines with a single corrosion defect:

$$MAOP \leq \eta \cdot p_{burst} = \eta \cdot 0.5 (SMYS + SMTS) \left(\frac{2t}{D} \right) \frac{1 - \left(\frac{d}{t} \right)}{1 - \frac{d}{t \sqrt{1 + 0.8 \left(\frac{L}{\sqrt{Dt}} \right)^2}}}$$

where

- $MAOP$ = maximum allowable operating pressure
- p_{burst} = internal overpressure at burst
- D = average diameter
- t = wall thickness measurement
- d = depth of corrosion defect, not to exceed $0.8 \times t$
- L = length of corrosion defect
- $SMYS$ = Specified Minimum Yield Strength in hoop direction
- $SMTS$ = Specified Minimum Tensile Strength in hoop direction
- η = usage factor which is to be taken in accordance with A2-1/Table 1

TABLE 1
Usage Factors for Hoop Stress Criteria

Usage Factor	Safety Class		
	Low	Normal	High
η	0.76	0.72	0.63

Note:

- 1 Safety classes are in accordance with Appendix 1, Section 3.
- 2 Load factors and condition load factors are in accordance with A1-2/3.

13 Maximum Allowable Moment

Local buckling may occur due to excessive combined pressure, longitudinal force and bending. The failure mode will be a combination of local yielding and flattening/local buckling. The failure mode mainly depends on the diameter-to-wall-thickness ratio (D/t), load condition and local imperfections in material and geometry. This Subsection gives the maximum allowable bending moment for pipes with a local corrosion defect. The formulas in this Subsection are applicable to diameter-to-thickness ratio in between 10 and 60. For pipes of larger D/t ratio, the use of the moment criterion is subjected to ABS approval.

The maximum allowable bending moment for local buckling of corroded pipes, valid for both internal- and external- overpressure, can be expressed as given below. The bending strength is to be found by both calculations 1 and 2, after which the lowest value is to be used as the maximum allowable design moment.

The maximum allowable bending moment for local buckling can be found by:

$$M_{all} = \frac{\eta_{RM}}{\gamma_C} M_\ell \left[\delta_1 \sin(\psi) \sqrt{1 - \left(1 - \alpha^2\right) \left(\frac{P}{\eta_{RP} P_\ell}\right)^2} + 0.5(1 - k_2) \sin(\beta) \left(\alpha \frac{P}{\eta_{RP} |P_\ell|} + \delta_2 \sqrt{1 - \left(1 - \alpha^2\right) \left(\frac{P}{\eta_{RP} P_\ell}\right)^2} \right) \right]$$

where the angle to the plastic neutral axis is given by:

$$\psi = \frac{\pi + \delta_3(1 - k_1)\beta}{2\delta_4} + \frac{\pi - (1 - k_1)\beta}{2\delta_5} \Delta, \quad \Delta = \frac{\left(\frac{\gamma_C F}{\eta_{RF} |F_\ell|} - \alpha \frac{P}{\eta_{RP} |P_\ell|} \right)}{\sqrt{1 - \left(1 - \alpha^2\right) \left(\frac{P}{\eta_{RP} P_\ell}\right)^2}}$$

For grooves on the inner side of the pipe wall:

$$k_1 = \left(1 - \frac{d}{t}\right) \left(1 + \frac{d}{D}\right), \quad k_2 = \left(1 - \frac{d}{t}\right) \left(1 + \frac{d}{D}\right)^2$$

For grooves on the outer side of the pipe wall:

$$k_1 = \left(1 - \frac{d}{t}\right) \left(1 - \frac{d}{D}\right), \quad k_2 = \left(1 - \frac{d}{t}\right) \left(1 - \frac{d}{D}\right)^2$$

The strength anisotropy factor is given by:

$$\alpha = \frac{\pi \cdot D^2}{4} \cdot \left| \frac{p_\ell}{F_\ell} \right|$$

For extreme pressure and/or axial force conditions, it is advised that this factor be verified by finite element analysis.

13.1 Calculation 1

$$\text{If } \beta \geq \frac{\pi}{1+k_1} \frac{(1-\Delta)}{(1+\Delta)}$$

$$\text{then } \delta_1 = 1, \quad \delta_2 = -1, \quad \delta_3 = 1, \quad \delta_4 = 1, \quad \delta_5 = -1$$

$$\text{else } \delta_1 = k_1, \quad \delta_2 = 1, \quad \delta_3 = -1, \quad \delta_4 = k_1, \quad \delta_5 = -k_1$$

13.3 Calculation 2

$$\text{If } \beta \geq \frac{\pi}{1+k_1} \frac{(1+\Delta)}{(1-\Delta)}$$

$$\text{then } \delta_1 = -1, \quad \delta_2 = 1, \quad \delta_3 = 1, \quad \delta_4 = 1, \quad \delta_5 = 1$$

$$\text{else } \delta_1 = -k_1, \quad \delta_2 = -1, \quad \delta_3 = -1, \quad \delta_4 = k_1, \quad \delta_5 = k_1$$

where

M_{All}	=	allowable bending moment
p	=	pressure acting on the pipe
F	=	longitudinal force acting on the pipe
D	=	average diameter
t	=	wall thickness
d	=	defect depth
ψ	=	angle from bending plane to plastic neutral axis
k_i	=	constant
α	=	strength anisotropy factor
β	=	half the defect width
δ_i	=	constants
γ_C	=	condition load factor
η_R	=	strength usage factor, in accordance with A2-1/Table 2

The moment M_ℓ , which is the moment capacity in pure bending, may be calculated as:

$$M_\ell = \left(1.05 - 0.0015 \cdot \frac{D}{t} \right) \cdot SMYS \cdot D^2 \cdot t$$

where

D	=	average diameter
t	=	wall thickness
$SMYS$	=	Specified Minimum Yield Strength in longitudinal direction

The longitudinal force F_ℓ may be estimated as:

$$F_\ell = 0.5(SMYS + SMTS)[\pi - (1 - k_1)\beta]Dt$$

where

D	=	average diameter
t	=	wall thickness

- β = half of the corrosion defect angle
 $SMYS$ = Specified Minimum Yield Strength in longitudinal direction
 $SMTS$ = Specified Minimum Tensile Strength in longitudinal direction
 k_1 = constant given in A2-1/13

The pressure p_ℓ is for external overpressure conditions equal to the pipe collapse pressure and may be calculated based on:

$$p_\ell^3 - p_{el} p_\ell^2 - \left[p_p^2 + p_{el} p_p f_0 \left(\frac{D}{t_{cor}} \right) \right] p_\ell + p_{el} p_p^2 = 0$$

where

$$p_{el} = \frac{2E}{(1-\nu^2)} \left(\frac{t_{cor}}{D} \right)^3$$

$$p_p = \eta_{fab} SMYS \frac{2t_{cor}}{D}$$

t_{cor} = minimum measured wall thickness, including proper reduction factor accounting for inaccuracy in measurement method

f_0 = initial out-of-roundness, $(D_{max} - D_{min})/D$

Note: Out-of-roundness caused during the construction phase is to be included, but not flattening due to external water pressure or bending in as-laid position. Increased out-of-roundness due to installation and cyclic operating loads may aggravate local buckling and are to be considered. Here, it is recommended that out-of-roundness due to through life loads be simulated using finite element analysis.

$SMYS$ = Specified Minimum Yield Strength in hoop direction

E = Young's modulus

ν = Poisson's ratio

k_{fab} = fabrication de-rating factor given in 3-4/7

For internal overpressure conditions, the pressure p_ℓ is equal to the burst pressure, which may be found as:

$$p_\ell = 0.5 (SMYS + SMTS) \left(\frac{2t}{D} \right) \frac{1 - \frac{d}{t}}{1 - \frac{d}{t \sqrt{1 + 0.8 \left(L / \sqrt{Dt} \right)^2}}}$$

where

D = average diameter

t = wall thickness measurement

d = depth of corrosion defect, not to exceed $0.8 \times t$

L = measured length of corrosion depth

$SMYS$ = Specified Minimum Yield Strength in hoop direction

$SMTS$ = Specified Minimum Tensile Strength in hoop direction

Load factors and condition load factors are to be taken in accordance with A1-2/3, and resistance factors η_R are listed in A1-4/Table 1.

APPENDIX 2 Assessment of Corrosion, Dent and Crack-like Defects

SECTION 2 Maximum Allowable Operating Pressure for Dented Pipes

The determination of maximum allowable operating pressure for a dented pipe with cracks is given in the following.

Maximum allowable operating pressure may be calculated as:

$$P = 2 \cdot \sigma \cdot \frac{t}{D} \cdot \eta$$

where the usage factor η may be taken as 0.72, and the critical stress at failure σ is given by:

$$\sigma = \frac{2 \cdot \sigma_p}{\pi} \cdot \cos^{-1} \left[\exp \left(- \frac{\pi \cdot K_{mat}^2}{Y^2 \cdot 8 \cdot a \cdot \sigma_p^2} \right) \right]$$

The plastic failure stress σ_p of may be taken as:

$$\sigma_p = \sigma_f \cdot \frac{t - a}{t - \frac{a}{\sqrt{1 + 0.8(L/\sqrt{Dt})^2}}}$$

where

D	=	average pipe diameter
t	=	pipe wall thickness
L	=	length of dent
a	=	maximum depth of pipe wall thickness defect
σ_f	=	flow stress, here defined as the mean value of Specified Minimum Yield and Tensile Strength

Pipe toughness is measured in terms of the Charpy energy C_v . This measure is a qualitative measure for pipe toughness and has no theoretical relation with the fracture toughness parameter, K_{mat} . Therefore, it is necessary to use an empirical relationship between K_{mat} and C_v which can be taken as:

$$K_{mat}^2 = 1000 \frac{E}{A} (C_v - 17.6)$$

where

K_{mat}	=	material toughness, in $\text{N/mm}^{3/2}$
C_v	=	Charpy energy, in J
E	=	Young's modulus, in N/mm^2
A	=	section area for Charpy test, in mm^2 , normally $A = 80 \text{ mm}^2$

The geometry function Y can be expressed as:

$$Y = \frac{F}{\sqrt{Q}} \cdot \left[1 - 1.8 \cdot \left(\frac{D_d}{D} \right) + 5.1 \cdot H \cdot \left(\frac{D_d}{t} \right) \right]$$

where

$$D_d = \text{depth of dent}$$

and geometry correction factors Q , F and H are given by the following:

$$Q = 1 + 1.464 \left(\frac{a}{c} \right)^{1.65} \quad \text{for } \frac{a}{c} \leq 1$$

where

$$c = \text{half length of dent}$$

$$F = \left[M_1 + M_2 \left(\frac{a}{t} \right)^2 + M_3 \left(\frac{a}{t} \right)^4 \right] f_\phi g f_w$$

where

$$M_1 = 1.13 - 0.09 \frac{a}{c}$$

$$M_2 = -0.54 + \frac{0.89}{0.2 + (a/c)}$$

$$M_3 = 0.5 - \frac{1}{0.65 + (a/c)} + 14 \left(1 - \frac{a}{c} \right)^{24}$$

$$g = 1 + \left[0.1 + 0.35 \left(\frac{a}{t} \right)^2 \right] (1 - \sin \phi)^2$$

where

$$\phi = \text{parametric angle of the elliptical-crack}$$

The function f_ϕ , an angular function from the embedded elliptical-crack solution is:

$$f_\phi = \left[\left(\frac{a}{c} \right)^2 \cos^2 \phi + \sin^2 \phi \right]^{1/4}$$

The function f_w , a finite-width correction factor is:

$$f_w = \left[\sec \left(\frac{c}{D} \cdot \sqrt{\frac{a}{t}} \right) \right]^{1/2}$$

The function H has the form:

$$H = H_1 + (H_2 - H_1) \sin^p \phi$$

where

$$p = 0.2 + \left(\frac{a}{c} \right) + 0.6 \left(\frac{a}{t} \right)$$

$$H_1 = 1 - 0.34\left(\frac{a}{t}\right) - 0.11\left(\frac{a}{c}\right)\left(\frac{a}{t}\right)$$

$$H_2 = 1 + G_1\left(\frac{a}{t}\right) + G_2\left(\frac{a}{t}\right)^2$$

and

$$G_1 = -1.22 - 0.12\left(\frac{a}{c}\right)$$

$$G_2 = 0.55 - 1.05\left(\frac{a}{c}\right)^{0.75} + 0.47\left(\frac{a}{c}\right)^{1.5}$$



APPENDIX 3 Design Recommendations for Subsea LNG Pipelines

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APPENDIX 3 Design Recommendations for Subsea LNG Pipelines

1 General

The design, fabrication, installation, testing and maintenance of subsea liquefied natural gas (LNG) pipelines are to be based on all applicable requirements of Chapters 1 through 4. Alternatively, industry-acceptable codes and standards for subsea pipeline systems may also be used based upon mutual agreement between ABS and the Designer/Owner. However, the criteria for pipelines operating under ambient temperatures may be inadequate for pipelines working under cryogenic temperatures. This Appendix provides special recommendations for subsea LNG pipelines working under cryogenic conditions.

3 Application

This Appendix sets out recommendations for technical aspects specific to metallic subsea cryogenic pipelines transporting LNG from offshore LNG receiving terminals to LNG storage facilities or vice versa, or subsea LNG pipelines installed in lieu of the conventional trestle/jetty construction. This Appendix is not applicable to in-air offshore LNG transfer pipes or hoses.

5 Materials and Welding

5.1 Materials

Materials suitable for cryogenic services are to have sufficient toughness and strength at the lowest anticipated temperature during operation or testing. Metals that can be used for cryogenic services include, but are not limited to, austenitic stainless steels 304L and 316L, Invar (with 36% content of nickel alloy), and aluminum alloy 5083. Components (such as outer pipe in a pipe-in-pipe design) which remain at ambient temperatures during operation are allowed to be manufactured from carbon steel. The selection of materials is also to consider thermal expansion properties and possible temperature-induced strain (thermal strain) in pipe joints and connections. Considerations are also to be given to the requirements specified in Chapter 2 for the selection of materials, welding, components and corrosion control.

Materials for an insulation system are to be designed with sufficiently low thermal conductivity, watertight and enough mechanical strength for handling.

5.3 Welding

The welding of metallic LNG pipes is to be performed in accordance with welding procedures specified in API STD 1104, Section IX of the ASME Boiler and Pressure Vessel Code or comparable industry-acceptable standards. The welds are to be inspected visually, and by NDT procedures that are developed and qualified according to API STD 1104.

7 Design Considerations

7.1 General

The identification, definition and determination of loads to be considered in the design of subsea LNG pipelines are to be in accordance with Chapter 3, Section 1. Chapter 3, Section 5 is applicable for strength and stability criteria including hoop stress, longitudinal stress, Von Mises stress, global and local buckling, and fatigue. Special design considerations for subsea LNG pipelines are listed in the following Paragraphs.

7.3 Loads

The subsea LNG pipeline system is to be designed to withstand the following loads:

- Loads induced by the installation process (string weight, associated tension, hydrostatic pressure and temperature variations)
- Cryogenic bending during fill-up/emptying of the line (thermal loads due to temperature differential across cross-sections during fill-up/emptying)
- Loads in operation, including thermal loads, internal and external pressure load, seabed interference, and fatigue load during the life of the pipeline.

7.5 Allowable Stresses

Criteria for allowable stresses are to be in accordance with Chapter 3, Section 1. Consideration is to be given to changes in material tensile properties from ambient temperatures to cryogenic temperatures. Generally, metallic materials have better tensile properties at lower temperatures. However, increase of allowable stresses may be considered only if the safety factors specified in Chapter 3, Section 1 can be strictly maintained for all load cases and is subject to approval from ABS.

7.7 On Bottom Stability

Subsea LNG pipelines resting on the seabed, trenched or buried are not to move from their as-installed position unless accounted for in the design. The lateral stability of the pipelines may be assessed in the design using two-dimensional static or three-dimensional dynamic analysis methods specified in 3-6/5.

7.9 Cryogenic Bending

Fill-up and emptying procedures of subsea LNG pipelines are to be clearly defined. The fill-up or emptying processes could be critical in terms of static and fatigue strengths. Differential cooling or heating across a cross-section of the pipe may result in cryogenic bending (significant pipe deformation or upheaval movement). Heat transfer analysis is to be performed to evaluate the effect of cooling rate on pipe stresses at filling.

7.11 Global and Local Buckling

Subsea LNG pipelines designed and fabricated without internal bellows or expansion loops over long distances may be subject to global buckling due to internal overpressure and differential temperature across the cross-section of the pipe during operation. Analysis is to be performed to predict the possible position and amplification of the buckle.

Local buckling may occur when the pipeline is under external overpressure, bending or their combination. Formulas in 3-5/9 are to be used for the prediction of local buckling. The maximum anticipated differential pressure and bending moment acting on the pipe are to be used in the formulas. In the case of pipe-in-pipe designs, accidental flooding of the annulus is to be taken into account for local buckling of the internal pipe in a damaged condition.

7.13 Fatigue

Criteria for fatigue assessment of subsea LNG pipelines are specified in 3-5/13. Subsea pipelines for cryogenic services may be subject to high thermal stresses throughout their entire life cycle. Considerations should be given to the temperature-induced high-stress range, low-cycle fatigue. Temperature effects on material fatigue resistance properties are to be assessed in choosing an S-N design curve. VIV induced fatigue damages are to be taken into account for pipelines subjected to VIV effects. A safety factor of 10 is to be used in calculating fatigue life of subsea LNG pipelines.

7.15 Insulation

Subsea LNG pipelines are to be insulated such that the outermost pipe maintains a positive surface temperature at all times. No build-up of ice is allowed on any components of the pipelines exposed to seawater, except if it can be proved that ice build-up has no adverse effects on integrity of the pipeline. Effective thermal conductivity (U-value) of the pipeline is to be designed such that two-phase flow is avoided in the LNG pipelines. In addition, consideration should be given to the amount of heat gain between ship unloading operations. The boil-off rate of LNG inside the pipeline is to be controlled within an allowable level defined by the Owner/designer.

7.17 Thermal and Mechanical Analysis

Finite element analysis using an industry-accepted solver is recommended for thermal calculation and mechanical analysis of the pipeline components. The mechanical analysis is to consider temperature distributions from thermal calculations and structural and contained fluid weight.

9 Installation

Subsea LNG pipelines can be installed using installation methods described in 3-7/3.7. In the case of installation by towing, the pipeline system can be launched into the sea from either a perpendicular site or a parallel site depending on the type of fabrication site available. Stresses that may be induced in the pipe during lay operations are to be fully considered. For pipes that will remain bent, initial as-laid stresses are to be accounted for in any in-place analysis. Once the towing operation has been completed and the pipeline has been installed into its final position on the seabed, the pipeline is to be secured by trenching, backfilling, protective covering or anchoring.

11 Testing

11.1 Mill Pressure and Thermal Test

The mill pressure test is required to constitute a pressure containment proof test and ensure that all pipe sections have at least a minimum yield stress. Thermal cycling tests and boil-off are recommended for LNG pipelines involving novel design concepts.

11.3 Test After Construction

Pressure testing is to be performed at the ambient temperature on the completed LNG pipeline system and on all components not tested comprising the pipeline system, or components requiring a higher test pressure than the remainder of the pipeline. Testing procedure, test media, test pressure level and acceptance criteria are to be in accordance with 3-7/7 and 4-1/5.



APPENDIX 4 References by Organization

Standards/codes acceptable to ABS are not limited to the following references.

When updates of the referenced documents are available, these are to be used as far as possible.

Which standards/codes are to be followed during design, manufacturing, transportation, storage, installation, system testing, operation, amendment, decommission etc., is generally to follow international agreements and be agreed upon between Local Authorities, Owners, Operators, Clients and Contractors.

ABS claims the right to reject documents, procedures, etc., where standards/codes are judged misused, e.g., by “shopping around”.

ABS **American Bureau of Shipping**

ABS Plaza, 16855 Northchase Drive,
Houston, TX 77060, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
	2014	Rules for Building and Classing Single Point Moorings
	2018	Rules for Building and Classing Offshore Installations
	2018	Rules for Building and Classing Floating Production Installations
	2018	Rules for Building and Classing Steel Vessels
	2003	Guide for the Fatigue Assessment of Offshore Structures
	2004	Guide for Building and Classing Subsea Pipeline Systems

AGA **American Gas Association**

400N Capitol Street NW
Washington, DC 20001, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
PR-3-805	1989	A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe
L51698	1993	Submarine Pipeline On-Bottom, Vol. I :Stability Analysis and Design Guidelines

AISC **American Institute of Steel Construction**

One East Wacker Drive, Suite 3100
Chicago, IL 60601-2001, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
	1989	ASD Manual of Steel Construction, 9th Edition

API
American Petroleum Institute

1220 L Street, NW
Washington, DC 20005-4070, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
SPEC 5L	2000	Specification for Line Pipe
SPEC 5LC	1998	CRA Line Pipe
SPEC 5LD	1998	CRA Clad or Lined Steel Pipe
SPEC 5LW	1996	Recommended Practice for Transportation of Linepipe on Barges and Marine Vessels.
SPEC 6A	1999	Wellhead and Christmas Tree Equipment
SPEC 6D	1996	Pipeline Valves (Gate, Plug, Ball, and Check Valves)
SPEC 17D	1992	Subsea Wellhead and Christmas Tree Equipment
STD 600	1997	Steel Gate Valves—Flanged and Butt-Welding Ends, Bolted and Pressure Seal Bonnets,
STD 1104	1999	Welding of Pipelines and Related Facilities,
RP 2A-WSD	2000	Planning, Designing, and Constructing Fixed Offshore Platforms – Working Stress Design
RP 2N	1995	Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions
RP 2RD	1998	Design of Risers for Floating Production Systems (FPS's) and Tension-Leg Platforms (TLP's)
RP 2SK	1996	Design and Analysis of Stationkeeping Systems for Floating Structures
RP 2T	1997	Planning, Designing and Constructing Tension Leg Platforms
RP 5L1	1996	Railroad Transportation of Line Pipe
RP 5LW	1996	Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels
RP 14G	2000	Fire Prevention and Control on Open Type Offshore Production Platforms.
RP 17A	1996	Design and Operation of Subsea Production Systems
RP 579	2000	Fitness-For-Service
RP 1110	1997	Pressure Testing of Liquid Petroleum Pipelines
RP 1111	1999	Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines

ASME
American Society of Mechanical Engineers

22 Law Drive, P.O. Box 2900
Fairfield, New Jersey 07007-2900, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
B16.5	1996	Pipe Flanges and Flanged Fittings
B16.9	1993	Factory-Made Wrought Steel Buttwelding Fittings
B16.10	2000	Face to Face and End to End Dimensions of Valves
B16.11	1996	Forged Steel Fittings, Socket-Welding and Threaded
B16.20	1998	Metallic Gaskets for Pipe Flanges: Ring-Joint, Spiral-Wound, and Jacketed
B16.25	1997	Buttwelding Ends
B16.34	1996	Valves-Flanged, Threaded, and Welding End
B31G	1991	Manual for Determining the Remaining Strength of Corroded Pipelines: A supplement to B31
B31.4	2002	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids
B31.8	1999	Gas Transmission and Distribution Piping Systems
Boiler and Pressure Vessel Code	1998	Section V: Non-Destructive Examination Section VIII: Pressure Vessels – Divisions 1 and 2 Section IX: Welding and Brazing Qualifications

ASNT 1711 Arlingate Lane
American Society for Nondestructive Testing Columbus, OH 43228-0518, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
SNT-TC-1A	1996	Personnel Qualification and Certification – Recommended Practice

ASTM 100 Barr Harbor Drive
American Society for Testing and Materials West Conshohocken, Pennsylvania, 19428-2959, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
A36	2003	Specification for Structural Steel.
A82	2002	Specification for Steel Wire, Plain, for Concrete Reinforcement
A105	2003	Specifications for Forgings, Carbon Steel for Piping Components.
A193M	2003	Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service
A194M	2003	Specification for Carbon and Alloy-Steel Nuts for Bolts for High-Pressure and High-Temperature Service
A216	2003	Specification for Steel Castings, Carbon suitable for Fusion Welding for High Temperature Service.
A234	2003	Specification for Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures.
A370	2003	Test Methods and Definitions for Mechanical Testing of Steel Products.
A388	2003	Practice for Ultrasonic Examination of Heavy Steel Forgings
A578	2001	Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Application.
A694	2003	Specification for Forgings, Carbon and Alloy Steel for Pipe Flanges, Fittings, Valves, and Parts for High Pressure Transmission Service.
A790/ A790M-03	2003	Standard Specification for Seamless and Welded Ferritic/Austenitic Stainless Steel Pipe
B861	2003	Standard Specification for Titanium and Titanium Alloy Seamless Pipe
B862	2002	Standard Specification for Titanium and Titanium Alloy Welded Pipe
C29	2003	Test Method for Unit Weight and Voids in Aggregate.
C31	2003	Test Method for Making and Curing Concrete Test Specimens in the Field.
C33	2003	Specifications for Concrete Aggregates.
C39	2003	Test Method for Compressive Strength of Cylindrical Concrete Specimens.
C150	2002	Specifications for Portland Cement.
C172	1999	Method of Sampling of Fresh Mixed Concrete.
C642	1997	Test Method for Specific Gravity, Absorption and Voids in Hardened Concrete.
D75	2003	Methods for Sampling Aggregates.
D4285	1999	Method for Indicating Oil or Water in Compressed Air
E23	2002	Methods for Notched Bar Impact Testing of Metallic Materials.
E165	2002	Practice for Liquid Penetrant Inspection Method.
E337	2002	Test Method for Measuring Relative Humidity with a Psychrometer (The Measurement of Wet and Dry Bulb Temperatures).

AWS 550 N. W. LeJeune Road ,
American Welding Society Miami, FL 33126, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
A3.0	2001	Standard Welding Terms and Definitions.
A5.5	1996	Specification for Low Alloy Steel Electrodes for Shielded Metal Arc Welding
D1.1	2000	Structural Welding Code-Steel
D3.6M	1999	Specification for underwater welding

American Water Works Association (AWWA)

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
AWWA C-203	2002	Coal-Tar Protective Coatings and Linings for Steel Water Pipelines, Enamel and Tape Hot-Applied (Modified for use of Koppers Bitumastic High-Melt Enamel).

BSI

British Standards Institute

2 Park Street

London W18 2BS, England

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
BS 427	1990	Method for Vickers hardness test and for verification of Vickers hardness testing machines
BS 4147	1980	Bitumen Based Hot Applied Coating Materials for Protecting Iron and Steel
BS 4515-1	2000	Specification for welding of steel pipelines on land and offshore. Carbon and carbon manganese steel pipelines
BS 4515-2	1999	Specification for welding of steel pipelines on land and offshore. Duplex stainless steel pipelines
BS 7910	1999	Guidance on Methods for Assessing Acceptability of Flaws in Fusion Welded Structures
BS 8010-3	1993	Code of practice for pipelines. Pipelines subsea: design, construction and installation

CSA

Canadian Standard Association

178 Rexdale Boulevard

Toronto, ON, M9W 1R3, Canada

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
Z662-99	1999	Oil and Gas Pipeline Systems

HSE

Health and Safety Executive

UK

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
	1990	Offshore Installations: Guidance on Design, Construction and Certification

ISO

International Organization of Standards

Case Postale 65

CH 1211 Geneve 20, Switzerland

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
ISO 3183-1	1996	Petroleum and natural gas industries- Steel pipe for pipelines-Technical delivery conditions, Part 1: Pipes of Requirement Class A
ISO 3183-2	1996	Petroleum and natural gas industries- Steel pipe for pipelines-Technical delivery conditions, Part 2: Pipes of Requirement Class B
ISO 3183-3	1999	Petroleum and natural gas industries- Steel pipe for pipelines-Technical delivery conditions, Part 3: Pipes of Requirement Class C
ISO 9712	1999	Non-destructive testing – Qualification and certification of personnel
ISO 14313	1999	Petroleum and natural gas industries – Pipeline transportation systems – Pipeline valves

MSS 127 Park Street, NE.
Manufacturers Standardization Society Vienna, VA 22180, USA
of the Valve and Fittings Industry, Inc.

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
SP-6	2001	Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings
SP-44	1996	Steel Pipe Line Flanges
SP-53	2002	Quality Standard for Steel Castings and Forgings – Magnetic Particle Examination Method.
SP-54	2002	Quality Standard for Steel Castings – Radiographic Examination Method.
SP-55	2001	Quality Standard for Steel Castings – Visual Method.
SP-75	1998	Specification for High Test Wrought Butt Welding Fittings

NACE International 1440 S. Creek Drive
Houston, TX 77084-4906, USA

<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
MR0175	2000	Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment
RP0176	1994	Corrosion Control of Steel, Fixed Offshore Platforms Associated with Petroleum Production
RP0274	1998	Recommended Practice, High Voltage Electrical Inspection of Pipeline Coatings Prior to Installation.
RP0387	1999	Metallurgical and Inspection Requirements for Cast Sacrificial Anodes for Offshore Applications.
RP0675	Withdrawn, new standard planned.	Recommended Practice for Control of Corrosion on Offshore Steel Pipelines.
TM0177	1996	Laboratory Testing of Metals for Resistance to Sulfide Stress Cracking and Stress Corrosion Cracking in H ₂ S Environments
TM0284	1996	Evaluation of Pipeline and Pressure Vessel Steels for Resistance to Hydrogen-Induced Cracking

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<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
SSPC-PA-2	1996	Measurement of Dry Paint Thickness With Magnetic Gauges
SSPC-SP-1	2000	Solvent Cleaning
SSPC-SP-3	2000	Power Tool Cleaning
SSPC-SP-5	2000	White Metal Blast Cleaning
SSPC-SP-10	2000	Near-white Blast Cleaning

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<i>Code No.</i>	<i>Year/Edition</i>	<i>Title</i>
SIS 05 5900	1988	Pictorial Surface Preparation Standard for Painting Steel Surfaces