DANISH SUBMARINE PIPELINE GUIDELINES

FIRST DRAFT

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and
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Future editions will also include chapters on:

Field Makeup & Installation

Maintainance & Emergency Repair Aspects of Design

Subsea Survey & Inspection

Internal Inspection

as well as supporting appendices.

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	1. FOREWORD	(Referred to as "Introduction" in the original disposition).
	1.1 PERSPECTIVE	
	1.1.1	
	A submarine trunk pipeline for the export of oil or gas from an offshore field is typically the most expensive single capital element of an offshore production system, and may represent 40 to 50 percent of the total investment including platforms, wells, topside facilities, terminal facilities on land, and the pipeline itself.	
	Because of the time taken to repair a submarine pipeline failure it is also the greatest risk source in terms of supply outage - unless it is parallelled, which in turn is expensive.	
	In a subsea production system the flowlines and injection lines likewise typically represent 40 to 60 percent of the total investment including templates, wells, subsea completions, subsea manifolds, and the flowlines and injection lines themselves.	
	It is therefore usually a sound investment to undertake careful engineering of submarine pipelines based on the fullest possible investigation and analysis of all factors influencing design.	
	1.2 BACKGROUND TO THE PRESENT GUIDELINE	
	1.2.1	
	A considerable expertise has been built up by Danish firms and institutions in latter years in connection with feasibility studies and investigations, engineering design, and construction of pipelines for the transport cf oil and gas in Danish waters. In particular the engineering and construction supervision of DONG's gas transmission pipelines in the North Sea and the Danish Belts, and a feasibility study of the marine pipelines in Statoil's Trans-Scandinavian gas transmission system, both carried out by the Danish Hydraulic Institute and Rambøll & Hannemann A/S in joint venture, are examples. In addition to these there have been a number of pipeline engineering tasks which the Danish Hydraulic Institute have carried out for foreign clients including work on Arabian Gulf pipelines for ARAMCO, the Casablanca, Montanazo, and Cadiz projects for CHEVRON Spain, the Øresund pipeline for SYDGAS/VBB, the Esmond pipeline system for Hamilton Brothers Oil & Gas (U.K.) Ltd, and other marine pipelines and	This clause is a translation of Section 2.1 in the application for project support submitted to the Danish Energy Ministry in August 1983, updated with some minor additions and modifications.

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	flowlines in the U.K. and Norwegian sectors of the North Sea. In addition Rambøll & Hannemann and the Danish Hydraulic Institute have worked together on the Oseberg trunk pipeline for Norsk Hydro and the Dan F and Rolf interfield pipelines for Mærsk Oil & Gas. In accordance with the requirements of the Danish Authorities the main code for the engineering of the Danish natural gas pipelines in the North Sea and Belts has been the ASME Guide (American Society of Mechanical Engineers: "Guide for Gas Transmission and Distribution Piping Systems", 1981), supplemented by the DnV Rules (Det norske Veritas: "Rules for Submarine Pipeline Systems", 1981). In addition there have been the Danish Works Inspectorate's supplementary provisions to the ASME Guide together with a large number of individual standards dealing with specific subjects such as the manufacture and corrosion protection of linepipe, cathodic protection, soil mechanics, and pressure testing. These standards stem from the national standard sets of several different countries including the U.S.A., U.K., and FRD, as well as Denmark. The resulting conglomerate of standards is not entirely consistent. The main codes of practice do not always refer to the relevant supporting standards, and there is a range of overlap, and in some parts conflict, between the main codes themselves. Furthermore during the course of the Danish pipeline engineering work it has become apparent that there are a large number of technical questions which are unclear or inadequately prescribed in the existing rules. The Danish Hydraulic Institute and Rambøll & Hannemann have had to develop new methods of analysis and design on a number of points and have had to seek a clarification of the ultimate requirements through dialogue with the authorities. During the course of this dialogue the Danish Energy Agency has evinced a technical involvement which has made possible a rational establishment of design criteria in various areas, for example the stability, trenching, and backfilling of the pipelines. Against this background it is now plain that there is a need to transpose the experience thus harvested, and methods newly developed, into a consistent Danish guideline manual for submarine pipelines.	

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	1.3 THE PURPOSE OF THE GUIDELINE 1.3.1 The purpose of the exercise of which the draughting of this provisional guideline forms part is to prepare a complete guide covering the engineering, the supervision of manufacture and construction, and the subsequent inspection and maintenance of submarine pipelines. The manual should incorporate the newest technological developments with a view to introducing the application of more reliable engineering methods thereby achieving cheaper works coupled with greater safety. The new manual should figure internationally as an advanced supplement to the existing codes insofar as concerns submarine pipelines. It is intended as a basis for constructive dialogue rather than as a closed definitive prescription. The ultimate objective behind this is partially to achieve a rationalisation of the engineering of future Danish submarine pipeline works and partially to place the expertise developed in Denmark at the disposal of the world at large. For a large number of subjects it is possible to prepare guideline material solely by drawing up a status based on experience to date. For other subjects additional clarification is needed before final guideline material can be draughted.	This is a translation of Section 2.2, ibid. with minor editorial improvements.
	1.4 PHASING OF THE GUIDELINE PREPARATION PROCESS 1.4.1 It has been envisaged that the preparation of the guideline material will be divided into two phases:- 1) Preliminary Phase The preliminary phase is to embrace the detailed arrangement of all constituent subjects which the manual is to cover. This arrangement will constitute the skeleton for the final manual. For each constituent subject reference will be made to existing codes and standards and to the relevant newly developed methods. The need for any further investigations will be identified. Such further investigations will constitute the content of the main phase.	This is a translation of extracts from Chapter 3, ibid.

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	The preliminary phase will culminate in a report formulated in such a way that it can function as a provisional guideline. The preliminary phase will thus be of value on its own in the event that all or part of the main phase should be delayed. The present document constitutes the provisional guideline arising out of the preliminary phase. 2) <u>Main Phase</u> In the main phase a number of separate working groups will undertake the analyses and elucidations identified during the preliminary phase, and the final manual will be formulated. <u>1.5 RELATIONSHIP TO OTHER CODES</u> 1.5.1 1) <u>The ASME Guide</u> The ASME Guide contains rules for the design, construction, operation, and maintainance of gas transmission pipelines. It incorporates, and is an explanatory expansion of, Part 192 of the United States Minimum Federal Safety Standards based on ANSI B.31.8 for gas pipelines on land. It was originally formulated solely with land pipelines in mind and does little to treat the special considerations applying to submarine pipelines although its validity has subsequently been formally extended to include them. Much of its content is irrelevant to submarine pipelines. Those parts which are relevant are concerned mainly with the design, manufacture testing, operation, and maintainance of the pipeline as a pressure vessel. The requirements of the ASME guide, together with the supplementary requirements of the Danish Works Inspectorate (Arbejdstilsynet), are mandatory for gas transmission and distribution pipelines under Danish jurisdiction. 2) <u>ANSI B.31.4</u> This is the American National Standards Institute code for oil pipelines on land and is analogous to ANSI B.31.8 for gas pipelines on land. 3) <u>The DnV Rules</u> The DnV Rules, which are specific to submarine oil and gas pipelines, are designed primarily as a basis for the issue of a DnV Certificate of Approval for insurance purposes. They cover a number of areas which are not adequately	

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dealt with in the current version of the ASME Guide. The DnV Rules (both 1976 and 1981 editions) have been a valuable tool in the engineening of Danish projects, and represent the stating point for many sections of the present provisional guideline.

4) The NPD Rules (Proposal, November, 1979)

The Norwegian Petroleum Directorate: "Regulations for the Design, Fabrication, and Installation of Submarine Pipelines and Pipeline Risers" has not been officially issued, and exists only in draft form. The NDP draft follows the general patern of the DnV Rules but a number of the detailed requirements are different and the NDP draft is a useful adjunct to the ASME Guide and the DnV Rules in the present context.

5) Guidelines for Pipelines on the Seabed (Danish Safety Coordination Committee, March, 1980)

This document explains clearly the relationship between ANSI 31.4, ANSI 31.8, the ASME Guide and Danish Supplement, the NDP Rules of 1976, and the 1976 DnV Rules in the context of the state of the art at the beginning of 1980, ie: prior to the execution of most engineering work on Danish submarine Pipeline projects.

6) The Present Guideline

The present provisional guideline is formulated less as a set of rules, conformity with which is a criterion for official approval, and more as a code of practice to aid and guide the engineer in achieving an optimum balance between economy and safety. The requirements recommended in it are generally in line with the requirements which were made mandatory for the Danish natural gas transmission system except insofar as recent technological advances have indicated the desirability of modifications.

It may be appropriate to expand this text.

1.6 THE LEGAL CONTEXT

1.6.1

The present provisional guideline has no official mandate as a putative Danish Standard or authoritative rule set, and its use does not therefore in any way absolve the engineer from the obligation to refer to such documents as do have legal mandate where they exist, eg: Ministry of Public Works Order No. 406 of September 18, 1979, in relation to safety rules for natural gas plant in accordance with the law con-

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	cerning the working environment, and corresponding Orders governing other specific public works projects. Indeed it includes much material which might be considered inappropriate in such a context, albeit important as part of a more informal code of practice whose objectives are pragmatic and didactic rather than juridical.	It may be appropriate to expand this text.
	<u>1.7 APPLICABILITY</u> 1.7.1 This guideline is applicable to the engineering of the following categories of submarine pipeline: Trunk pipelines for the transmission of crude oil, natural, gas, and refined oil and gas products. In-field and interfield hydrocarbon pipelines Well head flowlines Gas injection lines Water injection lines. Many of the principles and procedures delineated are also applicable to submarine pipelines for the transport of slurries, sewage, and other fluids. In these cases other factors may need to be taken into consideration particularly with reference to corrosion and to linepipe and weld metallurgy.	
	<u>1.8 INDUSTRY FEEDBACK</u> 1.8.1 The value of the ultimate manual can be enhanced through the incorporation of material based on the experience of other submarine pipeline engineers. Comments and suggestions should be addressed to: The Editor Submarine Pipeline Guidelines Danish Hydraulic Institute Agern Allé 5 2970 Hørsholm Denmark	

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The formal position on Danish projects has generally been that professional liability for the engineering work lay with the partners or managers of the consulting engineering organizations retained by the Owners. In practice there has from time to time been ambiguity insofar as senior staff representatives of the Owner have issued detailed technical instructions without any explicit modification of the formal professional liability status. Such ambiguity can have far-reaching consequences.	2. BASIC ENGINEERING PRINCIPLES 2.1 ENGINEERING ORGANIZATION & PROFESSIONAL RESPONSIBILITY 2.1.1 The quality of the engineering work, including supervision of manufacture and construction and the planning and supervision of commissioning, should be assured primarily through the creation of an effective organization of competent staff directed by a qualified leader with access to expert specialist advice as appropriate, all as described in Clause 2.1.3.	The principles delineated here are applicable to any major construction project offshore or on land, and their implementation is not normally a problem in Scandinavia in relation to general civil engineering work. In the offshore industry, however, which has inherited many of its organizational and contractual practices from the more amorphous traditions of oil and gas operators in the Mexican Gulf and Continental North America, it is easier for the concept of professional liability to become obscured, and therefore that much more important to make an effort to keep it constantly in mind. Chapter 2 could appropriately be expanded into a separate guideline on the organization of engineering work for the offshore industry analogous to the guide "The Organization of Engineering Work" published by the Institution of Civil Engineers in London, but until such time it is appropriate to include this brief stricture in the present guide.

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	2.1.2 It may be appropriate to institute a system of formal check procedures of a type sometimes associated with the expression "quality assurance procedures". The value of such check procedures is dependent upon their being designed and implemented in an enlightened manner by experienced practical engineers and upon the exercise of great care in avoiding their degeneration into bureaucratic ritual without real content. Under no circumstances should the existence of formal check procedures, whether under the title "quality assurance" or otherwise, be treated as a justification for relaxing the requirements of Clause 2.1.1.	Much could be written by way of expansion of Clause 2.1.2. The construction industry in Scandinavia has operated effectively for generations without the aid of the concept of "quality assurance" as something distinct from straightforward "good management". The concept of "quality control" of fabrication and construction, ie: checking by observation or measurement that products and structures comply with the prescribed specifications (alias: "inspection") has long been well established and integrated into the standard procedures of the industry, as has the concept of the separation of lines of responsibility as between those performing quality control and those performing line management of fabrication and construction. Similarly the principle of arranging for independent checking of engineering calculations and engineering drawings is nothing new. The term "quality assurance" is used simply to denote a systematic approach to all such measures. A good description is presented in Norwegian Standard NS 5801, which is based on AQAP-1 (NATO requirements), BS 5750 Part I, and ANSI/ASME SPPE-1-1-77. "Quality assurance" has become a shibboleth in the offshore sector, but there are inherent dangers in constructing elaborate quality assurance systems, particularly those applicable to the engineering process. The existence and apparent operation of a Q.A. system may give a sense of security which is not justified by its real effectiveness, since there is a strong tendency for such systems to be so heavy that they quickly fall into disrepute and are ignored or paid lip service only. Heavy Q.A. systems are also costly. There is not easy way out. One cannot get good engineering out of a bad engineer, however, elaborate the Q.A. procedure, and the risk of getting bad engineering out of a good engineer is greatly increased if he is fettered with unhelptful bureaucratic procedures. There is no substitute for the requirements of Clause 2.1.1, and if a Q.A. system is to be an asset rather than an encumbrance it must be devised with wisdom and applied with insight by engineers with experience in the technical field concerned and with some management acumen.

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	2.1.3 The engineering of a marine pipeline system should be performed by or under the immediate day-to-day direction and control of an academically qualified professional engineer with adequate prior experience of the type of work involved. This person is hereinafter referred to as the Engineer. The Engineer should be supported by a technical team who together with the Engineer cover in depth all specialist skills and experience relevant to the project. The Engineer and/or other senior members of the technical team should have adequate experience of the supervision of manufacture, construction, and testing in connection with major project works including works of the type in question. Insofar as any relevant skills are not available within the team itself at a sufficiently expert level, arrangements should be made for the requisitioning of ad hoc support from expert specialists outside the main team. The Engineer may be: either a) a professional engineer who is a senior officer on the staff of the Owner; or b) a professional engineer who is a partner or senior officer in a firm of professional consulting engineers engaged by the Owner; and the identity of the Engineer should be clearly defined prior to commencement of any engineering work. In the case of larger projects the Engineer may be a committee of senior professional engineers all of type a) above of alternatively all of type b) above provided that at least one member of the committee is involved in the immediate day-to-day direction and control of the engineering work. Care should be taken to avoid any organizational structure involving a division of responsibility between different bodies unless the details of the division are meticulously defined with particular regard to the allocation of professional liability.	

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	2.1.4	
	The Engineer should have the right and the obligation to draw the attention of those instructing him to any aspect in his brief which might represent an impediment to the execution of the engineering work in a proper professional manner in the best interests of an optimal balance of the conflicting requirements of economy and safety, and to make recommendations which may go beyond the terms of reference of the brief or imply modification of the brief.	
	Any specialist working as a member of or advising the technical team should have a similar right and obligation vis-ã-vis the Engineer.	
	It is the prerogative of the Owner to accept or reject the Engineer's advice after evaluating it alongside other considerations. Rejection of the Engineer's advice involves a transfer of liability.	
	2.1.5	
	The Engineer and his technical team should be afforded every facility for close liaison with those responsible for the engineering and operation of contiguous and related parts of the total system (eg: hydrocarbon reservoir, well bore, subsea production facilities, offshore platform structures, platform topside process facilities, terminal facilities on shore, associated pipelines, and onward transmission systems), and should themselves be under an obligation to promote and implement such liaison.	
	2.1.6	
On a number of important Danish marine pipeline projects the design stage engineering has been let as a discrete contract with no guarantee of involvement by the same team at the construction stage.	The supervision of manufacture and construction should be the responsibility of the Engineer, and the greatest possible continuity should be sought between design stage engineering on the one hand and construction stage engineering and all levels of supervision on the other.	The expression "all levels of supervision" is intended to embrace both "overtilsyn" and "tilsyn".

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	2.1.7 The Engineer should be intimately involved, with appropriate support from the technical team, in the preparation of tender documents for procurement and construction contracts and should advise on appropriate contract forms. The Engineer, with appropriate support from the technical team, should likewise by intimately involved in the analysis of tenders and should make recommendations on contract award. It should be recognized that the commercial and technical aspects of manufacture and construction contracts are inextricably intervoven and must never be treated in isolation from each other.	Attempts to separate the "technical" aspects and the "contractual" aspects of the tendering and contracting process are misguided and can lead to costly oversights. In major engineering works involving complex technological considerations the technical and contractual aspects are inextricably interwoven, and competent document draughting, tender analysis, and contract negotiation can only be undertaken by engineers with an overview of both aspects and an understanding of their interaction.
	2.1.8 In the case of major offshore works outside the jurisdiction of the Danish "Licitationslov" consideration should be given to the award of construction contracts on the basis of the international FIDIC model form, with appropriate adjustment, in place of the Danish AB72.	The lack of an international standard contract for offshore work is a hindrance to efficient and competitive tendering and contracting and stands in stark contrast to the position in the international civil engineering industry. The FIDIC model form does not meet all the requirements, but forms a good starting point. There have been moves to develop and promote an offshore model contract from on FIDIC lines, but little progress has been to date.

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	2.2 ENGINEERING PHILOSOPHY 2.2.1 The engineering of the pipeline system should strive for optimization of the balance between the conflicting requirements of economy and safety and for an appropriate synthesis of the interests of the Owner and the interests of all other parties affected or involved. 2.2.2 The economic considerations should include both capital cost and the cost of operation, maintainance, and emergency repair. Comparisons of capital and annual cost should be based on appropriate procedures for nett cash flow discounting. Estimates of the discounted cost of emergency repairs should take account of the estimated probability of occurrence. 2.2.3 The pipeline system should be engineered and operated in such a manner that the risk to persons and property introduced by its presence does not represent a significant increase in the total risk from other normal sources. In situations where no special hazards are identical this may be assumed to be the case provided that the pipeline system is engineered, constructed, and operated in accordance with the present Guideline. In situations where special hazards are identified a safety analysis should be performed. This analysis should embrace the probability of failure, the consequences of failure, and the detection of failure. Special hazards which require analysis include the following: Offshore operation activities (erroneous anchoring, dropped objects) Maritime traffic interference (anchoring, grounding) Fishing activities (bottom trawl impact) Dredging and excavation Military hazards (old mines, firing ranges) Out-of-specification materials or workmanship (linepipe defects, weld defects)	

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	The presence of toxic components in the fluid being transported (eg: H_2S) The proximity of the pipeline route to population concentrations (residential, working, or recreational), industrial activities, major structures, or the like. The consequences of failure to be considered include: 1) death, injury, property damage and reduced amenity due to jetstream, explosion, fire, thermal radiation, poisoning, and pollution. 2) Supply outage.	

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	<u>3. SAFETY</u> <u>3.1 PROBABILITY FAILURE</u> 3.1.1 In the absence of special hazards or special protective measures and provided that the pipeline system is engineered, constructed, and operated in accordance with this Guideline, it may be assumed that the probabilities of failure do not significantly exceed those indicated in Tables 3.1, 3.2, 3.3, 3.4, 3.5 and 3.6. Failure in this context means any event (eg: deformation, serious corrosion, leakage, or rupture) the detection of which leads to untimely operational shutdown of the system. The probability of traumatic failure (ie: failure involving a rapid escape of a large quantity of oil or gas) may be assumed to be one order of magnitude lower. The probability of failure of a discrete length of pipeline during a longer period may be obtained from the relationship: $P_{f(L,N)} = 1 - (1-p_f)^{LxN}$ in which: $P_{f(L,N)}$ is the probability of failure for a length L kilometres during a period of N years; p_f is the probability of failure per kilometre per year.	This is based on data from the British Gas Engineering Research Station.

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	See Tables 3.1 and 3.2 below	These tables are derived from the statistics presented in "Pipeline Reliability" by R.F. de la Mare & Ø. Andersen (DnV 80-0572). The marine statistic are dominated by Mexican Gulf experiences as recorded by the U.S. Geological Survey. The reason for the lower probability of failure of gas lines with diameters less than 20" is not clear.

Table 3.1 P_F for Zone 1 Marine Pipelines of Nominal O.D. < 20 inches.

Cause of Failure	P_F per km. per year: Crude Oil Lines	P_F per km. per year: Gas Lines
A. Defects in materials and workmandships	0.1×10^{-3}	-
C. Corrosion		
a) external	0.4×10^{-3}	0.2×10^{-3}
b) internal	0.2×10^{-3}	-
D. Environmental loading		
a) hydrodynamic	0.2×10^{-3}	0.1×10^{-3}
b) soil movement	0.1×10^{-3}	-
E. Third party interference (trawls, anchors, etc.)	0.6×10^{-3}	0.1×10^{-3}
Z. Other causes and unknown causes	0.8×10^{-3}	0.3×10^{-3}
TOTAL	2.4×10^{-3}	0.7×10^{-3}

Table 3.2 P_F for Zone 1 Marine Crude Oil and Gas Pipelines.

Cause of Failure	P_F per km. per year: < 20 inch Nominal OD	P_F per km. per year: 20 inch Nominal OD and above
A. Defects in materials and workmandship	-	0.4×10^{-4}
C. Corrosion		
a) external	0.3×10^{-3}	0.4×10^{-4}
b) internal	0.1×10^{-3}	0.4×10^{-4}
D. Environmental loading		
a) hydrodynamic	0.1×10^{-3}	-
b) soil movement	0.1×10^{-3}	-
E. Third party interference (trawls, anchors, etc.)	0.4×10^{-3}	-
Z. Other causes and causes unknown	0.7×10^{-3}	0.5×10^{-4}
TOTAL	1.7×10^{-3}	1.7×10^{-4}

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Table 3.3 P_F for Marine Oil & Gas Risers.

Cause of Failure	P_F per Riser per year
A. Defects in materials and workmanship	0.3×10^{-3}
C. External corrosion	2.2×10^{-3}
D. Environmental loading	1.4×10^{-3}
E. Third party interference (collision)	0.3×10^{-3}
Z. Other causes and causes unknown	1.8×10^{-3}
TOTAL	6.0×10^{-3}

This table is based on the assumption that the pipeline population forming the basis of the Mexican Gulf statistics includes one riser for every 15 km. of line.

Table 3.4 P_F for Zone 2 Marine Pipelines.

Cause of Failure	P_F per km. per year
E. Third party interference (high-holding anchors of offshore work barges)	2.0×10^{-2}
A, C, D, and Z	As for Zone 1

The figure in this table is discussed in NGG-MPPO 31372 "North Sea Pipeline Protection Concept".

Table 3.5 P_F for Land Pipelines of Nominal O.D. < 20 inches.

Cause of Failure	P_F per km per year		
	Crude Oil Lines	Product Oil Lines	Gas Lines
A. Defects in materials and workmanship	0.5×10^{-4}	1.1×10^{-4}	2.6×10^{-4}
C. Corrosion a) external b) internal	$1,6 \times 10^{-4}$	5.9×10^{-4}	1.3×10^{-4} 0.3×10^{-4}
D. Natural hazard	-	0.2×10^{-4}	5.8×10^{-4}
E. Third party	1.8×10^{-4}	4.1×10^{-4}	
Z. Other causes and causes unknown	-	-	0.7×10^{-4}
TOTAL	3.9×10^{-4}	11.3×10^{-4}	10.7×10^{-4}

The oil line figures are based on Western European pipeline statistics (the "CONCAWE" data), while the gas line figures are based on U.S. Department of Transportation statistics.

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Table 3.6 P_F for Land Pipelines of Nominal O.D. 20 inches and Over.

Cause of Failure	P_F per km. per year	
	Crude Oil Lines	Gas Lines
A. Defects in materials and workmanship	1.5×10^{-4}	0.7×10^{-4}
C. Corrosion a) external b) internal	0.2×10^{-4}	0.3×10^{-4} 0.1×10^{-4}
D. Natural hazard	1.0×10^{-4}	1.6×10^{-4}
E. Third party interference	1.2×10^{-4}	
Z. Other causes and causes unknown	-	0.2×10^{-4}
TOTAL	3.9×10^{-4}	2.9×10^{-4}

The annual probability of failure of a pipeline may increase with age insofar as concerns the following causes of failure:

A. Defects in materials and workmanship (fatigue mechanism);

C. Corrosion (time dependent);

E. Third party interference (familiarity syndrome).

Consequently the value of P_F in early life may be lower and in later life higher than the average value.

Albeit for that proportion of the pipeline population which experiences failure at some stage, the mean time to first failure may be assumed to be 4 years in the case of marine pipelines and 8 years in the case of land pipelines.

This is based on analysis of the ESGS Gulf of Mexico statistics and CONCAWE West European landline statistics respectively.

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	3.1.2 The probability of failure in the presence of special hazards should be evaluated individually for the circumstances concerned. Guidance on the evaluation of the probability of failure due to maritime traffic interference (ship anchoring and grounding) will be available in Appendix 301. Guidance on the evaluation of the probability of failure due to explosions in the vicinity of the pipeline will be available in Appendix 302. Guidance on the evaluation of the probability of failure due to out-of-specification materials or workmanship will be available in Appendix 303.	Appendix 301 is to be developed from "Risk of Ship Interference with Submarine Pipelines", by R.S. Colquhoun, IABSE, Copenhagen, 1983, and the appendices thereto. Appendix 302 is to be developed from relevant MPPO Technical Notes. Consideration may be given to including part of this material in the Chapter on Stresses. Appendix 303 is to be developed from "Fitness for Service Analysis of the Danish North Sea Oil Pipelines", by Nielsen, Flemmer, Hofmann & Thygesen, Houston, 1984 (OTC 4669), and from "Some Aspects of Defect Tolerance in Pipelines" by Nielsen, Colquhoun and Björk, Birmingham, 1984.

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	the risk of explosion of the gas, the potential extent of the zone over which such risk may extend under different weather conditions, and the potential radius of the fireball;	
	the steady burn radiation flux and the critical distances for secondary ignition and injury from radiation burns; in the absence of more accurate analysis it should be assumed that the full calorific value of the escaping gas is dissipated in the form of radiation;	To be checked. Calorific values for hydrocarbons to be presented (next edition).
	the risk of dangerous concentrations of toxic vapours and the potential extent of the zone over which such risk may extend under different weather conditions;	
	the risk of pollution from condensates and the potential extent of such pollution.	
	3) for all lines:	
	the risk of secondary consequences of events under (1) and (2) above in the form of:-	
	death or injury to persons due to fire or explosion; death or injury to persons due to jet-stream impact; death or injury to persons due to asphyxiation or poisoning; damage to platforms, buildings, forests, crops, animals, and other property due to fire or explosion, and the potential value of such damage; damage to forests, crops, and animals due to poisoning, and the potential value of such damage;	
	the economic, commercial, and social consequences of supply outage.	
	For evaluation of the risks listed in (1), (2), and (3) above the following procedures should be employed where appropriate:	
	analysis of rate of egress of oil from a full-bore rupture under the influence of the difference between equilibrium hydrocarbon vapour pressure and ambient pressure at the rupture;	
	analysis of gas flow transient to a full-bore rupture;	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	3.2 CONSEQUENCES OF FAILURE 3.2.1 In situations where special hazards are identified and in which the probability of failure cannot reasonably be reduced to the same level as for the rest of the pipeline system, a detailed evaluation of the consequences of failure should be performed. Such studies should include, where appropriate, the following considerations in the context of both traumatic rupture and slow leakage: 1) for crude oil lines and heavy product lines: the risk of ignition of escaping oil (and/or associated vapour in cases where the equilibrium vapour pressure is greater than asmospheric pressure), and the potential extent of the conflagration; the risk of explosion of associated vapour, the potential extent of the zone over which such risk may extend under different weather conditions (wind speed, wind direction, atmospheric stability number), and the potential radius of the fireball; the potential steady-burn radiation flux and the critical distances for secondary ignition and injury from radiation burns; the risk of dangerous concentrations of toxic vapours and the potential extent of the zone over which such risk may extend under different weather conditions; in the event of failure on land, the potential extent of ground pollution and groundwater pollution; in the event of submarine failure, the potential extent, location, and concentration of marine and littoral pollution under different wind and tide conditions; 2) for gas lines and volatile product lines: the mechanical effects of a high pressure jetstream in the case of traumatic rupture; the risk of ignition of escaping gas and the potential extent of the zone over which such risk may extend under different weather conditions; ignition should be assumed to be inevitable in the case of traumatic rupture;	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	analysis of gas jet plume dimensions and velocities;	
	application of mathematical model for the simulation of marine surface transport and dispersion of oils and condensates from a point source;	
	application of mathematical model for the simulation of atmospheric transport and dispersion of gases and vapours from a point source.	
	3.2.2	
	The mitigating effects of an emergency shutdown valve on a platform, on the seabed, or on land may be taken into account provided that it is:	
	either: (a) a pneumatically actuated ball valve controlled from a permanently manned position with on-line failure detection display;	
	or: (b) an automatic gravity-operated subsea check valve (clapper valve) backed up by a manually operated ball valve immediately downstream.	Clapper valves are rarely leakproof.
	3.2.3	
	The following emergency shutdown valves should be provided in addition to platform emergency shutdown valves:	For over-pressure relief see "Process" chapter.
	1) on land at every marine pipeline arrival or departure point, as close to the shore as possible, a valve as defined in Clause 3.2.2, item (a);	This is similar to ASME requirements, but more specific.
	2) on the seabed on every pipeline incoming to a platform, if the contents of the pipeline exceed 100 tons of hydrocarbon gas or 700 tons of hydrocarbon liquid, a valve as defined in Clause 3.2.2, item (a), located between 1000 and 2000 metres from the platform;	Items (2) and (3) represent a new codification of current philosophy.
	3) on the seabed on every pipeline outgoing from a platform, if the contents of the pipeline exceed 100 tons of hydrocarbon gas or 700 tons of hydrocarbon liquid, a valve as defined in Clause 3.2.2, item (a) or item (b), located between 1000 and 2000 metres from the platform.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	If the minimization of supply outage is a critical consideration, then all subsea valve assemblies should be incorporated in spoolpieces of manageable length tied into the pipeline with bolted flange joints or metal-to-metal seal mechanical connectors to facilitate removal for servicing and replacement of the operational emergency shutdown valving, while close-off ball valves should be fitted in the line upstream and downstream of the spoolpiece to minimize the length of pipeline to be flooded and dewatered. Any protective cover over the valve assemby should be removable or openable, so as to permit vertical access to the whole valve assembly spoolpiece from above for removal and re-insertion.	This requirement reflects the fact that, in terms of supply outage, time is money, and the most time consuming operation is the dewatering and drying of the flooded line.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	3.3 DETECTION OF FAILURE	
	3.3.1	
	The terminals at both ends of all major marine hydrocarbon transmission pipelines should be provided with permanently manned watch stations with appropriate instrumentation displaying pressure, temperature, flow, and other relevant parameters, and these stations should be in permanent open-channel communication with each other.	It may be appropriate to replace the description "major" with something more precise.
	3.3.2	
	The following should be provided with permanent on-line leak detection systems:	
	1) all sections of land pipelines;	
	2) all sections of marine pipeline less than 15 km. from land;	
	3) all long-distance transmission marine pipelines;	
	4) all marine pipelines whose content exceeds 100 tons of hydrocarbon gas or 700 tons of hydrocarbon liquid.	
	Unless it can be demonstrated that alternative devices would be equally effective, the leak detection system should consist of the following:	
	a) a turbine flow-meter plus pressure, temperature, and density sensors located in an extractable spool in a valved bypass at the upstream end of the pipeline (the through-line being opened only during pigging);	
	b) a turbine flow-meter plus pressure, temperature, and density sensors located in an extractable spool in a valved bypass at the downstream end of the pipeline;	
	c) appropriate seawater temperature sensors;	
	d) an on-line data transmission system for transferring output from the flow-meters and sensors to a central computer;	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	e) a computer model capable of simulating the transient flow regime within the pipeline on the basis of the data received, and of detecting any significant out-of-balance in the mass transfer relative to prior calibration: f) an on-line display and alarm at a permanently manned station. The meters and sensors should be selected for good repeatability rather than absolute accuracy.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

4. THE PIPELINE PROCESS
(System Engineering and Internal Environment)

4.1 SYSTEM OPTIMIZATION

4.1.1

The design of a pipeline or pipeline system as a transportation medium should embrace an optimization of the balance between economy (capital and annual) on the one hand and safety (security of supply and third party risks) on the other, in the course of meeting the prime objective of moving a quantity Q of fluid from point A to point B within a given time period. (The value of Q may alter on a daily, weekly, monthly, or annual cyclic basis and/or change progressively during the design life of the system).

The main variables available for this optimization process are:

- Available pressure range (ie: operating pressure, p_1, at upstream end less minimum acceptable pressure, p_2, at delivery end);
- Number of pipelines in parallel (N);
- Internal diameter of pipeline(s) (d_i):
- Spacing of intermediate pumping or compression stations, if any.

The main constraints are:

- Maximum permissable average flow velocity (V_{max}) in the context of pipewall erosion;
- Minimum permissable average flow velocity (V_{min}) to ensure sweep-out of detritus, water, and heavy components in the absence of pigging;
- Maximum pipe wall thickness (t_{lim}), that can be manufactured/welded to acceptable quality.

In the absence of other indications the values of these constraints may be taken from Table 4.1.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Table 4.1 Values of System Design Constraints

Constraints	Value
V_{max}	3.5 m/sec
V_{min}	1.0 m/sec
t_{lim} (steel)	30 to 40 mm

4.1.2

The optimization procedure should include the following steps:

1) Determine the maximum diameter for a single line system from the lowest expected flow rate and minimum permissable velocity;

2) Select a suitable value of the maximum allowable operating pressure (p_1);

3) Determine the necessary pipe diameter to pass the maximum flow rate with the prescribed pressure difference (p_1-p_2) for N = 1, N = 2, and if appropriate also for greater values of N;

4) Select system alternatives which can reconcile the requirements of (1) and (3);

5) Estimate the capital costs of the alternative pipeline systems;

6) Compute the installed power requirement of the pumping/compression plant (including any intermediate stations);

7) Estimate the capital costs of the pumping/compression plant including supporting structures and ancillary works;

8) Determine the appropriate capital amortization factor on the basis of the project design life and the estimated real rate of interest (ie: nett of inflation);

9) Assess the average pumping/compression power requirement;

10) Estimate the operation and maintainance costs, including power costs and fixed costs;

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	11) Repeat items (2) to (8) for different values of p_1; . 12) Calculate the probability of failure of the alternative systems; 13) Estimate the quantifiable costs of a system failure and identify other consequences which may not be quantifiable in cost terms; 14) Review the trade-off between economy and safety and identify the system with the optimum balance. 4.1.3 In the case of flowlines and in-field and interfield pipelines, the requirements of pigging and TFL operations should be carefully considered in relation to selection of the value of N, ie: the decision as to whether or not to parallel ("loop") the lines. 4.1.4 In the case of pipelines which are parallelled for the sake of security of supply in the face of a risk of failure due to ship interference, the spacing of the lines should be not less than 1500 metres.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS

GUIDELINE RECOMMENDATION

4.2 COMPUTATION OF ISOTHERMAL FLOW

4.2.1

The flow rate of a stable single-phase liquid through a uniform pipeline under isothermal conditions may be determined from the relationship:

$$Q = \left[\frac{(\frac{\Delta p}{g} \cdot 10^6 - x\rho g)\ \pi^2 \cdot d_i^5 \cdot \rho}{8\ f\ L}\right]^{\frac{1}{2}}$$

in which

- Q is the mass flow rate (kg/sec)
- Δp is the change in pressure over the pipeline length being considered (bar)
- x is the increase in elevation from input to delivery (m)
- g is the dimensionless conversion factor from kgf to Newtons or the acceleration due to gravity (m/sec^2)
- d_i is the internal diameter (m)
- ρ is the density of the fluid (kg/m^3)
- L is the pipeline length being considered (m)
- f is the dimensionless friction factor obtained with the aid of Fig. 4.1 and Fig. 4.2.

The mean fluid velocity v may be determined from the relationship:

$$v = Q \ / \ \frac{\pi}{4} d_i^2 \ \rho \qquad \text{(m/sec)}$$

The Reynolds Number (Re) may be determined from the relationship:

$$Re = \frac{D_i \ v \ \rho}{\mu}$$

in which μ is the absolute viscosity (kg/m/sec, ie: units of 10 poises).

The viscosity of gas free crude oil may be obtained from Fig. 4.3 and corrected for gas content with the aid of Fig. 4.4.

DISCUSSION FURTHER STUDIES ETC.

The formulae and data presented in these clauses have been available to the petroleum industry for many decades and are well known to the petroleum engineer. They are given here (duly converted to 1SO units) in order to give the pipeline engineer a ready reference to suitable formulae and data in connection with the optimization process prescribed in Clause 4.1.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

The viscosity of water may be obtained from Table 4.2.

Table 4.2 Viscosity of water

Temperature (^{o}C)	Viscosity (centipoises)
0	1.8
10	1.3
20	0.95
30	0.75
40	0.6
50	0.5

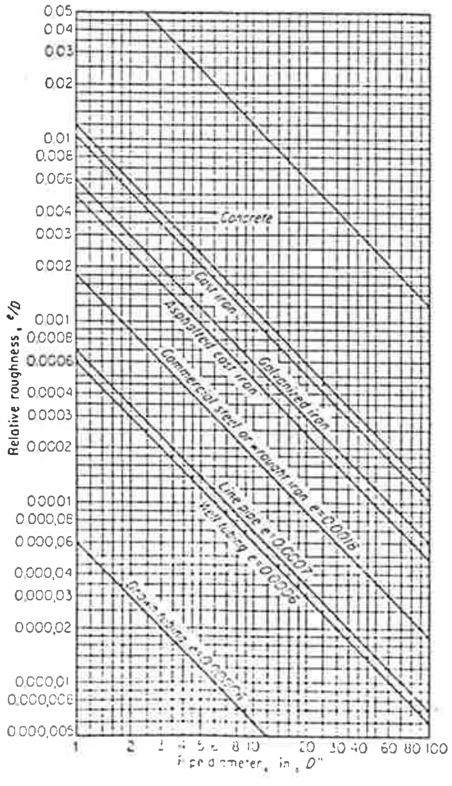
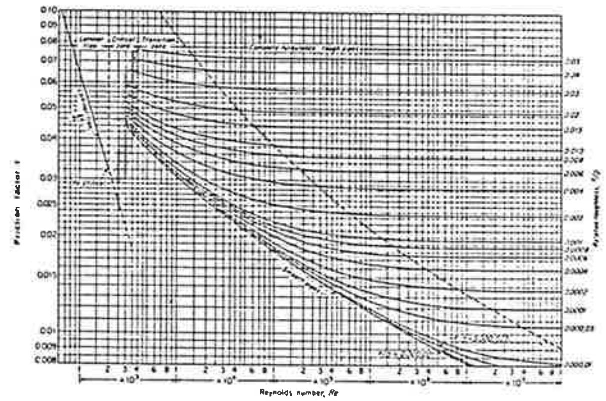
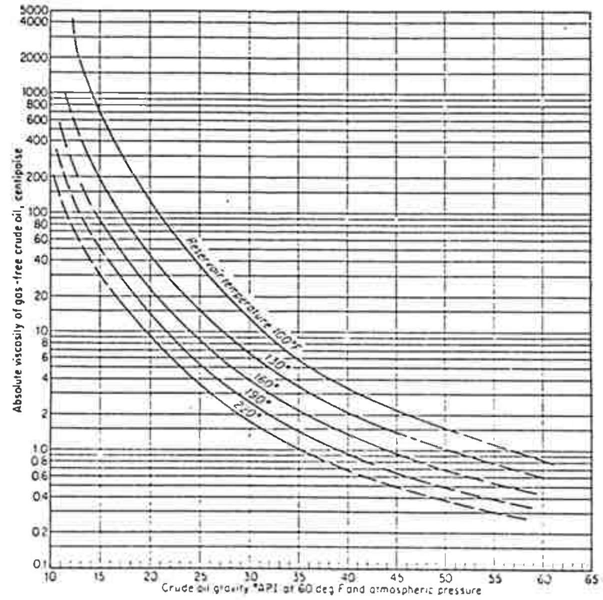
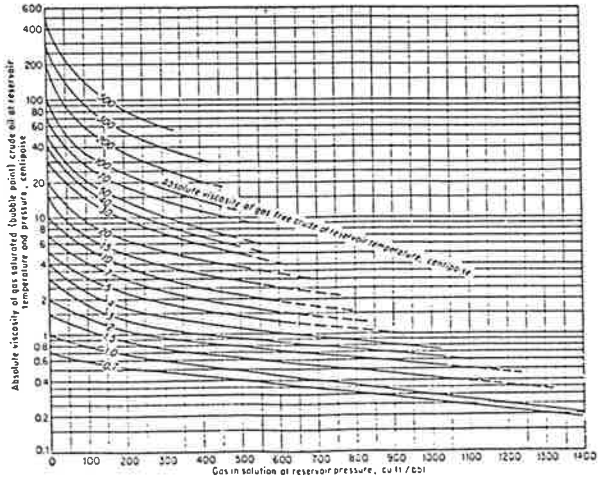


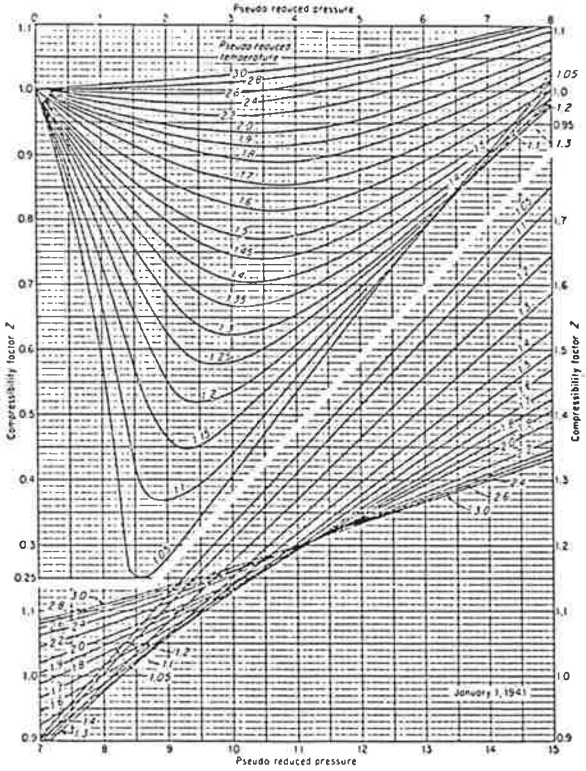
Fig. 4.1 Relative roughness of various pipes (after Moody, ASME, 1944)

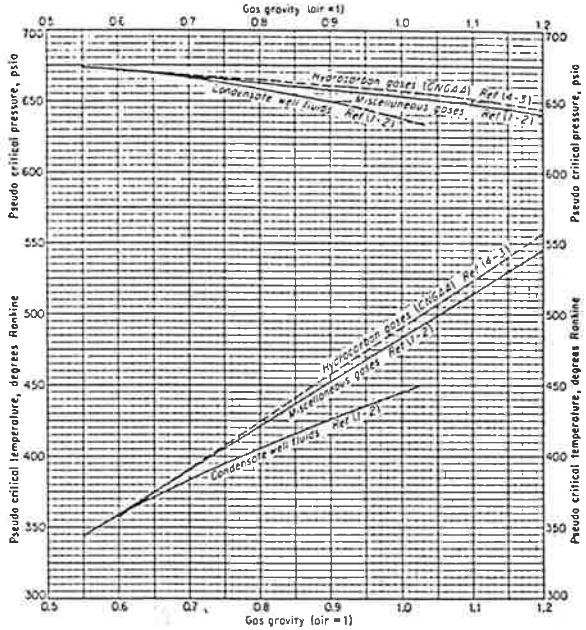
PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 4.2 Friction factor for fluid flow in pipe (after Moody, ASME, 1944)  Fig. 4.3 Viscosity of gas free crude oils (after Beal, AIME, 1946)	(From Handbook of Natural Gas Engineering p. 179, Fig. 4-111 - to be converted to ISO units and redrawn).

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 4.4 Effect of dissolved gas on viscosity of crude oil (after Beal, AIME, 1946)	(Ibid - Fig. 4-112 Ditto)

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	4.2.2 The flow rate of a stable single-phase gas through a uniform pipeline under isothermal conditions may be determined from the relationship: $Q' = 0.025 \frac{T_o}{P_o} \left[\frac{(p_1^2 - e^S p_2^2)\, d_i^5}{G\, T_a\, f\, Z_a\, J\, L} \right]^{0.5}$ in which: Q' is the volumetric flow rate (m^3/sec) at standard temperature and pressure T_o is standard temperature (^oK) P_o is standard pressure (bar) p_1 is the input pressure (bar) p_2 is the delivery pressure (bar) $e = 2.7183$ $S = 0.077\ GX/T_a Z_a$ d_i is the internal diameter (m) G is the gas gravity (relative to air = 1) T_a is the average temperature (^oK) f is the dimensionless friction factor obtained from Fig. 4.1 Z_a is the average compressibility factor X is the increase in elevation from input to delivery (m) L is the pipeline length being considered $J = (e^S - 1)/S$ (Note: when $S = 0$, $J = 1$)	
	Compressibility factors (Z) for natural gasses may be taken from Fig. 4.5.	Fig. 4.5 is HNGE p. 106 Fig. 4-16.
	The pseudo critical temperature and pseudo critical pressure may be taken from Fig. 4.6. (The pseudo-reduced pressure is the pressure divided by the pseudo critical pressure; the pseudo-reduced temperature is the temperature divided by the pseudo critical temperature).	Fig. 4.6 is HNGE p. 112, Fig. 4-22 converted to degrees Kelvin and omitting "miscellaneous gasses".
	The pseudo critical temperature and pressure may alternatively be obtained from the actual gas composition using the following relationships: $T_c = \sum_i y_i T_{ci}$ $P_c = \sum_i y_i P_{ci}$	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	in which: T_c is the pseudo critical temperature of the mixture (^oK) y_i is the mole fraction of the ith component T_{ci} is the critical temperature of the ith component (^oK) which may be taken from Table 4.3 P_c is the pseudo critical pressure of the mixture (bar abs.) P_{ci} is the critical pressure of the ith component (bar abs.) which may be taken from Table 4.3. The mass flow rate may be obtained from the following relationship: $Q = Q'\rho$ in which ρ is the mass density of the gas (kg/m^3). Values of ρ for natural gas are given in Fig. 4.7.	

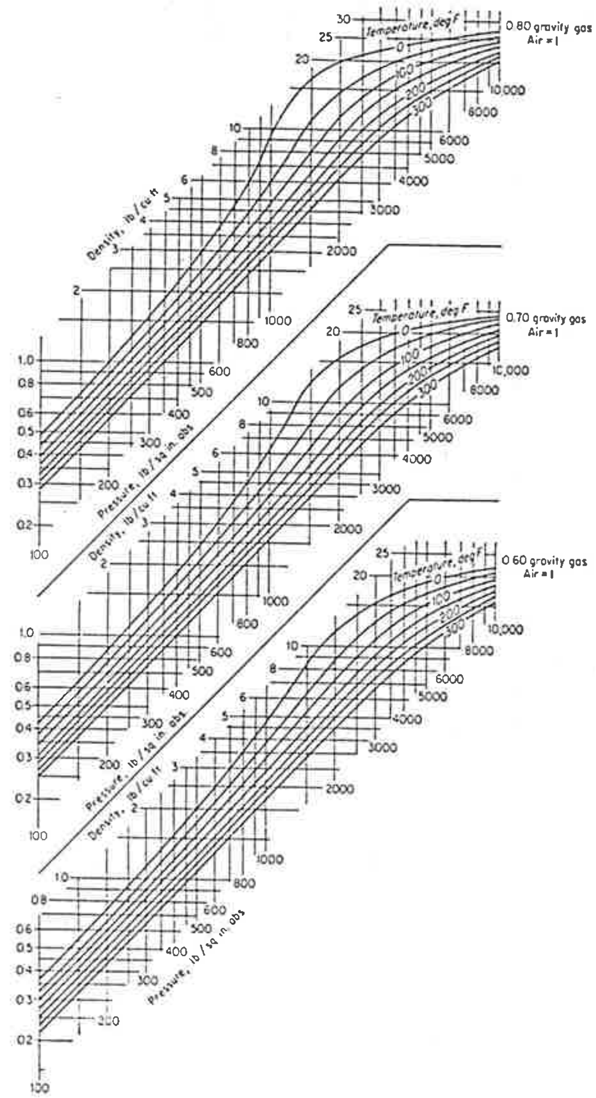
PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 4.5 Compressibility factor for natural gasses (after Standing & Katz, AIME, 1942)	(From Handbook of Natural Gas Engineering, p. 106, Fig. 4-16 - to be redrawn).

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 4.6 Pseudo critical properties of natural gasses (after Brown, Katz, Obefell, & Alden, NGA, 1948)	(From Handbook of Natural Gas Engineering, p. 112, Fig. 4-22 - To be redrawn omitting curves for "miscellaneous gasses" and converting temperatures to ^{o}K and pressures to bar abs.).

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Table 4.3 Critical properties of natural gas constituents

Constituent	Molecular Weight	Critical Temperature ^{o}K	Critical Pressure Bar abs.
Methane	16.04	190.7	45.79
Ethane	30.07	305.4	48.18
Propane	44.09	370.0	42.00
Isobutane	58.12	408.2	35.99
n-Butane	58.12	425.2	37.46
Isopentane	72.15	461.0	32.86
n-Pentane	72.15	469.8	33.30
Isohexane BP 49^{o}C	86.17	489.4	30.65
Isohexane BP 60^{o}C	86.17	498.1	29.94
n-hexane BP 68^{o}C	86.17	507.8	29.91
Isoheptane BP 79^{o}C	100.20	520.9	28.37
Isoheptane BP 90^{o}C	100.20	531.1	27.21
n-Heptane BP 98^{o}C	100.20	540.2	27.00
Isooctane BP 109^{o}C	114.22	555.0	25.78
Isooctane BP 116^{o}C	114.22	566.0	26.60
n-Octane BP 126^{o}C	114.22	569.4	24.63
n-Nonane	128.25	595.0	22.52
n-Decane	142.28	618.9	20.82
Helium	4.00	5.2	2.26
Air	29.00	132.4	37.21
Nitrogen	28.02	126.1	33.47
Oxygen	32.00	154.4	49.66
Carbon dioxide	44.01	304.3	72.99
Hydrogen sulphide	34.08	373.6	88.84

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 4.7 Density of natural gasses (after Standing & Katz, AIME, 1042)	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

The pressure at any intermediate point along a horizontal gas pipeline may be obtained from the relationship:

$$P_x = \left[P_1^2 - (P_1^2 - P_2^2)\,\frac{x}{L} \right]^{0.5}$$

in which x is the distance from the upstream end (metres).

4.2.3

For 2-phase flow the following procedure may be used to determine the pressure drop along a length of pipeline for a given flow rate and given gas/oil ratio:

a) Compute the pressure drop ΔP_L for the liquid phase flow using the relationship in Clause 4.2.1 above as though the gas phase flow were not present, and the pressure drop ΔP_g for the gas phase flow using the relationship in Clause 4.2.2 above as though the liquid phase flow were not present.

Evaluate parameter $x = \sqrt{\Delta P_L / \Delta P_G}$

b) Compute the Reynolds Numbers for the liquid phase and gas phase flows as though each were flowing in the pipe by itself. The viscosities of hydrocarbon gasses may be taken from Fig. 4.7.

c) Determine the viscous-turbulent flow mechanism code from Table 4.4

Table 4.4 Flow mechanisms

Reynolds Number		Flow mechanism	Code
Liquid Phase	Gas Phase		
> 2000	> 2000	Liquid turbulent - gas turbulent	tt
< 1000	> 2000	Liquid viscous - gas turbulent	vt
> 2000	< 1000	Liquid turbulent - gas viscous	tv
< 1000	< 1000	Liquid viscous - gas viscous	vv

d) Determine the value of parameter Ø from Fig. 4.8 for the liquid flow (or the gas flow) for the appropriate flow mechanism.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

e) Compute the effective friction factor from the relationship:

$$f = 4\,\emptyset \left[\frac{d_i\,W_G}{\mu_G}\right]^a \left[\frac{d_i\,W_L}{\mu_L}\right]^b$$

in which:

- d_i is the internal diameter (meters)
- W_G is the mass velocity of the gas (kg/m^2 sec)
- W_L is the mass velocity of the liquid (kg/m^2 sec)
- μ_G is the viscosity of the gas (kg/m-sec)
- μ_L is the viscosity of the liquid (kg/m-sec)
- $a = \Psi/(1+\Psi)$
- $b = 1/e^{0.1\Psi}$
- Ψ = gas mass flow rate/liquid mass flow rate

f) Recompute the pressure drop for the liquid flow (or the gas flow) using the effective friction factor derived in (e). This is the pressure drop for the 2-phase flow.

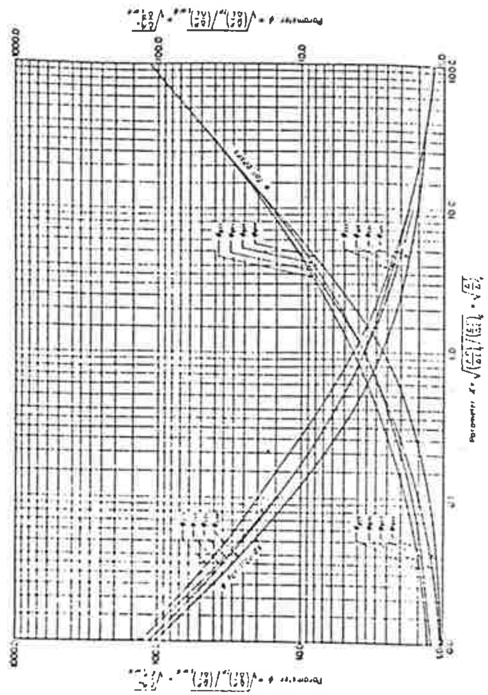
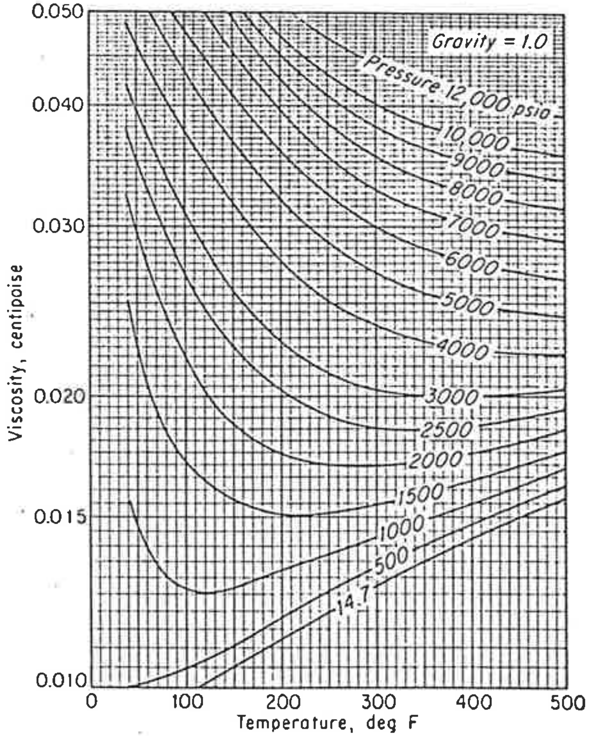


Fig. 4.8 Correlation for multiphase flow.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 4.9 Viscosity of natural gasses.	Note: 1 centipoise = 0.1 kg/metre second. From Handbook of Natural Gas Engineering p. 176, Fig. 4-107. To be redrawn in bar, ^oC, and centipoises.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	4.3 PIPELINE HEAT LOSS 4.3.1 The temperature of the fluid at the downstream end of a length of pipeline from which heat is escaping may be determined from the following relationship provided that the flow is turbulent: $T_2 = T_S + \left[T_1 - T_S - \frac{\phi^*}{k}\right] \exp - \left[\frac{kl}{p\rho\ (c+EX)}\right] + \frac{\phi^*}{k}$ in which: T_2 is the downstream (delivery) temperature (^oK) T_S is the ambient soil temperature (^oK) T_1 is the upstream (input) temperature (^oK) ϕ^* is the heat loss due to friction per unit length of pipe (W/metre) $= \frac{\Delta p \cdot q}{\ell}$ Δp is the pressure loss (N/m^2) g is the volumetric flow rate (m^3/sec) ℓ is the pipe length considered (metres) ρ is the fluid density (kg/m^3) c is the fluid specific heat (Joules/kg ^oK) E is the paraffin dropout (kg/kg/^oK) X is the latent heat of solidification of paraffin (Joules/kg) k is the heat transfer factor per unit length of pipe (Watts/metre ^oK) and $k = \frac{\pi}{\frac{1}{2\lambda_{in}} \ln \frac{d_{in}}{d_o} + \frac{1}{\alpha\ d_{in}}}$	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

in which:

d_{in} is the diameter of the pipe overall including insulation (if any) (metres)

d_o is the outside diameter of the fluid conductor (steel) pipe (metres)

λ_{in} is the thermal conductivity of the insulation material (Watts/metre ^oK)

and $$\alpha = \frac{2\ \lambda_s}{d_{in}\ \ln \frac{4h}{d_{in}}}$$

where

λ_s is the thermal conductivity of the soil (Watts/metre ^oK)

h is the depth from seabed to centre of pipe (metres)

Typical conductivity values of insulating materials are given in Table 4.5.

Typical conductivity values of soils are given in Fig. 4.10.

Table 4.5 Typical conductivities of insulators

Material	Bulk density kg/m^3	Conductivity Watts/m ^oK
Dry polyurethane foam	40 100	0.030 0.037 for $T \leq 80^oC$

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

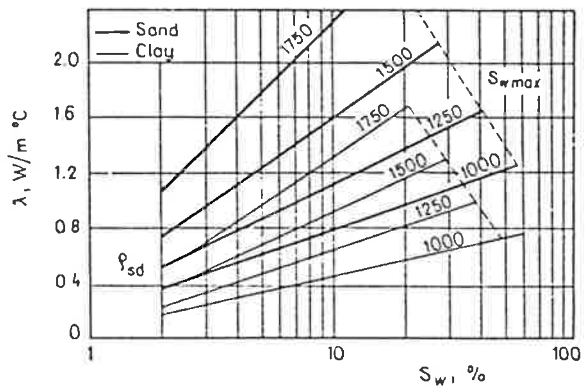


Fig. 4.10 Typical conductivities of soils of different bulk density and water content

4.3.2

The computed temperature profile of the fluid flow in the pipeline should be reviewed, and if necessary the flow calculations should be adjusted to reflect the corrected mean temperature. In zones of steep temperature gradient the pipeline should be divided into short sections for the purposes of flow calculations. Suitable computer programmes may be used.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	4.4.2 In addition to the PRV and in addition to such instrumentation and control devices as may be fitted to the pump or compressor discharge manifold for the purpose of controlling and monitoring the machines, a device should be fitted adjacent to the PRV to (a) give a constant indication of pipeline gauge pressure at this location, (b) give an alarm in the appropriate control room when the set pressure of the device is exceeded, and (c) automatically trip the pump or compressor shutdown when the set pressure of the device is exceeded. The set pressure of the device should be 4 bar below p_{RV}. The set pressure of the pump or compressor discharge manifold shutdown trip device should be 8 bar below p_{RV}.	It should be recognized that the implementation of Clauses 4.4.1 and 4.4.2 may with certain configurations imply that it is impossible ever to achieve a gauge pressure of p_R in the pipeline/riser at water level under high flow conditions. This does not alter the fact that the precautions are necessary for the protection of the pipeline and riser against excessive pressure due to human and/or instrumentation failure during conditions of high pressure and low flow. This is particularly important in the context of corrosion fatigue and stress corrosion cracking.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	<u>4.5 INPUT TEMPERATURE REGULATION</u> 4.5.1 A device should be fitted adjacent to the PRV to (a) give a constant indication of pipeline fluid temperature at this location, (b) give an alarm in the appropriate control room when the set temperature of the device is exceeded, and (c) automatically trip the pump or compressor shutdown when the set temperature of the device is exceeded. The set temperature of the device should be determined from the following expression: $T_S = T_D - \Delta T_E$ in which: T_S is the set temperature T_D is the maximum fluid temperature for which the pipeline and riser, including their coatings and anodes, have been designed ΔT_E is the maximum set temperature error of the device.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

4.6 FLUID STABILITY IN LIQUID PIPELINES

4.6.1

The pressure in pipelines intended for single-phase operation should nowhere be permitted to fall below the vapour pressure, at the relevant temperature, of the most volatile component of the liquid mixture.

The vapour pressures of normal saturated hydrocarbons at different temperatures are presented in Fig. 4.11 while the vapour pressures of isomeric saturated hydrocarbons are presented in Fig. 4.12. The vapour pressures of water are presented in Fig. 4.13.

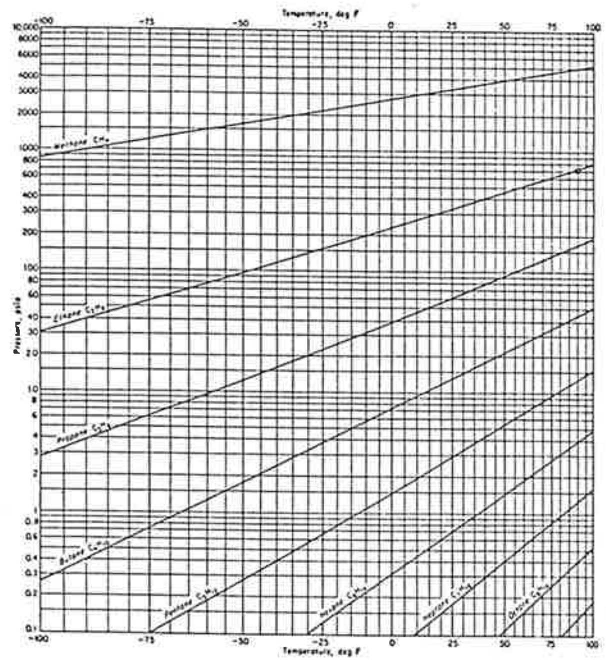
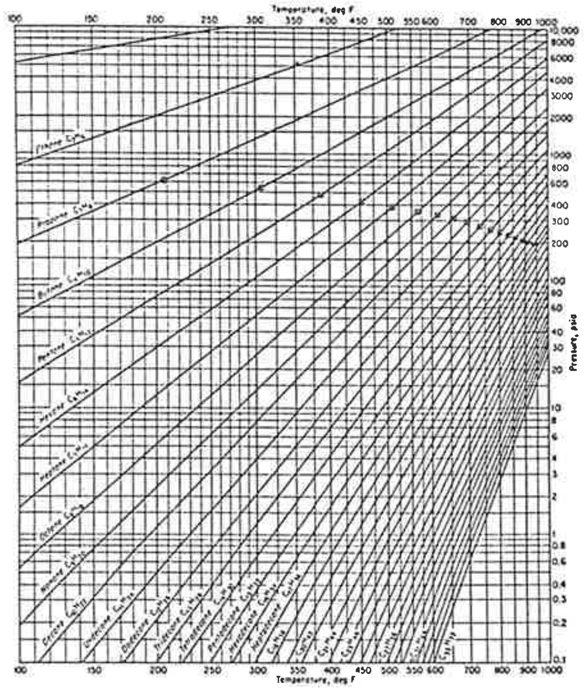


Fig. 4.11 (a)

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 4.11(b) Vapour pressures of normal saturated hydrocarbons.	

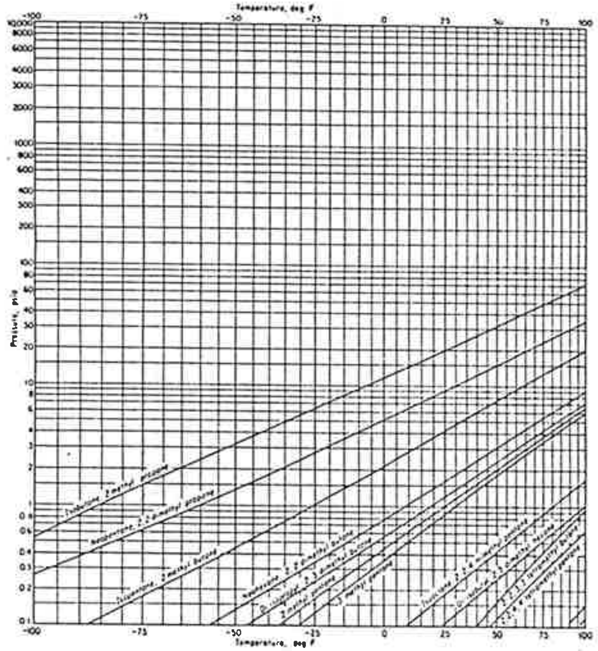
<table>
<tr><th>PROCEDURES ADOPTED IN
DANISH/NORDIC PROJECTS</th><th>GUIDELINE RECOMMENDATION</th><th>DISCUSSION FURTHER
STUDIES ETC.</th></tr>
<tr><td></td><td>

Fig. 4.11(c)</td><td></td></tr>
</table>

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

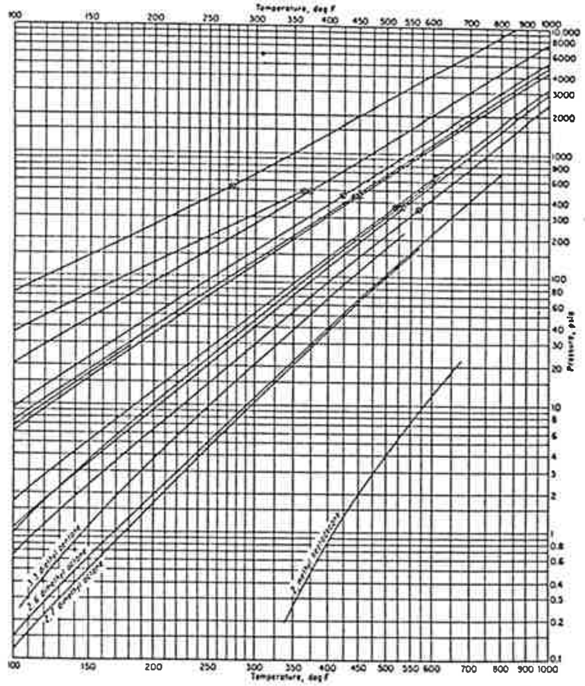
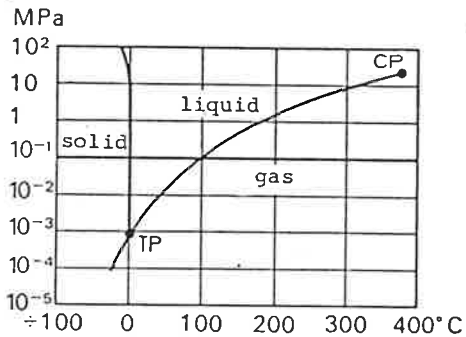


Fig. 4.12 Vapour pressures of isomeric saturated hydrocarbons.



CP = Critical Point
TP = Triple Point

Fig. 4.13 Vapour pressures of water.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	<u>4.7 FLUID STABILITY IN GAS PIPELINES</u> 4.7.1 (Hydrocarbon dewpoint) 4.7.2 (Water dewpoint) 4.7.3 (Conditions for hydrate formation)	These sections have not yet been drafted. They are important, however, and will be added at the next stage.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	<u>5. EXTERNAL ENVIRONMENT</u> <u>5.1 GENERAL</u> 5.1.1 Success in reconciling economic design on the one hand with demonstrable safety (probability of failure) on the other is strongly dependent on the availibiity of accurate environmental data. This consideration should be made fundamental to the planning and execution of all environmental data gathering and analysis and of the engineering process as a whole. 5.1.2 The tendering and contractual arrangements for the gathering and analysis of environmental data should be such as to avoid incentives to cost cutting at the expense of data quality and reliability and should be such as to promote a professional engineering approach at all levels. In all cases where the environmental data available to the engineer is for one reason or another of an inferior quality or inadequate scope or is suspect, the engineering should be performed using augmented safety factors or partial coefficients.	

<table>
<tr><th>PROCEDURES ADOPTED IN
DANISH/NORDIC PROJECTS</th><th>GUIDELINE RECOMMENDATION</th><th>DISCUSSION FURTHER
STUDIES ETC.</th></tr>
<tr><td>The procedures used have generally been those prescribed in this Section.</td><td><u>5.2 PRE-ENGINEERING SURVEYS</u>

5.2.1

Adequate surveys should be performed in good time to provide all necessary input data for the routing and engineering processes, except insofar as data of satisfactory scope, reliability, and continued validity is already available from surveys performed by others.

5.2.2

The physical surveys should be preceded by a thorough investigation of all relevant available meteorological, oceanographic, geographic, maritime, construction, and other records, and by discussions with all relevant operators, utility companies, defence arms, and other parties who have activities or plant in the area in question or who may have plans to engage in such activities or install such plant. Special attention should be given to ship traffic movements and fishery activities and the risk of interference from groundings, anchors, and trawls.

5.2.3

The appropriate physical survey corridor width, survey depth below seabed, and survey accuracy may vary along the route. The survey corridor width should generally be not less than 200 metres. The depth of seabed soil investigated should extend below the intended final soffit level of the pipeline. A wider scope and higher degree of accuracy is required in areas characterized by offshore activities, maritime activities, complex seabed topography or sub-bottom conditions, or obstructions or hazards. If the pipeline construction equipment is expected to include vessels with wide anchor patterns (eg: laybarges and trenching barges) or if the presence of hazards or awkward topography indicates a need for iterative route adjustment during engineering and/or installation, the appropriate survey corridor width may be from 600 to 2000 metres.</td><td>Clause 5.2 has the same general scope as DnV Sections 2.2.2, 2.2.3, 2.2.4, 2.3.6, 2.3.7, 2.3.8, and 2.3.9, while the subjects dealt with in DnV Sections 2.3.1 to 2.3.5 inclusive are addressed in Clause 5.3, and the subject of DnV Section 2.2.1 is covered elsewhere under Design. To this extent the deviations from DnV are related to format. In addition, however, there is a greater emphasis on guiding the engineer towards procedures which recent Danish and other Nordic project experience has indicated may be appropriate.</td></tr>
</table>

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	5.2.4 The surveys should be adequate to identify and quantify the following: (i) all topographical features influencing the pipeline during installation or operation including rock outcrops, boulders, wrecks, or other obstructions that could require removal or levelling prior to pipeline installation, and including unstable slopes, sand waves, scour, erosion, and sedimentary deposition processes;	
	(ii) the geotechnical characteristics of the seabed soil and sub-bottom soil down to the intended final soffit level of the pipeline including in-situ conditions (eg: bulk density and void ratio for sands and in-situ shear strength for clays);	This information is important in relation to the evaluation of pipeline trenching techniques and production rates.
	(iii) the corrosivity characteristics of the seabed soil and seabed seawater around the year including temperature conditions, salinity, oxygen content, pH value, resistivity, water particle movement, and biological activity (sulphate-reducing bacteria, etc.);	
	(iv) the ambient temperatures around the year of the soil, water, and air through which the pipeline is to pass, and which will thus affect heat transfer to and from it;	
	(v) the rate and extent of marine growth to be expected along the pipeline route, which may increase the effective diamter and rugacity of the pipe;	
	(vi) sufficient hydrographic field data on the pipeline route, and/or near it, and at more remote locations, to enable regional mathematical models to be calibrated and verified with regard to wave, current, and water level conditions; this involves the acquisition of data from specific storms for which meteorological records are also available.	
	(vii) ice conditions, with particular reference to loadings which may be generated by drift ice and pack ice and to interference by icebergs in the operational phase, and the effects of ice during the installation phase.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	5.2.5 The survey types considered in relation to the requirements of Clause 5.2.4 should include those listed in Table 5.1. Typical functional specifications for surveys types A/GS.1, B, IS, and E will be available in the form of separate DHI guidelines. The advantages of combining survey types A, GS.1, and E in order to economize on vessel deployment should be considered. 5.2.6 The results of the physical surveys should be displayed on accurate scale drawings representing the vicinity of the pipeline route in plan and in vertical longitudinal profile. In the case of survey types A, B, and IS the use of automated on-board computation and plotting of positional bathymetric data is to be preferred to post-plotting ashore. The advantages of establishing an integrated pipeline database already at this early stage should be considered.	

Table 5.1 Pre-Engineering Surveys Types

Type Code	Purpose	Typical Spread	Appropriate Accuracy of Surface Positioning System
A	Quick & relatively cheap wide coverage of bathymetry and seabed features, and sub-bottom profiles	Standard vessel with precision echo-sounder and towed fish sidescan sonar & seismic units (pinger and boomer), plus integrated on-line computing & plotting hardware & software. In deeper water an HPR system is also required.	30-50 m RMS
B	Accurate bathymetry & hazard identification	Dynamically positioned vessel with ROV fitted with digiquartz, TV, giro, and HPR system plus integrated on-line computing & plotting hardware & software.	3-5 m RMS
GS.1	Geotechnical correlation of A	Vessel as A plus drop sampler & vibracover and refrigerator for corrosivity test samples.	As A
GS.2	Determination of in-situ geotechnical parameters	Vessel plus cone penetrometer, plate bearing rig, vane rig.	As A or B
IS	Survey inshore and in depths inaccesible to Survey Type A&B vessels	Rubber dinghy with echosounder & washboring rig. An alternative source are LANDSAT satellite photographs and the use of colour photogrammetry for depth evaluation.	3-5 m RMS
E	Wave & current measurements to calibrate & verify mathematical models	Deployment vessel plus waverider buoys, current meter racks, & DTS profiler.	30-200 m RMS

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	5.2.7 The resolution of echosoundings should be sufficient to ensure that all conditions relevant to the routing and engineering of the pipeline are revealed; for this reason signal filtering should be applied only with circumspection. The resolution of sidescan sonar records should be the best achievable with normally available equipment. This will generally mean that the selected mode should have a maximum range of 125 metres or less. The coverage of parallel runs should overlap by an amount which makes due allowance for surface positioning error, vessel deviations from planned run lines, and lateral deviations of the towed fish relative to the vessel. All sidescan sonar and sub-bottom profiler records should bear frequent position fix marks applied automatically by the on-line position computation system with due allowance for the instantaneous value of fish layback from the surface positioning antenna. All sidescan sonar and sub-bottom profiler records should be monitored daily on board by a geotechnical engineer with experience in interpreting them, and he should as soon as possible either on board or ashore fully annotate these records identifying all features and classifying zones and providing correlations between sidescan sonar records, sub-bottom profiler records, bathymetric records, and geotechnical test results. The recorded data and annotations should be transferred from the sidescan sonar records and sub-bottom profiler records to the plan and vertical longitudinal profile respectively on the scale drawings as soon as possible in order to provide a coherent database for the design engineer. The interpolation of bathymetric data should always be performed with due regard to the annotated sidescan sonar records. For this reason caution should be exercised in the use of computer interpolation routines unless a fine grid of data points is available.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	5.3 GENERATION OF HYDROGRAPHIC DATA 5.3.1 Submarine pipeline design should involve a rational assessment of the probability of occurrence and cumulative duration of exceedance of the most adverse combinations of wave, current, and water level conditions at each point on the system during the period for which the system is exposed to them. Wind conditions should also be considered in the case of exposed pipeline risers. 5.3.2 In the case of short pipelines in the immediate vicinity of older platforms or shore stations from which continuous records of physical measurements of wind, wave, current, and water level for a period of at least 10 years are available, including directionality information and including reliable data from all major storms, it may be sufficient to base the pipeline design on a statistical treatment of these records alone, provided that the multi-year weather cycles are taken into account in this treatment. Interpolation or extrapolation of recorded data from other locations should not be performed except with the aid of regional mathematical models of the type referred to in Clause 5.3.3. 5.3.3 Records of the type referred to in Clause 5.3.2 are not generally available, and the evaluation of environmental conditions of given probability of occurrence (return period) and cumulative duration of exceedance should then be based on historical meteorological records (3 or 6 hourly synoptic weather charts) using regional mathematical time domain wave hindcast models and current/water-level hindcast models which take full account of the effects of bathymetry, including wave breaking on shallow banks, and of storm surge as well as tide. 5.3.4 At locations where historical meteorological records are inadequate it may be appropriate to run the mathematical models on the basis of synthetic weather charts derived from a knowledge of the characteristics of typical storms in the region being treated (eg: monsoon storms).	The subject of hydrographic data generation, which is absolutely fundamental to the economic and safe design of marine pipelines and risers, is treated with the utmost brevity in the DnV Rules. Clause 4.3 aims to cover this gap. It draws on the experience of project work for DONG, Danbor, ARAMCO, Hamilton Brothers, and other operators.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

5.3.5

All regional mathematical hindcast models should be calibrated with field data recorded during specific storms which have been run on the model on the basis of meteorological data (weather charts) from those same storms (or storm types in the case of synthetic storms).

5.3.6

In addition to the requirement of Clause 5.3.5 all regional mathematical hindcast models should be verified against field data, likewise from specific storms which have been run on the model on the basis of meteorological data from those same storms (or storm types in the case of synthetic storms), but recorded at locations other than those used in the calibration process.

5.3.7

The resolution (ie: mesh size) of the regional mathematical hindcast model grids should be sufficiently fine to ensure that local bathymetric effects are not masked. Models with a nesting grid facility may have a coarser mesh at more remote locations within the energy catchment.

5.3.8

The regional mathematical hindcast model types which may be appropriate are listed in Table 5.2. These may be used individually or in combination.

Table 5.2 Regional Mathematical Model Types.

Type Code	Designation	Generic Description
WW	Wind-Wave Model	This type of model describes the regional development of the wave field under the influence of changing weather conditions. Inputs are regional bathymetry on selected grid(s) and a series of 3 or 6 hourly synoptic weather charts for specific storms from which the model generates the instataneous wind fields. The model computes regional wave energy growth, transport, and decay under the influence of the changing wind field, expressing the instantaneous wave energy at each grid point in terms of a set of direction components for each component of a frequency set.

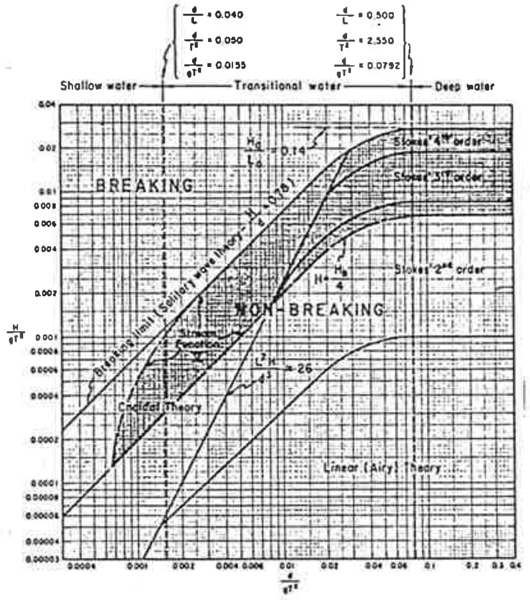
PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Table 5.2 (cont'd)

Type Code	Designation	Generic Description
		Each local instantaneous wave energy component thus has the form: $E(x,y,t,f,\theta)$. The output can be expressed either as the full spectral wave energy description at any grid point at any instant or in terms of composite parameters such as H_{mo} and T_{02}.
WR	Wave Refraction Model	In shoaling areas where rapid refraction occurs, it may not be practicable or economic to run a WW model with a sufficiently fine resolution (grid mesh) to yield accurate results. On the other hand the area considered may be sufficiently small that wind-wave energy growth within it is negligible. In such circumstances a non-windlinked depth-refraction model or combined current/depth refraction model taking input from the WW model at the area boundary may yield a suitable detailed description of local variations of wave intensity and direction.
GW	Gravity Wave Model	Thys type of model describes the regional development of the depth-averaged current field under the influence of changing weather conditions and tide. Inputs are regional bathymetry on selected grid(s) and a series of 3 or 6 hourly synoptic weather charts for specific storms for which the model generates the instantaneous wind fields. The model solves the equations of conservation of mass and momentum in two horizontal directions. Effects treated include convective and cross momentum, wind shear stress, barometric pressure gradients, Coriolis forces, momentum dispersion (eddies), radiating boundaries (tidal driving functions), and dissipating and reflecting boundaries. The output is expressed as the intensity and direction of the instantaneous depth-averaged current at each grid point and the associated water level.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	5.3.9 Two-dimensional regional hindcast models of the GW type should not be applied in water depths in excess of approximately 50 to 75 metres. In greater depths the fully developed wind-induced surface current speed may be taken as 3 percent of the 1 hour mean wind speed, and the tide-induced current may be estimated on the basis of an analysis of all relevant recorded data available. These estimates should be verified against field measurements from current meter strings deployed on the pipeline route for as long a period as possible and preferably for at least one full year. The strings should carry meters at a number of levels between seabed and surface. One of the strings should remain at the same location throughout the deployment period.	
	5.3.10 Vertical current profiles between seabed and surface should be estimated separately for the wind shear induced component and tide/surge induced component respectively using appropriate logarithmic correlations which may take into account both actual bottom roughness and wave-induced apparent added bottom roughness.	
	5.3.11 For a pipe on the seabed in water depth h, the mean current velocity $U(D_t)$ over a height equal to the total diameter D_t of the pipe may be obtained from the depth-averaged current U_{av} by the following correlation: $U(D_t) = U_{av} \times \frac{\ln (11\ D_t/k_w)}{\ln (11\ h/k_w)}$ in which k_w is the total hydraulic bed roughness including wave-induced apparent added roughness. In the absence of more accurate data the value of k_w may be taken as 0.07 metres.	Note: The value of the expression is not particularly sensitive to the exact value of k_w. Some typical values are given belows for k_w = 0.07 m. h (m) / D (m) / $U(D)/U_{av}$: 20 / 0.2 / 0.43 20 / 1.25 / 0.66 80 / 0.2 / 0.37 80 / 1.25 / 0.56 300 / 0.2 / 0.32 300 / 1.25 / 0.49 The correlation is based on the assumption that the vertical profile has the form: $U(y) = C \log (30\ y/k_w)$ where U(y) is the velocity at height y above the seabed and C is a constant. This is valid for tide/surge induced current, and for combinations in which the surface velocity found in this way is at least 3 percent of the wind speed. When wind shear is predominant this correlation is not valid and will yield extremely conservative results for pipeline design.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	5.3.12	
	For rough preliminary calculations it may be appropriate to compute the wave-induced water particle velocities at a seabed pipe from the composite wave height and period parameters using the appropriate wave theory for single frequency waves. See Fig. 5.1 and Appendix 501.	
	Wave-induced water particle velocities used in the final design of seabed pipelines should be derived from spectral transfer using the full wave energy directional spectrum information available from the mathematical hindcast model results. Spectral transfer should be based on the appropriate wave theory. See Fig. 5.1.	
	Alternatively simple Airy theory may be applied subject to suitable corrections.	Appropriate corrections will be provided in a subsequent appendix.
	For the purpose of 2-dimensional analysis of the hydrodynamic loading on a unit length of pipe, the directional water particle velocity spectrum at the pipe may be recomposed to yield the bottom significant (peak energy) water particle velocity, the bottom peak energy period, and bottom peak energy direction.	The peak energy direction and peak energy period of the water particle velocity spectrum at the pipe may be different from the peak energy direction and peak energy period of the surface wave spectrum
	For the purposes of 3-dimensional analysis of the hydrodynamic loading on a finite length of pipeline significantly greater than the peak energy wave length the directional energy water particle velocity spectrum time series at regular intervals along the pipe should be used as input to the stability simulation model.	
	Wave-induced water particle velocities used in the final design of risers should be derived from the application of the most appropriate wave theory under the circumstances. See Fig. 5.1.	
	The wave spectra used as input to the mathematical models should in all cases be those which are the most appropriate under the circumstances depending on, for example, fetch and depth and whether or not the sea state is fully developed. See Appendix 502 for guidance.	Appendix 502 will be drafted ab initio.
	This simple calculation method generally yields a more conservative result than that obtained from spectral transfer.	
	Appendix 501 will be a reproduction of the Airy theory section of the DtH leaflet giving formulae and tables - plus a reproduction of the DHI table relating H_s to Beaufort wind and sea states.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 5.1 Regions of validity for various wave theories (after U.S. Army Corps of Engineers Coastal Engineering Research Centre Shore Protection Manual Volume I).	To be simplified and clarified in next edition.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	5.3.13 Evaluation of wave data for pipeline design in shallow areas should take full account of the effect of refraction on wave energy density and wave direction. The distinction between deep and shallow water in this context is dependent upon the wave length. All depths less than one half wave length should be regarded as shallow and checked for refraction effects. For rough preliminary calculations the refraction effects may be assessed by graphical methods using an application of Airy theory and Snell's law to a single frequency sinusoidal deep water wave of given height and period.	
	The angle between the wave crest and the contour at any point is given by: $\sin \alpha = (\frac{C}{C_o}) \sin \alpha_o$ in which α is the angle between the wave crest and the seabed contour at the point in question. α_o is the angle between the same wave crest in deep water and the seabed contour in deep water. C is the wave celerity at the point in question. C_o is the wave celerity in deep water. The celerity at any point is obtained from the expression $C = \sqrt{\frac{gL}{2\pi}} \tanh (\frac{2\pi d}{L})$ in which d is the local water depth and L is the wave length at that depth computed from the deepwater wave height and period by Airy theory. The local wave height is given by: $H = H_o \times K_s \times K_R$ in which H_o is the deep water wave height K_s is the shoaling factor K_R is the refraction factor	One half wave-length will typically be a depth of 150 metres.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

and $K_s = \sqrt{\frac{1}{2} \cdot \frac{1}{n} \cdot \frac{C_o}{C}}$

in which $n = \frac{1}{2} \left[1 + \frac{4\pi d/L}{\sinh(4\pi d/L)} \right]$

where: d is the depth
L is the wave length at depth d

while: $K_R = \sqrt{\frac{b_o}{b}}$

in which b is the local orthogonal spacing
b_o is the orthogonal spacing in deep water.

In the case of straight parallel seabed contours the refraction factor may be calculated as:

$$K_R = \sqrt{\frac{b_o}{b}} = \sqrt{\frac{\cos \alpha_o}{\cos \alpha}}$$

In areas of complex bathymetry where wave energy may reach the location of interest simultaneously from different directions, the refraction analysis should be performed with the aid of the backward tracing technique for each component frequency, so that a directional wave energy spectrum at the location of interest in the shallows can be recomposed on the basis of a knowledge of the directional wave energy spectra at the points of origin of the orthogonals in deeper water. The amount of calculation involved in this will normally necessitate the use of a computer. Circumspection should be exercised if lines cross.

5.3.14

The return periods and exceedances of wind, wave, current, and water level conditions should be evaluated by applying statistical analysis to the parameters obtained from the treatment of meteorological storm data input as described above. This analysis will typically include extrapolation with the aid of a Weibull correlation.

The evaluation should take due account of the fact that the meteorological conditions which yield the extreme waves in a particular direction at a particular location may not be the same as those which yield the extreme water levels or the extreme wind speeds or currents in the same direction at the same location. The assessment of probability of joint occurrence of extreme wind, wave, and current conditions may be based on statistical analysis or deterministic considerations or a combination of the two.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

The selection of the particular storms to be run on the regional mathematical hindcast models should be made in such a manner as to include all those which are expected to yield the most adverse combinations of conditions in relation to each aspect of the design.

5.3.15 Wave slamming

Wave slamming loads

Horizontal pipes in the wave zone may be subjected to forces caused by wave slamming. The dynamic response of the pipe should be investigated.

The wave slamming force per unit length of the pipe may be calculated as

$$F_s = \tfrac{1}{2} \; C_s V^2 D$$

where

F_s = slamming force per unit length in the direction of the velocity

= mass density of the surrounding water

C_s = slamming coefficient

D = pipe diameter

V = velocity of the water surface normal to the surface of the pipe.

The slamming coefficient C_s may be determined using theoretical and/or experimental methods. For smooth, circular cylinders the value of C_s should not be taken as less than 3.0.

As the slamming force is impulsive, dynamic amplification must be considered when calculating the response.

For a pipe section fixed at both ends, dynamic amplification factors of 1.5 and 2.0 are recommended for the end moments and the midspan moment respectively.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

5.4 EVALUATION OF FRICTION COEFFICIENTS

5.4.1

The evaluation of coefficients of friction between pipeline and seabed should be based on consideration of the geotechnical characteristics of the seabed and the rugacity of the pipe.

For rough preliminary calculations it may be appropriate to adopt those static friction coefficient values from Table 5.4 which are the most adverse for the particular design aspect being treated. The coefficient of dynamic friction in the longitudinal direction may be taken as one half of the coefficient of static friction. The coefficient of dynamic friction in the transverse direction should be considered to be the same as the coefficient of static friction. Design aspects influenced by effective coefficients of friction include pipeline lateral stability, stresses and movements in expansion devices, and pipeline movement on the seabed during installation and operation.

Seabed Soil	Pipe Material	Friction factors: Lateral, Minimum		Lateral, Maximum	Longitudinal, Minimum		Longitudinal, Maximum	
Loose sand	Concrete	tan ϕ	Failure in soil	2,0 #	0,5	Accounting for hysteresis, creep, remoulding, & marine growth	0,8	Accounting for adhesion, & high loading rate
	Steel, epoxy	tan ϕ		2,0 #	0,2		0,6	
Compact sand	Concrete	tan ϕ		1,0 #	0,2		0,6	
	Steel, epoxy	tan ϕ		1,0 #	0,2		0,6	
Soft clay, $c_u<25 KN/m^2$	Concrete	0,4		Adhesion c_u			Adhesion, c_u	
	Steel, epoxy	0,4		Adhesion c_u			Adhesion, c_u	
Stiff clay $c_u>25 KN/m^2$	Concrete	0,2	Sliding on soil	2,0	0,2		Adhesion, c_u	
	Steel, epoxy	0,2		2,0	0,1		Adhesion, c_u	
Moraine Clay	Concrete	0,4		2,0	0,4		1,0	
	Steel, epoxy	0,4		2,0	0,4		1,0	
Rock	Concrete	0,7		2,0	0,5		1,0	
	Steel, epoxy	0,4		2,0	0,4		1,0	
Rock with Marine Growth	Concrete	0		1,0	0		1,0	
	Steel, epoxy	0		1,0	0		1,0	
Mud	Concrete	0		Adhesion, c_u	0		Adhesion, c_u	
	Steel, epoxy	0		Adhesion, c_u	0		Adhesion, c_u	

Note: ϕ is the planar angle of internal friction and may be taken as 1.1 times the angle of internal friction determined from triaxial tests.

For more accurate evaluation see section 5.4.2

Table 5.4 Typical Friction Factors (μ)

Real life friction factors depend on:

- soil material
- pipe material
- pipe dimension/weight
- stress history
- loading rate.

Table 5.4 summarizes the present state of the art but should be used with circumspection.

For "soft clay" c_u is by definition 12.5-25 kN/m^2.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

5.4.2 Passive Soil Resistance

The passive soil resistance on the partial or whole buried pipe may be calculated using N. Krebs Ovesen's anchor plate theory as described in the following:

Anchor Plate Theory

Definitions:

W_{sub} = submerged weight of pipe per unit length

D = outer diameter of pipe

H = soil cover on top of pipe

γ = effective unit weight of soil

ϕ = friction angle

$\tan\rho_r$ = mobilized friction soil/anchor slab

K_a = active soil pressure coefficient

A^o = passive soil resistance for basic case

A^s = $E_{p_{ulp}}$ = passive soil resistance for actual case

δ = lateral displacement of pipe

The active soil load has the resultants:

$E_{ay} = \frac{1}{2} \bar{\gamma} (H+D)^2 K_a$

$F_a = E_a \tan\phi$

Vertical force equilibrium requires:

$$K_\gamma \tan \rho_\gamma = \frac{W_{sub} \quad F_a}{\frac{1}{2} \bar{\gamma} (H + D)^2} \text{, and hereafter}$$

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	K_γ is determined from Fig. 5.2.	

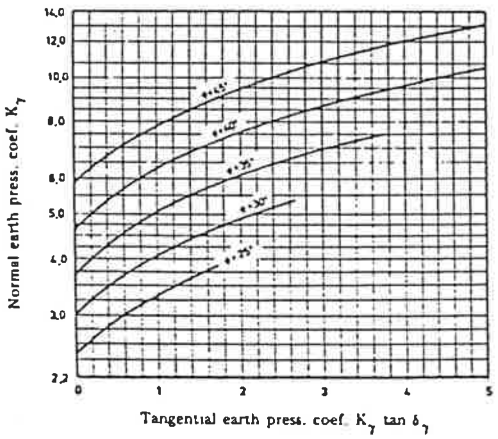


Fig. 5.2 Earth pressure coefficients for the normal earth pressure in front of an anchor slab.

A^o = $1/2\ \bar{\gamma}\ (H+D)^2\ K_\gamma - E_a$, whereafter A^s is determined from Fig. 5.3 as a function of $\frac{D}{D+H}$.

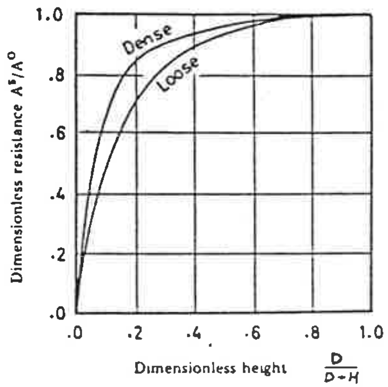
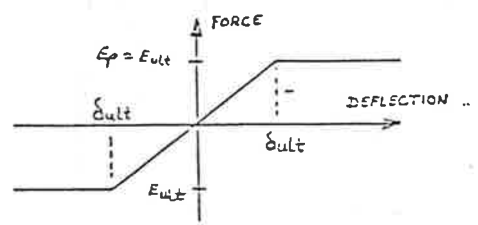


Fig. 5.3 Diagrams for design of vertical rectangular anchor slabs in sand.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	A^s represents the ultimate passive resistance Ep_{ult} on the pipe. This value is reached at a displacement of approximately 2% of the depth to the pipeline bottom: $\delta_{ult} = 0.02\ (H+D)$ The relationship is illustrated in Fig. 5.4.  Fig. 5.4 Relationship between Passive Soil Resistance and Lateral Displacement.	

APPENDIX 5.A

EXPLANATION OF CORRIDOR TERMS COMMONLY USED

Route Centreline (The Design Alignment)	- The line which the Engineer intends that the pipeline should follow subject only to minor deviations during laying to negotiate local obstables or hazards by agreement between Engineer and contractor.
Installation Corridor	- A band extending to either side of the route centreline within which the authorities have given a mandate for the pipeline to be laid. This band is typically from 10 m to 200 m wide depending on the circumstances.
Construction Corridor	- A band extending to either side of the route centreline within which the authorities have given a mandate for construction activities to be performed (including for example the deployment of high-holding anchors). This band may be 1500 m wide or more.
Survey Corridor	- The band of seabed covered by a survey. The survey may involve only a single linear run of the survey vessel, in which case the corridor will typically be 250 m wide, or may involve several parallel runs. The corridor width for a pre-engineering marine pipeline route survey will typically be 600 m to 800 m.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

6. STRUCTURAL DESIGN

6.1 DESIGN CRITERIA

Pipelines and risers are to be designed against the following possible modes of failure:

- Excessive yielding
- Buckling (incl. flattening and denting)
- Fatigue failure
- Brittle fracture
- Excessive damage to or loss of weight coating (see Section 10)
- Loss of inplace stability (external equilibrium) (see Section 7)
- Propagating ductile fracture

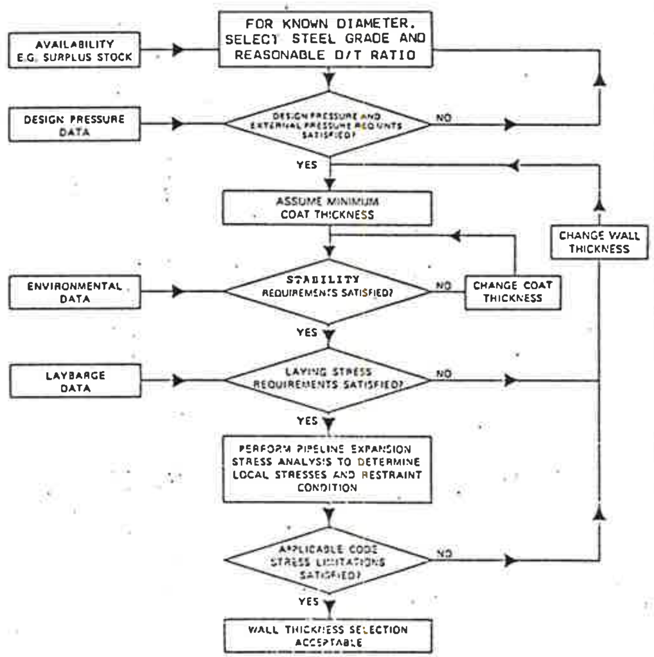
The interconnection between different design aspects is illustrated in Fig. 6.1.

For design against corrosion, see Section 9.

Strength criteria are here primarily based on the method of permissible stresses for operation and strain criteria for installation. The limit state method may also be used, provided the load and material factors used for the ultimate limit state will represent the corresponding safety level.

The safety against brittle fracture is normally considered satisfactory if the materials with the workmanship, welding and testing are in accordance with Section 8.

Brittle fracture is usually only a decisive criterion under specially low temperatures (arctic conditions and in connection with leaks or venting) if API5L line pipe is used.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 6.1 Structural Design Sequence.	Code stress limitations related to: a) Hoop Stress b) Combined stress in restrained condition c) Risk of local buckling or initiation of propagating buckle

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	6.2 GENERAL DESIGN PROCEDURES The design analyses should be based on accepted principles of statics, dynamics, strength of materials, and soil mechanics. Simplified methods of analysis may be used if these are reasonably conservative. When determining responses to dynamic loads, the dynamic effect is to be taken into account if deemed significant. Dynamic analyses or reasonably conservative quasistatic considerations may be used. All forces and support displacements which may influence the safety, are to be taken into account. For each cross-section or part of the system, and for each possible form of failure to be analysed, the relevant combinations of forces which may act simultaneously should be considered.	

6.3 DESIGN CONDITIONS

Safety against the modes of failure mentioned in 6.2 is to be checked for the design conditions in which the mode of failure in question is possible - with due regard to permissible stress (or strain) levels in the condition considered.

A summary of the design conditions to which different stress levels are connected is given below in Table 6.1.

In these guidelines two main design conditions are defined:

- Pipeline systems during operation
- Pipeline systems during installation

The term "during operation" refers to normal situations after completed installation whether the system is in operation or not. Shut-down conditions and conditions during maintenance operations are included. Repair situations are normally not included.

The term "during installation" refers to any situation (construction, installation, laying, burial) before completed installation of the system. Repair situations will normally also be included.

Design Criteria	Loading Condition		Design Condition	
	Operation	Installation	Functional	Functional + environment.
Hoop Stress	x		x	
Total Operational Stresses	x		x	x
Flattening	x	x	x	x
Buckling	x	x	x	x
Installation Stresses (Strain)	x	x	x	x
Trenching		x	x	x
Spanning	x	x	x	x

Table 6.1 Summary of Design for Structural Design of Marine Pipelines.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

6.4 OPERATION

6.4.1 General

In order to avoid damage to the pipeline and risers they should not be located too close to foreign structures, pipelines, wrecks, boulders etc. If this is unavoidable, however, the pipeline or riser should be kept in position by clamps, supports, etc. When one pipeline is crossing another, the recommended minimum clearance between the two pipelines is 0.3 m.

When a submerged pipeline is to be thermally insulated, special attention is to be paid to the watertightness and shear strength of the insulation as well as to corrosion monitoring.

API 5LX Specifications:

Tolerances on Internal Diameter, Wall thickness, and Weight

Absolute minimum and maximum internal diameters are of interest in relation to pigging (ordinary, caliper, and "intelligent").

Outside Diameter, D:

Pipe Body
Less than 20 in. .... ± 0.75 per cent
20 in. to 36 in.
    Non-expanded.............. ± 1.00 per cent
    Cold-expanded............. ± 0.25 per cent

Larger than 36 in.
    Non-expanded.............. ± 1.00 per cent
    Cold-expanded............. + 6.35 mm
                               − 3.20 mm

Wall thickness, t:
    For pipe in sizes 18 in. and smaller.............. + 15.0 per cent
                                                      − 12.5 per cent

    For pipe in sizes 20 in. and larger
    Seamless................. + 17.5 per cent
                              − 10.0 per cent

    Welded................... + 19.5 per cent
                              − 8.0 per cent

Weight:
    Single lengths:
    All sizes in regular-weight series.... + 10.0 per cent
                                           − 3.5 per cent

    All sizes in special light-weight series...... + 10.0 per cent
                                                   − 5.0 per cent

The API specified negative wall thickness tolerance is used as Δt_1 in hoop stress formula unless the material specifications are more stringent than API.

The effect of negative tolerance whould be treated as a part of a general analysis of tolerances which include:

- tolerance on SMYS
- tolerance on diameter
- tolerance on general linepipe wall thickness
- tolerance on weldings
- strength of weldings
- analysis of defect distributions.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS

ASME (192.103)

Danish supplement to ASME:

Minimum wall thickness for pipe of ductile cast iron:

Nominal pipe diameter mm	Minimum wall thickness mm
80	6.1
100	6.1
125	6.2
150	6.3
200	6.4
250	6.8
300	7.2
350	7.7
400	8.1
500	9.0
600	9.9
700	10.8
800	11.7
900	12.6
1000	13.5
1200	15.3

GUIDELINE RECOMMENDATION

Bending Radii

Diameter tolerances on the bend should be 2% of nominal internal diameter. The minimum bending radius should be greater than or equal to 5 times the external diameter, and should allow planned pigging to be performed.

Minumum Allowable Wall Thickness

Nominal Pipe Size (Inches)	Outside Diameter (Inches)	Least Nominal Wall Thickness (Inches) — Plain End Pipe[1] — Class 1 Location	Fabricated Assemblies Class 1 Location	Class 2 Location	Class 3 & 4 Location	Threaded Pipe — All Class Locations	All Pipe — Compressor Stations
1/8	0.405	.035	.065	.065	.065	.068	.095
1/4	0.540	.037	.065	.065	.065	.088**	.119
3/8	0.675	.041	.065	.065	.065	.091	.126
1/2	0.840	.046	.065	.065	.065	.109	.147
3/4	1.050	.048	.065	.065	.065	.113	.154
1	1.315	.053	.065	.065	.065	.133	.179
1 1/4	1.660	.061	.065	.065	.065	.140	.191
1 1/2	1.900	.065	.065	.065	.065	.145	.200
2	2.375	.075	.075	.075	.075	.154	.218
2 1/2	2.875	.083	.085	.085	.085	.203	.203
3	3.500	.083	.098	.098	.098	.216	.216
3 1/2	4.000	.083	.108	.108	.108	.226	.226
4	4.500	.083	.116	.116	.116	.237	.237
5	5.563	.083	.125	.125	.125	.258	.250
6	6.625	.083	.134	.134	.156	.280	.250
8	8.625	.104	.134	.134	.172	.322	.250
10	10.750	.104	.164	.164	.188		.250
12	12.750	.104	.164	.164	.203		.250
14	14.0	.134	.164	.164	.210		.250
16	16.0	.134	.164	.164	.219		.250
18	18.0	.134	.188	.188	.250		.250
20	20.0	.134	.188	.188	.250		.250
22,24,26	22,24,26	.164	.188	.188	.250		.250
28,30	28,30	.164	.250	.250	.281		.281
32,34,36	32,34,36	.218	.250	.250	.312		.312
38,40,42	38,40,42	.250	.312	.312	.375		.375

Compressor stations, sizes 1/8 to 4: plain end or threaded; sizes 5 to 38,40,42: plain end only

[1] For tubing in wall thicknesses over 0.035 inches, the wall thickness may be obtained by interpolating between the pipe outside diameters listed above. Instrument, control and sample piping are not limited by table. (see 192.203).

Table 6.2 Recommended least nominal wall thicknesses

The least nominal thickness of plain and steel pipe or tubing in sizes smaller than 2 inches nominal used in service lines is not limited in the above Table but should not be less than 0.035 inches in any location class. Such service lines should be externally coated, and cathodic protection should be applied. They should not operate at a pressure exceeding 60 percent of the mill test pressure or 10 barg, whichever is less.

DISCUSSION FURTHER STUDIES ETC.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
The pipeline wall thickness is determined using the recommended formula in the ASME-Guide for Gas Transmission and Distribution Piping Systems, 1980, section 192.105 as modified by the Danish Supplement to include a correction factor to allow for maximum negative tolerance on pipe wall thickness. NPD: $F = 0.72$ zone 1 $F = 0.60$ zone 2 but negative wall tolerance = 0%	5.4.2 Yielding <u>Hoop Stress Loading Condition</u> The primary requirement as to pipe wall thickness is to sustain stresses from the internal pressure. The thickness should be not less than that given by the following formula: $t = \frac{p \cdot D}{2S \cdot F \cdot E \cdot T} + \Delta t_1 + \Delta t_2$ where t = nominal design wall thickness (mm) p = Design pressure (MPa) S = Specified minimum yield strength of the linepipe (MPa) (SMYS) Δt_1 = Negative tolerance for pipe wall thickness Δt_2 = corrosion allowance F = Design Factor for different Class locations = 0.72 for class location 1 (Offshore: ASME 192.5) = 0.60 for class location 2 = 0.50 for class location 3 Risers and pipelines within 500 m of any structure: (ASME 192.111 and DnV (81) 4.2.2) = 0.40 for class location 4 May be topical for crossings or shore approaches E = Longitudinal joint factor = 1.00 for API 5L~ or 5LS linepipe See also Table 6.3. T = Temperature derating factor (see Table 6.5) D = Nominal <u>outside</u> diameter of the steel linepipe (mm) A marine pipeline is in general defined as class location 1, except for the riser and the pipeline within 500 m of any structure, where riser and pipeline are in class location 3. Depending on the population density close to the landfall, the shore approach sections may require a higher class location.	We should select the terms zone 1 and 2 or class location 1 & 3. Maybe modify to cover crossings/shore approaches in high population density areas.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The above design criteria for a pipe in the operational condition are converted to minimum permissible radii of curvature. With combined internal pressure, temperature loads, and varying soil restraint, this may be a complicated design problem.	
	The possible strengthening effect of weight coating on a steel pipe is normally not to be taken into account in the design against yielding. Coating which adds significant stiffness to the pipe may increase the stresses in the pipe at discontinuities in the coating. This effect is to be taken into account insofar as it leads to a more adverse condition.	
	In the case of concrete coated pipe the position of the neutral axis of the composite pipe section should be determined on the basis of a "cracked section analysis" and the transfer of shear through the corrosion coating should be verified.	
	<u>Total Operational Stresses</u>	
	In the operational condition the pipeline will be influenced by various loads in addition to that of the static internal pressure, viz.:	
	- Effect of changes in operating pressure.	In the exceptional case that the internal pressure is changing with time rapidly enough to cause dynamic effects, the DnV Rules state that these are allowed for in the permissible hoop stress in the static condition.
	- Strain resulting from thermal expansion. This may have an effect where the pipeline is not completely restrained by the surrounding soil and has a horizontal or vertical curvature.	
	- Strain due to horizontal curvature at changes in direction.	
	- Strain to accommodate vertical curvature due to undulations in the seabed along the pipeline route.	
	- Strain due to soil overburden combined with small free spans.	
	After the minimum allowable radius of curvature has been determined a check calculation should be performed to verify that the pipe with the given stiffness has sufficient weight to follow the profile of the trench or seabed.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Soil pressure below pipe centerline:	
	$$\sum \sigma_n = \frac{\pi}{2} \cdot \bar{\gamma} \cdot R \cdot (H+R) \cdot (1+k_o) + \frac{4}{3} \cdot (2+k_o) \cdot \frac{W_{pipe}}{\pi} - \frac{2}{3} \cdot (2+k_o) \cdot \bar{\gamma} \cdot R^2$$	
	<u>Expansion Quantification</u>	
	Expansion of pipelines due to temperature and internal pressure.	
	The longitudinal strain ε_L and stress σ_L, the circumferential (Hoop-) stress σ_H and the temperature riser ΔT are related by the stress-strain-temperature relation:	
	$$\varepsilon_L = \frac{1}{E} (\sigma_L - \nu\sigma_H) + \alpha\Delta T \quad (1)$$	
	E = Young's modules α = Thermal expansion coefficient	
	and the change in circumferential stress to the pressure p by	
	$$\sigma_H = p \frac{D - 2t}{2t} \quad (2)$$	
	D = outer diameter of pipe t = wall thickness of pipe	
	Due to friction between the pipeline and the soil, longitudinal movements are confined to a length L beyond which no movement occurs.	
	Beyond this, ε_L is zero, and	
	$$\sigma_L = \nu\sigma_H - E\alpha\Delta T \quad \text{for } x > L \quad (3)$$	
	Force equilibrum for $x < L$ requires	
	$$f\,x + A_s\,\sigma_L - A_i\,p = 0 \iff$$	
	$$\sigma_L = \frac{1}{A_s} (p\,A_i - f\,x) \quad (4)$$	<u>Restrained conditions</u>
	f = longitudinal friction	The pipe is restrained if the expansive force is taken up without longitudinal or transverse deformations.
	A_s = Area of steel (pipe) $\frac{\pi}{4}(D^2 - d^2)$	
	A_i = Internal pipe area $\frac{\pi}{4} d^2$	Minimum radius of curvature $R = \frac{F}{W}$
	d = Inner diameter = D - 2t	Where W = effective transverse or longitudinal force

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	L = Expansive length f = Friction force (pr. length) δ = Expansion ε_L = Longitudinal strain p = internal pressure (difference) P = Pressure force T = Temperature force F = Expansive force Passive Soil Resistance The passive soil resistance on the partial or whole buried offset should be calculated using N. Krebs Ovesen's anchore plate theory as described in the following: Anchor Plate Theory Definitions: W_{sub} = submerged weigth of pipe per unit length D = outer diameter of pipe H = soil cover on top of pipe $\bar{\gamma}$ = submerged effective unit weigth of soil ϕ = friction angle $\tan\sigma_r$ = mobilized friction soil pipeline K_a = active soil pressure coefficient K_v = carth pressure coefficient in frot of pipeline A^o = passive soil resistance for basic case A^s = $E_{P_{ult}}$ = passive soil resistance for actual case δ = lateral displacement of pipe $W_{soil} = M \cdot D \cdot \bar{\gamma}$	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

The active soil load has the resultants:

$$E_a = \frac{1}{2} \bar{\gamma} (H+D)^2 K_a$$

$$F_a = E_a \tan\phi$$

Vertical force equilibrium requires:

$$K_\gamma \tan \rho_\gamma = \frac{W_{soil} + W_{sub} + F_a}{\frac{1}{2} \bar{\gamma} (H+D)^2}$$, and hereafter

K_γ is determined from Fig. 6.3.

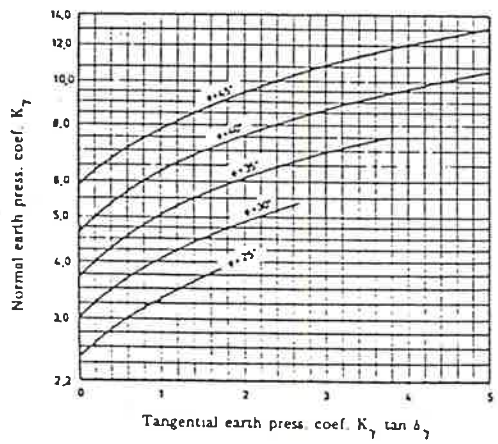


Fig. 6.3 Earth pressure coefficients for the normal earth pressure in front of an anchor slab.

$A^o = 1/2\ \bar{\gamma}\ (H+D)^2 K_\gamma - E_a$, whereafter A^s is determined from Fig. 6.4 as a function of $\frac{D}{D+H}$.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

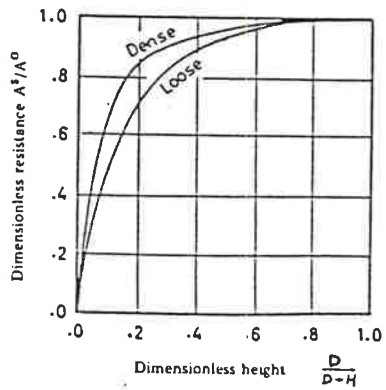


Fig. 6.4 Diagrams for design of vertical rectangular anchor slabs in sand.

A^s represents the ultimate passive resistance Ep_{ult} on the pipe. This value is reached at a displacement of approximately 2% of the depth to the pipeline bottom:

$$\delta_{ult} = 0.02\ (H+D)$$

The relationship is illustrated in Fig. 6.5.

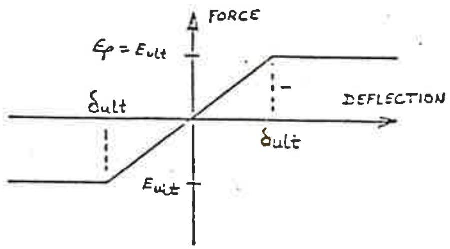


Fig. 6.5 Relationship between Passive Soil Resistance and Lateral Displacement.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
Ref. DnV 4.2.2.6 and 4.3.2.4	<u>6.4.3 Flattening and Buckling</u> <u>Flattening</u> The flattening due to a permanent curvature together with the out-of-roundness tolerance from fabrication of the pipe should not exceed 2 percent. $2\Delta = 2\,\frac{Dmax - Dmin}{Dmax + Dmin} \leq \frac{2.0}{100}$ Assuming a fabrication out-of-roundness tolerance equal to 1% leaves another 1% for installation/operational-induced flattening. It is also required that the residual longitudinal strain after installation is not to exceed 0.002.	Flattening criteria correspond sometimes to maximum flattening and somtimes "residual flattening". Which is correct^2 DnV 4.2.2.6 The flattening due to bending together with the out of roundness tolerance from fabrication of the pipe (see 7.2.6.2) is not to exceed 2%: $2\,\frac{Dmax - Dmin}{Dmax + Dmin} < \frac{2}{100}$
Ref. DnV 4.3.2.1	In Fig. 6.6 the flattening of the pipe, Δ, is shown as a function of K, where $K = \frac{1}{R}\,\frac{D2}{4t}$ D = Diameter of pipe T = Wall thickness R = Radius of curvature for the pipe The limit for acceptable permanent flattening leads to the following limit on K, K < 0.006, ie: $R_r/D > D/t \times 1/0.24.$ where: R_r = Residual radius of curvature	DnV 4.2.2.7 The requirements of 4.2.2.5 and 4.2.2.6 apply to conditions of permanent strain, such as the permanent curvature of a buried pipeline. They also apply to exposed pipelines in (almost) continuous contact with the bottom. For exposed pipelines not in continuous contact with bottom the requirements of 4.2.2.5 and 4.2.2.6 will apply provided yielding would lead to such contact that the strain would be stopped before exceeding the permissible value.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

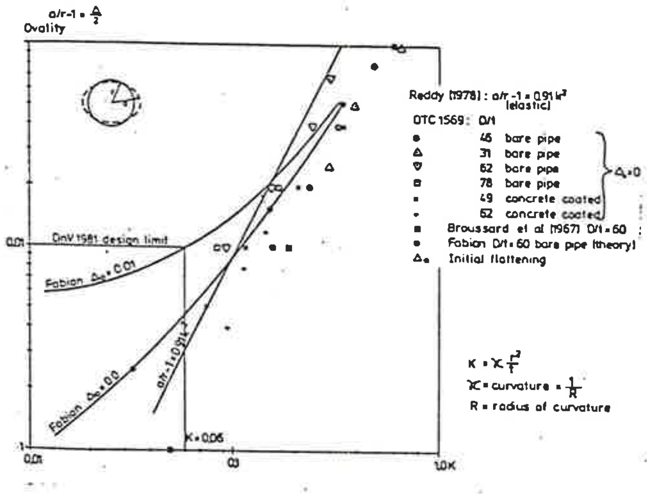


Fig. 6.6 Ovality Versus Curvature.

The limit for acceptable residual longitudinal strain leads to the following requirement:

$$\varepsilon = \frac{1}{2} \cdot \frac{D}{2} < 0.002$$

whence: $R_r/D > 250$

From the two requirements above, it can be seen that flattening will be the governing criterion for $D/t \geq 60$. However, lower D/t rations may be selected for other reasons, and the above does therefore not form the governing basis for selection of wall thickness.

The formulation could be altered to read:

D/t should not exceed 60 to allow full use of permissible strain = 0.002 without exceeding 1% additional flattening.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	At great depths it may be this, rather than the tensile hoop stress under operating conditions, which is the governing criterion for the pipe wall thickness. B) The initiation pressure p_i is the nett external overpressure at which a dent in the pipe (due to damage or to local bending-compression buckling) will develop into a buckle of the full cross-section (ie: a local collapse) and may be calculated as: $p_i = 4.1 \cdot 10^4 \left(\frac{D}{t}\right)^{-2.064}$ bar If the pressure is to be exceeded, there are three potential remedies: - ensure that the pipeline is well protected from any possible mechanical damage, and ensure that the pipeline is not subjected to substantial bending stresses during installation or operation. or - reduce the D/t ratio.	
	If the probability of initiation is small (ie: the pipeline is well protected and not subjected to substantial bending moments), and the consequences of local failure are acceptable, then it may be appropriate to accept a D/t ratio giving an initiation pressure less than the expected maximum nett external overpressure. In this case, however, buckle arrestors should be provided at regular intervals to ensure that the buckle cannot propagate over a long distance. The spacing of the arrestors will be related to the maximum replacement spoolpiece length envisaged in the emergency repair procedures. Propagation Buckling Since propagation buckling cannot be initiated before a local buckle has occured, no additional safety against propagation buckling is required.	This is one of the areas in which emergency repair and pipeline design are closely interrelated.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Column "Buckling"

If the pipe on the seabed were laid perfectly straight, and the friction between the pipe and seabed were almost non-existent, the pipe would "buckle" under the influence of axial compression.

References to "buckling" in the preceding paragraphs are synonymous with references to collapse of the pipeline cross-section, ie: pipeline failure. Column "buckling" refers to the Euler mechanism involving large lateral deflections under the influence of a compressive axial load. The occurence of column buckling may or may not be detrimental to the pipe. Detrimental stresses following column buckling are associated with constraints on movement or rotation at the ends of the pipeline length concerned.

It should therefore be documented either that the safety against column buckling is acceptable, or that the pipeline/riser will not suffer any damage in the postbuckled mode. For a non-buried pipeline such proof will normally not be required.

To avoid column buckling, the axial force S must be limited to:

$$S \leq S_{cR} + R \cdot fH = \frac{9\pi^2 EI}{4L^2} + R \cdot fH$$

on the assumption that the effective buckling length is two thirds of the span length.

The transverse restraint required to prevent the pipeline from "column buckling" (alias: snaking) may thus be determined from the expression:

$$fH = \frac{S}{R} - \frac{9\pi^2 EI}{4L^2 R}$$

in which:

fH is the required transverse force per unit length

S is the axial force (see below)
R is the radius of curvature

L is the span length

E is the modulus of elasticity of the pipe
I is the area moment of inertia of the pipe.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The above phenomena, together with possible other causes of stress fluctuations, are to be considered to the extent relevant in each case. Fatigue analyses are in particular to be made for structural details likely to cause stress concentrations. The aim of fatigue design is to ensure adequate safety against fatigue failures within the planned life of the structure. The specific criteria will depend on the method of analysis. One of the two following categories may be used: a) Methods based on fracture mechanics b) Methods based on fatigue tests.	Recommended fatigue curves and SCF factors will be given in later editions of this guideline.
	In cases where the transported fluid contains corrosive components (eg: H_2S), the corrosion fatigue is to be studied. In the case of the fracture mechanics method the techniques and results of Vosikovsky may be used. If corrosion fatigue is to be evaluated on the basis of tests, then the tests should reflect the effects of the corrosive components; in the case of H_2S the tests may be accelerated tests in NACE solution.	An appendix addressing corrosion fatigue and stress corrosion will be prepared on the basis of Nielsen & Colquhoun: "Inherent Properties of Linepipe for Sour Oil & Gas Service", Chapters 3 and 5.
	<u>Propagating Ductile Fractures</u> Pipelines transporting gas or mixed gas and liquids under high pressure are to have reasonable resistance against propagating (fast running) ductile fractures. This may be obtained by using steel with a high upper shelf Charpy V-notch toughness, lowering the stress level, mechanical crack arrestors, changing the fracture direction, or by a combination of these measures. The design is to be supported by calculations based on relevant experience and/or suitable tests. See also Section 8.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

b) Longitudinal indentations

The relation between the load and the displacement for a longitudinal knife load can be written:

$$F = 0.56\ (b + 6.6\ R) \times E \times \left(\frac{t}{R}\right)^3 \times \delta = K \times \delta$$

The collapse load can be written:

$$F_p = \left(b + 1.4R\sqrt{\frac{R}{t}}\right) \frac{t^2}{R}\ \sigma_y$$

Evaluation of the above formula is based on a collapse model of the pipe as shown in Fig. 6.9.

List of symbols used in the formulae:

- R : pipe radius
- t : wall thickness
- E : modules of elasticity, 210 000 $^N/mm^2$
- δ : indentation depth
- beff : (b+6, 6R) : effective width
- b : loaded width
- σ_y : yield stress

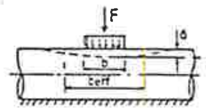


Fig. 6.9 Load distribution for longitudinal indentation.

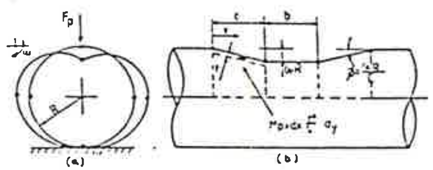


Fig. 6.10 Collapse model of the pipe.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Trawl Boards Pipelines which are not trenched should as a minimum be able to resist: Impact from a 1000 kg trawl board with 2m/s impact velocity. Pull over force of 250 kN. **Punching Shear of Concrete** Tests on reinforced concrete cylinders indicate a punching resistance of $P = 0.3 \cdot \pi \cdot h\ (b + h)\ (fc)^{2/3}$ where P = statically applied load (N) h = concrete thickness (mm) b = Min. dimension of loaded area (mm) fc = compressive concrete strength (MPa) It is assumed that $h/D \approx 0.07$ where D is the internal diameter of the concrete coating. Dynamic tests on slabs indicate that the concrete may resist a load twice the static capacity for 10 m sec, the peak load being three times the static punching resistance. **6.5 INSTALLATION** **6.5.1 General** Strength considerations for the pipeline/risers during installation should be made in order to determine how the pipeline/riser may be installed without suffering any damage which may impair the function or the safety of the completed line, or which may involve hazardous installation or repair work. If the installation analyses for a proposed pipeline/riser show that an acceptable set of installation parameters cannot be obtained with the installation equipment to be used, the pipeline/riser should be modified. The requirements of 6.5 apply also, as far as applicable, to repair operations. Only those sections found pertinent to the various installation techniques/phases should be considered.	

<table>
<tr><th>PROCEDURES ADOPTED IN
DANISH/NORDIC PROJECTS</th><th>GUIDELINE RECOMMENDATION</th><th>DISCUSSION FURTHER
STUDIES ETC.</th></tr>
<tr><td></td><td>Any installation phase/techinque is to be checked.

Such phases and techniques include:

- Start of laying operations
- Normal continuous laying
- Pipe abandonment and recovery
- Termination of laying operation
- Tow out
- Bottom tow
- Bottom pull
- Reeling
- Tie-in
- Straightening
- Trenching
- Back-filling

For any of the phases mentioned above the pipeline/riser is to have the required factor of safety against the following modes of failure and damage.

- Yielding
- Buckling and flattening
- Fatigue effect
- Excessive damage to weight coating.

Yielding

Actual stress-strain and moment curvature relations should be established.

The primary requirement as to yielding during installation is that the residual longitudinal strain after installation is not to exceed 0.002 (0.2 per cent).

The above strain limitation does not apply to the bending and straightening involved in the reel barge method, pulling through a J-tube, or similar operations where the magnitude of the strain is closely controlled.

When a pipe has variable stiffness e.g. due to concrete coating, this will locally give high strain. Such local strains are not to exceed 0.02 (2.0 per cent).

When the pipe is to be given a permanent curvature (e.g. by the "bending shoe" or the "J-tube" method), the strain and flattening limits are as follows:</td><td><u>Comment</u>
The permissible strain criteria are confused. They should be discussed further (SVC, KC). Sometimes 2% is allowed, sometimes only 0.2%. The 0.2% <u>may</u> be to provide an indirect safety factor against buckling but this is not rational.

<u>Proposal</u>:
If special care in design criteria and installation procedures is taken with regard to:

- material changes versus strain (ductility)
- safety against flattening and buckling
- loss of concrete coating and local stress increase due to the effect of cracked concrete
- local forces

a total maximum permanent (residual) strain of up to 0.02 (2%) may be allowed. Such a criterion requires higher D/t ratio than shown in Fig. 6.7.</td></tr>
</table>

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The permissible permanent strain depends on the ductility of the pipe material. A total, permanent, bending strain of 0.02 (2 per cent) is acceptable. If the bending procedure involves successive bending and straightening of a portion of the pipe, the maximum plastic strain is not to exceed 1%. (The corresponding radii of curvature are 25D and 50D.) See also Section 6.7.2. The limit on residual strain applies to the most unfavourable condition during installation, i.e. maximum wind, waves and current acting (Loading condition b). This limit applies also to portions of the pipeline where the strains are completely controlled and cannot change, e.g. where the curvature is controlled by the curvature of a rigid ramp, whether or not environmental loads are acting. Instead of a direct consideration of residual strain the following criterion may be applied: $\sqrt{\left[\frac{N}{A} + \frac{0.85M}{W}\right]^2 + \sigma_y^2 - \left[\frac{N}{A} + \frac{0.85M}{W}\right]\sigma_H} < \eta \cdot \sigma y$ where the usage factor η is 0.72 for loading condition a) and 0.96 for loading condition b) and: N = Axial force in the steel (including effect of water pressure. A = Cross sectional area of the pipe. M = Bending moment. W = Section modulus of pipe. σ_H = Hoop stress. σy = Specified minimum yield strength. It is to be noted that if M is determined on the basis of a given curvature, the non-linear relationship between moment and curvature is to be taken into account. Effects of weight coating should be analysed as specified in Section 6.4.2. Under appropriate circumstances the following two assumptions may be introduced: 1) Axial stresses (N) are neglected, since they normally fall below 5% of σy. 2) Hoop stresses (σ_H) are neglected, since they are normally quite small during the installation stage.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
Experience from dynamic analysis of typical lay-barge show a typical increment of 60% in Southern North Sea conditions.	The expression then reduces to:	It is emphasized that above considerations are preliminary and that final static and dynamic laystress analyses have to be performed by the installation contractor for the client's approval.

The expression then reduces to:

$$(1) \quad \frac{0.85 \times M}{W} \leq \eta \times \sigma y$$

From this follows that the maximum permissible static bending moment during installation is governed by the estimated ratio of dynamic to static beinding moment in the manner shown in Table 6.9.

Incremental bending moment M expressed as a percentage of the bending moment due to functional (ie: "static") loads	Usage factor η according to the DnV Rules (ie: "static" loading conditions)	Resulting Max. permissible static bending stress, σe, in % of σy
33 or less	0.72	85
50	0.64	75
60	0.60	70
70	0.56	65
80	0.53	62
100	0.48	56

Table 5.9 Bending Moments, Usage Factors and Permissible Static Bending Stresses.

If the specified laying conditions cannot be met for all unfavourable conditions of operation, the following possibilities exist:

a. Laying is restricted to calmer weather conditions.
b. Tension requirements are increased.
c. Laying requires buoyancy tanks.
d. Horizontal stability design and thereby pipe specific density is modified by requiring trenching immediately after laying.
e. Pipe wall thickness is increased.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	For installation methods involving a J or S shaped curve of the pipeline N and M are to be determined by a method suitable for the water depth, pipe stiffness, and weight in question.	
	The effect of transverse forces acting on the pipe during laying, namely the change in direction of the pipe axis in the horizontal plane near the lift-off point, is to be specially considered.	An appendix will be provided giving guidelines on simple manual calculations for approximate laystress analysis.
	In particular the effects of transverse and longitudinal current should be considered.	
	Mathematical models (computer programmes) for laystress analysis should be verified and calibrated with the aid of simple bench mark cases for which the solutions can be checked by manual calculations.	
	<u>Trenching Stresses</u>	
	The pipeline trenching procedure shall not give pipe stresses that would result in exceeding a usage factor of 0.72 corresponding to $\sigma e \sim 0.85$ SMYS.	An appendix will be provided incorporating Mousseli's results.
	This requirement will result in fixed relationships between coating thickness and maximum allowable trenching depth for the pipeline for empty and water filled conditions respectively.	
	<u>Roller Forces during Laying and Trenching</u>	
	Special attention should be given to the effect of the concentrated roller force from the lay-barge and the trenching gear. Reference is made to the section on concentrated loads.	
	Limits on roller forces should be determined from the results of punching tests on concrete coating and calculations of denting limits for pipe steel. Restrictions on roller design should be stated so the risk of concrete spalling is minimized.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	<u>Tow Out</u> (Not yet drafted).	To be based on experience from the DONG Lillebælt gas pipeline, the Sydgas Øresund pipeline, studies for the Dan F and Rolf pipelines, and studies for Smit International for the Shell Cormorant flowlines bundles and Iranian Kharg Island oil pipelines.
	<u>Reeling</u> (Not yet drafted).	To be based on Chapter 3 of "Advances in Offshore Oil & Gas Pipeline Technology" (Oyez, 1985).
	<u>Backfilling</u> (Not yet drafted).	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	<u>6.5.3. Flattening and Buckling</u> <u>Flattening</u> The flattening due to a permanent curvature together with the out-of-roundness tolerances from fabrication of the pipe should not exceed 2% (See clause 6.4.3). Flattening criteria should not limit allowable strain, as this would require special precautions and supervision procedures more stringent than normal practice. Local buckling of the pipe wall is to be considered in accordance with the applicable clauses from 6.4.3. <u>Buckling</u> The buckling criteria should not limit allowable strain (stress) during installation as this would require special attention and supervision procedures more stringent than normal practice. <u>6.5.4 Fatigue</u> When checking the fatigue life, possible fatigue effects in the installation phases are to be added. When bottom tow, bottom pull, floatation methods or deep water conventional laying is used for installation of a pipeline, fatigue is considered to be a major effect, and this effect should be given special attention both through theoretical calculations and tests. Wind induced cyclic loads on risers during construction and transportation are to be considered and taken into account.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	6.6 COMPONENTS AND ACCESSORIES	
	6.6 General	
	All pressure-containing piping components and accessories are generally to have the same factor of safety as that required above for the linepipe.	See Table 6.6.
	For all components for which detailed design procedures and criteria are not given, sufficient strength is to be documented in at least one of the following ways: - Equal or similar components have been proven satisfactory through previous successful performance under comparable conditions. - By proof tests. - By experimental stress analyses. - By engineering calculations.	
	If components designed according to a recognized code or standard have proven satisfactory, design according to that code or standard may be generally accepted.	
	6.7 RISER J-TUBES, TIE-INS, E~PANSION DEVICES, CROSS-OVERS, BRANCH CONNECTIONS, VALVE STATIONS	
	6.7.1 Risers	
	A riser is defined as that essentially vertical run of pipe connecting platform piping to the submarine pipeline. A riser commences at the first flange above water level and terminates at the first horizontal connection, welded or flanged, in the submarine pipeline out from the platform.	
	The above-water riser connection should normally be a flange of a rating not less than that of the platform piping to which it ties. The riser should be of sufficient diameter and wall thickness to ensure that adequate machanical strength exists.	
	Risers of greater or lesser diameter than the pipeline may be employed when justified for operational reasons. Risers of extra wall thickness may be warranted to accommodate wave forces and minimize the possibility of damage from launches and marine craft. The minimum wall thickness for mechanical strength is usually 12.7 mm (0.500 inch) for external riser diameter larger than or equal to 10". Risers should be adequately bracketed into the platform structure so that they are sufficiently strong and stable under environmental design conditions.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

For this reason the design of the risers should be coordinated with the design of the associated jacket structure.

Protection may be obtained by sufficient elasticity in the riser, inclusion of a spring, or by provision of an expansion offset. The riser should normally be protected against vessel impact equal to a momentum of up to 9 MNsec.

Risers should be designed so that they have a negative buoyancy below water when installed void. Special provisions against corrosion should be provided in the splash zone.

The design of the risers should take into consideration any geometry changes from thermal gradients in the pipeline during operation, as well as platform deformation during environmental loading.

Mud mats should be employed under riser elbows only when they can be justified as necessary and useful during the operating life of the line.

Special account should be given to vortex shedding in the case of relatively elastic riser and to fatigue loads for small KC-numbers (increased drag).

Risers

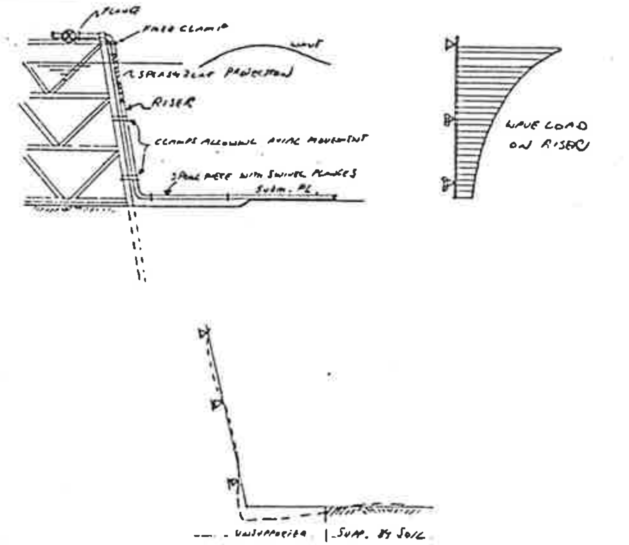


Fig. 6.13 Example of Riser

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Riser analyses should include the study of installation procedures which do not endanger existing structures or pipelines.	
	Risers should be designed for dead weight, weight of contents, temperature differential, pressure diffential, wave and current loads, and platform motions during wave and current load following the principles for platform design as set out in DS 449.	
	It may be convenient to leave some space between bottom of riser and seabed to account for the expansion of the riser during operation if precautions are taken against spanning and scour. The riser is normally fixed at deck-level by means of a heavy clamp. The other clamps are not to resist weight, temperature or pressure movement, but only to resist wave and current forces.	
	For flowline risers the possibility of slugs must be investigated, as they can cause high impact forces in the elbows.	
	<u>6.7.2 J-Tubes</u>	
	(Not yet drafted).	To be based on paper by H. Percival.
	<u>6.7.3 Tie-ins</u>	
	The connection between riser and submarine pipeline should be selected with due regard to the possible need for riser change-out.	
	Connections between subsea line valves and the adjacent pipeline should likewise be selected with due regard to the possible need for servicing and changent.	
	(Remainder of this section not yet drafted).	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

6.7.4 Expansion

When large expansion stresses are calculated, provisions in the form of a single or double expansion offset should normally be built into the submarine line just out from the riser as a protective measure. In this case the expansion offsets should be installed on the seabed or placed on sleepers to allow sliding to occur freely. Care should be taken not to obstruct downward expansion of the riser-to-platform piping connection. Deep water risers containing high temperature crude require special attention.

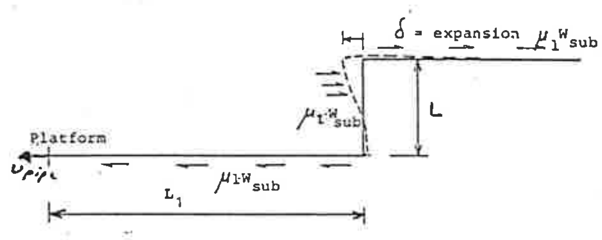


Fig. 6.14 Expansion offset

In the analysis of the expansion offset the stiffness length is important parameter and is given by:

$$l_c = \sqrt[3]{\frac{EI}{\mu_t \cdot w_{sub}}}$$

in which:

μ_t is the transverse coefficient of friction between pipe and bed

w_{sub} is the submerged weight of the pipe and contents per unit length

The effect of partial or total burial is included in the parameter.

(This subsection requires further editing).

When the ratio $L/l_c \approx 1.0$ to 1.5 only limited bending forces are transferred through the offset and no advantage is gained from increased offset length.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

The forces on the platform are generated from local expansion of the length L_1.

Minimum platform force is normally equal to

$$F_{min} = \mu_1 w_{sub} L_1$$

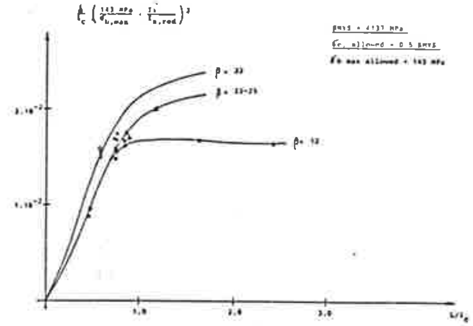
in which k = 1.0 to 1.4.

Preliminary design curves are given for the non-dimensional parameters L/l_c, δ/l_c, L_1/lc and β

where

$$\beta = \frac{P}{\mu_t \cdot w_{sub} \cdot l_c}$$

and P = end cap pressure force.
$\rho_{b,max}$ = maximum allowed bending stress.



Ix = moment of inertia

Ix,red = moment of inertia for wall thickness reduced by corrosion allowance

Fig. 6.15 Expansion Offset Design Curve, (x60)

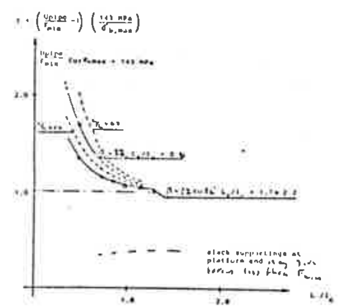


Fig. 6.16 Forces on platform

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	6.7.5 Cross-overs Cross-overs should be avoided when minor re-routing is practical. When a cross-over is required, it should be executed either by trenching the lower line into the sea floor so that the top of the pipe at the cross-point is at least 0.50 meter below the upper line, or by bridging over the lower pipe. An approach which combines the two methods should not be specified. Impact from fishing gear should be considered. Bridging may be accomplished with a prefabricated frame of tubular members, by sand or grout bags, by asphalt mattresses, or by rock backfilling. Provision should be made to avoid electrical potential differences. It should normally be a prefabricated frame of tubular members which is placed down over the lower pipe in advance of laying the upper pipe. This minimizes the underwater work and minimizes contraints on the movement of the lower line. When the framed cross-over is used it should be designed with practical dimensions for underwater placement tolerances. Individual supporting sleepers should be specified under the upper pipe for some distance back from the cross-over point when necessary to establish the required profile without exceeding an acceptable span length. Bridging may also be accomplished, when necessary, by placing bags containing a mixture of sand and cement under the upper pipeline in the area of the cross-over, and independent sleepers for some distance back from the cross-over when required. Care must be taken to ensure that this type of bridging results in acceptable clearances and a favourable final profile of the upper pipe. This method is acceptable only when the prefabricated frame is precluded for some reason. 6.7.6 Branch Connections Branch connections are typically employed to introduce production from independent offshore platforms into a main trunkline or conversly to distribute fluids or gases from a main trunkline to individual injection platforms. Three general approaches should be considered and evaluated in the design of any new offshore system:	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	- Underwater branch connections/PLEM structure - Over the platform branch connections - Independent tie-in platform connections. Principal requirements to the connections include: - ease of inspection and maintenance - future flexibility - possibility of pigging and scraping. Underwater branch connection: Underwater branch connections require detailed analysis of installation procedures and a high safety against damage, leakage and malfunction. Underwater branch connections must be rationally designed with valve provisions to permit isolation of the individual platforms and with expansion provisions to avoid overstressing of the connections. They should present a minimum profile on the seafloor to minimize the risk of contact from spuds, anchors, or fouling from marine tackle. The under-water connection should usually contain both block valves and check valves. Where large lateral movement of the main pipeline can occur it can be advantageous to restrict this lateral movement of the trunkline by installing straddle piles in the area of the connection while permitting and accommodating longitudinal movement of the trunkline. It is common practice to incorporate a reducer (increaser) just upstream from the branch connection to provide for favourable hydraulics, and improved section modulus in this high stress concentration location. However, if the change in cross sectional area will introduce additional movements of the trunkline at the tie-in point and the end of the branchline, the latter should have a horizontal offset running parallel to the trunkline. The direction of this offset should be the same as that of the expected movement of the trunkline upon start-up. The dimensions of the branch offset or expansion loop should be determined so as to avoid overstressing the connection under the maximum expected movements.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Structural bracing should be applied between the trunkline and the parallel branch offset close to the tie-in point and valves in order to protect the valves, flanges, and the tee from large expansion forces. Sleepers on the sea bottom may be installed to avoid unwanted reduction in expansion flexibility due to bottom friction or undulating seabed.	
	<u>6.7.7 Valve Stations</u>	
	(Not yet drafted).	To be based primarily on the requirements of the ASME Guide.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
Stability design has generally been performed in accordance with the DnV 1976 or 1981 Rules, but with certain modifications. The ASME Guide, being concerned primarily with land pipelines, is silent on the matter of marine pipeline stability. The same applies to the Danish "tillægsbestemmelser". Analysis techniques with regard to vertical stability (liquefaction) and horizontal stability have been advanced significantly during the course of the DONG gas transmission project and DHI work for ARAMCO.	<u>7. PIPELINE STABILITY DESIGN</u> <u>7.1 GENERAL</u> 7.1.1 The pipeline should be weighted, supported, anchored, trenched, or buried in such a way that it is not subjected to unacceptable movement under the influence of the design environmental loadings. Criteria governing the acceptability of movement at any particular location include: Stresses in the pipe in the context of yielding, buckling, and fatigue; Abrasion of coatings as a result of repetitive movement; Clearances to other pipelines, structures, and hazards; Finite extent of pipeline supports. Sections of the pipeline subjected to significantly different conditions (depth, seabed soil type, environmental conditions) should be treated separately.	This clause is similar to DnV Section 4.2.5.1.
	7.1.2 The design environmental loadings in this context should be no less severe than the following: (i) for the permanent operational condition: the most extreme combination of wave and current expected to prevail for a period of 3 hours during a period equal to 3 times the design life of the system; (for a 30-year design life this will typically be taken as the 100-year return event); in evaluating the probability of failure or change of state of structures exposed to environmental loadings the exceedance figures given in Table 6.1 may be used.	This clause is similar to DnV Sections 3.3.1.3, 3.3.1.4, and 3.3.1.5. DnV Section 3.3.1.3 prescribes the 100-year return event for design in the permanent operational condition regardless of the actual design life of the system. This seems unnecessarily arbitrary.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Table 7.1 Storm Exceedance Probabilities.

Design life	Return Period of Design Storm	Probability of Exceedance during Design Life
N years	N/3 years	0.96
	N years	0.67
	3 N years	0.29
	10 N years	0.10
	20 N years	0.05
	33 N years	0.03
	100 N years	0.01
	3.3×10^{4} N years	3×10^{-5}

(ii) for temporary conditions other than those referred to in (iii) below:

the most extreme combination of wave and current expected to prevail for 3 hours during a period equal to 3 times the duration of the temporary condition in question; when the duration of the temporary condition is significantly less than 4 months, the time of the year during which the temporary condition will occur should be taken into account;

(iii) for temporary conditions which can be interrupted at short notice (eg: less than 48 hours) in the event of a storm warning:

the most extreme combination of wave and current which can arise before interruption is completed, assuming that the environmental conditions at the time of the warning are the most severe under which the installation activities in question can take place.

This is a clearer formulation than DnV Section 3.3.1.5.

For exposed risers the most extreme combination of wave and current is that which yields the highest combined water particle velocity in any direction. For horizontal pipelines it is that which yields the highest combined water particle velocity normal to the pipe (which may be significantly less).

The water level assumed in computation of the design environmental loadings should be that water level which, being compatible with the wind, wave, and current conditions, yields in conjunction with them the most adverse loading for the design aspect in question.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The environmental loadings should be considered together with the most adverse combinations of platform movement, temperature, and operating pressure, which can occur simultaneously.	
	7.1.3	
	Regardless of the nature of the product the pipeline is designed to transport, the evaluation of pipeline stability should assume that the pipeline contents are: (i) for the permanent operational environmental loading : either the intended contents or air/gas at atmospheric pressure, or seawater, whichever is the more adverse in the context of the design aspect under consideration; (ii) for the environmental loading under temporary conditions: the intended contents of the pipeline during the temporary condition in question, provided that the risk of unplanned flooding or unplanned dewatering can be shown to be insignificant, otherwise as for (i) above.	The formulation here is clearer than in the DnV Rules insofar as horizontal stability is concerned.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	7.2 VERTICAL STABILITY	
	7.2.1 The pipeline when filled with air/gas at atmospheric pressure should have a specific gravity greater than that of the surrounding water (ie: it should have negative buoyancy) unless it is permanently anchored to the seabed by devices which are secure against extraction.	See DnV 4.2.5.7. This is to ensure that shear failure of the soil surrounding a buried pipe can at worst lead to flotation up to the seabed and never to flotation to the sea surface.
	7.2.2 Analysis should be performed to demonstrate that the combined effect of submerged weight and shear strength of the seabed material on which or in which the pipeline lies is adequate to resist the vertical movement of the pipe: In the absence of liquefaction the greatest risk of flotation of a buried pipeline or of settlement of a pipeline (on the seabed, in open trench, or buried) occurs in weak cohesive sediments with zero internal friction, particularly during trenching by the jetting method.	See DnV 4.2.5.3, 4.2.5.4, 4.2.5.5, and 4.2.5.6.
These relationships are after Ghazzaly et al. They were used in the design of the DONG gas transmission marine pipelines.	For this type of soil the limiting unit weight of the empty pipe at incipient flotation may be determined from the relationship: $\gamma_{pf} - \gamma_s = - K_f \frac{c}{2r}$ in which: γ_{pf} is the unit weight (weight/unit volume) of the empty pipe in air, γ_s is the buoyancy force, ie: the saturated unit weight of the soil, c is the undrained strength of the soil above the pipe, r is the outside radius of the pipe = $D_T/2$, K_f is a dimensionless factor governed by the relationship between the depth d of the centre of the pipe below seabed level and the radius r, and whose value may be obtained from Fig. 7.1. while the limiting unit weight of the water-filled pipe at incipient settlement may be determined from the relationship: $\gamma_{ps} - \gamma_s = + K_s \frac{c}{2r}$ in which: γ_{ps} is the unit weight of the water-filled pipe in air, K_s is a dimensionless factor governed by the relationship between d and r, and whose value may likewise be obtained from Fig. 7.1.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

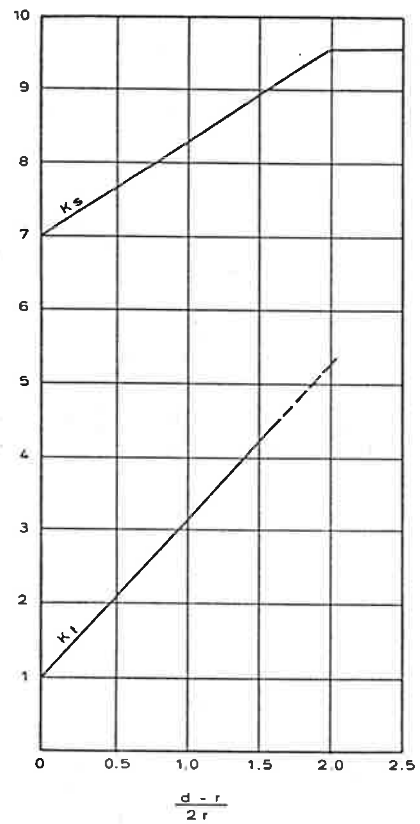


Fig. 7.1 Values of K_f and K_s.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	7.2.3 The risk of liquefaction of the seabed material under the influence of the design environmental conditions should be evaluated and the depth of such liquefaction should be assessed. The greatest risk of liquefaction occurs in cohesionless soils with low permeability (silts) in water depths which are shallow relative to the wave length. Guidance on liquefaction analysis is given in Appendix 701.	Appendix 701 will be developed from NGG-MPPO 3126 and Gravesen & Fredsøe, Copenhagen, 1983. (Ideally Appendix 701 should in due course be integrated into the main text).
	For rough preliminary calculations the following relationship may be used as the limit criterion for no liquefaction in a freshly deposited sand:	
The method described here is a simplified resumé of the analysis method developed during the engineering of the DONG North Sea gas transmission pipeline.	$e^{-2\pi\frac{d}{4}} \cdot \frac{H_s \pi}{L \cosh kh}\left(1+\frac{0.6}{n^{1.5}}\right) \leq 0.26\, D_R (1.4-0.17 \ln n)$ in which: H_s is the significant wave height at the location in question (metres), L is the associated wave length (metres), k $= 2\pi/L$, h is the water depth (metres), D_R is the soil relative density (fraction), n is the effective number of wave load cycles during the time required for the excess pore water pressure to dissipate to 1/e of its initial value, and is given by the relationship: $n = 0.35 \frac{d^2}{D_{20}^{2.32}\, T}$ where: d is the depth below seabed of the point being considered (metres); T is the wave period (seconds); D_{20} is the lower quintile grain size (millimetres).	The important feature of this relationship is that it takes into account the effect of permeability in dissipating the excess pore water pressure which induces liquefaction. Methods of analysis in use in recent years (eg: by DnV) have not taken permeability into account and in consequence have been markedly over-conservative.
	This criterion is conservative, particularly at high relative densities and for older deposits where resistance against liquefaction is greater.	This is due to the fact that some non-linear relationships have been linearized for the sake of algebraic simplicity.
	If the risk of liquefaction is significant then: either (i) means of vertical restraints other than the shear strength of the surrounding seabed material must be provided;	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	or (ii) it must be demonstrated that the resulting vertical movements will not give risk to unacceptable stresses or be unacceptable in other respects.	

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Past projects have been geared to the DnV 1976 Rules and/or the DnV 1981 Rules, or to guidelines favoured by individual operators. Design has traditionally been based on a no-movement criterion determined from a simple 2-dimensional analysis using Morison's equation or modifications of it. The DONG North Sea gas pipeline engineering saw the introduction of a design based on H_s and acknowledging movement under H_{max} but involving a stress check based on 3-D analysis. The Danish Energy Agency and DnV accepted this technique, which is presented separately in Appendix 702.	**7.3 HORIZONTAL STABILITY** 7.3.1 Pipelines lying on the seabed or in an open trench and relying on their own weight for stability against horizontal movement under the influence of hydrodynamic loading should be designed in accordance with the following procedures: 1) Dimension the pipeline (ie: the steel wall thickness and the concrete weight coating, if any) to give sufficient submerged weight for stability (ie: zero movement) under the influence of the wave-induced water particle velocities and associated steady currents considering a unit length of pipe; 2) Compute the cumulative lateral excursions (deflections) and greatest instantaneous stresses during the design life using 3-dimensional dynamic simulation and sea-state exceedance data considering a finite length of pipeline which is long by comparison with the longest wave lengths encountered at the location in question. 3) Repeat item (2) for alternative designs having submerged weights above and below the value obtained from item (1) so as to obtain curves showing the sensitivity of excursion and stress to submerged weight; 4) Select the final design submerged weight on the basis of the curves obtained from item (3). If the horizontal stability design procedure is restricted to item (1) above, then the wave-induced water particle velocity and period used should be the maximum normal water particle velocity with associated seabed period plus associated normal component of steady current under the design environmental conditions or alternatively the greatest normal water particle velocity due to the monochromatic maximum wave height with associated period plus associated normal component of steady current.	This chapter brings together the content of a number of items from DnV 1981 Chapters 3.3, 4.2.5, and Appendix A, but also introduces more specifically the concept of a stability design which acknowledges that some movement may occur. An alternative approximate (3D-static) method of stress check is presented in Appendix 702.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Alternatively, the wave-induced water particle velocity and period and steady current used may be those defined in the succeeding paragraph, provided that the stability usage factor as defined in 7.3.2 does not exceed 0.85. If the procedure includes items (2), (3), and (4), then the wave-induced water particle velocity and period used in item (1) should be the significant normal wave-induced water particle velocity with associated seabed peak energy period plus associated normal component of steady current or alternatively the greatest normal water particle velocity due to the monochromatic significant wave height with associated period plus associated normal component of steady current.	The appropriate limit on γ is debatable. A value of 0.85 may be insufficiently conservative. It may be appropriate to prescribe a value as low as 0.6. An array of benchmark calculations is required in order to illuminate this question.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	7.3.2	

7.3.2

For the purpose of static calculations the zero movement state of the pipeline may be defined by the following relationship:

$$Y = \frac{\frac{1}{2}\rho D_t C_D (u_c + u_w \cos\theta)^2 + \frac{\pi}{4}\rho D_t^2 C_M \left(\frac{2\pi \cdot u_w}{T}\right)\sin\theta}{Wg - \frac{1}{2}\rho D_t C_L (u_c + u_w \cos\theta)^2} \cdot \frac{\eta}{\mu} \le 1$$

in which:

- Y is the stability usage factor (dimensionless),
- W is the submerged weight of the pipeline per unit length with the contents in question (k_g),
- g is the acceleration due to gravity (m/sec^2),
- ρ is the mass density of the surrounding water (kg/m^3),
- D_t is the total outside diameter of the pipe including coatings and marine growth (m),
- μ is the effective coefficient of friction between pipe and seabed in the transverse direction (dimensionless),
- η is the partial coefficient (ie: partial safety factor) associated with μ; its value should be not less than 1.1 (dimensionless),
- u_c is the normal component of the steady current (ie: the mean value obtained from integration of the current profile over a height D_t from the seabed) (m/sec),
- u_w is the amplitude of the normal component of the wave-induced water particle velocity at the pipe (the significant velocity U_{mo} in the case of spectral transfer) (m/sec),
- T is the period of the wave-induced water particle velocity (the peak energy period T_p associated with U_{mo} in the case of spectral transfer - which is different from the peak energy period of the surface wave spectrum) (seconds),
- C_D is the hydrodynamic drag coefficient obtained from Clause 7.3.4 (dimensionless),
- C_L is the hydrodynamic lift coefficient obtained from Clause 7.3.4 (dimensionless),
- C_M is the hydrodynamic inertia coefficient and has a value of 3.29 (dimensionless),
- θ is that angle between 0 and $\frac{\pi}{2}$ radians which yields the maximum value of the expression (ie: of Y).

Note: the units of numerator and denominator in the expression for Y are Newtons (per unit length).

Discussion: The familiar modified version of the Morison equation is presented here in a form which introduces the concept of "stability usage factor", and which defines clearly the manner in which current and wave-induced water particle velocities are to be combined.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

As an alternative to the computer analysis required for solution of the relationship in Clause 7.3.2, the limiting value of W may be obtained from the expression below and the curves in Fig. 7.4, which together also reveal the relative importance of the drag and lift effects on the one hand and the inertia effect on the other.

$$W = k \times A \quad \text{for } B \leq A$$
$$W = k \times B \quad \text{for } B \geq A$$

in which k is obtained from Fig. 7.2 for a given values of B/A and U_c/U_w and

$$A = \frac{(u_c + u_w)^2}{2g} \left(\frac{\eta}{\mu} \cdot C_D + C_L \right)$$

$$B = \frac{\eta}{\mu} \cdot C_M \cdot \frac{\pi^2 D_t^2 \cdot u_w}{2g\,T}$$

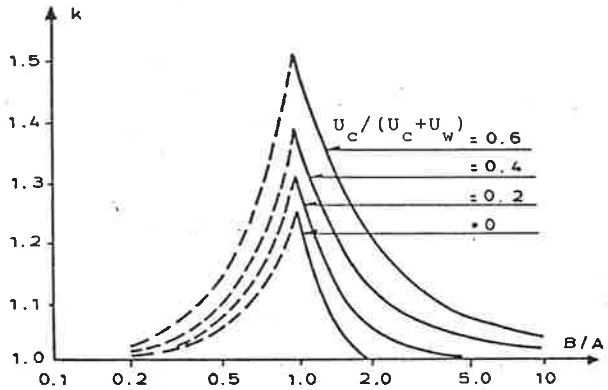

Fig. 7.4 Values of k

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GUIDELINE RECOMMENDATION

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7.3.3

For small diameter pipelines the maximum value of the expression in Clause 7.3.2 is only a few percent greater than the value at $\theta = 0$ (though this does not necessarily imply that the inertia force is small by comparison with the drag force). In this case the relationship of Clause 7.3.2 reduces to:

$$\frac{\frac{1}{2}\,\rho\, D_t\, C_D\, (u_c + u_w)^2}{Wg - \frac{1}{2}\,\rho\, D_t\, C_L\, (u_c + u_w)^2} \cdot \frac{\eta}{\mu} \leq 1$$

and this relationship may be used as an approximation in the case of pipelines with a total diameter less than 600 mm.

7.3.4

The hydrodynamic drag and lift coefficients C_D and C_L are influenced by the Keulegan-Carpenter Number (KC) of the wave-induced motion and by the ratio α between the normal component of the steady current and the normal component of the amplitude of the wave-induced water particle velocity. These parameters may be evaluated in the following manner:

$$KC = \frac{u_w \times T}{D_t}$$

$$\alpha = u_c/u_w$$

The values of C_{DO} and C_{DL}, which are the values of C_D and C_L when $\alpha = 0$, may be obtained from Figs. 7.5 and 7.6 for a pipe surface roughness e/D_t in the range 0.0016 to 0.0043, which is typical for a concrete-coated pipe without marine growth.

The values of C_D and C_L for the actual value of α may then be obtained with the aid of Figs. 7.7 and 7.8.

In cases where $u_c >> u_w$ the values of the hydrodynamic coefficients approach their limiting steady current values:

$$\left.\begin{array}{l} C_D \text{ without marine growth: } 0.7 \\ \quad \text{(with marine growth : } 1.0) \\ C_L \text{ without marine growth: } 0.9 \\ \quad \text{(with marine growth : } 1.2) \end{array}\right\} \text{for Re} > 2 \times 10^5$$

The use of steady current hydrodynamic coefficients in situations of pure wave-induced motion or combined wave and current is likely to result in unsafe design.

Note: At lower Re numbers these values should be increased by some 85 percent.

(See also DS.449).

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The use in situations of combined wave and current of hydrodynamic coefficients appropriate to pure wave-induced motion is likely to result in uneconomic design.	

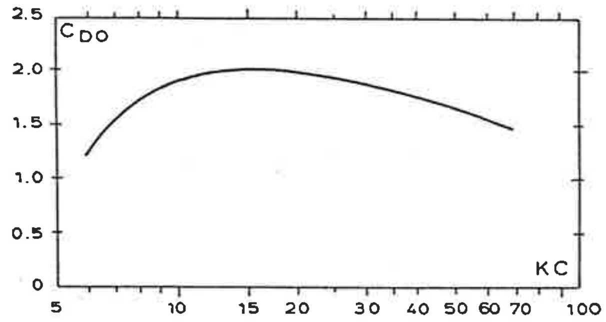


Fig. 7.5 Drag coefficient C_{D0} at $\alpha = 0$

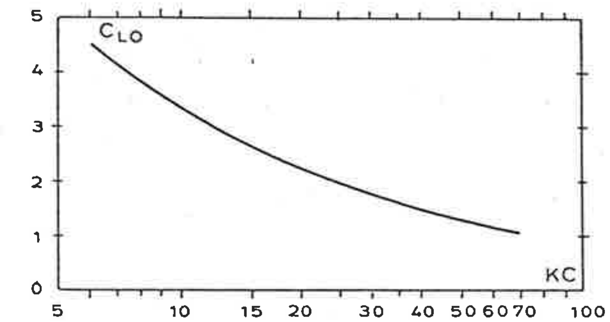
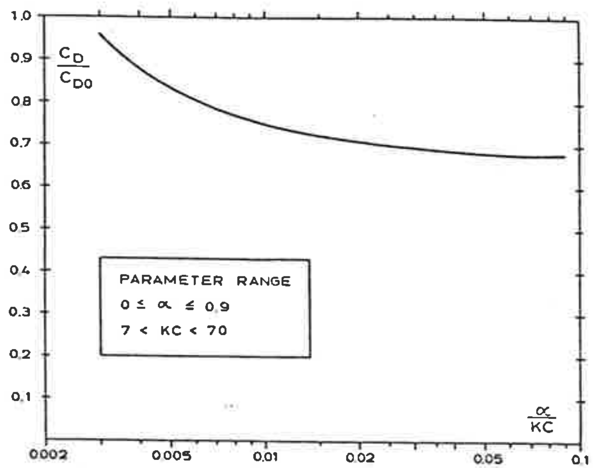
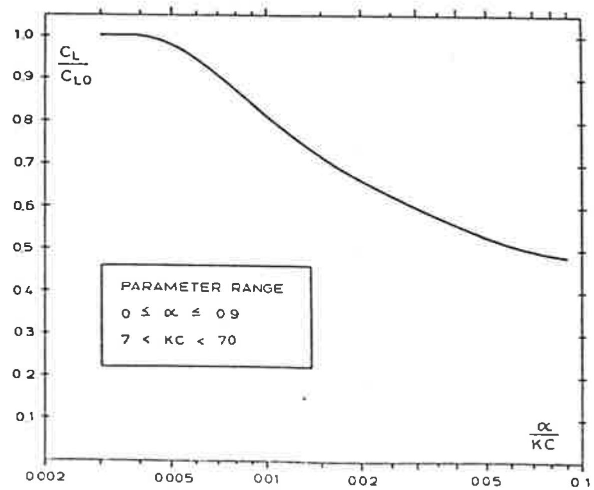


Fig. 7.6 Drag coefficient C_{L0} at $\alpha = 0$

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	 Fig. 7.7 Reduction of drag coefficient.  Fig. 7.8 Reduction of lift coefficient.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

7.3.5

For pipeline sections which do not lie on the seabed but at a distance from it the hydrodynamic coefficients C_D, C_L, and C_M should be corrected. In the absence of more accurate information based on physical model tests at the relevant values of KC, α, and H/D, the reduction factors R_D, R_L, and R_M indicated in Figs. 7.9, 7.10, and 7.11 may be used. These reduction factors may also be used in connection with the calculation of hydrodynamic loadings on individual risers.

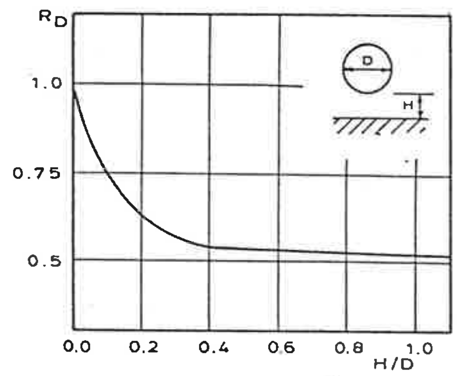


Fig. 7.9 Influence of a fixed boundary on the drag coefficient of a circular cylinder in oscillatory supercritical flow, $K_C > 20$, $R_e = 10^5$ to $2 \cdot 10^6$.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

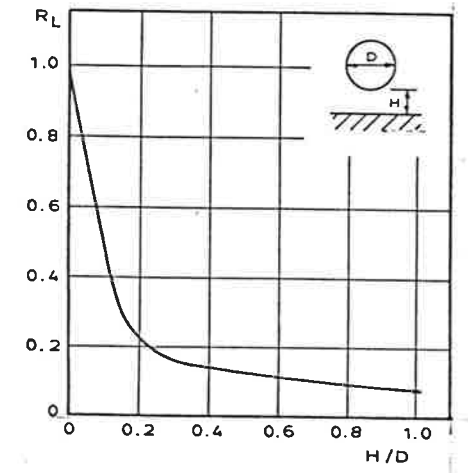


Fig. 7.10 Reduction of lift force coefficient with distance from a fixed boundary.

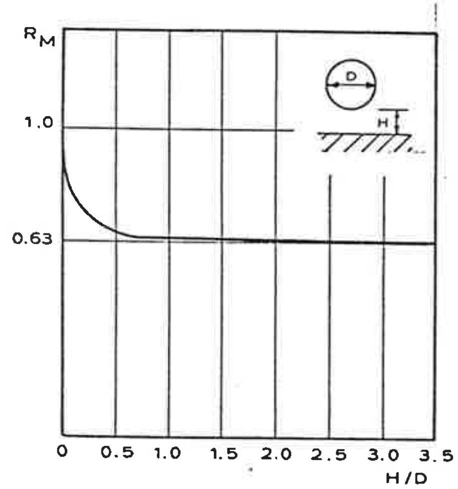


Fig. 7.11 Reduction of inertia force coefficient, C_m for a circular cylinder.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

7.3.6

For pipelines which lie in open trenches account may be taken of the effect of the trench in reducing the water particly velocities and accelerations at the pipe.

When the angle of slope β of the trench sides is flatter than approx. 10^{o} (ie: a slope of 1:6) the steady current and wave-induced water particle velocities at the pipe should be those applicable in the case of a pipe on a level seabed at a depth equal to the depth of the bottom of the trench.

When the angle of slope β is steeper than approx. 10^{o} the steady current and wave-induced water particle velocities in the trench may be obtained by adjusting the steady current and wave-induced water particle velocities at the seabed with the reduction factors (R) given in Tables 7.12 and 7.13 respectively. (D_{TR} is the height from seabed to bottom of trench, y is the height of the location in question above the trench bottom, and x is the horizontal distance of the location in question from the upstream trench lip - see Fig. 7.14).

Table 7.12 Trench reduction factors (R) for u_c

Location	
Undisturbed seabed level and x/D_{TR} =	Values of R
1.0	0.5
2.0	0.5
3.0	0.6
4.0	0.7
12.0	1.0
On separation line sloping down at 1 in 6 from upstream lip of trench	R to be taken as 0.4 (the theoretical value on the line is zero, but the increase above the line is very rapid).
Below the separation line	R to be taken as minus 0.3

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Table 7.13 Trench reduction factors (R) for u_w

Location		R
X/D_t	y/D_{TR}	
All values	1.0 0.33 0.16	0.75 0.5 0.5

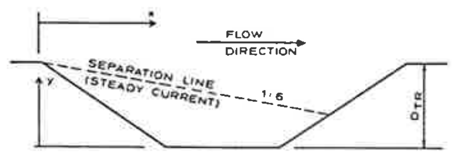


Fig. 7.14 Location referencing in trench cross-section

7.3.7

For pipelines lying snugly in the apex of a V-form trench the effective transverse coefficient of friction μ may be increased by the addition of an amount equal to sin β, where β is the smallest angle of slope of the trench sides.

7.3.8

In the case of a pipeline on the seabed or in an open trench where the restraint against movement is provided by positive anchors rather than by the weight of the pipeline, the anchors should be designed to withsand the hydrodynamic loadings described in the preceeding Clauses, and the stresses in the pipe should be checked for conformity with the limits prescribed in Chapter 6.

7.3.9

In all situations in which buoyancy tanks or other devices are attached to a pipeline the effect of hydrodynamic loading on such devices should be taken into account in evaluating the horizontal stability.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS

The engineering of Danish projects has generally been in conformity with the DnV Rules as regards materials and fabrication, but additional requirements have been specified with particular reference to propagating ductile fracture and resistance to sour conditions.

GUIDELINE RECOMMENDATION

8. MATERIAL REQUIREMENTS AND FABRICATION

8.1 GENERAL

This section specifies general requirements for characteristic material properties, fabrication, and quality control of steel linepipes.

The manufacturer should be capable of producing materials and line pipes of the required quality, and this capability should be documented before any order is placed.

The manufacturer should document, implement and maintain a system for quality control. This may be in accordance with a recognized standard (including possible supplementary requirements/modifications as indicated in the Specification for Supply of Pipes), e.g.:

- BS 5750, Part 1. 1979
  Quality Systems Specification for Design, Manufacture and Installation.
- ANSI/ASQC Z1.15-1979
  Generic Guidelines for Quality Systems.
- ASME, Section VIII, Appendix X, latest edition Quality Control System (only for holders of U-stamp).
- DIN 55355. Nachweissstufe 1. November 1979 Grundelementse für Qualitätssicherungssysteme.
- NS 5801. 1. utg. Aug. 1981 System for kvalitetssikring.

The Engineer or his representatives should immediately be informed in the event that unexpected/unusual defects are observed during fabrication.

A Specification for Supply of Pipes should be prepared covering at least the following subjects:

- Manufacturing methods
- Chemical Composition
- Mechanical Properties including Test Methods
- Heat treatment
- Soundness
- Dimensions, Weights and Lengths
- Quality Control Testing incl. acceptance limits
- Repair of Defects
- Marking
- Documentation

DISCUSSION FURTHER STUDIES ETC.

This Section is based primarily on Sections 5 and 7 of the DnV Rules, but with modifications, additions, and deletions. An explanation of the deviations will be provided at a later stage.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	8.2 MATERIALS 8.2.1 General The guidelines are applicable to C-Mn steels, C-Mn-fine grain treated steels and low alloyed steels having a specified minimum yield strength up to 500 MPa, and to consumables for welding. Steels of higher strength, other alloys, and other materials may be used subject to special approval. Materials are to be selected with due consideration to the commodity to be transported, loads, temperature, corrosion, and consequences of a possible failure during installation, operation, and maintenance of the pipeline system. All materials are to be delivered with test certificates stating the heat number, manufacturing methods, test results, identification etc. All materials are to be traceable and suitably marked for easy identification of manufacturer, grade, heat number, size and application. Materials of uncertain origin or uncertain quality are to be rejected, or a special identification and test programme is to be agreed upon. 8.2.2 Steel Making The steel is to be processed and cast in a manner ensuring uniform composition, properties and soundness. Impurities and residual elements are to be kept at a level consistent with specified property and service requirements. The steel should be fully killed and manufactured to a fine grain practice. 8.2.3 Heat Treatment Steel castings and forgings are to be normalized, normalized and tempered, or quenched and tempered. Rolled steel is either to be normalized, quenched and tempered, or thermomechanically treated.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

8.2.3 Chemical Composition

The steel is to have a chemical composition which with the specified manufacturing, fabrication and welding procedures will ensure sufficient strength, ductility, toughness and corrosion resistance.

The chemical composition of C-Mn and C-Mn fine grain treated steels to be welded is to be specified within the analysis limits given in Table 8.1. Modifications may be agreed upon subject to the application of suitable fabrication and welding procedures.

Analysis	C % max	Mn % max	Si % max	P % max	S % max	Cu % max	Ni % max	Mo % max	Cr % max	Al (total) % max	Others %	Carbon equivalent[2]
Ladle	0.18	1.60	0.55	0.025	0.020	0.35	0.40	0.25	0.20	0.08	1)	0.40
Check	0.20	1.70	0.60	0.030	0.025	0.35	0.40	0.25	0.20	0.08	1)	0.42

1) V max 0.10 (V + Nb) max 0.12
Nb max 0.05
Ti max 0.05
N max 0.009 (0.015 when Al fine grain treated)
Residuals (Cr + Mo + Cu) max 0.50

2) $CE = C + \frac{Mn}{6} + \frac{Cr + Mo + V}{5} + \frac{Cu + Ni}{15}$

Table 8.1 Chemical composition of C-steel, C-Mn steel and C-Mn fine-grain treated steel for general service.

The hardenability of a steel may be predicted with another carbon equivalent formula together with a revised CE-limit.

Procedures adopted in Danish/Nordic projects:

Upper limit of CE on ladle analysis:

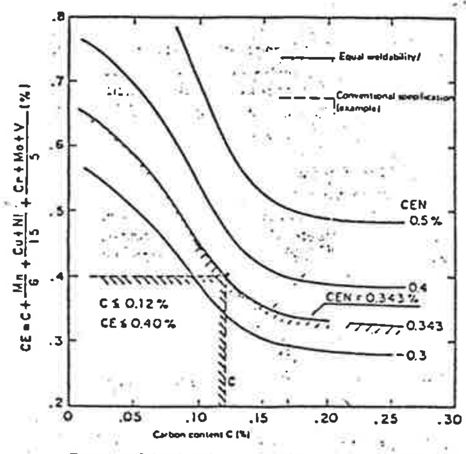
North Sea Gas Pipeline (X 60) : 0.36
Belt Crossings (X 65) : 0.39

Discussion, further studies etc.:

It may be appropriate to allow the max. CE-value to vary with the wall thickness.

Cold cracking susceptibility and maximum hardness of HAZ are usually evaluated by means of IIW's carbon equivalent formula (CE). However, this is recently acknowledged to be rather conservative for low carbon steels ($C \leq 0.17\%$), and other formulae can be used, e.g. CEN (see below).

For both low and high carbon steels equivalent cold cracking susceptibility may be given by the condition CEN = constant. This is illustrated in the figure below, CE (IIW) versus C%, where it can be seen from the solid curves that higher values of CE are permissible for reduced carbon content.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The chemical composition is to be determined both in the ladle and the product. Ladle analyses are to be taken for every heat. A check analysis is to be taken for each batch of 50 finished products, but at least once every heat. The elements listed in Table 8.1 are to be determined and reported. Other remaining elements added on purpose to control the material properties are also to be checked, and to be reported. The chemical composition of low-alloy and alloyed steels are to be considered in each case. The impurity level and inclusion contents are to be kept specially low in steel to be used in pipeline systems designed to transport commodities which under unfavourable conditions may cause blistering or stepwise cracking.	 Ranges of CE (IIW) and C % for equal weldability (cold cracking) of low-alloy high strength steels, $CEN\ (\%) \equiv C + A(C)\ [Si/24 + Mn/6 + Cu/15 + Ni/20 + (Cr + Mo + V + Nb)/5 + 5B]$ where $A(C) \equiv 0.75 + 0.25 \tanh [20 (C - 0.12)]$ (Yurioka et al.) This question should be subject to further study.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	8.2.4 Mechanical Testing 8.2.4.1 General The following mechanical properties are essential and are to be determined and reported as part of the quality control: - Yield strength - Ultimate tensile strength - Elongation - Reduction of area - Fracture toughness - Hardness The reduction of area is normally to be measured only for cast and forged steels. The mechanical properties of the base material are, when practically possible, to be tested with specimens orientated transverse to the principal rolling/working direction.	
	Procedures for mechanical testing should be performed in accordance with standardized methods subject to agreement or as prescribed in the Specification for Supply of Pipes.	Further study (comparison) of applicable standards is recommended.
	8.2.4.2 Tensile Properties The yield strength and ultimate tensile strength are to meet the specified values for the actual grade as prescribed in the Specification for Supply of Pipes. Downgrading of high strength steels is not acceptable. The ratio of yield to ultimate tensile strength is normally to be maximum 0.85. A ratio up to 0.90 may be accepted for cold expanded pipes having actual yield strength proportionally higher than the specified minimum.	
North Sea: Max. tensile strength prescribed based on a hardness consideration.	An upper limit for the ultimate tensile strength shall be considered based on considerations of hardness, cathodic protection, etc. The stress-strain curve for the specified linepipe material is to be recorded (see Table 8.4). The elongation of the base materials is to comply with Table 8.2.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Specified minimum yield strength MPa	Minimum percent elongation in 50 mm gage length for wall thickness, t mm:		
	t<12.5	12.5<t<25.5	t>25.5
200-295	27	29	39
295-340	23	25	26
230-390	22	24	25
390-440	21	23	24
440-500	20	22	23

Table 8.2 Minimum elongation of base materials

The reduction of area of cast and forged steels C-, C-Mn, and C-Mn grain treated is to be at least 35 percent. For heavy wall components or higher strength steel a higher ductility level may be required.

8.2.4.3 Toughness Properties

Brittle fracture resistance

Base materials and weldments are to be reasonably resistant against initiation of brittle fractures. This is to be ensured by keeping the transition temperature from brittle to ductile behaviour sufficiently below the minimum design temperature.

The Charpy V-notch transition curve is to be established for the base material of linepipes. (See Table 8.4).

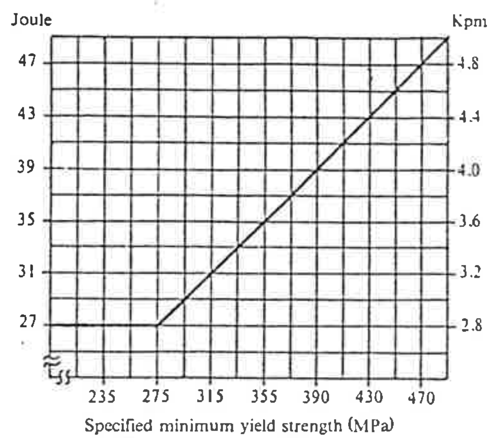
Base materials and welded joints are normally to meet the average Charpy V-notch energy values given by Figure 8.1. Single values are to be at least 75% of the specified minimum average. Where standard specimens cannot be made, subsize specimens may be used with energy conversion factors as given in Figure 8.1.

The impact testing temperature is to be selected in accordance with Table 8.3.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS

The Danish North Sea Gas Transmission Pipeline and Belt Crossings comply with the guideline recommendation for brittle fracture resistance.

GUIDELINE RECOMMENDATION



Specimen section (mm^2)	Energy factor
10 x 10	1
10 x 7.5	5/6
10 x 5	2/3

Fig. 8.1 Average Charpy V-notch energy values

Nominal[1)] wall thickness mm		PIPELINES Gas[2)]	Liquid[2)]
$t \leq 30$ mm	Base material	$T=T_p-30$	$T=T_p-20$
	Weldments	$T=T_p-10$	$T=T_p$
$t>30$ mm		T to be decided in each case	

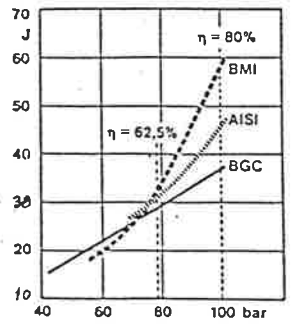
1) Corrosion allowances may be disregarded.
2) Mixed gas and liquid(s) are to be treated as gas.

T = test temperature;
T_o = design temperature

Table 8.3 Charpy V-notch impact testing temperature (°C).

DISCUSSION FURTHER STUDIES ETC.

It is recommended that the base material be tested at a temperature 20°C lower than the weld metal as a logical consequence of a normally lower obtainable impact energy value in the HAZ.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
In accordance with the requirements for the Danish North Sea Gas Transmission Pipeline and Belt Crossings.	Resistance against propagating fractures Pipelines transporting gas or mixed gas and liquids are to be designed in a manner preventing propagating fractures. When the design is based on the installation of linepipe materials with arrest properties, resistance against brittle as well as ductile fracture propagation should be ensured. Resistance against brittle fracture propagation is ensured by requiring minimum 85% average shear area of DWTT full thickness base metal specimens at the lowest design temperature.	
	Resistance against ductile fracture propagation is ensured by requiring a minimum upper shelf Charpy-V energy of the base material at the lowest design temperature.	Methods for determination of the necessary Charpy-V energy to arrest ductile fracture propagation have been studied by several groups, e.g. Battelle, AISI, British Gas, and others. A comparison of the three methods is indicated in the Figure below.  Abmessung des Rohres 870 x 12 mm; Werkstoff X 65
The Battelle method has been used for the Danish North Sea Gas Transmission Pipeline.		In the following the Battelle method is shortly outlined. Formula describing - Decompression of a gas in an opened-up pipeline (Pressure level within the expansion wave and the propagational velocity of this pressure level) - Fracture behaviour of the pipe (Fracture arrest stress, Charpy-V notch energy, yield strength and pipe geometry)

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
		(see below)

- Crack propagation velocity of ductile fractures.

By interlinking these three relationships for a particular pipeline design the necessary toughness for fracture arrest can be found.

The determination of C_v required is an iteration process best made on a computer.

However, under the following conditions

- Pipe backfilled (cover 0.8 m)
- Decompression is above the hydrocarbon dew-point
- Initial acoustic gas velocity of 1300fps
- $2\text{min}^2 < R * t < 20\text{min}^2$
- 60ksi < Yield Strength < 80ksi
- 0.6 x SMYS < Operating stress level < 0.8 x SMYS

the following simple relationship exists:

$$C_v = 2.38*10^{-5}*\sigma_H{}^2*(R*t)^{1/3}$$

C_v = (J) Toughness (Charpy-2/3-specimen)

σ_H = (N/mm^2) Hoop Stress

R = (mm) Pipe Radius

t = (mm) Wall Thickness

It should be noted that above method has been developed using data for typical pipe materials of grades X52 through X65, both semi-killed and fully killed steels, produced prior to 1973 and in diameters up to and including 42 inches.

A quantitative assessment of the influence of water head, concrete coating, and backfill has not been considered. In general water head will have a favourable effect on limiting ductile crack propagation which is expected to be pronounced for non-backfilled submarine lines and nominal for backfilled lines. The presence of a concrete coating would be expected to have a favourable effect on limiting ductile crack propagation.

Further literature studies of the latest knowledge concerning newer linepipe steels (e.g. controlled rolled with low content of carbon and sulphur), as well as the special conditions for submarine pipelines as indicated above, are recommended.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Supplementary fracture toughness testing Fracture toughness tests other than the Charpy-V and DWTT tests may in special cases be allowed or required to assess the resistance to unstable fractures and/or determine defect tolerances in materials and welds. Such tests could be Crack Opening Displacement Test (COD), Compact Tension Tests (CT), Drop Weight test (DW) or full scale type tests. Procedures, extent of testing, conditions and interpretation of results are to be agreed in each case. 8.2.4.4 Hardness The maximum hardness is to be kept at a level safely assuring resistance to hydrogen induced cracking during welding and in service. After welding the hardness is not to exceed 325 HV5 at any part of the weld unless otherwise required (see 8.2.5). 8.2.5 Corrosion	
The Danish North Sea Gas Transmission Pipeline: Stepwise cracking tests (NACE TM 0284) required for the first three heats produced Acceptance criteria: Crack sensitivity ratio = 0.00% Cross sections from above three heats have been metallographically examined in detail and used as references by micro-examination of the Macro/Hardness specimens required, Tables 8.4 and 8.6.	Resistance against environmental induced blistering. Steel for pipelines designed to transport commodities which may cause blistering (also often called hydrogen induced pressure cracking or stepwise cracking) is to be made in a manner making the steel reasonably resistant. Verification by relevant experience or suitable laboratory tests may be required for the base material. (See 8.2.3).	A hardness of 260 HV5 is a "translation " of HRC 22 originating from NACE NR 0175. However, there are significant differences in the two test methods. By hardness measurements in HAZ, the HRC-method can be considered to indicate the average hardness, whereas the HV-method measures very local areas and by it the very small hard zones close to the fusion line. It has been reported that HRC 22 and HV 245-275 have been measured in the same area of steel. Therefore it may be considered appropriate to increase the HV-limit or adapt the HRC-method or some other method with similar impression area.
The Danish North Sea Gas Transmission Pipeline: Sulfide Stress Cracking Tests required for the first three heats Acceptance criteria: No detectable cracking when examined visually and with MT.	Resistance against sulphide stress corrosion cracking (SSC) Materials and welding consumables for use in pipeline systems required to be designed against sulphide stress corrosion cracking are to have a chemical composition and strength level suitable for such service. Selection is to be based on documented experience, e.g. NACE Standard MR-01-75 (Rev. 1980).	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The final hardness of the base material and any part of welded joints is to be kept in the range of 260 HV5 or lower for pipeline systems required to be designed against sulphide stress corrosion cracking. The actual limit is to be agreed upon with due consideration to operational conditions, corrosivity of the commodity being flowed, material properties, fabrication and welding procedures, corrosion control and monitoring systems, etc. Suitable heat treatment may be required for high strength steels and welds to ensure adequate resistance against SSC. Cold formed C-Mn and C-Mn fine grain treated steels are to be heat treated and meet the applicable hardness limit for SSC resistance, when the accumulated plastic strain exceeds 5%. Cold formed and/or welded low alloy steels are normally to be heat treated and meet the applicable hardness limit when SSC resistance is required. Resistance against SSC shall be documented. 8.2.6 Soundness The material is to be free from any defects which may make it unsuitable for the intended service. Cracks, notches, gouges and tears are not acceptable. Overlaps, slivers, impressed mill scale, arc spots, etc. are to be removed by grinding unless proved to be of a superficial nature. The material is to be free from gross laminations, gross inclusions, segregations, shrinkages and porosity. The soundness of rolled, forged and cast material is to be verified by non-destructive testing according to agreed procedures and standards.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

8.3 FABRICATION

8.3.1 General

Pipes are to be produced seamless or by fusion welding of shaped plates or strips. The submerged arc welding process is normally to be used. Other welding methods may be used subject to special approval.

Where cold expansion is used to adjust size and strength, the nominal permanent strain is not to exceed 2 percent. Cold expansion is to be performed with tools avoiding high local deformations. Welded pipes shall always be expanded.

8.3.2 Procedure Specifications

A fabrication procedure specification is to be established for each work describing the sequences of fabrication and the successive quality control steps and requirements. The procedure shall include, but not be limited to, the following main points:

- Steel Making Process and details of all heat treatments
- Hot Working Processes
- Welding Procedure (see below)
- Detail of mechanical testing, non-destructive testing and quality control procedures
- Expected ladle and product analyses
- Expected maximum hardness in base material including steps taken to prevent hard spots
- Expected grain size.

The specification is to be submitted for approval.

When pipes are to be produced by welding, a detailed welding procedure specification is to be prepared giving:

- pipe material standard, grade and project specification
- diameter and wall thickness
- groove preparation and design
- welding process
- welding consumables, trade name, recognized classification
- electrode/wire diameter
- welding parameters: current, voltage, type of current, polarity, travel speed for each arc
- number of welding arcs as well as cold and hot wire additions

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	- welding position - welding direction - number of passes - pre-heat and interpass temperatures - post-weld heat treatment.	
	The fabrication procedure is to be qualified prior to or during initial production. Type and number of tests are given in 8.3.4 and Table 8.4.	
	Previously qualified fabrication procedure may be transferred to a new production when the manufacturer has used it recently for production of pipes to the same or more stringent requirements.	
	All welding is to be carried out strictly in accordance with the qualified procedure. If any parameter is changed outside the acceptable limits, the welding procedure is to be re-specified and re-qualified.	Essential parameters and variation limits on their values will be specified in an Appendix.
	8.3.3 Qualification of Welding Personnel	
	Qualification testing is required for welding operators when their tasks are to pre-set, adjust, start, guide, and stop the welding operation, and thereby may influence the quality of the weld. Qualification testing may be exempted for welding operators whose tasks have no influence on the weld quality provided they have been given adequate training on the actual welding equipment.	
	Welders are normally to be qualified for single side butt-welding of pipes in the required principal positions. Under special circumstances qualification may be carried out on plates.	
	Repair welders may be qualified for partial thickness repair on a representative devised test set-up if only such weld repairs will be made.	
	The qualification test is to be carried out with the same or equivalent equipment as is to be used during production welding, and normally at the actual premises.	
	Qualification testing is normally to be based on visual inspection and radiographic examination. When the gas metal arc process is used, mechanical testing is also to be performed, normally using side bend and nick break test specimens.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The qualification expires when the welder and welding operator have not been welding regularly within the qualified range during a period of more than 6 months. A welder or a welding machine operator who has produced a complete and acceptable welding procedure qualification test is thereby qualified. Personnel to perform arc-air gouging are to be trained and experienced with the actual equipment. Qualification testing is required. 8.3.4 Qualification of Fabrication Procedure From the first production batch of maximum 50 pipes, two pipes selected by the Engineer or his representatives are to be used for qualification testing. Type and number of tests to be made for each pipe are given in Table 8.4. Dimensions of test specimens, testing procedure and acceptance limits as per Specification for Supply of Pipes. The qualification of the fabrication procedure is to be based on the following requirements: - hydrostatic testing to the specified test pressure (see 8.3.5). - Dimensional tolerances and workmanship to the specified limits - Soundness of base material and welds within the specified acceptance limits - Check analyses within the specified composition limits - Tensile properties of base material at least equal to the specified minimum values - Notch toughness of base material at least equal to the minimum specified values for resistance against brittle fracture, and propagating ductile fractures when so required - Shear area of DWTT of base material at least equal to the minimum specified value when so required - Transverse weld tensile strength at least equal to the specified minimum tensile strength - Bending ductility to specified deformation without appearance of any defect greater than 3 mm, however, max. 6 mm at the specimen edge	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	- Brittle fracture resistance of weld metal and heat-affected zone at least equal to the required average and minimum single values - Macrosections with a sound weld merging smoothly into the pipe - Maximum hardness equal to or below the specified limit. All the above mechanical testing shall be performed on samples cut from a produced pipe without further heating. Failure of a test specimen due to defective preparation may be disregarded and is to be replaced by a new test specimen.	
	8.3.5 Hydrostatic Testing Every pipe is to be hydrostatically tested and withstand without any sign of leakage a test pressure determined by the following formula for at least 10 seconds: $p = \sigma_F * \frac{2t}{D}$ (MPa) σ_F = specified minimum yield strength (MPa) t = minimum allowable wall thickness (mm) D = nominal outside diameter (mm) For hydrostatic testers equipped with end sealing devices, the applied sealing force for end-sealing resulting in an additional longitudinal stress has to be considered. Supporting calculations to achieve the required stress intensity for computing the test pressure are to be submitted by the pipe manufacturer. Pressure test records showing test pressure and duration are to be available for each pipe. Pipes which have failed on pressure testing are to be rejected.	This Guideline Recommendation follows Danish practice, there being no reduction factor K as prescribed in the DnV Rules.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS

The table as presented here was used for the Danish North Sea Gas Transmission Pipeline and Belt Crossings

GUIDELINE RECOMMENDATION

Pipe size outside diameter (mm)	FULL LENGTH PIPE TESTS			BASE MATERIAL TESTS					WELD TESTS			
	Hydrostatic tests	Dimensional inspection	Non-destructive tests	Check analysis	Tensile test 1)		Charpy V-notch transition curve 2) 3)	Drop weight tear test 8)	Tensile test transverse to weld 4)	Guide bend test 5)	Charpy V-notch toughness 6)	Macro-section/ hardness
					Longitudinal	Transverse						
Seamless OD<300 OD>300	Acc. to 7.3.5	Acc. to 7.3.6	Acc. to 7.3.7	1 1	1	- 1	1 1	1 1				
Welded OD<300 OD>300	Acc. to 7.3.5	Acc. to 7.3.6	Acc. to 7.3.7	1 1	1 7)	- 1	1	1 1	2 2	4 4	4 samp. 4 samp.	1 1

Table 8.4 Qualification of pipe fabrication procedure

Type and number of tests for each pipe.

Notes:

1. Yield strength, ultimate tensile strength and elongation to be determined with recording of the stress-strain curve.
2. Charpy V-notch transition curve is to be established using transverse test samples where this is possible. Acceptance testing temperature is to be as specified.
3. Where resistance to propagating ductile fracture is to be evaluated by other tests than Charpy testing, the specified tests are to be performed additionally.
4. The ultimate tensile strength of the weld is to be determined.
5. Guided bend tests to be either 2 face bend plus 2 root bend specimens, or 4 side bend specimens for thickness less and greater than 12.5 mm respectively.
6. Charpy V-impact testing is to be performed at the specified temperature in the weld metal and the heat-affected zone at sufficient positions to determine the overall resistance to brittle fracture. Charpy testing is normally to be performed with the notch positioned in: Center of weld, on fusion line, 2 mm from fusion line and 5 mm from fusion line (each sample to provide 3 test specimens).
7. Longitudinal tensile test is to be taken 180^{o} opposite to the longitudinal weld.
8. DWTT when so required. 1 sample to provide 2 test specimens, (min 70% shear for each specimen, 85% average).

DISCUSSION FURTHER STUDIES ETC.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	8.3.6 Dimensions, Weights, Lengths and Workmanship Dimensions, weights, and lengths with corresponding tolerances should be in accordance with the Specification for Supply of Pipes. 8.3.7 Visual Examination and Non-destructive Testing	
Extent of ND-testing as performed for the Danish North Sea Gas Transmission Pipeline and Belt Crossings.	Each pipe is to be visually examined and non-destructively tested after pressure testing. If a pipe is cut back, the new pipe end is also to be inspected. NDT-records of each pipe are to be identified and traceable. Visual examination is to be performed at the outside, and also inside if access allows. The surface finish of the base material and the welded seams is to comply with requirements set out in the Specification for Supply of Pipes. All operators of NDT equipment shall have a valid certificate in accordance with a recognized standard approved by the Engineer or his representatives. Welded and seamless pipes are to be ultrasonically tested full length, or by other suitable, agreed methods, for laminations and cluster inclusions. Procedures and acceptance criteria are to be in accordance with agreed, recognized standards. Plates and strips may optionally be tested prior to pipe fabrication, but after quenching and tempering, if this has been applied. Longitudinal welds and spiral welds are to be ultrasonically tested full length. The testing procedure is to be capable of detecting two-dimensional and three-dimensional defects located in any direction and position. Additionally such welds are to be radiographed over a length of 200 mm from each pipe end. On every pipe the weld seams for a distance of 200 mm at each end shall be magnetic particle or penetrant inspected for cracks.	Quantified criteria will be introduced in the next edition. Considerable material is now available as a result of the studies relating to the DORAS oil pipeline, but further work is needed to present this in a clear concise form.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	On every pipe the full circumference of each bevelled end shall be magnetic particle or penetrant inspected for cracks.	
	Weld repairs are to be radiographed and ultrasonically inspected full length.	More specific guidance on non-destructive testing will be introduced in the next edition. Considerable experience has been gained as a result of the studies relating to the DORAS oil pipeline, but further work is needed to present this in a clear and concise form.
	Non-destructive testing including acceptance limits is to be in accordance with the Specification for Supply.	
	8.3.8 Production Testing	
	Production testing is to be carried out to verify that the pipes are fabricated to the composition, mechanical properties, soundness and dimensions specified. Production tests are to be performed as directed in Tables 8.5 and 8.6.	
	All mechanical testing shall be performed on samples cut from a produced pipe without further heating.	
	Testing is to be witnessed by the Engineer or his representatives.	
	If any of the selected test specimens do not fulfil the requirements, the corresponding pipe is to be rejected. In order that the remaining pipes from the same batch of maximum 50 pipes (or 50 tons, see note in Table 8.5) may be accepted, two similar tests are to be repeated on two different pipes, and both tests are to be satisfactory. Should one of these tests fail, individual testing of the remaining pipes of the batch is to be carried out.	
Extent as for the Danish North Sea Gas Transmission Pipeline and Belt Crossings	(see Table 8.5 below)	

Chemical composition 1)		Mechanical testing 2)	Hydrostatic test	Dimensional inspection	Non-Destructive tests
Each heat	Each 50 pipe, minimum one a heat	Each 50 pipe, minimum once each heat (acc. to Table 8.6)	Each pipe	Each pipe	Each pipe

Table 8.5 Frequency and extent of pipe production tests

Notes:

1. Check analysis is not required if this has already been performed during an intermediate stage.
2. If there are more than 50 pipes manufactured from each 50 tons, mechanical testing is only required for each 50 tons.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS

Extent as for the Danish North Sea Gas Transmission Pipeline and Belt Crossings

GUIDELINE RECOMMENDATION

Pipe size outer diameter (mm)	Pipe material tests: Tensile test 1) Longitudinal	Pipe material tests: Tensile test 1) Transverse	Pipe material tests: Charpy 2) 3) V-notch toughness	Drop weight tear 7) test	Weld tests: Tensile 4) transverse to weld	Weld tests: Guided bend test	Weld tests: Charpy 6) V-notch toughness	Weld tests: Macro-section/hardness
Seamless OD<300	1		1 sample	1				
Seamless OD≥300		1	1 sample	1				
Welded OD<300	1		1 sample	1	1	2	2 samples	1
Welded OD≥300		1	1 sample	1	1	2	2 samples	1

Table 8.6 Number and type of mechanical tests on pipe production tests

Notes:

1. Yield strength, ultimate tensile strength and elongation to be determined.
2. Brittle fracture resistance to be determined by Charpy V-notch testing at the specified testing temperature.
3. When pipe material is required to be resistant against propagating ductile fractures, production tests are also to include the specified type and number of tests.
4. Ultimate tensile strength of the weld to be determined.
5. Bend test to be either 1 face + 1 root bend, or 2 side bend specimens for thickness less and greater than 12.5 mm respectively.
6. Charpy V-notch of weld metal and heat affected zone. Notching of HAZ to be performed at the position giving lowest average energy absorption during qualification testing.
7. DWTT when so required. 1 sample to provide 1 test specimen, min. 85% shear area.

DISCUSSION FURTHER STUDIES ETC.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

Non-destructive tests	Tensile test transverse to weld 1)	Guided bend test 2)	Charpy V-notch toughness 3)	Macro-section/ hardness
Acc. to 8.3.9	2	4	4	1

Table 8.7 Mechanical testing of weld repair procedures

Notes:

1. Tensile test to record ultimate tensile strength of the joint.
2. Either two root bends plus two face bends, or four side bends for thickness less and greater than 12.5 mm respectively.
3. Impact testing to be carried out with the notch positioned in centre of weld, fusion line, 2 mm from f.l. and 5 mm from f.l. This testing may be exempted from surface repair procedure provided same welding consumable, size and heat input is applied.

Failure of a test specimen due to defective preparation may be disregarded and the specimen replaced by a new test specimen.

Pipes which have failed the mechanical testing are not allowed to be restored by heat treatment.

8.3.9 Repairs

Pipes containing defects may be repaired, or the defective sections cut off. Weld deposits having unacceptable mechanical properties are to be completely removed before re-welding.

Defects may be repaired by grinding, but shall be to procedures and by operators qualified and approved by the Engineer or his representatives.

Where defects are eliminated by grinding, the remaining wall thickness is to be within the minimum specified limit. Grinding is to be performed in a workmanlike manner.

Weld defects may be weld repaired by procedures and welders qualified in accordance with the recognized standards approved by the Engineer or his representatives and with the following restrictions:

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	A local weld repair is to be at least 100 mm long. Weld seams may be repaired full length, however, not more than twice in the same area. Weld repairs are to be ground to merge smoothly into the original pipe contour. When a heat-treated pipe is repaired by welding, a new suitable heat treatment may be required depending on the effect of the weld repair on the properties and microstructure of the pipe. Qualification testing is to be based on visual inspection, radiography, mechanical testing and SSC resistance testing, if applicable. Mechanical testing is to be performed according to Table 8.7. Repair welding procedures are to meet all the pipe requirements. Pipes shall be repeat hydrostatically tested after weld repair.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS

Danish projects have generally followed the requirements of the DnV Rules 1981 as regards corrosion protection.

GUIDELINE RECOMMENDATION

9. CORROSION PROTECTION

9.1 DESIGN CRITERIA

The corrosion protection of pipelines and risers should be designed to prevent reductions of serviceability or structural safety due to corrosion attack during fabrication, installation or operation. The corrosion protection should be effective during the design lifetime of the pipeline system.

Corrosion allowance may be specified to take account of corrosion during storage and of internal corrosion; reference is made to Section 5.4.2.

9.2 GENERAL DESIGN PROCEDURES

External surfaces of pipelines and risers shall generally be provided with a corrosion coating, constituting a physical barrier between the steel and the marine environment. On submerged parts the corrosion coating shall be backed up by a cathodic protection system.

The DnV Rules specify that risers are to have a corrosion allowance against external corrosion in addtion to other means of corrosion protection.

Special consideration shall be given to the corrosion protection of risers, particularly in the splash zone.

Internal protection is required for pipeline systems transporting corrosive or erosive media.

DISCUSSION FURTHER STUDIES ETC.

The corrosion allowance is to provide protection for 2 years. Table 9.1 gives guidelines on determination of the corrosion allowance as function of operating temperatures of the riser.

Table 9.1 Corrosion allowance of risers as function of operating temperature.

Temperature °C	Corrosion allowance, mm
< 20	2
20 - 40	4
40 - 60	6
60 - 80	8
80 - 100	10

NACE RP-06-75

Coatings should perform effectively against barnacles, marine attack, and mechanical damage.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

9.3 EXTERNAL CORROSION COATING

9.3.1 General

The following generic types of external coatings may be used for corrosion protection:

- Tape wrap or heat shrink sleeves, for field joints only.
- Coal tar and asphalt enamels and asphalt mastic, normally in combination with protective concrete coating, for submarine pipelines and risers.
- Polyethylene (extruded or fusion bonded) for submerged pipelines and risers.
- Fusion bonded epoxy, for submerged pipelines and risers, including field joints.
- Vulcanized rubber, for risers in splash zone and submerged, including field joints.
- Epoxy paint systems, for risers in atmospheric zone and for subsea flanges, fittings and components.
- Metal claddings, for riser splash zones.

Other generic types of coating may be used if satisfactory long term performance under similar exposure conditions are documented by relevant laboratory testing or field records.

The selection of an external coating for a pipeline system should take account of the following properties:

- Adhesion and resistance to disbonding.
- Resistance to physical, chemical and biological deterioration.
- Tensile elongation and flexibility.
- Strength and impact resistance.
- Range of service temperature.
- Compatibility with concrete coating.
- Ease of coating repair.

The softening point of asphalt or coal tar based coatings shall be at least 30^{o}C above the maximum design operating temperature of the pipeline system.

The above properties should be documented by relevant tests or by reference to earlier successful application.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	In addition to the properties listed above, the coating specification should include information on: - Generic type and composition - Surface preparation - Priming - Coating thickness - Reinforcement and fillers - Casing and handling - Testing and repair. 9.3.2 Factory Coating Application The external coating should be applied according to an approved procedure, including: - Handling and treatment of coating materials. - Surface preparation. - Temperatures, air humidity and timing of different steps in the coating process. - Testing methods, with reference to generally recognized standards or correspondingly detailed descriptions. - Acceptance criteria. - Repair procedures for deficiences, damages, or attachments of cables, etc. - Handling, storage and transport of coated items. - Quality control and inspection. - Reporting. Special attention should be given to adhesion and coating thickness at weld reinforcements. The minimum requirement to pipe surface preparation is generally grit blasting to Sa 2.5 according to SIS 055900, or equivalent standard. Quartz sand with steel grit should be used. Round shot is not recommended. The quality control reports should generally include: - Acceptance criteria according to coating specification. - Surface preparation data. - Temperature and humidity measurements. - Coating composition and total coating thickness. - Adhesion data. - Holiday detection data. - Coating repair data. A pre-production test is generally required to demonstrate that the coating can be applied under the prevailing fabrication conditions.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.3.3 Field Joint Coating. External coating of field joints should be applied according to approved procedures of the same nature as the one for factory applied coating. Surface preparation by power tool brushing to a uniform near-white metal finish is acceptable for field joint coatings with adhesive mastic linings. The field joint coating should be compatible with the pipe coating, and the procedure for field joint coating should describe procedures for repair of pipe coating under field conditions. Criteria for acceptance, rejection and repair of coating before final installation should be stated. Hyperbaric weld field joints may be left uncoated if adequate account of the bare metal is taken in the cathodic protection design.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
Danish projects have generally followed the requirements of the DnV Rules 1981 and the DnV Technical Note A.703 with regard to cathodic protection.	**9.4 CATHODIC PROTECTION** 9.4.1 General A cathodic protection system shall be designed to provide adequate protection during the design lifetime of the pipeline system. The design may be based upon a shorter period if procedures for re-establishment of protection are developed. The possiblities of stray currents in connection with nearby structures should be evaluated, and appropiate preventive methods should be employed to prevent detrimental effects. The cathodic protection system is normally based upon sacrificial anodes. If an impressed current system is used, special attention should be taken to avoid overprotection. The cathodic protection design should include: - Calculation of protection current demand - Anode weights and distribution. - Anode material specification. - Calculations documenting adequate protection during design lifetime. - Procedures for anode attachment. The anode specification should furthermore include rejection criteria concerning casting quality and bond to reinforcement. Anodes should be furnished with certificates, stating chemical analysis and the results of performance tests. The anode potential and capacity at the required operating temperature range should be documented. 9.4.2 Electrical Isolation 9.4.2.1 Electrical insulating should be installed where electrical isolation is needed for effective corrosion control.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.4.2.2 Typical locations where insulating devices may be required are as follows: (a) at the junction of dissimilar metals (b) for riser pipe where electrical isolation from the platform is desired, insutating devices should be located above splash zone level and be readily accessible. 9.4.2.3 The use of underwater insulating devices should be avoided. 9.4.3 In areas where interference currents are suspected, appropriate tests should be conducted. The type of test will depend on water depth and accessibility of the pipelines. Any one or combination of the following test methods can be used: 9.4.3.1 Measurement of pite-to-electrolyte potentials with recording or indicating instruments. 9.4.3.2 Measurement of current flowing on the pipeline with indicating or recording instruments. 9.4.3.3 Measurement of the variations in current output of the suspected source of interference current and correlation with measurements obtained in Paragraphs 9.4.3.1 and 9.4.3.2. 9.4.3.4 General methods for resolving interference corrosion problems. (It should be understood that interference problems are individual ones, and the solution should be mutually satisfactory to the parties involved). (a) Prevention of the pick-up or limitation of the flow of interfering current through a submerged pipeline.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

(b) Removal of the detrimental effects of interfering current from a submerged pipeline by means of a metallic conductor connected to the return (negative) side f the interfering current source.

(c) Counteraction of the effect of interfering current by means of cathodic protection.

(d) Removal or relocation of interfering current.

9.4.4 Design Procedures

The weight and distribution of sacrificial anode material shall be designed to deliver the current output required for protection of a structure under the following conditions:

- Start-of-life (polarization)
- Average service
- End-of-life.

For a coated pipeline system only the latter two criteria are governing.

The amount of anode material required to provide protection may be calculated from the formula

$$L = \frac{u \cdot W}{E \; I} ,$$

where

L : Design lifetime (years)

u : Anode utilization ratio, i.e. proportion of anode which can be consumed before the anode ceases to be functional.

W : Mass of anode material (kg/km)

E : Consumption rate of anodes (kg/ A . yr)

I : Protection current requirement (A/km)

The current demand is calculated as the product of current density and protection area, i.e.

$I = i \, \Delta \, S_p$, where

i : Current density on bare steel (A/m^2)

Δ : Coating breakdown ratio (m^2/m^2)

S_p: Total external pipeline area (m^2)

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	The current output from the individual anodes may be calculated from the formula: $I_a = \frac{\Delta V}{R_a}$, where: I_a: Current output (A) ΔV : Driving voltage, i.e. difference between required steel potential and anode potential R_a: Circuit resistance (Ohms). The circuit resistance can normally be taken as the anodic resistance between the anode surface and the surroundings, which depends upon the anode shape and the environment resistivity. Interference between anodes should be taken into account if anodes are closely grouped. 9.4.5 Environmental Conditions The following parameters should be taken into account in the design: - Operating temperature - Ambient temperature - Chemical composition and oxygen content of environment - Resistivity of environment - Biological activity of environment - Current velocity of seawater. The specific resistance of seawater may be taken as 33 Ohm cm. In seabed sediments the specific resistance may be assumed at 100 Ohm cm, if no measurements are carried out. Free flowing seawater and seabeds consisting of sand or clay may be considered as aerated, whereas muddy sediments shall be considered as anaerobic, particularly in the presence of organic matter with sulphate reducing bacterial activity. 9.4.6 Protection Requirements Cathodic protection of steel in an aerated marine environment at ambient temperature is achieved at a potential of -0.80V, measured against a siver/silver chloride (Ag/AgCl) reference electrode. Thus adequate protection requires potentials as low or lower (more negative). For anaerobic environments, the maximum potential should be -0.90V (vs. Ag/AgCl).	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

To avoid overprotection and associated hydrogen formation, the lower limit for the steel potential should be -1.05V (vs. Ag/AgCl). For very high strength steels (SMYS $\geq$ 700 MPa), this limit should be reduced to -0.95V (Vs. Ag/AgCl).

NPD limit: 800 MPa

The minimum current densities for protection of bare steel in different environments may be taken as follows:

	Current Density (mA/m^2) Initial Value	Mean Value	Final Value
Northern North Sea	160	120	100
Southern North Sea	130	100	90
Internal Danish Waters	130	100	90
Stagnent Seawater	120	90	80
Saline Sediment	25	20	15
Buried Pipelines	50	40	30

The higher values for buried pipelines take account of possible uncovering of pipeline sections. On the other hand, these values may be used with the potential requirements for an aerated environment.

The above values are valid for steel at ambient temperatures. For hot pipelines, 1 mA/m^2 should be added for each ^{o}C the difference between operating temperature and ambient temperature exceed $25^{o}C$.

The current requirements of a coated pipeline are highly dependent upon the quality of coating materials and application. For coatings with satisfactory application and mechanical protection the following coating breakdown ratios may be assumed where the design life is 25 years:

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

	Breakdown Ratio (%) Initial Value	Mean Value	Final Value
Thick film enamels and mastic	1	10	20
Polyethylene	1	10	20
Fusion bonded epoxy	1	10	20
Epoxy paint system	2	20	50

DnV regards Fusion Bonded Epoxy as equivalent to epoxy paint, but accepts the 20% final breakdown ratio provided regular inspection is carried out.

9.4.7 Anode Shapes

The anodic resistance for various shapes of anodes may be found from the following formulae:

Slender, Stand-off Anodes

$$R_a = \frac{\rho}{2\pi l} \left(\ln \frac{4l}{r} - 1\right)$$

Flat, Flush-Mounted Anodes:

$$R_a = \frac{\rho}{2s}$$

Bracelet Anodes and Other Shapes:

$$R_a = \frac{0.315\rho}{\sqrt{S_a}}$$

Here:

R_a : Anodic resistance (Ohm)

ρ : Specific environment resistance (Ohm m)

l : length of anode (m)

r : Equivalent radius of anode(m), $r = \sqrt{A/\pi}$, where A is the cross-sectional area.

s : Mean dimension (m), $s = \frac{1}{2}(b + l)$, where $b < l/2$ is the width

S_a : Exposed anode surface area (m^2)

The following values may be used for the utilization factor:

Slender and flat anodes	:	u = 0.90-0.95
Bracelet anodes:	:	u = 0.75-0.80
Other shapes:	:	u = 0.75-0.85

Anodes mounted on pipelines are normally of the bracelet type, either cast in sections or as cylindrical half-shells.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

9.4.8 Anode Fabrication and Installation

Sacrificial anodes for marine pipelines are normally made from zinc or aluminium alloys. The corresponding potentials in seawater may be assumed to be -1.03 V (vs. Ag/AgCl) and -1.00V (vs. Ag/AgCl), respectively.

Zinc anodes are susceptible to intergranular corrosion at elevated temperatures, and should not be used at temperatures exceeding 50°C. Unless the anode is mounted outside a layer of pipeline insulation, the temperature should be assumed to be 2°C lower than the pipeline product. To avoid intergranular corrosion at temperatures above 35°C, the following zinc alloy composition is recommended:

Iron	:	0.002% (max)
Copper	:	0.005% (max)
Lead	:	0.006% (max)
Silicon	:	0.125% (max)
Aliminium	:	0.10% - 0.20%
Cadmium	:	0.03 - 0.06%
Zinc	:	Remainder

Aluminium anodes have a tendency to passivate in seabed sediment, a problem which is alleviated by indium activation. The following aluminium alloy is recommended:

Iron	:	0.1% (max)
Copper	:	0.006% (max)
Silicon	:	0.2% (max)
Indium	:	0.005% - 0.05%
Zinc	:	2% - 6%
Aliminium	:	Remainder

The anode consumption rate is the reciprocal of the faradaic capacity, which decreases with temperature for zinc as well as for aluminium.

At ambient temperature capacities of 760 Ahr/kg and 2400 Ahr/kg may be assumed for zinc and aluminium, respectively.

The anodes should be provided with adequate reinforcement, and electrical and mechanical bond between reinforcement and anode alloy should be ensured.

The anodes should be mounted securely on the pipe, and protected against mechanical damage during handling and installation.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Each anode should normally be connected to the pipe by two attachments made by manual welding or thermite welding. The minimum distance between each attachment weld and other welds should be 150 mm. Manual welds for electrical connections should be made on doubler plates welded directly onto the pipeline by a qualified welding procedure. Thermite welding should be performed according to a qualified procedure. A minimum of three test welds should be examined for bond, copper penetration and hardness. The maximum allowable copper penetration is 0.8 mm and 0.3 mm for pipelines and risers, respectively. The hardnesses should be within the limits specified for the pipeline system. The spacing between anodes should be sufficiently close to secure protection, and normally no more than 120 m.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.

9.5 INTERNAL CORROSION CONTROL

9.5.1 General

Internal corrosion control should be provided for pipeline systems transporting corrosive hydrocarbons.

The following properties of the pipeline content should be considered in the establishment of a corrosion control programme:

- Oil/gas/water ratios.
- Salinity and acidity of water phase.
- Contents of corrosive gases, such as O_2, CO_2 and H_2S.
- Presence of bacteria.
- Contents of solids.
- Characteristics of temperature, pressure and flow.

Internal corrosion control is normally required if the transported medium contains liquid water or a gas phase with more than 50% humidity, and when the partial pressure of corrosive gases exceeds the following limits:

- Oxygen (O_2) : 0.001 MPa
- Carbon Dioxide (CO_2) : 0.01 MPa
- Hydrogen Sulphide (H_2S) : 0.01 MPa

Combinations of the above corrosive gases may be more agressive, especially combinations of H_2S and O_2. The corrosivity will also generally increase with increasing temperature.

Expected time dependence and variations of operational conditions, such as injection of water or lift gas, should be taken into consideration.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.5.2 Inhibitor injection In the selection of inhibitors, the following conditions should be considered: - General philosophy for inhibitor selection. - Chemical type and inhibition mechanism. - Solubility and dispersibility. - Inhibitor concentrations. - Limitations on temperature, pressure or flow rate. - Compatibility of different inhibitors. - Ecological effects. The protective properties of the selected inhibitor system should be documented by appropriate laboratory and/or field testing, or by reference to previous application records. Laboratory tests should include exposure testing under relevant conditions of fluid composition, temperature, pressure, flow etc., and should normally be carried out by an independent body. Inhibitor injection should be performed in accordance with an approved procedure, including: - Principles of inhibitor application. - General arrangement of system. - Dosage. - Control system.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.5.3 Internal Coating. The selection of an internal coating should take account of the following properties: - Adhesion - Resistance to physical, chemical and biological deterioration - Range of service temperature. The properties of the coating should be documented by relevant tests or by reference to earlier application records. The coating specification should furthermore include information on: - Generic type and composition - Surface preparation - Application principle - Coating thickness - Inspection and repair. The internal coating should be applied in accordance with an approval procedure, with due consideration to surface preparation and quality control, particularly for coatings applied after installation of the pipeline. For coatings applied during fabrication and installation, special attention should be given to internal coating of the field joints. Internal coatings applied to reduce wall friction or yard corrosion are normally not regarded as effective against internal corrosion during pipeline operation; moreover, due consideration should be given to the possibilities of increased corrosion at imperfections or field joints. 9.5.4 Corrosion Resistant Pipe Material Corrosion resistant material may be used as solid linepipe or as a lining inside the pipeline. Generic types include polyethylene pipe, stainless steels, or other corrosion resistant alloys. The corrosion resistance of the material should be documented by relevant laboratory and/or field testing, or by reference to earlier successful application. Special attention should be given to the make-up of field joints.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.6 RISER PROTECTION	
	9.6.1 Splash Zone Protection	
	In the design of corrosion protection of risers or riser casings in the splash zone, due consideration should be given to: - Operating temperatures. - Wave forces. - Intermittent wetting and drying. - Ageing by seawater and sunlight - Compatibilty of different materials. - Maintenance and repair.	Cf. p. 8.1 concerning riser corrosion allowance.
	Acceptable splash zone protection systems are vulcanized rubber and metal sheathing. Other means of corrosion protection may be acceptable, provided adequate properties are documented for the actual conditions.	
	Vulcanized rubber should be applied according to an approved procedure, reference is made to Section 9.3. Any field joints should be coated by vulcanized rubber as well.	
	Metal sheathing should be completely seal welded to itself and to the riser doubler plate, no mechanical type sealing being permissible. The welding should be carried out according to a qualified procedure, and all welds subjected to 100% NDT examination. A sacrificial anode should be placed below the sheating.	
	9.6.2 Protection of Cased Risers	
	Risers in J-tubes, tunnels, casings or other inaccessible areas should be protected by suitable external coating, cf. Section 9.3. The environment should be either dry or inhibited seawater or other non-corrosive fluid.	
	Inhibitors should be adequately documented (see Section 9.5.2), and the effectiveness should be monitored regularly.	
	Special attention should be given to the sealing of the riser casing.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
Danish projects have generally followed the requirements of the DnV Rules 1981 with regard to weight coating and mechanical protection.	10. WEIGHT COATING AND MECHANICAL PROTECTION 10.1 DESIGN CRITERIA Weight coating on pipelines should be provided to maintain hydrodynamic stability in cases where the negative buoyancy of the steel pipe is not sufficient, and where stability is not ensured by other means, such as seabed anchors, rock cover or trenching. Impact and abrasion resistant coating should be provided to protect asphalt or coal tar based corrosion coatings against damage during installation and operation. Risers should be protected against ship impact.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	10.2 GENERAL DESIGN PROCEDURES Weight coating and mechanical protection on pipelines should generally consist of yard-applied reinforced concrete coating on the pipe joints. A similar protection should be applied on the field joints, and allowance for the field joints should be made in the concrete coating design with respect to negative buoyancy. The abrasion resistance of coatings on pipelines to be installed by bottom tow or bottom pull should be documented by testing or by reference to earlier applications under similar conditions. A thin fibre-reinforced cement coating may be used for abrasion resistance. In areas subjected to fishing activities the pipeline should be trenched to a minimum depth from seabed to top of pipe of 0.30 m. Trenching as mechanical protection may be omitted for pipelines with a steel outer diameter if 16 inches or more.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	10.3 CONCRETE COATING 10.3.1 General The design of concrete coating shall take account of the following: - Required negative buoyancy of pipeline - Type of corrosion coating - Pipeline installation method - Mechanical hazards during installation and operation - Chemical and biological properties of environment. The concrete shall be applied according to an approved specification, containing information on: - Concrete strength and density - Concrete materials and mixing - Reinforcement type and installation - Method of application and curing - Testing of coating properties - Weight control - Repair - Quality control and inspection - Reporting.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	10.3.2 Materials	
	All materials should be clean and free from any constituents or impurities which would impair the mixing, curing, strength or durability of the concrete.	
	Cement should be low-alkali, sulphate resistant Portland cement.	
	Water should be fresh water.	
	Sand should be well-graded from fine to coarse, and coarse aggregate should be crushed material. Iron or barium ore may be used to increase the density of the concrete.	
	Reinforcement should generally consist of steel cages with a circumferential bar spacing between 90 mm and 150 mm. Minimum reinforcement ratios should be 0.5% in the circumferential direction, and 0.05% longitudinally. Welded wire mesh may be used for thin coatings (less than 40 mm), or as supplementary reinforcement for thick coatings (more than 100 mm).	
	10.3.3 Properties	
	The minimum characteristic compressive strength of the concrete should be 30 N/mm^2 at 28 days, referred to standard 150 mm x 300 mm cast cylinders. The strength should be demonstrated by in-situ testing on coated pipes by means of a well-documented relationship between in-situ strength and standard cylinder strength. The minimum characteristic strength at 7 days should be 25 N/mm^2.	Acceptable in-site testing: - Cores - Pull-out (CAPO)
	To ensure a durable concrete, the maximum water/cement ratio should be 0.40, and the minimum cement content should be 350 kg/m^3.	
	Calculations of the weight of the coated pipe joint should take account of water absorption in the concrete, which should be documented by immersion tests.	A water absorption of 2% (by weight) may be assumed for design.
	The shear transfer between steel pipe and concrete coating should be ensured, and if necessary documented by tests.	On Fusion Bonded Epoxy coating an intermediate layer of fibre reinforced cement may be used. On PE sleeve pipe mechanical grooving (depth 3 mm, pitch 50 mm) may be used.

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	10.3.4 Application and curing The following methods of concrete application may be used: - Casting - Impingement - Extrusion.	
	Other methods may be used if satisfactory coating performance is documented by relevant field records. The application method should be chosen so as not to damage the corrosion coating.	Impingement on FBE coating requires an FRC buffer layer.
	The concrete should generally be applied to the pipe joint in one continuous operation and interruptions exceeding 30 minutes are not acceptable. Concrete mix should not be used more than 45 minutes after the introduction of water. Concrete should not be applied when the ambient temperature is below $5^{o}C$ or above $30^{o}C$, unless provisions are made to protect the newly applied concrete. Use of rebound concrete is permitted only if it is thoroughly mixed with freshly batched materials to produce an acceptable concrete mix. The outer surface of the concrete coating should be without corrugations, and concentric with the steel pipe. Curing of the concrete should take place under strict control of humidity and temperature, and without damage to the corrosion coating. Storage of coated pipe should not take place at temperatures below $5^{o}C$, or before the concrete has attained a minimum strength of 15 N/mm^2. All coated pipe should be cured for a minimum of 7 days, and no pipe should be loaded out until the specified 7 day strength has been documented.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	10.4 FIELD JOINT COATING Field joints of concrete coated pipelines should be provided with protection which is flush with the adjoining concrete coating. The following types of field joint infill may be used: - Hot marine mastic - Polyurethane foam - Concrete - Polymer concrete. Other types may be used if satisfactory properties are documented by laboratory and/or field testing, or by reference to earlier applications.	
	The infill should be placed within a mould, which may be left on the pipeline or removed. Moulds depth on the pipeline should be designed in such a way that they cannot snag fishing nets and gear. A complete filling of the annulus should be ensured.	Pre-production tests are required for infill. Min. temp. of marine mastic is approx. 170°C. Max. temp. of marine mastic on Servi-Wrap tape is 190°C.
	Care should be taken to avoid damage to the field joint corrosion coating (cf. Section 9.3.3). The temperature of hot mastic is particularly critical.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	<u>10.5 RISER PROTECTION</u> Risers should be protected from damage due to vessel impact. Outside risers may be protected by the following means: - Riser guards - Casing pipes. Riser guards and supports for riser casings are designed together with the corresponding platform structure. Reference is made to Section 6.4.3 concerning the resistance of casing pipe.	

Preliminary List of Proposed Appendices

301 Calculation of failure probability due to ship anchoring and grounding

302 Calculation of failure probability due to explosions

303 Calculation of failure probability due to inherent defects

501 DtH leaflet on Airy theory & DHI Beaufort Scale equivalence guide

502 Guidance on appropriate wave energy spectra

701 Liquefaction analysis

702 Static 3D horizontal stability analysis

DANSK VANDBYGNINGSTEKNISK SELSKAB
DANISH SOCIETY OF HYDRAULIC ENGINEERING
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Denmark

1985-11-26
HG/at

Re.: Seminar on Danish Submarine Pipeline Guidelines

Enclosed we hereby forward:

./. - Minutes of seminar.
./. - Letter from Mærsk Oil & Gas
./. - Feedback from Bergsøe Anti Corrosion on cathodic protection.
./. - List of participant on seminar.

Yours sincerely,

Helge Gravesen

Helge Gravesen

Encl.

Comments and Discussion During the Seminar 19. September.

1. General Comments

The guidelines should in phase 2 be developed also to cover the point of view of the owner of the pipelines and the authorities.
The formal status of the guidelines should be clarified and eventually changed to "Proposal for a Danish Marine Pipeline Design Practice" or "Danish Handbook of Marine Pipeline Design".

It should be mentioned that the guidelines correspond to design in accordance with ASME Guide plus Danish supplement plus ad hoc agreements with authorities obtained during the design and construction of Danish transmission and interfield pipelines. However, operational experiences of design has not been incorporated into the guidelines.

Desirable with list of codes and standards referred to.

Proposal for QA system to be mentioned more precisely.

The requirement should be established for independent check on all aspects of design (independent of both operator and designer).

The term 'submarine pipeline system'should be defined (e.g. is riser included, and to what point of deck piping). This point has caused difficulty in British sector.

Future editions shall consider Trenching, Backfilling and Self-burial.

2. Pipeline Process

The set pressure should be close to design pressure and systems should include indicators to counter for minimum regulating range e.g. safety valve/pressure increase protection. Slug catcher sizing to be included.

Maximum and minimum velocities (table 4.1) should distinguish between gas and liquid lines and between trunklines and interfield lines. The table covers trunklines with long design life. Fig. 4.10 could be misleading. It is proposed to review experienced conductivities from North Sea soils. Leak detection systems should also be auditive.

3. External Environment

Discussion on sedimentation/erosion is missing. Trenching in conditions like Storebaelt should be discussed. Discussions on utilization of different surveys to be included. Qualified interpretation of f.ex. sub-bottom and side scan surveys is vital. How to combine different surveys?
Interaction wave and current to be discussed.
Table 4.5 should be extended and discussed.
5.2.4 is incomplete (liquefaction, large stones)
5.2.7 different frequencies are required for soft and hard soil conditions.
Requirement to opening angle for echosounder to be given.
5.4.1 Typing error: Dynamic longitudinal friction may be taken as twice the coefficient of static friction.

4. Safety

Requirements for sub-sea valve should be related to consequences of leak/rupture. The requirement for the sub-sea

valve station in the Danish Transmission gas line was highly related to the sour (poisonous) contents of the gas. The discussion on specific valve system is too specific.
The risk level should distinguish between failure (small leak) and rupture. A valve is a complication to the system which by itself may induce extra risk for failure, e.g. due to anchor damage on valve. Discussion on risk safety should be consistent with requirements for riser protection in section 10.
It should be discussed if statistics of failures in Mexican Gulf may be applied for North Sea conditions.

Failure data may not be representative for modern design. Thus high P_F for oil land pipelines due to corrosion (Table 3.5) might be due to lack of cathodic protection.

The consequences of failures are too conservatively estimated, e.g. ineviatbility of ignition of escaping gas (3.2.1). Discussion of leak detection requirements should be evaluated (accuracy of leak detection system, different in gas and liquid lines, influence on operation).

5. Structural Design

Usual to use outer diameter in hoop stress analysis. 75% SMYS criteria for longitudinal stress should be included. Negative wall tolerance should distinguish between general plate under-thickness and local under-thickness. Defect criteria (2 mm) too general. Direct reference to D.O.N.G. project f. example page 81 should be left out. Flow Chart p. 73 shows that installation may require extra wall thickness. This should not be the case for lay stress criteria. Distinguish between deformation controlled load (strain criteria) and force controlled load (stress criteria). This distinction corresponds to proposal for DS320. Expansion is deformation controlled.

Different oppinion if rupture for hot restained pipeline occur for combined stress load equal to von Mises criteria or if rupture only occurs after yielding due to internal pressure, (so rupture hoop strees is equal to yield stress). This needs clarification.
Criteria for installation should relate to how accurately possible damages (denting, flattening, buckling, fatigue, overstraining) during installation could be identified.

Expansion offset is deformation controlled (strain criteria). Risers are both force controlled (upper part) and deformation controlled (lower part).

Upheaval should be itemised as a possible mode of failure for trenched/covered pipelines.

It was discussed if upheaval buckling could be allowed if no critical spans and if risk of damages due to fishing gear was small.

The discussion of buckling phenomena requires expansion to include upheaval buckling which is a consequence of lateral restraint (e.g. for trenched or covered pipelines).

Lateral snaking may be analysed by assuming a sinusoidal laying pattern, and considering lateral equilibrium.

Free span vortex induced vibration should be specified as a problem area to be checked.

Where possible complete riser/expansion loop/pipeline interaction should be modelled for analysis, including soil contact and sliding, and platform imposed deplacements.

Proposal to new DS 320 replaces class change by increased welding check.

P. 81 comment on 3-4 mm crack should be deleted as it is too general.

Improved detection of buckling should be specified (better buckling detector during laying, caliper surveys, utilization of cathodic potential survey to detect damages during trenching).

P 98 Formula for column force to be checked.

6. Stability

The case vertical stability of laid pipe (before trenching) should be included.
Dynamic analysis should include change in load coefficient during the wave cycle, which increases the forces during the second half cycle of the waves in combined waves/current load situation. The Ghazzaly method should be improved. The shear strength of soft soil is time dependent and should relate to the critical depth (not to shear strength above the pipeline). Experienced values should be mentioned for typical North Sea soft clay.

The wide range in estimates of required submerged weight could be due to increased short term resistance for low permeable soils (clay) and to combined scour/self-burial for friction type soils more than to details in hydrodynamic loads.

7. Material requirements and fabrication

Phase 2 should improve material criteria to higher level than criteria in DnV rules improved on carbon equivalent and on ductile fracture. The section should be more specific and not relate to a general statement on requirements to specification.
100% SMYS mill testing is a too general requirement.

Requirements to flexible pipes are missing, but to day there exist no guidelines for these pipes.
Hardness criteria could be increased (to 280 HV5) for sweet gas service.
Elongation criterion for cost and forged steels should be reconsidered.

8. Corrosion protection

The requirement to anode fabrication (cracks, contents of Al in Zn anodes and of Fe in Al anodes) should be revaluated because rigid criteria may give rise to extra costs when the criteria do not correspond to standard production of Zn and Al.
Requirements to coatings should, if possible be given as performance criteria. It would be desirable to distinguish between corrosion coating alone and corrosion coating in combination with weight coating.

MÆRSK

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RAMBØLL & HANNEMANN A/S
Teknikerbyen 38
2830 Virum

Attn.: Helge Gravesen

21 November 1985
SM-06-019
049/RT/cst

Dear Sir

Subject: Comments to "Danish Submarine Pipeline Guidelines"
First Draft July 1985.

The following comments relate to the above document which was initially issued to Mærsk Olie og Gas A/S August 1985 for review and further discussed during a seminar held at Danmarks Tekniske Højskole September 1985.

1. The document is of a general nature covering the management, design, fabrication, and installation aspects of Danish Submarine Pipelines and as such provides a useful overview of existing codes and standards and recent pipeline design work carried out by D.H.I. and R.& H. Recognising that the document is not intended to be a code or standard to be adopted for the complete spectrum of design, manufacture and construction we recommend that the title be ammended to "Engineering Handbook for Danish Submarine Pipelines".

2. Section 4

   It is relevant to have a pipeline process chapter included in the guideline but the content should be brought up to current industry standard practice.

3. Section 6.7.5, paras 1 and 2

   You state that a combination of lowering and bridging (asphalt mattresses) is unacceptable at pipeline crossing locations. We have previously utilized this technique and have additionally dumped rock over the upper pipeline and consider the results to be acceptable.

.../2

In light of recent scour problems encountered with prefabricated tubular frames in the Danish sector we consider it inappropriate to recommend this solution for pipeline crossings.

4. <u>Section 10.2, paras 3 and 4</u>

Clarification of Danish Authorities lowering requirements should be included.

5. <u>Section 10.3.2, last para</u>

If welded wire mesh is used as supplementary reinforcement care should be taken to ensure that all reinforcement (rebar and mesh) is compatable to avoid possible galvanic corrosion.

Yours faithfully
for MÆRSK OLIE OG GAS A/S

Bent Lyngberg

Bent Lyngberg

Bergsøe Anti Corrosion

BAC

Rambøll & Hannemann,
Rådgivende Ingeniører A/S,
Teknikerbyen 3,
2830 Virum.

1985-10-08
HB/lk 57

Att.: Ingeniør Helge Gravesen.

Re: Industry Feedback on Danish Submarine Pipeline Guidelines, First draft, July 1985.

Dear Sir.

We, Bergsøe Anti Corrosion, take the opportunity to comment and forward suggestions on your DSPG as requisted in point 1.8 of the DSPG.

We have suggestions on two subjects in part 9.4 "Cathodic protection", and we have taken the liberty of reediting the points in question, namely:

1. Point 9.4.5. "Environmental conditions" should be a little extended as per proposed test inclosed.

2. Point 9.4.8. "Anode Fabrication and Installation" should be extended to allow a more diversified selection of anode alloys together with recommendations on reinforcement design and a recommended standard of acceptance as per proposed text enclose

We trust that our proposals are of value to you and are at your service on any question you may have regarding cathocic protection.

Yours sincerely
BERGSØE ANTI CORROSION

Henrik Blomdahl
Manager offshore, div.

Enclosures: Six (6) text pages.

cc The Editor Submarine Pipeline Guidelines,
Danish Hydraulic Institute,
Agern Alle 5, 2970 Hørsholm.

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PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.4.5. Environmental Conditions The following parameters should be taken into account in the design: - Operating temperature - Ambient temperature - Chemical composition and oxygen content of environment - Resistivity of environment - Biological activity of environment - Current velocity of seawater. The specific resistance of North Sea seawater may be taken as 33 Ohm cm. For open Danish internal waters the specific resistance may be taken as 50 Ohm cm and 90-100 Ohm cm may be taken for seawater in Danish part of the Baltic Sea. In North Sea seabed sediment the specific resistance may be assumed, Mud : 60-75 Ohm cm Clay : 75-110 Ohm cm Sand : 110-160 Ohm cm if no measurements are carried out. Free flowing seawater and seabeds consisting of sand or clay may be consideres as aerated, whereas muddy sediments shall be considered as anaerobic, particularly in the presence of organic matter with sulphate reducing bacterial activity.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.4.8. Anode Fabrication and Installation **9.4.8.1. Anode Fabrication** Sacrificial anodes for marine pipelines are normally made from zinc or aluminium alloys. The corresponding potentials in seawater may be assumed to be -1.03 V (vs. Ag/AgCl) and -1.00V (vs. Ag/AgCl), respectively. Zinc anode alloy should as minimum confirm to the composition stated in U.S. Mil-A-18001 H norm which is: Al: 0.10-0.50% Cd: 0.025-0.15% Fe: 0.005% max. Cu: 0.005% max. Pb: 0.006% max. Si: 0.125% max. Zn: remainder For good castability the following zinc alloy composition is recommended: Al: 0.15-0.30% Cd: 0.04-0.06% Fe: 0.002% max. Sn: 0.001% max. Cu: 0.001% max. Pb: 0.004% max. Si: 0.001% max. Zn: remainder Zinc anode alloys are susceptible to intergranular corrosion at elevated temperatures, and should not be used at temperatures exceeding 50°C. Unless the anode is mounted outside a layer of pipeline insulation. Temperature for zinc bracelet anodes mounted on pipe corrosion coat should be assumed to be 2°C lower than the pipeline product. To reduce susceptibility to intergranular corrosion at temperatures above 35°C, the following zinc anode alloy composition is recommended.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Aluminium : 0.10% - 0.20% Cadmium : 0.03 - 0.06% Iron : 0.002% max. Copper : 0.005% max. Lead : 0.006% max. Silicon : 0.125% max. Zinc : remainder Aluminium anode alloys have a tendency to passivate in seabed sediment, a problem which is alleviated by indium activation. The following aluminium alloy is recommended: Indium : 0.005% - 0.05% Zinc : 2% - 6% Iron : 0.13% max. Copper : 0.01% max. Silicon : 0.2 % max. Aluminium : remainder Other aluminium anode alloy compositions can be used provided sufficient potential and capacity can be documented. The anode comsumption rate is the reciprocal of the faradaic capacity, which decreases with temperature for zinc as well as for aluminium. At ambient temperature capacities of 750 Ahr/kg and 2200 Ahr/kg may be assumed for zinc and aluminium, respectively. The anodes should be provided with adequate reinforcement, and electrical and mechanical bond between reinforcement and anode alloy should be ensured. The reinforcements for bracelet anodes should be designed to shipment and hold anodic material during the design lifetime of the bracelet. The reinforcement should be designed to allow cracks in any direction in the anodic material with dimensions descriped in 9.4.8.2. recommended standard of acceptance criteria. The reinforcement should be designed from flat-bar and/or circular section steel. The anodic material should not be considered as a structural member of the anode. Bracelet anodes should be cast to meet nett weight requirement and not to mould volume.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
Standard of acceptance criteria should generally follow the requirements of CCEJV/NACE: Draft Code of Practice: "Metallurgical and inspection requirements of sacrificial anodes for Northern European offshore applications". Dec. 1983 issue.	9.4.8.2. Recommended standard of acceptance criteria 9.4.8.2.1. <u>Chemical analysis</u> Each furnace melt or charge should be sampled at beginning and end of casting from the melt. The samples should be subject to analysis to prove compliance with the chemical composition limits of the alloy selected. 9.4.8.2.2. <u>Anode weight</u> Bracelet anodes should be cast to meet nett weight requirement and not mould to volume. Individual anodes of each type should be within +/- 3% of nominal nett weight, total contract weight should be -0%, +2% of nominal contract weight. 9.4.8.2.3. <u>Anode dimensions</u> Anode mean length should be +/- 3% of nominal or +/- 25 mm whichever is the more stringent. Bracelet anode innerdiameter tolerance should be -0/+5 mm. Bracelet anode wallthickness tolerance should be +/-4 mm. The straightness of the anode should be a maximum deviation of 2% of the anode nominal length from the longitudinal axis of the anode. 9.4.8.2.4. <u>Reinforcement position</u> Anode reinforcement location within the anodes should be within +/- 5% of the nominal position in anode width and length, and within 10% of the nominal position in anode depth. For bracelet reinforcements intentionaly close to innerdiameter surface should be minimum 5 mm embedded in anodic material.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
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PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	9.4.8.2.5. <u>Surface irregularities on the Anode Casting</u> Shrinkage depressions shall not exceed 10% of the nominal depth of the anode as measured from the uppermost corner to the bottom of the depression. For bracelets shrinkage depressions shall not exceed 1/3 of the wall thickness for half shell type bracelets or 20 mm, whichever is the less. Casting surface irregularities shall be fully bonded to the bulk anodic material. Not more than 1% of the total surface of the anode casting shall be contaminated with non-metallic inclusions visible to the naked eye. Cold shuts or surface laps shall not exceed a depth of 10 mm or extend over a total length of more than 3 times the width of the anode. On bracelets, where proper designed reinforcement steel intentionally is close to innerdiameter surface, cold shuts or surface Laps shall not exceed the depth to the reinforcement steel and not extend more than 1,1 time the width of the reinforcement steel member exposing max. 5% of the reinforcement steel member surface. All protrusions detrimental to the safety of personnel during handling shall be removed. Reduction in cross-section of anodic material adjacent to the emergence of reinforcements shall not exceed 10% of the nominal anode cross-section. 9.4.8.2.6. <u>Cracks in cast anodic material</u> Even with a good foundry practice particular compositions of anode alloy suffer a degree of cracking.	

PROCEDURES ADOPTED IN DANISH/NORDIC PROJECTS	GUIDELINE RECOMMENDATION	DISCUSSION FURTHER STUDIES ETC.
	Within the section of sacrificial anodic material, wholly supported by the reinforcement, transverse cracks are permitted with a maximum width of 5mm and unlimited length and depth, and a maximum of 10 cracks per anode. Small close cracks shall be taken as one crack. Cracks with maximum 0.5 mm width shall be ignored. Longitudinal cracks on the external active anode surface shall not be permitted, except for bracelets with proper reinforcement design and in final "topping up" metal. Anodic material shall not be considered as a structural member of the anode. 9.4.8.2.7. <u>Anode internal defects</u> For bracelet anodes with proper reinforcement design and cast to nett weight requirement, voids gas holes/pockets are insignificant. The sum of reinforcement area in contact with voids, gasholes/pocket should not exceed 5% of the total cast in reinforcement area. 9.4.8.3. <u>Installation</u> The anodes should be mounted securely on the pipe, and protected against mechanical damage during handling and installation. Each bracelet anode should normally be connected to the pipe by two attachments made by manuel welding, thermite welding or other qualified technology. The minimum distance between each attachment to the pipe and other welds should be 150 mm. Manual welds for electrical connections should be made on doubler plates welded directly onto the pipeline by a qualified welding procedure. Thermite welding should be performed according to a qualified procedure. A minimum of three test welds should be examined for bond, copper penetration and hardness. The maximum allowable copper penetration is 0.8 mm and 0.3 mm for pipelines and risers, respectively. The hardnesses should be within the limits specified for the pipeline system. The spacing between anodes should be sufficiently close to secure protection, and normally no more than 120 m.	

Tilmelding til VBS's seminar om DANSK MANUAL FOR SØLEDNINGER den 19. september 1985.

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