RECOMMENDED PRACTICE
DNV-RP-J202

DESIGN AND OPERATION OF CO_2 PIPELINES

APRIL 2010

DET NORSKE VERITAS

FOREWORD

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Amendments and Corrections

This document is valid until superseded by a new revision. Minor amendments and corrections will be published in a separate document normally updated twice per year (April and October).

For a complete listing of the changes, see the “Amendments and Corrections” document located at:
http://webshop.dnv.com/global/, under category “Offshore Codes”.

The electronic web-versions of the DNV Offshore Codes will be regularly updated to include these amendments and corrections.

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INTRODUCTION

— Background

The implementation of Carbon dioxide Capture and Storage (CCS) will require very large quantities of high concentration CO_2 to be transported from point of capture to point of injection into geological repository. Pipelines are seen as the primary transportation means of CO_2 in the context of CCS. There is limited experience worldwide in pipeline transportation of CO_2 in its liquid and/or supercritical phase (i.e. collectively termed "dense phase") in the scale that will be required for CCS.

This Recommended Practice (RP) has been developed in order to address the need for guidance for how to manage risks and uncertainties specifically related to transportation of CO_2 in pipelines.

This document provides guidance and sets out criteria for the concept development, design, construction and operation of steel pipelines for the transportation of CO_2. It is written to be a supplement to existing pipeline standards and is applicable to both onshore and offshore pipelines. The RP is intended to assist in delivering pipelines in compliance with international laws and regulations. The pipeline operator will also have to ensure that the project is in compliance with local laws and regulations.

— Acknowledgment

The development of the this RP was organized as a joint industry project and the partners are acknowledged with their support and for bringing necessary best available knowhow into the development of the document:

- ArcelorMittal
- BG Group
- BP
- Dong Energy
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- Gassnova
- ILF
- Petrobras
- Shell
- Statoil
- Vattenfall
- Chevron.

A special acknowledgement to representatives from Health and Safety Executive in the UK, the State Supervision of Mines in the Netherlands, and the Petroleum Safety Authority in Norway as observers in this JIP and to SINTEF, IFE and Polytec for carrying out technical studies as inputting to this document.

CONTENTS

1. General

1.1 Background

CO_2 Capture and Storage (CCS) has been identified as a key abatement technology for achieving a significant reduction in CO_2 emissions to the atmosphere. Pipelines are likely to be the primary means of transporting CO_2 from point-of-capture to sites (e.g. underground reservoirs) where it will be stored permanently to avoid its release to the atmosphere. While there is a current perception that transporting CO_2 via pipelines does not represent a significant barrier to implementing large-scale CCS, there is significantly less industry experience than for hydrocarbon (e.g. natural gas) service and there is a number of issues that needs to be adequately understood and the associated risks effectively managed.

Today, CO_2 is mainly transported in pipelines for industrial purposes. The majority of CO_2 pipelines are found in North America, where there is over 30 years of experience in transporting CO_2, mainly from natural deposits and gas processing plants for enhanced oil recovery (EOR). The only existing offshore pipeline for transporting CO_2 is the Snøhvit pipeline, which has been transporting CO_2 (obtained from natural gas extraction) through a 153 km seabed pipeline from Hammerfest in north Norway back to the Snøhvit field under the Barents Sea, since May 2008.

In a CCS context, there will be need for larger pipeline networks in more densely populated areas and with CO_2 coming from multiple anthropogenic sources. Also, offshore pipelines for transport of CO_2 to offshore reservoirs are likely to become common.

1.2 Objective

The objective of this Recommended Practise (RP) is to provide guidance on safe and reliable design, construction and operation of pipelines intended for large scale transportation of CO_2 to meet the requirements given in the referenced pipeline standards, ref. Sec.1.7.1.

1.3 Application

This document applies to:

- Rigid metallic pipelines
- Pipeline networks
- New onshore and offshore pipelines for transportation of fluids containing overwhelmingly CO_2
- Conversion of existing pipelines for transportation of fluids containing overwhelmingly CO_2
- Pipeline transportation of
  - anthropogenic CO_2 in the context of CCS
  - anthropogenic CO_2 in the context of combined CCS and EOR
  - CO_2 captured from hydrocarbon stream
  - CO_2 from natural (geological) sources for the purpose of EOR
  - other sources for large scale transportation of CO_2
- Pipelines as defined in the referenced standards, see Sec.1.7.1
- Transport of CO_2 in gaseous-, liquid and super critical phases
- Extent of pipeline system as described in Sec.1.8.27.

Guidance note:

In this document, the term 'overwhelmingly CO_2' refers to definitions given in the London Convention, the OSPAR convention and the EU CCS Directive. The actual percentage of CO_2 and other components present in the CO_2 stream shall be determined based upon technological and economical evaluations, and appropriate regulations governing the capture, transport and storage elements of a CCS project.

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Guidance note:

This document does not address how to secure public awareness and acceptance on a local/national level. This is, however, an important issue that needs to be managed carefully as an integral part of the pipeline development.

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1.4 Structure of this Recommended Practice

1 General

Contains the objectives and scope of the RP, and gives reference to Codes and Standards. It further introduces essential concepts, definitions and abbreviations.

2 Specific properties of CO_2

Provides an introduction to the fundamental properties of CO_2 and CO_2 stream composition relevant in the context of CCS.

3 Safety Philosophy

Provides recommendations and guidance on safety aspects of transportation of CO_2 in pipelines relevant in the context of CCS.

4 Concept development and design premises

Provides general recommendations and guidance on how to solve design issues specifically related to pipelines intended for transportation of CO_2.

5 Materials and pipeline design

Provides recommendations and guidance on how to solve materials and pipeline design issues related to pipelines intended for transportation of CO_2.

6 Construction

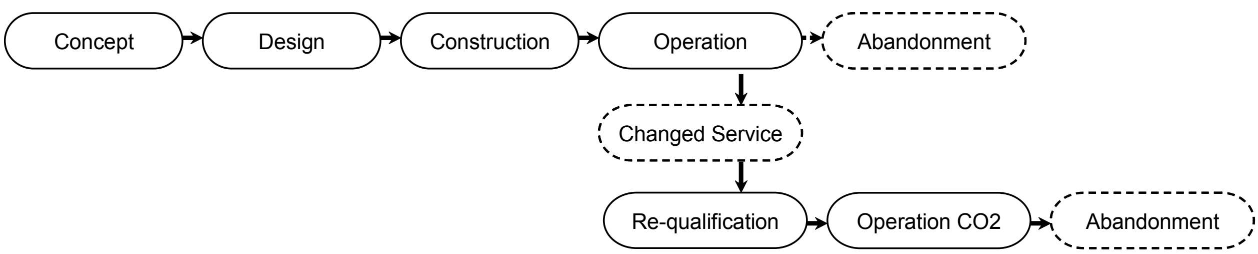
Provides recommendations and guidance for the construction phase of pipelines intended for transportation of CO_2.

7 Operation

Provides recommendations and guidance for commissioning, operation and integrity management of a pipeline specifically intended for transportation of CO_2.

8 Re-qualification of existing pipelines to CO_2 pipelines

Provides general guidance on how existing pipelines used for other purposes than transporting CO_2 can be re-qualified for the purpose of transporting CO_2.



1.5 Users of this Recommended Practice

Users of this RP are typically:

— CCS project developers
— Pipeline engineering and construction companies
— Pipeline operating companies
— Authorities
— Certification companies.

1.6 How to use this document

The recommendations given in this RP are restricted by the application areas stated in Sec.1.3.

The recommendations stated in this RP apply as a supplement to both offshore and onshore pipelines unless otherwise stated.

1.7 References

1.7.1 Reference to standards

Recommendations provided in this RP refer to, but are not limited to, the following pipeline standards:

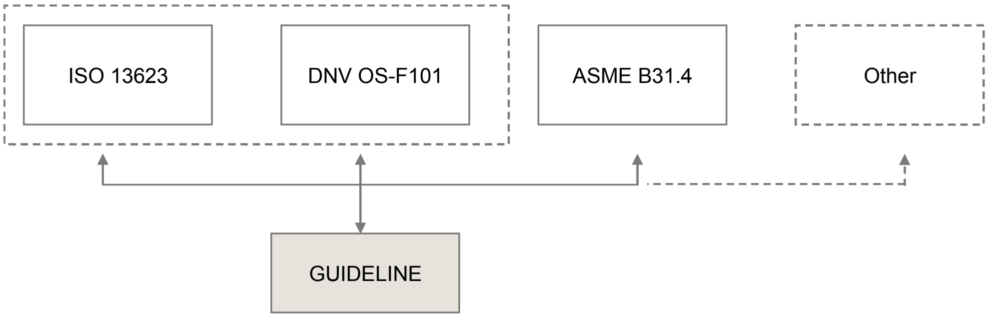


Figure 1-1
Reference to pipeline standards

ISO 13623	Petroleum and Natural Gas industries – Pipeline Transportation Systems, 2nd Ed. 15.06.2009
DNV-OS-F101	Submarine Pipeline Systems, Oct. 2007
ASME B31.4	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids, 2006

1.7.2 Cross references to pipeline standards

Section	*ISO 13623*	*DNV – OS - F101*	*ASME B31.4*
3 Safety Philosophy	Annex A Safety evaluation of pipelines	Sec.2 B 300 Systematic review of risks	
3.2.2 Categorization of CO_2	Sec.5.2 Categorization of fluids	Sec.2 C 200 Categorization of fluids	
3.2.3 Location classes	Annex B.2 Location Classes	Sec.2C 300	
4 Concept development and design premises		Sec.3 A200 Concept development	
4.3.2 Pressure control and overpressure protection system	Sec.5.4 Pressure control and overpressure protection	Sec.3 B 300	
4.5.3 Pipeline transport design capacity	Sec.5.3 Hydraulic analysis	Sec.3 B400	
4.7 Pipeline routing	Annex C Pipeline Route Selection Process	Sec.3 C	
4.7.2 Population density	Annex B.2 Location classification Annex B.3 Population density	Sec.2 C 300 Location Classes	
5 Materials and pipeline design	Sec.8 Materials and Coatings Sec.10 Construction	Sec.7 Construction - Linepipe Sec.8 Construction – Components and Assemblies Sec.9 Construction – Corrosion Protection and Weight Coating Sec.10 Construction - Installation	
5.1.6 Internal corrosion allowance		Sec.6 B200	
5.3.3 External coating	Sec.9.5.2 External coatings	Sec.8 C Pipeline external coatings	
5.5 Running ductile fracture control	Sec.8.1.6 Shear Fracture Toughness	Sec.7 I 200 Supplementary requirement, fracture arrest properties	Sec.402.5 (Specific for CO_2 pipelines)
6.2.2 Pressure testing	Sec.6.7 Pressure test requirements Sec.11 Testing	Sec.7E Hydrostatic testing and Sec.5 B200 Sec.10 O 100 Final testing and preparation for operation	
6.2.3 Dewatering and drying	Sec.12.3 Drying procedures	Sec.10 O 600 De-watering and drying	
7.5.2 Emergency response plan and procedures	Annex E.3 Emergency Procedures	Sec.12 B 500	

1.7.3 Other References, Codes and Standards

The latest revision of the following documents applies:

API 1160	Managing System Integrity for Hazardous Liquid Pipelines
ASME B31.8	Gas Transmission and Distribution Systems
ASME B31.8S	Managing System Integrity of Gas Pipelines
CSA Z662-07	Oil and Gas Pipeline Systems. Canadian Standard Association
DNV-RP-A203	Qualification Procedures for New Technology
DNV-RP-C203	Fatigue Strength Analysis of Offshore Steel Structures
DNV-RP-F107	Risk Assessment of Pipeline Protection
DNV-RP-F116	Integrity Management of Submarine Pipeline Systems
ISO 3183	Petroleum and natural gas industries – Steel pipe for pipeline transportation systems
ISO 15156	Petroleum and natural gas industries – materials for use in H_2S containing environments in oil and gas production – general principle for selection of cracking resistant materials
ISO 16708	Petroleum and natural gas industries – Pipeline transportation systems – Reliability-based limit state methods
ISO 17776	Petroleum and natural gas industries - Offshore production installations - Guidelines on tools and techniques for hazard identification and risk assessment
ISO 31000	Risk management -Principles and guidelines
IEC 61508	Functional Safety of electrical/electronic/programmable electronic safety-related systems
IEC 61511	Functional safety - Safety instrumented systems for the process industry sector
NACE TM0192-2003	Evaluating Electrometric Materials in Carbon Dioxide Decompression Environments
NACE TM 0297-2002	Effects of High-Temperature, High-Pressure Carbon Dioxide Decompression in Electrometric Materials
NORSOK Z-013	Risk and emergency preparedness analysis
PHMSA	Pipeline and Hazardous Materials Safety Administration. Pipeline Safety Regulations PART 195

1.7.4 Other References

/1/ "Carbon Dioxide Capture and Storage", prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, 2005

/2/ Interim guidance on conveying CO_2 in pipelines in connection with carbon capture, storage and sequestration projects, UK Health and Safety Executive, Hazardous Installations Directorate, 12 Aug. 2008, UK HSE Interim Guidance

/3/ Assessment of the Dangerous Toxic Load (DTL) for Specified Level of Toxicity (SLOT) and Significant Likelihood of Death (SLOD), Health & Safety Executive (HSE)

/4/ M. Mohitpour H. Golshan Q. Murray Pipeline Design & Construction; A Practical Approach. ASME Press.

/5/ A. Cosham, R. Eiber. Fracture control in CO_2 pipelines. Proceedings of the 2007 Transmission of CO_2, H_2, and biogas conference, Amsterdam, Netherlands

/6/ A. Cosham, R. Eiber. Fracture control in carbon dioxide pipelines – the effect of impurities. Proceedings of IPC2008, 7th International Pipeline Conference, September 29-October 3, 2008, Calgary, Alberta, Canada

/7/ P. Seevam, P. Hopkins, Transporting the Next generation of CO_2 for Carbon, Capture and Storage: The impact of Impurities on Supercritical CO_2 pipelines. IPC2008-64063

/8/ B. Weller A. Parvez, J. Conley, E. Slingerland, The use of reinforced thermoplastic pipe in CO_2 flood enhanced oil recovery.

/9/ Thermodynamic models for calculating mutual solubility in H_2O–CO_2–CH_4 mixtures. Chemical Engineering Research and Design (ChERD), Part A 2005. (Special Issue: Carbon Capture and Storage 84 (A9) (September 2006) 781–794)

/10/ M. F. Fingas. The Handbook of Hazardous Materials Spill Technology. McGraw-Hill Professional, 2001, ISBN 007135171X, 9780071351713

/11/ Metz, B., Davidson, O., de Coninck, H. C., Loos, M., and Meyer, L. A. (eds.), IPCC, 2005: *IPCC Special Report on Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA

/12/ E. de. Visser et. al. DYNAMIS CO_2 quality recommendations. International Journal of Greenhouse Gas Control. 2008

/13/ Jinying Yan et.al. Impacts of Non-condensable Components on CO_2 Compression/Purification, Pipeline Transport and Geological Storage

/14/ U.S. Environmental Protection Agency, *Carbon Dioxide as a Fire Suppressant: Examining the Risks*, February 2000 (http://www.epa.gov/Ozone/snap/fire/co2/co2report.pdf)

/15/ http://www.hse.gov.uk/carboncapture/carbondioxide.htm

/16/ http://www.chemicalogic.com

/17/ DNV-PHAST. Process Hazard Analysis Software Tool. Commercially available through DNV.

/18/ Office of Pipeline Safety (OPS) within the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (http://ops.dot.gov/stats/IA98.htm)

/19/ European Gas Pipeline Incident Data Group (http://www.egig.nl/)

/20/ CONCAWE Oil Pipelines Management Group, *Performance of European Cross-Country Oil Pipelines, Statistical Summary of Reported Spillages in 2006 and Since 1971*, August 2008.

/21/ PARLOC 2001, *The Update of Loss of Containment Data for Offshore Pipelines*, July 2003

1.8 Definitions

1.8.1 Arrest pressure

Defined as internal pipeline pressure where there is not enough energy to drive a running ductile fracture.

1.8.2 Carbon dioxide (CO_2)

Defined as a non-polar chemical compound composed of two oxygen atoms covalently bonded to a single carbon atom (O=C=O).

1.8.3 Carbon dioxide stream

A CO_2 stream shall be understood as a stream consisting overwhelmingly of carbon dioxide with a limited fraction of other chemical substances. The actual percentage of CO_2 and other components present in the CO_2 stream shall be determined based upon technological and economical evaluations, and appropriate regulations governing the capture, transport and storage elements of a CCS project.

1.8.4 Commissioning

Activities associated with the initial filling of the pipeline system with the fluid to be transported, part of operational phase.

1.8.5 Corrosion allowance

Extra wall thickness added during design to compensate for any reduction in wall thickness by corrosion (internal/external) during operation.

1.8.6 CP system

Cathodic protection system designated for a pipeline. Cathodic protection is typically the secondary system for external corrosion protection with the primary system provided by external coating.

1.8.7 Critical point

Critical point is defined by the critical pressure and temperature of the fluid composition above which the substance exists as a supercritical fluid, where distinct liquid and gas phases do not exist.

1.8.8 Critical pressure

Defined as the vapour pressure at the critical temperature.

1.8.9 Critical temperature

Defined as the temperature above which liquid cannot be formed simply by increasing the pressure.

1.8.10 Dense phase

Collective term for CO_2 in its liquid or supercritical phases.

1.8.11 Design pressure

Maximum internal pressure during normal operation (see DNV-OS-F101 or ISO 13623 for further details).

1.8.12 Direct assessment

Defined as a structured process for pipeline operators to assess the integrity of pipelines.

1.8.13 Direct examination

Examination and inspection, usually by non-destructive testing, of the pipe wall at a specific location to determine whether metal loss or other degradation has occurred. Non-destructive testing may be performed using visual, magnetic, ultrasonic, radiographic, or other means.

1.8.14 Ductile running fracture

A running ductile fracture is defined as a pipeline rupture, extending more than one pipeline joint.

1.8.15 Elastomer

An elastomer is a polymer with the property of elasticity. The use of elastomers in relation to pipeline transport of CO_2 is limited to application as seals and gaskets. Elastomer materials are characterized by being soft, elastic and almost incompressible.

1.8.16 Flow coating

Internal coating to reduce internal roughness, hence reduce friction pressure loss.

1.8.17 Free water

Water not dissolved in the dense CO_2 phase, i.e. a separate phase containing water. This can be pure water, water with dissolved salts, water wet salts, water glycol mixtures or other mixtures containing water.

1.8.18 Hazard

A hazard is a physical situation with the potential to cause harm, such as injury or death to workers, damage to property or disruption of business or pollution of the environment.

1.8.19 Hypercapnia

Defined as a condition where there is too much CO_2 in the blood. A cause of hypercapnia is inhalation of environments containing abnormally high concentrations of CO_2.

1.8.20 Incidental pressure

Maximum internal pressure that the pipeline is designed to withstand during incidental operation.

1.8.21 In-line inspection

Defined as the inspection of a pipeline from the interior of the pipe using an ILI tool; the tools used to conduct ILI are known as pigs, smart pigs, or intelligent pigs.

1.8.22 Line packing

Accumulation of fluid stream in pipeline to compensate for dynamic output/input at the upstream or downstream battery limit of the pipeline.

1.8.23 Linepipe

Cylindrical section (pipe) used in a pipeline for transportation of fluids or gases.

1.8.24 Major Accident Hazard (MAH)

Major Accident Hazards (MAH) are generally considered to be those hazards that could pose significant harm to one or more of the following categories: a large number of people; the environment; a facility or infrastructure; or a company's reputation. They can be categorized as high consequence, low frequency events as opposed to occupation type hazards (e.g. slips, trips and falls) which are generally significantly lower consequence but more frequent events.

1.8.25 Non-condensable gases

Chemical compounds that are in vapour state at typical pipeline operating conditions.

1.8.26 Operator

The party ultimately responsible for the concept development, design, construction, and operation of the pipeline; the operator may change between phases.

1.8.27 Pipeline system and CO_2 pipeline system

Pipeline system:

Pipeline with compressor or pump stations, pressure control stations, flow control stations, metering, tankage, supervisory control and data acquisition system (SCADA), safety systems,

corrosion protection systems, and any other equipment, facility or building used in the transportation of fluids.

CO_2 pipeline system (onshore) extends to the first weld beyond:

— the last isolation valve downstream of the CO_2 capture plant or pump/compression station
— the isolation valve just upstream of the pump/compression station or sequestration site.

CO_2 pipeline system (offshore) extends to the first weld beyond:

— the first valve, flange or connection above water on platform or floater
— the connection point to the subsea installation (i.e. piping manifolds are not included)
— the first valve, flange, connection or insulation joint at a landfall unless otherwise specified by the on-shore legislation.

1.8.28 Population density

The population density defines the location class that is used in specification of design factors. It is defined as number of people per square kilometre /ISO 13623/.

1.8.29 Risk assessment

An overall methodology consisting of: identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident, likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved /API 1160/.

1.8.30 S-N curve

Graphical presentation of the dependence of fatigue life (N) on fatigue strength (S).

1.8.31 Supercritical phase

Supercritical phase is defined as the physical state of a fluid at pressure above critical pressure and temperature above critical temperature of the fluid.

1.8.32 Safety integrity level

Defined as a measurement of performance required for a Safety Instrumented Function / IEC 61508/.

1.8.33 Safety Instrumented Function

Safety function with a specified safety integrity level which is necessary to achieve functional safety /IEC 61511/.

1.8.34 Safety risk

Defined as risk of fatalities or adverse health effects for humans inside the influence zone of the pipeline.

1.8.35 Temperature, design, maximum:

The highest possible temperature profile to which the equipment or system may be exposed to during installation and operation.

1.8.36 Temperature, design, minimum:

The lowest possible temperature profile to which the component or system may be exposed to during installation and operation (this may be applied locally).

1.8.37 Threats

An indication of impending danger or harm to the pipeline system.

1.8.38 Triple point

Defined by the temperature and pressure at which three phases (gas, liquid, and solid) of a substance coexist in thermodynamic equilibrium.

1.9 Units

The current document applies SI units as default notation.

1.10 Abbreviations

API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
CCS	Carbon dioxide Capture and Storage
CFD	Computational Fluid Dynamics
CP	Cathodic Protection
CPM	Computational Pipeline Monitoring
CRA	Corrosion Resistant Alloys
CVN	Sharpy V-Notch
DA	Direct Assessment
DTL	Dangerous Toxic Load
DOT	Department of Transportation
EOR	Enhanced Oil Recovery
EOS	Equation of State
FEM	Finite Element Method
GHS	Global Harmonized System
HC	Hydrocarbon
HDPE	High Density Polyethylene
HSE	Health, Safety and Environment
HSE UK	Health and Safety Executive UK
IEA	International Energy Agency
IEA GHG	IEA Greenhouse Gas R&D Programme
ILI	In-Line Inspection
IMP	Integrity Management Plan/Process
IMS	Integrity Management System
$KMCO_2$	Kinder Morgan CO_2
LC_{50}	Median Lethal Concentration
MAH	Major Accident Hazards
NG	Natural Gas
OEL	Occupational Exposure Limits
PA	Arrest Pressure
PE	Poly Ethylene
PHMSA	Pipeline and Hazardous Materials Safety Administration
PR	Peng Robinson (Equation of State)
PS	Saturation Pressure
RP	Recommended Practice
SCADA	Supervisory Control And Data Acquisition
SI	International System of Units
SIL	Safety Integrity Level
SLOD	Significant Likelihood of Death
SLOT	Specified Level Of Toxicity
STEL	Short Term Exposure Limit
SMYS	Specified Minimum Yield Stress
TCM	Two Curve Method

2. Specific properties of CO_2

2.1 General

CO_2 is a non-polar chemical compound composed of two oxygen atoms covalently bonded to a single carbon atom (O=C=O). The molecule has a linear shape and zero dipole moment. At ambient pressure and temperature pure CO_2

appears as a colourless and at low concentration an odourless gas.

CO_2 occurs naturally in the earth's atmosphere at a concentration of typically 0.038% by volume and is naturally resolved in the oceans. High purity CO_2 also exists in geological formations.

This section presents and discusses specific properties and behaviour of CO_2 that is relevant for the design and operation of a CO_2 pipeline.

2.2 Physical properties of pure CO_2

Fundamental physical properties of pure CO_2 are listed in Table 2-1 with reference to the phase diagram given in Figure 2-1.

CO_2 has a molecular weight approximately 50% higher than air, i.e. at ambient condition the density of (gaseous) CO_2 will be higher than air, which has implications on how CO_2 disperses when released to the ambient.

At normal atmospheric pressure and temperature, the stable carbon dioxide phase is vapour.

Dense phase occurs in the phase diagram, ref. Figure 2-1, for pressure and temperature combinations above the vapour (gas) - liquid line and under the solid-liquid line. When the temperature is below the critical temperature it is common to say that the CO_2 is in the liquid dense phase and above in the supercritical phase.

For temperatures below the critical temperature, crossing the vapour-liquid line by reducing the pressure, results in a phase transition from liquid to gas with an accompanying step change in enthalpy and density. For the CO_2 to transform from liquid to gas, heat must be added in the same way as heat must be added to convert liquid water into steam.

Above the critical temperature there is no noticeable phase change, hence when the pressure is reduced from above to below the critical pressure, a smooth enthalpy change occurs from super critical fluid to gas. Pure CO_2 has a triple point at -56.6 ºC and 5.18 bar, which determines the point where CO_2 may co-exist in gas, liquid and solid state. At the right combination of pressure and temperature CO_2 may turn into the solid state commonly known as dry ice.

Guidance note:

A CO_2 pressure-enthalpy diagram provides insight to the phase changes, and is the most frequently used diagram for design purposes.

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Figure 2-2 shows the mass density of pure CO_2 as function of pipeline operating temperature and pressure. The step change in mass density from vapour to liquid state should be noted. In general the effect of temperature and pressure on mass density should be considered in optimization of pipeline transportation capacity. It should be noted that various types of other chemical components in the CO_2 stream may to various degree affect the mass density.

Supercritical CO_2 is a highly volatile fluid that will rapidly evaporate when depressurized to ambient conditions.

Table 2-1 Selected physical properties of pure CO_2

Property	*Unit*	*Value*
Molecular Weight	g/mol	44.01
Critical Pressure	bar	73.8
Critical Temperature	ºC	31.1
Triple point pressure	bar	5.18
Triple point temperature	ºC	-56.6
Aqueous solubility at 25˚C, 1 bar	g/L	1.45
Gas density at 0˚C, 1 bar	kg/m^3	1.98
Density at critical point	kg/m^3	467
Liquid density at 0˚C, 70 bar	kg/m^3	995
Sublimation temp, 1 bar	ºC	-79
Latent heat of vaporization (1 bar at sublimation temperature)	kJ/kg	571
Solid density at freezing point	kg/m^3	1562
Colour	-	None

Guidance note:

High pressure CO_2 when released to atmosphere will undergo a significant cooling due to expansion and potential inclusion of solid CO_2 particles at -79˚C. Where the temperature of a CO_2 release plume is below the dew point temperature of the atmosphere into which it is being released, the water vapour in the atmosphere will condense to form a cloud which will be visible to humans, making it difficult to distinguish CO_2 solids from condensed water within the cloud.

The size and visual opacity of a formed water vapour cloud will be determined by the temperature within the cloud (i.e. < dew point temperature) as well as the humidity level of the air.

A high pressure release of CO_2 which creates a release plume above the dew point temperature of the atmosphere into which it is being released will be invisible to the naked eye.

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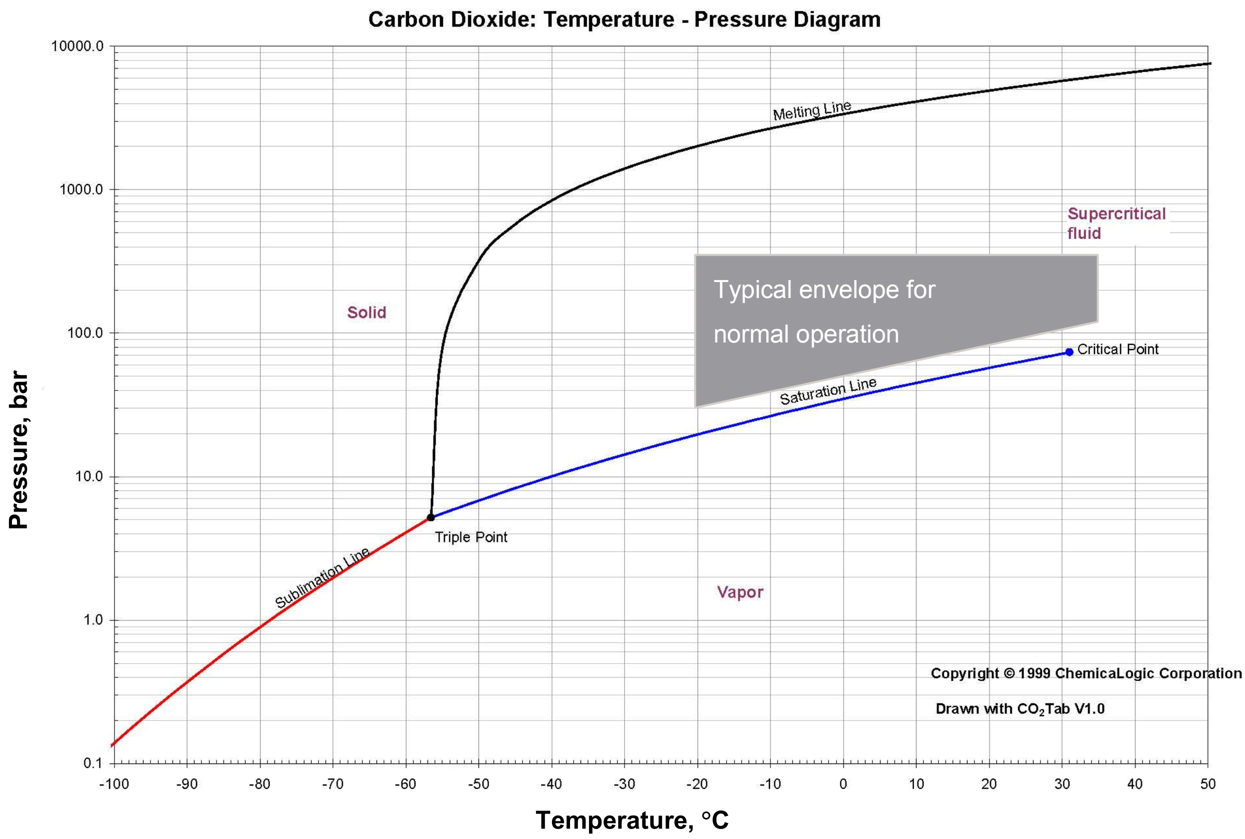

Figure 2-1
Phase diagram of pure CO_2 /16/

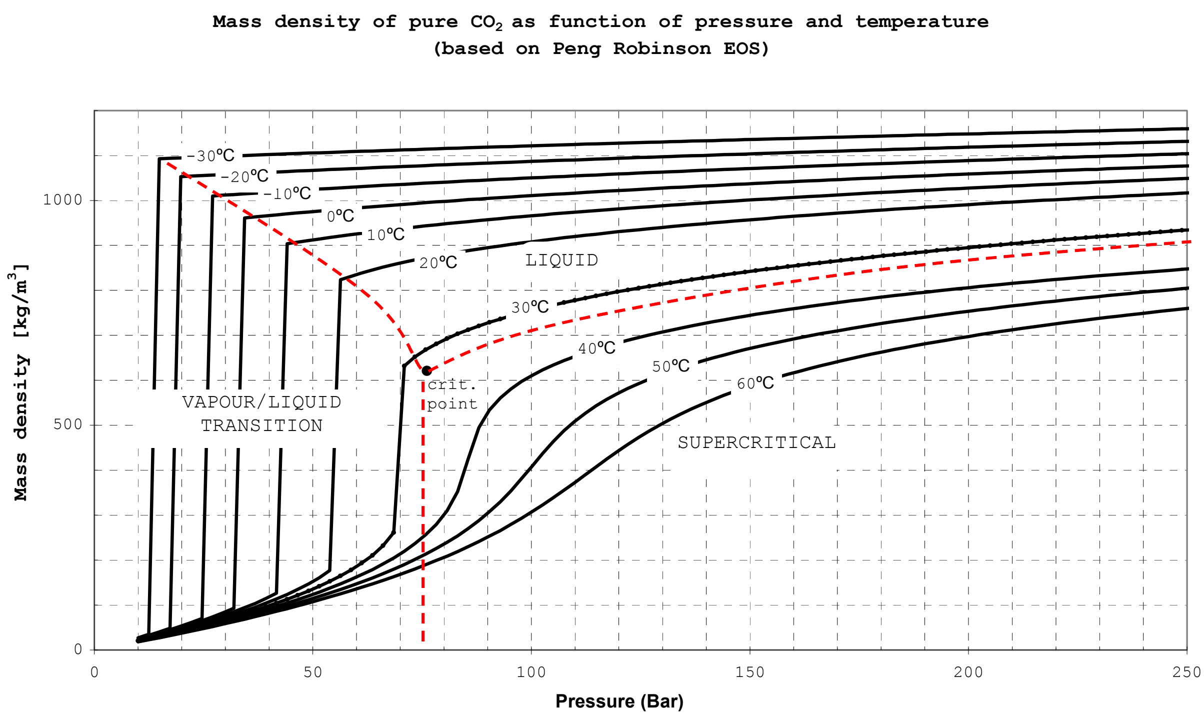

Figure 2-2
Mass density of pure CO_2 (PR EOS)

2.3 CO_2 stream composition

2.3.1 Implication of CO_2 composition on pipeline design and operation

Physical properties of a CO_2 stream defined by its individual chemical components may vary from the physical properties of pure CO_2 and will have implications on both pipeline design and operation.

The acceptable amount of other chemical components relates to techno-economic optimization not limited to the pipeline but including the facilities at the pipeline upstream and downstream battery limits.

The CO_2 composition will vary depending on the source:

— Captured from combustion/processing of fossil fuels.
— Generated from industrial processes.
— Extracted from high CO_2 containing HC streams.
— Explored from natural sources.

In the context of CCS, the CO_2 may come from large scale combustion of fossil fuels, typically gas, oil or coal fired power plants but also from industrial processes. The different techniques for capturing the CO_2 from combustion power plants are commonly characterized as pre-combustion, post-combustion or oxy-fuel processes. Further, CO_2 may be captured from a range of industrial processes (e.g. steel manufacturing, cement manufacturing refineries and chemical industries). These processes may generate different types and amounts of chemical components in the CO_2 flow, such as CH_4, H_2O, H_2S, SO_x, NO_x, N_2, O_2, Glycol and others, see Sec.2.3.2.

Table 2-2 provides an overview of the main identified issues associated with various components.

Table 2-2 Main issues related to various components in CO_2 streams

Component	*Properties*									*Comment*
	Health & Safety	Pipeline capacity	Water solubility	Hydrate formation	Materials	Fatigue	Fracture	Corrosion	Operations	
CO_2	•	•	•	•	•	•	•	•	•	Non-flammable, colourless, no odour at low concentrations, low toxicity, vapour heavier than air
H_2O				•	•	•	•	•	•	Non-toxic
N_2		•	•							Non-toxic
O_2			•					•		Non-toxic
H_2S	•	(•)			•	•	(•)	•		Flammable, strong odour, extremely toxic at low concentrations
H_2		•	•				•			Flammable, non-condensable at pipeline operating condition
SO_2	•		•					•		Non-flammable, strong odour
CO	•		•							Non-flammable, toxic
CH_4+		•	•						•	Odourless, flammable
Amines	•									Potential occupational hazard
Glycol	(•)							(•)		Potential occupational hazard
Ref. Sec.	3.3.3	4.5.3	2.3.5	4.5.11	5	5.6	5.5	5.1	7	

2.3.2 Indicative compositions from capture processes

The composition of the CO_2 stream will depend on the source and technology for capturing the CO_2. Indicative components, i.e. not exhaustive list, for CO_2 streams associated with types of power plants/ capture technologies are included in Table 2-3. Industrial capture plant compositions will differ from these, e.g. steel manufacturing, cement manufacturing, etc.

Composition limits require to be aligned throughout the CO_2 chain from capture through transport to storage.

Table 2-3 Indicative compositions of CO_2 streams /IEA GHG/. Unit % by volume

	Coal fired power plant			*Gas fired power plants*		
Component	Post-Combustion	Pre-combustion	Oxy-fuel	Post -combustion	Pre- combustion	Oxy-fuel
Ar/ N_2/ O_2	0.01	0.03-0.6	3.7	0.01	1.3	4.1
H_2S	0	0.01-0.6	0	0	<0.01	0
H_2	0	0.8-2.0	0	0	1	0
SO_2	<0.01	0	0.5	<0.01	0	<0.01
CO	0	0.03-0.4	0	0	0.04	0
NO	<0.01	0	0.01	<0.01	0	<0.01
CH_4+	0	0.01	0	0	2.0	0
Amines	-	-	-	-	-	-
Glycol	-	-	-	-	-	-

1) The SO_2 concentration for oxy-fuel and the maximum H_2S concentration for pre-combustion capture are for the cases where these chemical components are left in the CO_2 stream based on cost optimization of the capture process and compliance with local HSE and legal requirements. The concentrations shown in the table are based on use of coal with a sulphur content of 0.86%. The concentrations would be directly proportional to the fuel sulphur content.

2) The oxy-fuel case includes cryogenic purification of the CO_2 to separate some of the N_2, Ar, O_2 and NO_x. Removal of this unit would increase impurity concentrations but reduce costs.
3) For all technologies, the impurity concentrations shown in the table could be reduced at a higher capture costs.

2.3.3 Physical properties

Physical properties of a CO_2 stream defined by its individual chemical compounds may vary from the physical properties of pure CO_2 in terms of but not limited to:

— Toxicity
— Critical pressure and temperature
— Triple point
— Phase diagram
— Density
— Viscosity
— Water solubility.

Typical effects of selected chemical components on the phase envelope are shown in Figure 2-3. Adding lighter components such as CH_4, N_2 or H_2 primarily affects the boiling curve in the phase envelope.

Compared to a typical Natural Gas (NG) composition, the most essential difference is the higher critical temperature of CO_2 causing liquid- or dense state at typical pipeline operating conditions.

Guidance note:

Natural gas composition applied for obtaining the phase envelope in the figure contains; 88 Mol% CH_4, 8 Mol% C_2H_6, 2 Mol% C_3H_8, 2 Mol% CO_2.

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2.3.4 Solvent properties

The solvent properties of CO_2 increase with pressure and temperature with supercritical CO_2 being a highly efficient solvent. This characteristic must be taken into account when selecting materials in contact with the CO_2, such as elastomer materials, and when assessing the consequences of a significant pressure reduction (e.g. due to a leak).

There is potential for any substance that is in solution within a high pressure CO_2 pipeline inventory to be precipitated out at the point of pressure drop due to the decrease in solubility of the CO_2. The precipitation of any hazardous substance held in solution could then result in harmful human exposure or environmental damage at or near the point of release.

2.3.5 Water solubility

In the vapour state the ability of CO_2 to dissolve water increase with increased temperature and reduced pressure as for natural gas. With transition from vapour to liquid state there is a step change in solubility and the solubility increase with increasing pressure which is the opposite effect of what occurs in the vapour state, ref. Figure 2-4.

The ability of the CO_2 stream to dissolve water may be significantly affected by the fraction of different chemical components, hence this needs consideration.

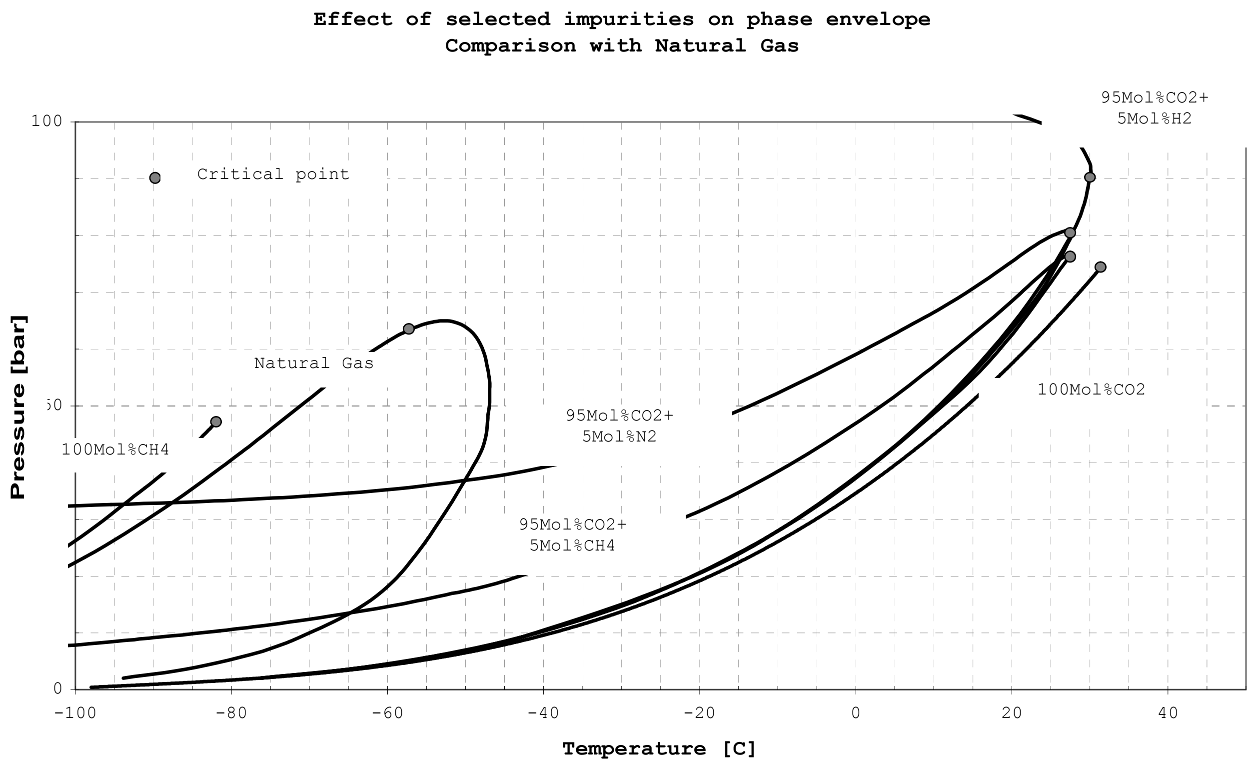

Figure 2-3
Effect of selected chemical components on phase envelope (PR EOS)

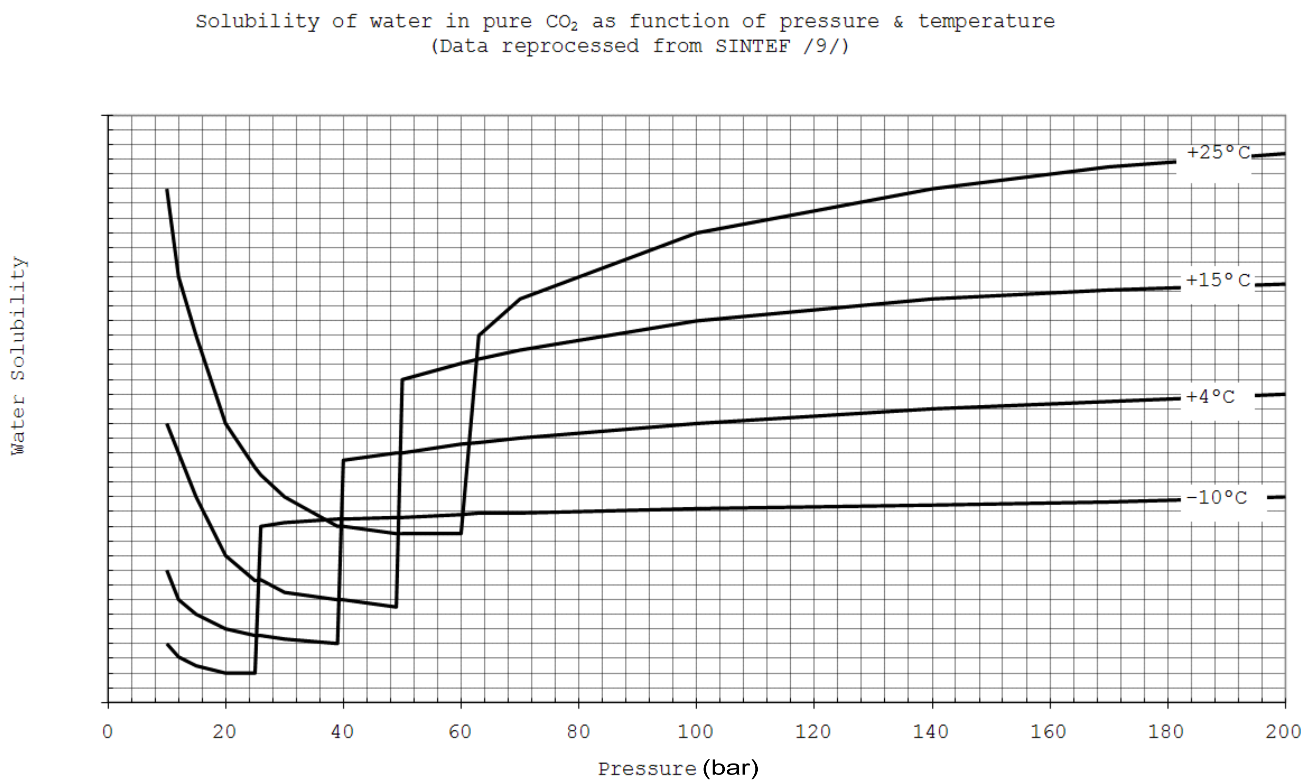

Figure 2-4
Solubility of water in pure CO_2; only for illustration /9/

Guidance note:

There is limited available knowledge on water solubility models for CO_2 streams including other chemical compounds. The indicative solubility for pure CO_2 should not be taken as representative for a CO_2 stream with other chemical components.

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2.3.6 Chemical reactions

Chemical reactions due to temperature and pressure variations and, in particular, due to mixture of CO_2 steams from multiple sources (ref. Table 2-3) must be assessed to avoid concerns such as those listed in Table 2-2. In particular, formation of free water shall be paid attention.

2.3.7 Equation of state (EOS)

For a CO_2 stream composition containing overwhelmingly CO_2, a Peng Robinson (PR) Equation of state (EOS) is considered to provide sufficient accuracy for prediction of:

— Mass density in both gaseous, liquid and supercritical CO_2.

For CO_2 mixtures containing significant levels of impurities, the applied EOS should ideally be tuned using experimental data. As a minimum the EOS should be verified against experimental data in order to assess the level of inaccuracy of the calculations.

Particular attention must be given when performing simulations near the critical point of the composition due to the reduced precision of the EOS (high non-linearity).

Particularly for water solubility and drop out prediction as well as hydrate formation, the EOS should be calibrated or verified towards experimental data for the project specific CO_2 stream.

3. Safety Philosophy

3.1 Safety Evaluations

3.1.1 Safety objective

An overall safety objective shall be established, planned and implemented, covering all phases from conceptual development until abandonment.

3.1.2 Risk assessment

A systematic review shall be carried out at all phases to identify and evaluate threats, the consequences of single failures and series of failures in the pipeline system, such that necessary remedial measures can be taken. The extent of the review or analysis shall reflect the criticality of the pipeline system, the criticality of a planned operation, and previous experience with similar systems or operations.

The risks to people in the vicinity of the pipeline shall be robustly assessed and effectively managed down to an acceptable level. To achieve this, CO_2 hazard management processes, techniques and tools require critical examination and validation. The safety risk related to transport of CO_2 should include but not be limited to controlled and uncontrolled release of CO_2.

3.1.3 Risk management

The (safety) risk management strategy should be based on relevant industry good practice which centres on inherent safety and the prevention of incidents which could endanger people, the environment or property. This establishes a hierarchy of prevention before control, mitigation, protection and emergency response.

ISO 13623-Annex A provides high level guidelines for the planning, execution and documentation of safety evaluations of pipelines and may be applied as reference. Additional guid-

ance on hazard identification and risk assessment approaches that may be applied to CO_2 pipelines, particularly in densely populated areas or other public-sensitive areas, can be found in ISO 17776, ISO 31000 and NORSOK Z-013.

It should be recognized that CO_2 pipelines at the scale that will be associated with CCS projects are novel to many countries and this should be reflected in the risk management strategy adopted.

3.1.4 Hazard identification

Rigorous and robust hazard identification is very important, particularly in a relatively immature industry such as the CCS industry. Hazards can not be effectively managed if they have not been identified.

For CCS, with few companies or people with hands on experience and few relevant hazard identification studies, great care should be taken during hazard identification exercises since hazards may be missed, or hazards that are identified may be deemed non-credible due to lack of relevant knowledge.

Until experience and knowledge is built up and communicated within the CCS industry, greater focus should be applied to hazard identification (and risk assessment) to compensate for the lack of experience.

Guidance note:

Loss of reputation in case of a single major accident in the early deployment phase of CCS may have impact not only on the operator but also the CCS industry at large.

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3.1.5 Major accident hazards

Major Accident Hazards (MAHs) are categorized as high consequence, typically low frequency, events as opposed to occupation type hazards (e.g. slips, trips and falls) which are generally significantly lower consequence but typically more frequent events.

A ‘Major Accident’ is defined in various regulations. The definition in the Seveso II Directive is:

“ Major accident' shall mean an occurrence such as a major emission, fire, or explosion resulting from uncontrolled developments in the course of the operation of any establishment covered by this Directive, and leading to serious danger to human health and/or the environment, immediate or delayed, inside or outside the establishment, and involving one or more dangerous substances.”

MAH risk assessment should be performed to provide estimates of the extent (i.e. hazard ranges and widths) and severity (i.e. how many people are affected, including the potential numbers of fatalities) and likelihood of the consequences of each identified major accident hazard. MAH risk assessment could be used as input to design requirements, operational requirements and planning of emergency preparedness.

Specific criteria for Lethal Concentration - LC_{50} are given in Sec.3.3.1 /2/.

3.1.6 Risk reduction

Guidance on risk reduction and evaluation of risk-reducing measures given in ISO 17776 may be applied as reference.

3.2 Risk basis for design

3.2.1 General

The pipeline shall be designed with acceptable risk. The risk considers the likelihood of failure and the consequence of failure. The consequence of failure is directly linked to the content of the pipeline and the level of human activity around the pipeline. Hence, both the content (CO_2) of the pipeline and the human activity around the pipeline need to be categorized, and will provide basis for safety level implied in the pipeline design criteria.

Categorization of CO_2 is described in Sec.3.2.2, and human activity level is given in Sec.3.2.3. The associated utilization factors are given in Sec.5.4. Sec.3.2.4 presents guidance on assessing pipeline failure frequencies.

3.2.2 Categorization of CO_2

ISO 13623 and DNV-OS-F-101 require the pipeline inventory to be categorized in one of the following five categories according to the hazard potential in respect of public safety:

Table 3-1 Fluid categorization /ISO13623, DNV OS-F101/

Category A	Typically non-flammable water-based fluids.
Category B	Flammable and/or toxic fluids which are liquids at ambient temperature and at atmospheric pressure conditions. Typical examples are oil and petroleum products. Methanol is an example of a flammable and toxic fluid.
Category C	Non-flammable fluids which are non-toxic gases at ambient temperature and atmospheric pressure conditions. Typical examples are nitrogen, carbon dioxide, argon and air.
Category D	Non-toxic, single-phase natural gas.
Category E	Flammable and/or toxic fluids which are gases at ambient temperature and atmospheric pressure conditions and are conveyed as gases and/or liquids. Typical examples are hydrogen, natural gas (not otherwise covered in Category D), ethane, ethylene, liquefied petroleum gas (such as propane and butane), natural gas liquids, ammonia and chlorine.

According to ISO 13623 and DNV OS-F101 CO_2 is categorized as a category C fluid.

The LC50 curve for CO_2 is well above 5%; hence according to the Globally Harmonized System (GHS) CO_2 is a “Not Classified” substance. CO_2’s lethal concentration levels are at least one order of magnitude higher than that required in the GHS to categorize it as a “Classified Acute Toxicity Substance”.

Guidance note:

Within the Globally Harmonized System (GHS) Acute Toxicity criteria, any substance that has a median lethal concentration (LC50) of less than 5000 parts per million (ppmV) (0.5% in air; by volume) is classified within one of the five defined Hazard Categories given in Table 3-1. A substance with a LC50 concentration greater than 0.5% is defined as “Not Classified”.

According to ASME B31.4, dense phase CO_2 is classified as a “Hazardous Liquid”.

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The introduction of CCS in regions where there is currently no CO_2 infrastructure will push the boundaries of experience within many areas including engineering, operations, risk management and public acceptance. CO_2 pipelines will have major accident potential due primarily to a combination of vast pipeline inventories and the consequences if CO_2 is inhaled at concentrations above around 7%, ref Sec.3.3.1. A precautionary approach to risk management is therefore recommended, and it is recommended that, until sufficient knowledge and experience is gained with CCS pipeline design and operation, a more stringent categorization should be applied in populated areas. This will be reflected in the pipeline wall thickness design, see Sec.5.4, and for pipeline pressure testing, see Sec.6.2.2.

3.2.3 Location classes

Specification of location classes for onshore pipelines should comply with ISO 13623; Annex B.2. Specification of location classes for offshore pipelines should comply with the requirements given in DNV-OS-F101.

Table 3-2 Location classes according to ISO 13623	
Location Class	*Description*
1	Locations subject to infrequent human activity with no permanent human habitation. Location Class 1 is intended to reflect inaccessible areas such as deserts and tundra regions
2	Locations with a population density of less than 50 persons per square kilometre. Location Class 2 is intended to reflect such areas as wasteland, grazing land, farmland and other sparsely populated areas
3	Locations with a population density of 50 persons or more but less than 250 persons per square kilometre, with multiple dwelling units, with hotels or office buildings where no more than 50 persons may gather regularly and with occasional industrial buildings. Location Class 3 is intended to reflect areas where the population density is intermediate between Location Class 2 and Location Class 4, such as fringe areas around cities and towns, and ranches and country estates
4	Locations with a population density of 250 persons or more per square kilometre, except where a Location Class 5 prevails. A Location Class 4 is intended to reflect areas such as suburban housing developments, residential areas, industrial areas and other populated areas not meeting Location Class 5
5	Location with areas where multi-storey buildings (four or more floors above ground level) are prevalent and where traffic is heavy or dense and where there may be numerous other utilities underground

For onshore pipelines, location classes shall consider possible dispersion of CO_2.

Safety measures in the different location classes depend on need for protecting the pipeline from 3rd party activities. The degree of protection will vary depending on location class, and should be determined based on a risk and safety assessment. Protection may be ensured by e.g. burial, fences, signs and similar. National legislation shall also be considered.

3.2.4 Pipeline failure frequencies

It is critical to characterize the possible failures of a pipeline system in terms for which frequency data is available. For CO_2 pipeline systems there are relatively little relevant experience available. However, some statistics from CO_2 pipeline incidents in the U.S. can be found at the Office of Pipeline Safety (OPS) within the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA)/17/.

Failure statistics for onshore and offshore pipelines shall be considered separately, particularly related to the cause of external third party damages.

Incident data from other relevant pipeline systems (none-CO_2 pipeline systems) should also be consulted and assessed as input to the frequency analysis. In addition to incident data for CO_2 pipelines, the PHMSA information source also provides data for other pipelines in the U.S. Other databases containing pipeline incident data are:

— The European Gas Pipeline Incident Data Group (EGIG) database /19/
— The CONCAWE Oil Pipelines Management Group incident database /20/
— The PARLOC database /21/

Guidance note:
Differentiating between external and internal threats one may expect that the external threats related to CO_2 pipelines provide equivalent statistics as for hydrocarbon pipelines. This is based on the assumption that the protection of the CO_2 pipelines will be similar to hydrocarbon pipelines.

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The frequency analysis should examine the available historical incident data in depth to extract and use the most relevant data for a particular CO_2 pipeline project. When applying failure statistics, one needs to consider pipelines designed according to equivalent codes.

Guidance note:
For internal threats the statistics may be applied based on that the control of the water dew point is sufficient. Lack of control of the water dew point is expected to increase the failure level in the CO_2 pipelines as the corrosion rates increase significantly from that of typical hydrocarbon gas pipelines that are operated with equivalent dew point control.

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It should be noted that there is a difference between nominal failure probabilities and target failure probabilities. Target failure probabilities are normally used in risk assessments based upon failure statistics, while nominal failure probabilities are reflected in design codes and hence exclude human errors and similar.

3.3 Safety assessments – CO_2 specific aspects

3.3.1 Human impact to inhaled CO_2

The acute health effects that are seen following inhalation of high concentrations of CO_2 are presented in Table 3-3 and should be used as reference values for safety risk assessments.

Table 3-3 Acute health effects of high concentrations of inhaled CO_2 /14/

CO_2 Concentration in Air (% v/v)	*Exposure*	*Effects on Humans*
17 – 30	Within 1 minute	Loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death
>10 – 15	1 minute to several minutes	Dizziness, drowsiness, severe muscle twitching, unconsciousness
7 – 10	Few minutes	Unconsciousness, near unconsciousness
	1.5 minutes to 1 hour	Headache, increased heart rate, shortness of breath, dizziness, sweating, rapid breathing
6	1 – 2 minutes ≤ 16 minutes Several hours	Hearing and visual disturbances Headache, difficult breathing (dyspnoea) Tremors
4 – 5	Within a few minutes	Headache, dizziness, increased blood pressure, uncomfortable breathing (Equivalent to concentrations expired by humans)
3	1 hour	Mild headache, sweating, and difficult breathing at rest
2	Several hours	Headache, difficult breathing upon mild exertion
0.5-1	8hrs	Acceptable occupational hazard level

Guidance note:

The reference source on which the above table was based /14/ does not provide specific details of the age, sex, fitness or general well-being of the people exposed. But a conservative and reasonable assumption would be that people with underlying health concerns would not have been selected as a volunteer in tests. Therefore the exposure limits may need to be adjusted for use in risk assessment should the exposed population being considered include vulnerable people (e.g. those with a respiratory illness).

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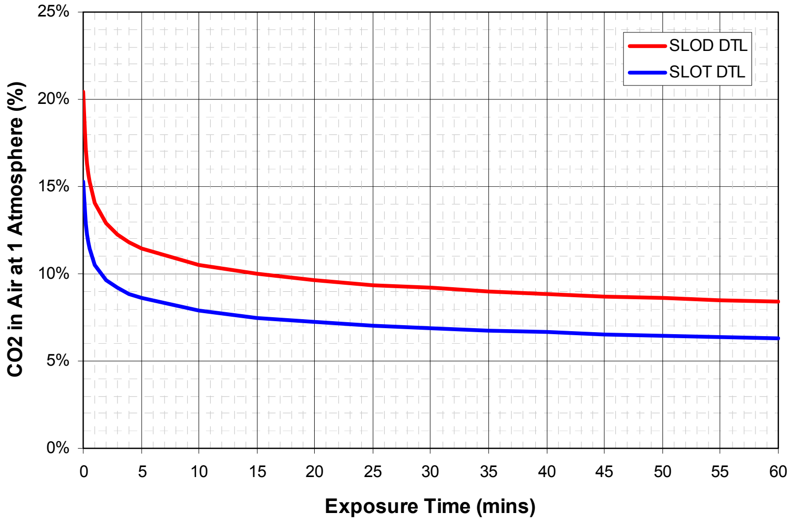
The harm level expressed by a given substance in the air is influenced by two factors, the concentration in the air (c) and the duration of exposure (t). The following expressions have been defined by the HSE UK for CO_2, ref. Figure 3-1:

SLOT DTL: $1.5 \times 10^{40} = c^{8} \cdot t$

SLOD DTL: $1.5 \times 10^{41} = c^{8} \cdot t$



SLOT DTL = Specified Level Of Toxicity Dangerous Toxic Load
SLOD DTL = Significant Likelihood Of Death Dangerous Toxic Load

Figure 3-1
SLOT and SLOD limits for CO_2

Guidance note:

Human respiration is controlled by the respiratory centre of the brain which keeps the basic rhythm of respiration continuous. One of the most powerful stimuli known to affect the respiratory centre is CO_2. CO_2 acts as both a stimulant and depressant on the central nervous system.

CO_2 is not a chemical asphyxiant like hydrosulphide or carbon monoxide in that it does not prevent the efficient transfer of oxygen via the blood.

With reference to Figure 3-1 the number of people injured (serious and minor) by the release may be approximated by the number of people estimated to be between the SLOD and SLOT DTL contours (i.e. the SLOT DTL contour is taken as a pragmatic limit for human harm).

With reference to Figure 3-1 the number of fatalities caused by a CO_2 release may be approximated by the number of people estimated to within the SLOD contour (i.e. the SLOD DTL contour is taken as a pragmatic limit for fatalities).

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3.3.2 Occupational exposure limits for CO_2

An occupational exposure limit (OEL) is an upper limit on the acceptable concentration of a hazardous substance in workplace air for a particular substance or class of substances.

The OEL given in Table 3-4 should be applied as reference for evaluating occupational hazards.

Table 3-4 Occupational exposure limits

Exposure Time	*% CO_2*	*Comment*	*Reference*
10 hours	0.50%	Time weighted average	NIOSH (US)
8 hours	0.50%	Time weighted average	OSHA (US)
	0.50%	Occupational Long Term Exposure Limit (LTEL)	COSHH HSE (UK)
60 min	4%	Emergency Exposure Level for submarine operations	USA Navy
	2.5%	Emergency Exposure Level for submarine operations	National (US) Research Council
	5%	Suggested Long Term Survivability Exposure Limit	HSE (UK)
	2%	Maximum exposure limit	Compressed Gas Association 1990
20 min	3%	Maximum exposure limit	Compressed Gas Association 1990
15 min	1.5%	Occupational Short Term Exposure Limit (STEL)	COSHH HSE (UK)
	3%	Short Term Exposure Limit (STEL)	Federal occupational safety and health regulations (US)
10 min	4%	Maximum exposure limit	Compressed Gas Association 1990
7 min	5%	Maximum exposure limit	Compressed Gas Association 1990
5 min	5%	Suggested Short Term Exposure Limit (STEL)	HSE (UK)
	6%	Maximum exposure limit	Compressed Gas Association 1990
3 min	7%	Maximum exposure limit	Compressed Gas Association 1990
1 min	15%	Exposure limit	NORSOK (Norway)
<1 min	4%	Maximum Occupational Exposure Limit	Federal occupational safety and health regulations (US)

3.3.3 Health effects from exposure of CO_2 composition with other chemical components

Supercritical CO_2 is a highly efficient solvent but when it undergoes a significant pressure reduction, for example during a leak, it changes to a gaseous state with virtually no solvent capability.

This characteristic of CO_2 introduces the potential for any compounds or elements that are in solution within the CO_2 inventory being precipitated out at the point of pressure drop.

In addition to the health hazards related to pure CO_2, the toxicity of the individual chemical components (e.g. H_2S and CO) should be considered as part of a safety risk assessment.

3.3.4 Other health effects

In addition to the hazards associated with inhalation of CO_2-rich air, the following health effects should be evaluated when found applicable:

— Injuries caused by direct exposure of the released solid state particles or cryogenic burns
— Inhalation of solid CO_2 particles within a release
— Noise level related to vent stations.

Guidance note:
Inhalation of air containing solid CO_2 particles within a release cloud is particularly hazardous since this could result in cryogenic burns to the respiratory tract as well as toxicological impact upon sublimation. As dry ice will quickly sublime upon emission from the pipeline, this risk of inhalation applies only in the immediate vicinity of the leak.

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3.3.5 Environmental impact

CO_2 may affect the flora and fauna with which it comes into contact, from microbes in the deep subsurface near injection point to plants and animals in shallower soils and at the surface. The effect of elevated CO_2 concentrations would depend on several factors, for example, for terrestrial ecosystems the type and density of vegetation; the exposure to other environmental stresses; the prevailing environmental conditions like wind speed and rainfall, the presence of low-lying areas; and the density of nearby animal populations.

Animals exposed to high CO_2 concentrations are assumed to experience the same effects as described for humans in Sec.3.3.1, and are caused by hypercapnia (elevated levels of CO_2 in the bloodstream) and asphyxiation leading to respiratory distress, narcosis and mortality. The extent of effect from the elevated CO_2 concentration will vary between species due to difference in, for example, behaviour and body size.

The consequences associated with accidental or planned release of CO_2 and its impact on flora, fauna and livestock need to be considered as part of the risk assessment process.

3.3.6 Accidental release of CO_2

Accidental release of CO_2 (controlled pipeline depressurization is described in Sec.7.6.5) from an initial liquid state to ambient conditions involves decompression and expansion of the released medium with a corresponding drop in temperature of the released medium and remaining inventory.

CO_2 differs from decompression of hydrocarbons with respect to that the release may appear as a combination of gaseous and solid state CO_2.

Particularly for CO_2, the erosive properties of the solid CO_2 particles released should be considered in case there is a potential for direct impingement on nearby critical equipment. Other components in the CO_2 inventory my increase the erosive properties of the release stream.

The temperature reduction through the crack/opening at the leak point may however not be significantly more pronounced than for volatile hydrocarbons.

Even though CO_2 is a colourless gas, a release from a cool CO_2 inventory will most likely cause condensation of the water saturated in the ambient air, resulting in a cloud visible to human eye (until the release cloud warms to above the air's dew point temperature).

A release of warm or hot CO_2 which results in a release above the air's dew point temperature will be invisible to the naked eye since there will be no condensing water or solid CO_2 particles.

3.3.7 Release rates

Accidental release rates from a CO_2 pipeline primarily differs from a hydrocarbon pipelines due to the potential phase

changes within the flow expansion region.

To enable modelling of accidental release rates the transient thermo hydraulic behaviour of the pipeline needs to be considered.

Calculation of the transient release profile needs to include but not be limited to:

— Hole size and geometry
— Pipeline diameter, length and topography
— Temperature, pressure and chemical composition of the CO_2 stream
— Heat transfer between pipeline and ambient
— Closing time of any inventory segregation valves (e.g. block or check valves)
— Initiation time and capacity of pipeline depressurization system.

Guidance note:

In case a pipeline depressurization system is installed within the pipeline section (between block valves) and activated in a pipeline accidental situation, the reduced duration of the release due to depressurization may be taken into account.

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3.3.8 Dispersion modelling

Empirical models for estimating dispersion of released gases in air and liquids are readily available; however, they need to be validated for CO_2 in CCS-scale applications /15/. Accidental release of CO_2 differs from other typical fluids in terms of formation of a solid state, ref. Sec.3.3.6.

Dispersion of gaseous CO_2 (either cooled or at ambient temperature) can best be compared with an equivalent release of propane (C_3H_8) due to their comparable physical properties (molecular weight and viscosity).

Effects that need to be considered within the modelling are:

— Release rate
— Leak profile
— Jet direction (consider both impinging and free jets)
— Release gas density
— Wind speed and direction
— Atmospheric stability class
— Air humidity
— Surface roughness.

The effect on modelling results of solid CO_2 formation within the release stream is not validated and results must therefore be handled with care. It is expected that the effect is larger for large leaks and full bore ruptures than for small releases. When the cold stream of CO_2 hits the ground, a small release will be heated by the surface, however, if the leak is large and/or long lasting, less of the gas will be heated by the surface and the effect of solid CO_2 is expected to be larger.

In addition to being influenced by the wind, the heavier than air CO_2 stream will spread out sideways, with off-axis ground level concentrations being higher than for a neutrally buoyant or buoyant gas release. Ground topography (e.g. slopes, hollows, valleys, cliffs, streams, ditches, road/rail cuttings and embankments, etc.) and physical objects (e.g. buildings), as well as wind direction may have a significant influence on the spread and movement of a CO_2 cloud. Particular care should be taken in identifying topographical features and assess how this may impact the consequences of a CO_2 release.

In many assessments, integral models should provide acceptable modelling capability, but in areas where the combined effects of topography, buildings, pits, etc. and the heavy gas properties of the released CO_2 may have a significant effect on the exposure of people or livestock, more detailed simulations using advanced dispersion tools (e.g. Computational Fluid Dynamics (CFD)) should be considered.

Also, the potential severity of the predicted consequences should influence the depth and breadth of consequence assessment. For example, the level of analysis for a small low pressure on-site CO_2 release will likely demand less analysis than for a large, liquid phase CO_2 release that could create a hazard range potentially exposing a large number of people. In addition, should a predicted hazardous release plume be assessed to fall just short of a densely populated area, the uncertainties in the analysis and any circumstances which could lead to extension of the hazard into the populated area would need careful consideration.

Modelling releases from underground pipelines need careful consideration since the crater formation and subsequent release flow could significantly reduce the momentum and therefore air mixing of the release thereby decreasing the dispersion and increasing the hazardous distances.

Submerged releases of CO_2 may be modelled in a similar way as for hydrocarbon gas having similar molecular weigh (i.e. propane). Dispersion models are readily available; however, they need to be validated for CO_2 in CCS-scale applications /15/.

Guidance note:

Several initiatives are currently taken to tailor and validate empirical dispersion models specifically for release of CO_2 /17/.

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3.3.9 Human impact assessment

Unless the use of alternative harm criteria is justified, the SLOT and SLOD dangerous toxic load as described in Sec.3.3.1 and Sec.3.3.3 should be applied.

4. Concept development and design premises

4.1 General

This section includes recommendations related to design issues that are specific to CO_2 and that are normally considered as part of the pipeline concept phase.

CO_2 pipelines shall be designed in accordance with industry recognized standards and applicable regulatory requirements.

Existing pipelines previously used for transportation of other media may be re-qualified for transportation of CO_2 given that appropriate standards and regulations as well as guidelines given in Sec.8 are followed.

4.2 Design Premises

With respect to design premises, the following issues should be paid particular attention to:

Issue:	*Onshore*	*Offshore*
Regulatory requirements	●	●
Safety objective	●	●
Design standards	●	●
Population density along pipeline route	●	(●)
Topography (reference to gas dispersion)	●	
Topography (reference to flow assurance)	●	●
Composition of CO_2 stream	●	●
Limitations to pipeline export and arrival conditions	●	●
Requirements to pipeline integrity management (monitoring, inspection, reporting)	●	●
Design life	●	●
Transport capacity and operational flexibility	●	●
Shut-in and re-start	●	●
Operational and upset inventory conditions (e.g. temperature, pressure, phases)	●	●
Material specifications	●	●
Pressure relief system	●	(●)
Requirements to pipeline energy efficiency	●	●

Guidance note:

As the CO_2 stream is common to all three parts of the CCS chain (capture, transport and storage), the design specification must be consistent and aligned throughout the CCS chain. In particular, the specification of impurity limits in the CO_2 stream is an example of an aspect that must be adequately considered along the complete CCS chain.

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4.2.1 Reliability and availability of CO_2 transport

A holistic approach must be taken when assessing the reliability and availability of the CO_2 stream since the reliability/availability of one part of the CO_2 chain has design and operation impact on another. The pipeline system can be used as a buffer to smooth out supply and storage interruptions, but this has to be assessed and the line-pack capacity optimized against cost and other project drivers early in the design phase of the various parts of the CO_2 chain.

4.2.2 Access to transport networks

A pipeline operator will have to clarify with authorities how to take the necessary measures to ensure that potential users are able to obtain access to transport networks. Access should be provided in a transparent and non-discriminatory manner.

4.3 System design principles

4.3.1 General

The pipeline layouts comprise the various valves as well as intermediate compressor and/or pump stations and instrumentation within the battery limits, and defined as part of the pipeline. The pipeline layout is a critical part of the pressure safety functions and it also determines the accessibility for maintenance and repair.

4.3.2 Pressure control and overpressure protection system

A pressure protection system shall be used unless the pressure source to the pipeline system cannot deliver a pressure in excess of the incidental pressure including possible dynamic effects. The pressure protection system shall prevent the internal pressure at any point in the pipeline system rising to an excessive level. The pressure protection system comprises the pressure control system, pressure safety system and associated instrumentation and alarm systems.

The purpose of the pressure control system is to maintain the operating pressure within acceptable limits during normal operation, i.e. to ensure that the local design pressure is not exceeded at any point in the pipeline system during normal operation.

The purpose of the pressure safety system is to protect the downstream system during incidental operation, i.e. to ensure that the local incidental pressure is not exceeded at any point in the pipeline system in the event of failure of the pressure control system.

For a pipeline operated in dense phase, the pressure control system should be designed to ensure that dense phase condition is retained both at the design operating condition, reduced flow rate and in a pipeline shut-in situation.

The pressure control system should be configured to ensure sufficient margin to water drop out, ref. Sec.4.8.3, in case of a pipeline shut-in condition

Guidance note:

If choking (pressure reduction) is required at the receiving facility to meet e.g. the storage reservoir pressure it may be more cost efficient to allow for parts of the pipeline to be operated in multiphase state.

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4.3.3 Pipeline Protection

As a reference, for onshore pipelines the minimum cover of depth should follow the specifications given in ISO 13623; Sec.6.8.2, however, as detailed previously, due consideration needs to be taken of the influence a crater release has on dispersion. Crater size and geometry will be a function of pipeline depth of cover.

For offshore pipelines, the requirements to protection against external threats should be evaluated according to ISO 13623; Sec.6.8.2, DNV-RP-F107 or DNV-OS-F101 with no particular issues related to CO_2.

Guidance note:

The requirements for the minimum cover of depth given in ISO 13623 are independent of fluid categorization.

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4.4 Dewatering

4.4.1 Definition

Dewatering – removal of water content to ensure that no free water can drop out at any location along the pipeline either during normal operating conditions or during transient or upset conditions.

4.4.2 Particular aspects related to CO_2

Performance and reliability of CO_2 stream dewatering is essential for corrosion control, ref. Sec.5.1.

Performance and reliability of CO_2 stream dewatering is essential for hydrate formation control, ref. Sec.4.5.11.

4.4.3 Maximum water content

Water content should be specified in terms of parts per million on mass bases (ppmW).

A sufficient safety margin between the specified water content allowed at the inlet of the pipeline and the water solubility at any location along the pipeline should be specified. Due account should be taken when determining the maximum water content limit of the variations in CO_2 pressure and temperature during operations and particularly during upset conditions when both the pressure and temperature may drop significantly.

4.4.4 Reliability and precision of dewatering

A Safety Integrity Level (SIL) /IEC 61508/ should be defined for the water monitoring system to ensure sufficient level of reliability. Appropriate SIL should be defined based on a risk assessment.

The response to detected off-spec water content should be defined based on appropriate assessment of the consequences.

Valid calibration certificates shall exist for the water monitoring system. Calibration should be performed taking the project specific CO_2 stream into account.

Guidance note:

IEC 61508 specifies 4 levels of safety performance for a safety function. These are called safety integrity levels. Safety integrity level 1 (SIL1) is the lowest level of safety integrity and safety integrity level 4 (SIL4) is the highest level. The standard details the requirements necessary to achieve each safety integrity level. These requirements are more rigorous at higher levels of safety integrity in order to achieve the required lower likelihood of dangerous failure / IEC 61508/.

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4.5 Flow assurance

4.5.1 Particular aspects related to CO_2

With reference to Flow Assurance the following particular issues should be considered:

- Effect on flow capacity of fluid temperature and pressure
- Transportation in dense (liquid) phase (i.e. above critical pressure) or as two-phase
- Hydrate formation, potentially causing pipeline blockage
- Transient operation.

4.5.2 Hydraulic model

In the pipeline design phase a thermo-hydraulic model should be established to enable:

- Determining and optimizing the pipeline transport capacity
- Pressure surge analysis
- Water drop-out analysis
- Simulation of release scenarios – controlled and accidental
- Pipeline shut-in and start-up analysis
- Pipeline depressurization
- Simulation of heat transfer to surroundings.

The thermo-hydraulic model should as a minimum be able to account for:

- Two-phase single and multi-component fluid
- Steady state conditions.

For performing pipeline depressurization analysis the hydraulic model should be able to account for:

- Transient simulation
- Model to properly account for solids formation when dropping below the triple point.

Guidance note:

Experience with currently available multiphase simulation codes is that tuning of the Equation of State models may be required to obtain stable solution when applied to near pure CO_2, particularly close to the critical point.

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4.5.3 Pipeline transport design capacity

Pipeline transportation of CO_2 over longer distances is most efficient and economical when the CO_2 is in the dense, i.e. in liquid or supercritical regimes. This is due to the lower friction drop along the pipeline per unit mass of CO_2 compared to transporting the CO_2 as a gas or as a two-phase combination of both liquid and gas.

From a cost and efficiency point of view keeping the CO_2 stream in single phase is of particular importance if the pipeline requires intermediate boosting stations.

For pipelines with no requirement to intermediate boosting, transport in multiphase regime may, for parts of the pipeline, be acceptable and in some cases economical in terms of requiring lower pipeline export pressure.

When determining pipeline capacity due consideration should be taken for any line-packing strategy for smoothing out upstream and/or downstream transients.

Recognized thermo hydraulic tools and suitable physical property models for the CO_2 composition shall be applied and documented for determination of the pipeline transportation capacity.

Guidance note:

Increasing amount of other components than CO_2 will generally reduce the transportation capacity of the pipeline, depending on the type, quantity and combination of the components. Indirectly this may have implications on the required pipeline sizing and/or inlet pressure and/or distance between intermediate pump stations.

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4.5.4 Reduced pipeline transport scenario

In addition to the design (maximum) transportation capacity, it shall be documented through thermo hydraulic analysis that the pipeline is able to operate at a reduced rate without significant operational constraints or upsets.

4.5.5 Available transport capacity

Seasonal variations in ambient temperature need to be part of the thermo hydraulic design due to its effect on mass density of the CO_2 stream.

Guidance note:

The pipeline may generally have higher capacity in winter conditions compared to summer conditions.

Effect of temperature (seasonal variations) is likely to be more pronounced for onshore pipelines compared to offshore pipelines, however, depending on geographical location.

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4.5.6 Pipeline export conditions

Due to the significant reduction in specific gravity of supercritical CO_2 with increase in temperature, the temperature at the upstream battery limit of the pipeline should be minimized. Cooling of the CO_2 stream after compression may significantly increase the capacity.

Guidance note:

The temperature at the upstream battery limit of the pipeline may be high due to temperature increase associated with compression.

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4.5.7 Pipeline arrival condition

For the maximum design transportation capacity the arrival pressure at the downstream battery limit of the pipeline should not be less than the boiling pressure corresponding to the maximum arrival temperature.

CO_2 arriving at the injection point at a pressure that is significantly above or below the required injection pressure will result in wasted energy. The pressure along the whole CO_2 chain should be optimized during the design.

4.5.8 Flow coating

Application of flow coating to reduce frictional pressure drop by reducing the internal roughness of the pipe is generally not recommended due to the following:

— The main concern that needs to be considered relates to detachment of the internal coating in a pressure reduction situation, due to diffusion of CO_2 into the space between the coating and steel pipe during normal operation or due to low temperature during depressurization. It should be noted that the decompression effects may be gradual, i.e. start as blistering and ultimately cause full detachment.
— Damaged coating may be transported to the receiving facilities causing process upsets or plugging of injection wells.

If flow coating is applied, the coating material shall be qualified for compatibility with CO_2 and the ability to withstand relevant pipeline decompression scenarios.

4.5.9 Thermal insulation

For a pipeline, the heat ingress from the surroundings is determined by the difference between the ambient temperature and the temperature of the CO_2 inside the pipeline, combined with the insulation properties and burial depth of the pipeline.

The implications of thermal insulation on minimum pipeline temperature in a depressurization situation should be considered.

Guidance note:

In a depressurization situation, a too rapid depressurization may cause sub-zero temperatures, potentially causing external icing on the pipeline.

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4.5.10 Transient operation and line packing

The resilience of the pipeline to dynamic flow conditions and the potential for line packing should be considered as part of the pipeline design.

Guidance note:

Inflow conditions may, depending on the CO_2 capture technology, vary in the order of percentages on flow rate per minute for a power plant due to supply demand for power. How the cyclic demand influence the operation of the CCS system need to be considered also for the pipeline system.

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4.5.11 Hydrate formation, prevention and remediation

The potential for hydrate formation both in gaseous and liquid CO_2 should be considered with reference to the water content in the CO_2 stream.

In addition to the potential for forming CO_2 hydrate, the potential for forming hydrates from other non-condensable components should be considered.

The potential for forming hydrates during commissioning or re-start should be considered with reference to the dewatering procedure and potential for residual water in the pipeline after pressure testing.

Use of ammonia for hydrate prevention is not recommended due to the potential for forming solid ammonium carbonate when reacting with CO_2.

The primary strategy for hydrate prevention should be sufficient dewatering of the CO_2 stream, ref. Sec.4.8.3. Water content should be controlled and monitored at the inlet of the pipeline.

Guidance note:

There is no clear scientific evidence that CO_2 hydrate may form without presence of free water. Moreover, operational experience from CO_2 pipelines operated in US does not flag this as a particular concern.

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4.6 Pipeline layout

4.6.1 General

Due to the vast pipeline inventory for a CO_2 pipeline, the recommendations to pipeline sectioning with either check valves or block valves need particular considerations. The rational for sectioning the pipeline may be for risk reduction or for operation and/or maintenance reasons.

4.6.2 Block Valves

For onshore pipelines, the location and performance requirements of intermediate block valves should be based on local legislative requirements (if any) and the risk management strategy. The following is relevant:

— Block valves, when closed, reduce the volume of released product in case of pipeline containment failure
— Block valves increase maintainability by limiting section of pipe that requires depressurization
— The effectiveness of block valves to limit the scale of a leak will be dependent on effective leak detection.
— The block valve closes based on a signal typically from the control system, either manually or automatic.

Guidance on spacing of block valves specifically for CO_2 pipelines is provided in the Canadian pipeline standard CSA-Z-662-7.

It should be acknowledged that block valves introduce additional risk associated with:

— Leak sources
— Operational cost due to maintenance and repair.

Mid-section block valves are not considered feasible for offshore pipelines although valves near landfall and near an offshore installation may be required as part of the risk management measures.

Guidance note:

For existing onshore pipelines, intermediate block valves are normally installed to reduce the total volume to be relieved in case of a planned or unplanned depressurization or in case of a pipeline rupture.

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4.6.3 Check valves

Rapid closing (autonomous) check valves (i.e. non-return valves) may assist in reducing the volume of released product during a release event, ref. Figure 4-1.

The check valve act autonomous and closes automatically as the flow rate is gradually reduced and finally reversed.

Since check valves prevents reverse flow in the pipeline, measures to enable depressurization may need to be put in place, ref. Figure 4-2.

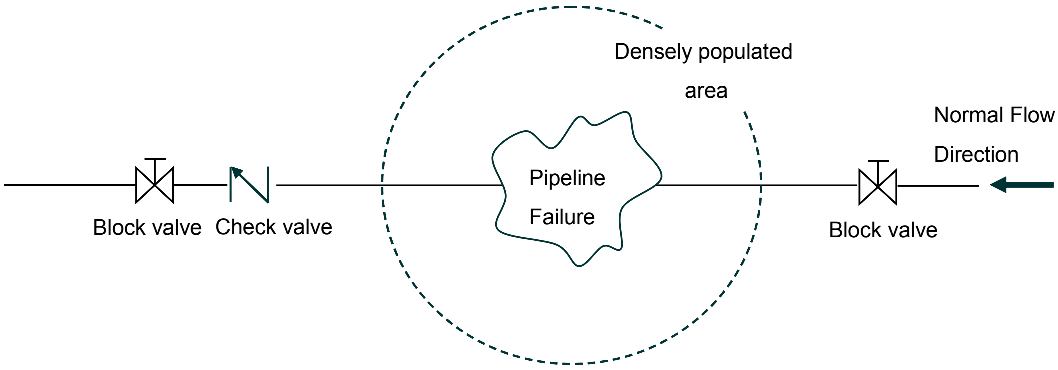

Figure 4-1
Illustration of potential location of check valve to prevent back-flow to densely populated area

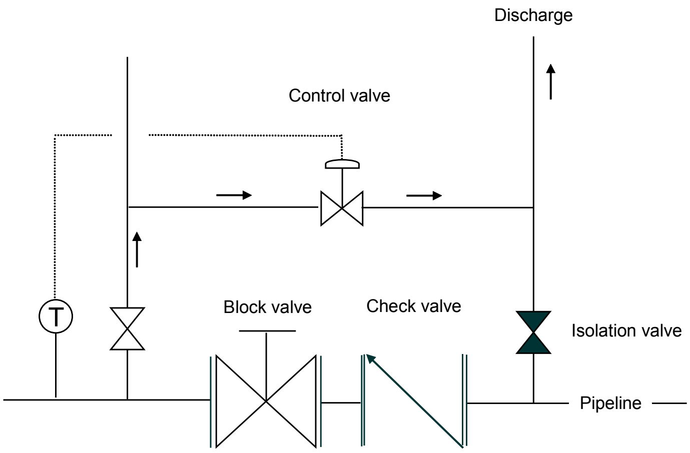

Figure 4-2
Schematic of valves configuration enabling depressurization

Installation and design of check valve stations have to consider the pipeline layout and utilities for depressurization.

4.6.4 Pump stations

For a natural gas pipeline, the transported fluid may act as a source of energy supply to remote valve or pump stations. This is however not the case for CO_2 pipelines. Power and signal/ control availability may influence the optimal location of valve and pump stations.

4.6.5 Pigging stations and pigging

Particular aspects related to CO_2 are materials selection, ref. Sec.5.

Pig launchers and/or traps may be either temporary or permanent. The primary purpose of the pig launcher/trap is to enable dewatering during commissioning and pigging either as part of commissioning or during operation.

4.6.6 Onshore vent stations

Onshore vent stations may either be permanent or temporary. Temporary vent stations may be portable for the purpose of depressurising sections of the pipeline for inspection, maintenance or repair.

As a minimum requirement, one permanent vent station shall be included that has access for depressurization of the entire pipeline. As a general recommendation, each vent station should have the capacity to depressurize the volume between block valves, also taking into account the integrity of the pipeline and any other safety considerations related to the release of CO_2.

Typical layout of an H-Stack vent station is illustrated in Figure 4-3, allowing for depressurization of either side of the Block Valve.

The vent stack may be equipped with a flow control valve connected to a temperature gauge on the pipeline. The set point for the control valve should be selected with a sufficient margin to the minimum pipeline design temperature so as to prevent the pipeline being exposed to sub-design temperature during venting.

Guidance note:
According to industry practice the control valve is often replaced with a sacrificial valve, as it is considered as a more cost efficient solution.

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An alternative to temperature control is pressure control since the temperature relationship with pressure can be determined.

Slow opening of all blowdown valves is recommended /4/.

Seal materials and lubricants should be selected in accordance with the recommendations given in Sec.5.3.1.

Due consideration should be given in the design of the vent system to the potential for very low temperatures down stream of the control valve due to the expansion and possibility for solid CO_2 creation. If solid CO_2 formation is possible, the vent design should minimize the potential for blockage.

To prevent the potential for solid CO_2 formation within the pipeline during venting, the pressure shall be maintained above the triple point of the inventory (i.e. 5.2 bar for pure CO_2).

In Sec.4.9 additional guidance regarding layout of vent stations are provided based on safety.

4.6.7 Submerged vent stations

For offshore pipelines, the feasibility of and requirements to submerged vent stations, shall consider relevant safety and environmental risks, such as risk of high CO_2 concentrations on the sea surface and potential acidification of the water column.

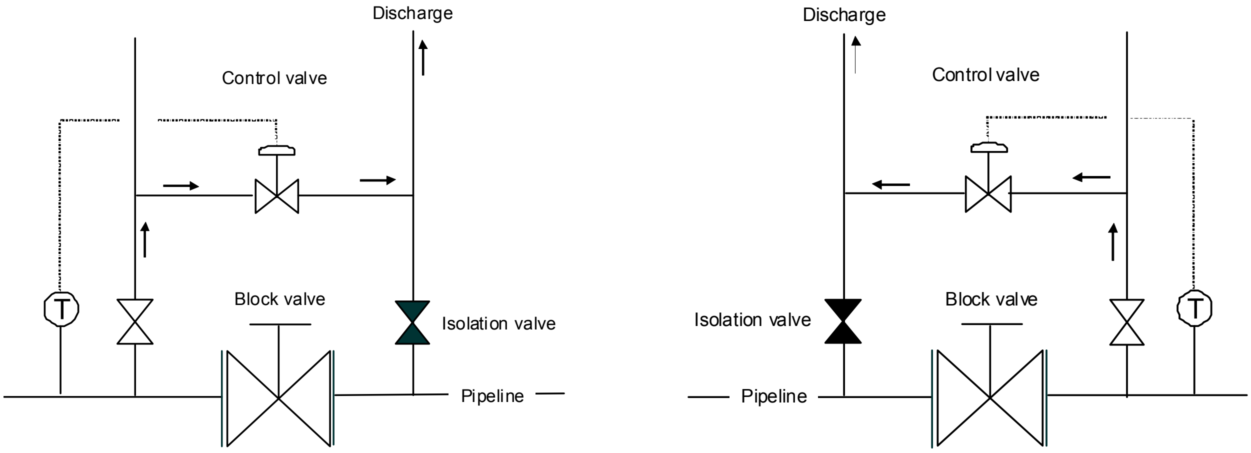

Figure 4-3
Schematic; H-Stack vent station; Depressurization of either side of block valve

4.7 Pipeline routing

4.7.1 General

The general recommendation with respect to CO_2 pipeline routing is that a standard approach as for route selection for hydrocarbon pipelines should be applied. The standards referred to in this RP, in combination with the specific CO_2 safety aspects described in Sec.3.3 and the pipeline design considerations provided elsewhere in Sec.4, should give the necessary guidance on CO_2 pipeline routing issues.

4.7.2 Population density

For onshore pipelines the population density should be determined according to ISO 13623; Annex B.3 and documented as illustrated in Figure 4-4. The distances used to determine the population densities should, until CO_2-specific distances are defined and stakeholder-accepted, be determined using dispersion modelling. The 400 m limit specified in ISO 13623 has not been validated for use with CO_2 pipelines.

Guidance note:

Due cognisance should be taken of the heavier than air characteristic of CO_2 and ground topography when determining the zone width along the pipeline, as required in ISO 13623; Annex B.3.

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For offshore pipelines surface vessel activity shall be considered in the same manner as for a natural gas pipeline.

4.8 CO_2 stream composition evaluations

4.8.1 Specifying the CO_2 stream composition

It is recommended that the CO_2 stream composition specification shall be determined based upon technological and economical evaluations, and compliance with appropriate regulations governing the capture, transport and storage elements of a CCS project.

Guidance note:

Yan et al. /13/ presents some ideas in assessing the techno-economical aspect in the CO_2 composition specification. The DYNAMIS project /12/ provides guidance on some likely concentration limits of selected impurities in the CO_2 stream for transportation in pipelines, based on CO_2 stream compositions from pre-combustion capture. These limitations do not necessary provide technical or operational limitation, and should be assessed from project to project. Reference is made to Table 2-3 for information regarding typical concentration ranges for components identified for various capture technologies.

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4.8.2 CO_2 composition in integrated pipeline networks

In case of mixing of different CO_2 streams in a pipeline network, it must be assured that the mixture of the individual compounds from the different CO_2 streams do not cause:

— Risk of water dropout due to reduced solubility in the comingled stream
— Cross chemical reactions /effects.

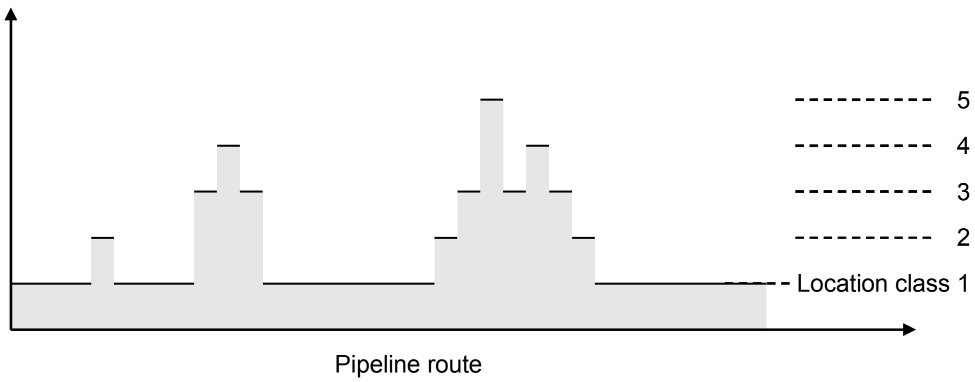

Figure 4-4
Visualization (example) of population density along pipeline route through Location class /ISO 13623; Annex B3/

4.8.3 Limitations on water content

Maximum water content in the CO_2 stream at the upstream battery limit shall be controlled to ensure that no free water may occur at any location in the pipeline within the operational and potential upset envelopes and modes, unless corrosion damage is avoided through material selection.

Guidance note:

The required maximum water content can be met by installing dehydration units in the intermediate compressor stages.

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The potential for water drop out should be calculated with reference to Sec.2.3.5 and according to the recommendations given in Sec.2.3.7 for the following operational modes:

— Normal operation pressure and temperature envelope
— Pipeline shut-in pressure combined with minimum ambient temperature
— Pipeline depressurization scenario.

For normal operation a minimum safety factor of two (2) between the specified maximum allowable water content and the calculated minimum water content that may cause water drop within the operational envelope should be specified.

For a pipeline shut-in case a minimum safety factor should be specified with reference to the shut-in condition. During a pipeline shut-in the pressure should be kept as high as practically possible to minimize risk of water drop out.

For pipeline depressurization it is likely that water drop out can not be prevented unless a very stringent requirement is specified for maximum water content.

Table 4-1 Indicative limits on maximum water content

Reference	*Maximum water content*				*Source of CO_2*
	lb/ MMScf	ppmW	ppmV	ppm Mol%	
/M. Mohitpour/	18 - 30	157 – 261			-
/KMCO$_2$/	30	261			CO_2 reservoir
/Statoil operated Snøhvit/			50		CH4+ Stream
/DYNAMIS/				500	CCS

Guidance note:

For an offshore pipeline operated in dense phase (i.e. above vapour liquid line), the minimum temperature is controlled by the ambient seabed temperature, i.e. typically ~5ºC. For an onshore pipeline the minimum temperature will be controlled by the minimum ambient design temperature.

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4.8.4 Limitations on content of toxic or environmentally hazardous substances

Limitations on content of toxic or environmentally hazardous substances shall be defined based on appropriate toxic harm criteria.

Guidance note:

The limitations on toxic substances in the CO_2 composition could be specified such that the harm criteria is determined by exposure limits for CO_2 rather than other toxic compounds /12/. It needs, however, to be documented that the combined hazardous effects are properly taken into account.

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4.8.5 Limitations on content of hydrocarbons

Hydrocarbons in the CO_2 composition should have a dew point such that condensation does not occur within the operational envelope (combined pressure and temperature) of the pipeline.

4.9 Vent stations

Vent stations should be designed and located to ensure the potential safety consequences of a depressurization is within the acceptance criteria both in terms of occupational health and 3rd party risk.

Potential for exposure of solid CO_2 particles and cryogenic exposure shall be considered.

As a general recommendation the vent stack should be pointing 45º from the horizontal plane in direction away from where exposure with CO_2 gives the highest consequences, ref Figure 4-5.

Dominant wind directions and topography effects should be considered when selecting location of vent stacks and vent orientation.

Height of vent stack should be assessed based on dispersion simulations and practical safety zones. Consideration should be given to vent tip design in the pursuit to maximising air mixing at the vent tip.

Noise generation from the vent tip shall be considered with reference to occupational health limits. Measures for noise reduction shall be considered as required.

In all cases, design and operation of vent stations should be based on a robust release consequence assessment of worst case reasonably foreseeable CO_2 flow and weather/environmental conditions.

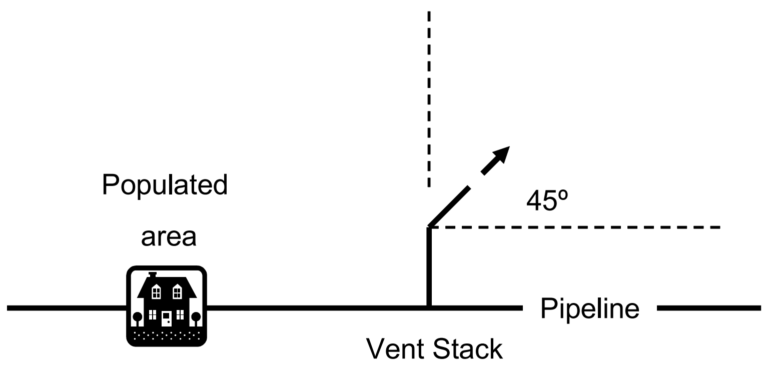

Figure 4-5
Configuration of vent stack

Guidance note:

The vent release consequence assessment should take due account of all the hazardous components within the CO_2 stream (e.g. H_2S). The consequence assessment should also use appropriate harm criteria noting that the harm level from two or more harmful substances, when mixed, may be less than, equal to, or greater than, the sum of the individual substances.

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5. Materials and pipeline design

5.1 Internal Corrosion

5.1.1 General

From the operational experience with onshore CO_2 pipelines in North America, internal corrosion is not reported as a significant pipeline failure mechanism resulting in other failure modes. According to U.S. Department of Transportation's Office of Pipeline Safety there are no reported pipeline damages caused by internal corrosion. Based on discussions with the pipeline operators, this is mainly a result of the high focus on controlling the water content in the CO_2 before entered into the pipeline, and the strict procedures for shutting down the line in case the dewatering system can not meet the specifications.

In the context of CCS, the CO_2 stream, depending on the source of CO_2 and capture technology applied, may vary from the CO_2 stream taken from natural geological CO_2 reservoirs. Added uncertainty in dewatering processes and water monitoring should be considered as part of pipeline design and operation.

Guidance note:

The most likely cause of off-spec water content is considered to be carry over of water/glycol from the intermediate compressor stages during compression of the CO_2 to the export pressure.

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Guidance note:

Potential for external corrosion is not considered significantly different for a CO_2 pipeline compared to hydrocarbon pipelines, hence the design principles provided in the existing standards should be followed.

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5.1.2 Internal corrosion rates

Field experience and experimental work show that dry pure CO_2 and pure CO_2 that contains dissolved water well below the saturation limit are non-corrosive to carbon steel at transportation pipeline operation conditions.

For a carbon steel pipeline, internal corrosion is a significant risk to the pipeline integrity in case of insufficient dewatering of the CO_2 composition. Free water combined with the high CO_2 partial pressure may give rise to extreme corrosion rates, primarily due to the formation of carbonic acid.

There are currently no reliable models available for prediction of corrosion rates with sufficient precision for the high partial pressure of CO_2 combined with free water.

Presence of other chemical components such as H_2S, NOx or SOx will also form acids which in combination with free water will have a significant effect on the corrosion rate.

Guidance note:

Based on the present understanding of CO_2 corrosion mechanisms at high partial pressure, there exists significant uncertainty, particularly considering the effects of other components in the CO_2 stream (typical components are listed in Sec.2.3).

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5.1.3 Internal corrosion control

The primary strategy for corrosion control should be sufficient dewatering of the CO_2 at the inlet of the pipeline.

No internal corrosion protection is required for C-Mn steel pipes provided that free water in the CO_2 stream is avoided through a strict humidity control procedure.

5.1.4 Internal corrosion protection-mechanical

For shorter pipeline sections internal polyethylene (PE) liners may be used for corrosion protection in areas where free water, hence corrosive service, may be present. Internal PE liners may be a cost efficient alternative to stainless steels.

When using PE liners the annulus between the PE liner and the outer C-steel pipe must be vented to avoid collapse of the PE liner in a pressure reduction situation /KMCO_2/.

5.1.5 Internal corrosion protection-chemical

Current knowledge and operational experience does not support that CO_2 corrosion rates in case of free water can be controlled using pH stabilization, hence this approach should not be applied without extensive qualification.

5.1.6 Internal corrosion allowance

The general recommendation is to operate the system such that internal corrosion is avoided through operational control, ref. Sec.5.1.3. Off-spec operations may occur and the likelihood of such events should be evaluated as part of the system design.

Corrosion allowance may be applied to the wall thickness for the complete pipeline or for shorter stretches. Tolerance to off-spec water content over shorter time periods may also be considered.

5.2 Linepipe Materials

5.2.1 General

The selection of materials should be compatible with all states of the CO_2 stream.

Candidate materials need to be qualified for the potential low temperature conditions that may occur during a pipeline depressurization situation.

5.2.2 Linepipe material

Carbon-Manganese steel linepipe is considered feasible for pipelines where the water content of the CO_2 stream is controlled to avoid formation of free water in the pipeline.

Application of homogenous corrosion resistant alloy (CRA) or CRA clad/lined linepipe may be an option, but normally only for shorter pipelines.

Guidance note:

Application of corrosion resistant alloys steels for longer pipeline sections is generally not considered feasible from a cost perspective.

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Candidate material types and compatibility with CO_2 are listed in Table 5-1. Pipelines with fluids containing hydrogen sulphide (H_2S) shall be evaluated for sour service according to ISO 15156.

Guidance note:

Parts of the CCS chain may be exposed to conditions where formation of free water may not be avoided. This may be in the capture part (source) and in the storage site (sink). E.g. injection wells may be exposed to CO_2 saturated water internally and externally and a CRA may then be needed.

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Table 5-1 Candidate material types compatible with dense and vapour CO_2

	No free water		With free water	
Material types	Pure CO_2	$CO_2 + H_2S$	Pure CO_2	$CO_2 + H_2S$
C-and low alloy steel	●	●		
304	●	●	●	●
316	●	●	●	●
13Cr	●	(●)	●	(●)
22Cr (duplex)	●	(●)	●	(●)
25Cr (duplex)	●	(●)	●	(●)
Nickel based alloys	●	●	●	●

Guidance note:

According to ISO 15156-3 type 25Cr is only marginally more resistant to H_2S cracking compared to 22Cr.

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5.2.3 Internal lining

A lined pipe is defined /DNV-OS-F101/ as a pipe with internal (corrosion resistant alloy-CRA) liner where the bond between the linepipe and liner is mechanical. Use of internal liner for corrosion protection is normally not a cost efficient option for longer pipelines, however, may be relevant for shorter section with insufficient control of water.

5.2.4 Internal cladding

A cladded pipe is defined /DNV-OS-F101/ as a pipe with internal (corrosion resistant alloy-CRA) liner where the bond between the linepipe and liner is metallurgical. Use of internal cladding for corrosion protection is normally not a cost efficient option for longer pipelines, however, may be relevant for shorter section with insufficient control of water content.

5.3 Non-linepipe materials

5.3.1 General

The selection of materials should be compatible with all states of the CO_2 stream. The fact that dense phase CO_2 behaves as an efficient solvent to certain materials, such as non-metallic seals, shall be considered.

With respect to elastomers, both swelling and explosive decompression damage shall be considered.

Candidate materials need to be qualified for the potential low temperature conditions that may occur during a pipeline depressurization situation.

Guidance note:

Swelling of the elastomers is attributed to the solubility/diffusion of the CO_2 into the bulk material.

Explosive decompression may occur when system pressure is rapidly decreased and the gases that have permeated into the elastomers expand. In the case of incipient damage, the elastomers will only show blistering, due to expansion of the diffused CO_2.

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5.3.2 Internal coating

Internal coating for either flow improvement or corrosion protection is generally not recommended due to the risk of detachment from the base pipe material in a potential low temperature condition associated with a too rapid pipeline depressurization.

Materials for internal coating or lining shall be selected with due regard to the partial pressure of CO_2 and the associated failure modes.

5.3.3 External coating

An incidental or uncontrolled depressurization of the pipeline may cause lower temperatures compared to traditional oil/gas pipelines, and hence the external coating for corrosion protection shall be qualified for these temperatures. Coatings qualified for traditional oil/gas pipelines may hence not be qualified for CO_2 pipelines due to lower design temperature.

Guidance note:

Failure of external coating due to exposure of low temperature resulting from a too rapid decompression has been experienced / KMCO$_2$/.

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The insulation properties of the external coating (including burial) shall be considered as part of the overall pipeline heat transfer coefficient, particularly related to the reduced heat ingress from the ambient temperature in case of planned or unplanned depressurization of the pipeline.

Guidance note:

Reduced heat ingress may affect the depressurization time of the pipeline.

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5.3.4 Non-metallic seals

High partial pressure CO_2 streams causes different types of deterioration mechanisms, in particular destructive decompression of o-rings, seals, valve seats etc. when the pressure is reduced from the liquid (dense) state to the vapour state of the CO_2 /4/.

Non-metallic materials shall be qualified to ensure:

- Ability to resist destructive decompression
- Chemical compatibility with CO_2 and other chemical components in the CO_2 stream (ref. Sec.2.3) without causing decomposing, hardening or significant negative impact on key material properties
- Resistance to full temperature range.

Guidance note:

Elastomers have usually more free volume in their structure compared to partly crystalline thermoplastics. As a consequence they are more permeable to gases and liquids and more vulnerable to fracture and cracking in cases of rapid gas decompression when they are saturated with gas under high pressure.

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5.3.5 Lubricants

Petroleum based greases and many synthetic types of greases, used in pipeline components such as valves, pumps etc., are deteriorated by CO_2 /4/. The compatibility of the applied grease with CO_2 shall be documented for the specified CO_2 composition and operating envelope in terms of pressure and temperature.

This recommendation applies in particular to safety critical valves such as block valves, check valves and pressure relief valves where lubrication may significantly affect the ability of the valve to operate in an emergency situation.

5.3.6 Materials testing and qualification standards

For testing of resistance of elastometric materials resistance to decompression, reference is made to the following standards:

- NACE TM0192-2003, Evaluating Electrometric Materials in Carbon Dioxide Decompression Environments
- NACE TM 0297-2002, Effects of High-Temperature, High-Pressure Carbon Dioxide Decompression in Electrometric Materials.

Table 5-2 Utilization factors onshore /ISO 13623, Sec.6.4.2 Strength Criteria/						
Location	*Fluid Category C*	*Fluid category D and E*				
		Location Class (Population density)				
		LC1	LC2	LC3	LC4	LC5
General Route	0.77 (LC>1) 0.83 (LC1)	0.77 (E) **0.83 (D)**	**0.77**	**0.67**	**0.55**	**0.45**
Crossings and parallel encroachments						
— minor roads	0.77	**0.77**	**0.77**	**0.67**	**0.55**	**0.45**
— major roads, railways, canals, rivers, diked flood defences and lakes	0.67	**0.67**	**0.67**	**0.67**	**0.55**	**0.45**
Pig traps and multi-pipe slug catchers	0.67	**0.67**	**0.67**	**0.67**	**0.55**	**0.45**
Special constructions such as fabricated assemblies and pipelines on bridges	0.67	**0.67**	**0.67**	**0.67**	**0.55**	**0.45**

5.4 Wall thickness design

5.4.1 General

The wall thickness is normally governed by pressure (internal and external) containment criterion. However, there are also other factors that may determine wall thickness:

— For pipelines where pressure containment requires a thin wall thickness, a higher wall thickness may be used if failure statistics indicate that impact loads and corrosion are the most likely causes of failure and have the decisive effect on thickness design.
— Installation method (reeling, offshore).

5.4.2 Pressure containment design

For onshore pipelines the allowable hoop stress design factors (yield strength utilization factor) should be specified according to ISO 13623; Annex B5, with reference to location classes and factors for category D fluid, ref. Table 5-2 (recommended utilization factors for CO_2 are given in bold). Note that the utilization factors for category C fluids are listed in the table as a reference.

Guidance note:

Compared to categorizing CO_2 as a C fluid, the current recommendation imply no change in design factors for LC1 and LC2 representing locations subject to infrequent human activity and without permanent human habitation and population density of less than 50 persons per square kilometre, respectively.

Design factor of 0.83 is allowed according to ISO 13623 for pipelines conveying category C and D fluids at locations subject to infrequent human activity and without permanent human habitation (such as tundra and desert regions).

The utilization factors above are equivalent to what is included in DNV-OS-F101, however, the pressure containment format is expressed differently.

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For offshore pipelines the allowable hoop stress design factors should be specified according to ISO 13623 for category D fluids, ref. Table 5-3 (recommended utilization factors for CO_2 are given in bold). Alternatively, DNV-OS-F101 may be used.

Table 5-3 Utilization factors offshore /ISO 13623, Sec.5.4.2 Strength Criteria/	
General route	*0.77*
	0.83
Shipping lanes, designated anchoring areas and harbour entrances	**0.77**
Landfalls	**0.77**
Pig traps and multi-pipe slug catchers	**0.67**
Risers and primary piping	**0.67**

Guidance note:

Design factor of 0.83 is allowed according to ISO 13623 for pipelines conveying category C and D fluids.

Utilization factor of 0.67 for landfall location may be relevant in case frequent human activity in the landfall area.

The utilization factors in the table (0.83-0.77-0.67) are equivalent to DNV-OS-F101 utilization for safety class low-medium-high. Reference is given to DNV-OS-F101 Sec.1 A604 and Sec.13 E400.

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5.4.3 Local buckling - Collapse

For design requirements for resisting external over pressure, reference is given to DNV-OS-F101 Sec.5 D400.

5.4.4 Local buckling - Combined loading

For design requirements for resisting combined loading from pressure, axial force and bending, reference is given to DNV-OS-F101 Sec.5 D600. Fulfilment of combined loading criterion is not achieved by increasing the wall thickness (the only common exception is reeling installation).

5.5 Running ductile fracture control

5.5.1 General

The pipeline shall have adequate resistance to propagating fracture. The fracture arrest properties of a pipeline intended for transportation of a CO_2 composition at a given pressure and temperature depends on the wall thickness of the pipe, material properties, in particular the fracture toughness, and the physical properties of the CO_2 composition in terms of saturation pressure and decompression speed. Adequate resistance to propagating fracture may be achieved by using; material with low transition temperature and adequate Charpy V-notch toughness, adequate drop wear tear testing, shear fracture area, lowering the stress level, use of mechanical crack arrestors or by a combination of these methods. The pipeline should be designed such that the rupture is arrested within a small number of pipe joints. Alternatively, fracture arrestors may be used.

Design solutions shall be validated by calculations based upon relevant experience and/or suitable tests. Requirements to fracture arrest properties need not to be applied when the pipeline design tensile hoop stress is below 40% utilization.

The fracture control design philosophy may be based on ensuring sufficient arrest properties of the linepipe base material to avoid ductile running fractures or installation of fracture arrestors at appropriate intervals.

5.5.2 Particular issues related to CO_2

To prevent ductile running fractures, the decompression speed of the fluid needs to be higher than the fracture propagation speed of the pipe wall, i.e. if the decompression speed outruns the fracture propagation speed, the fracture will arrest.

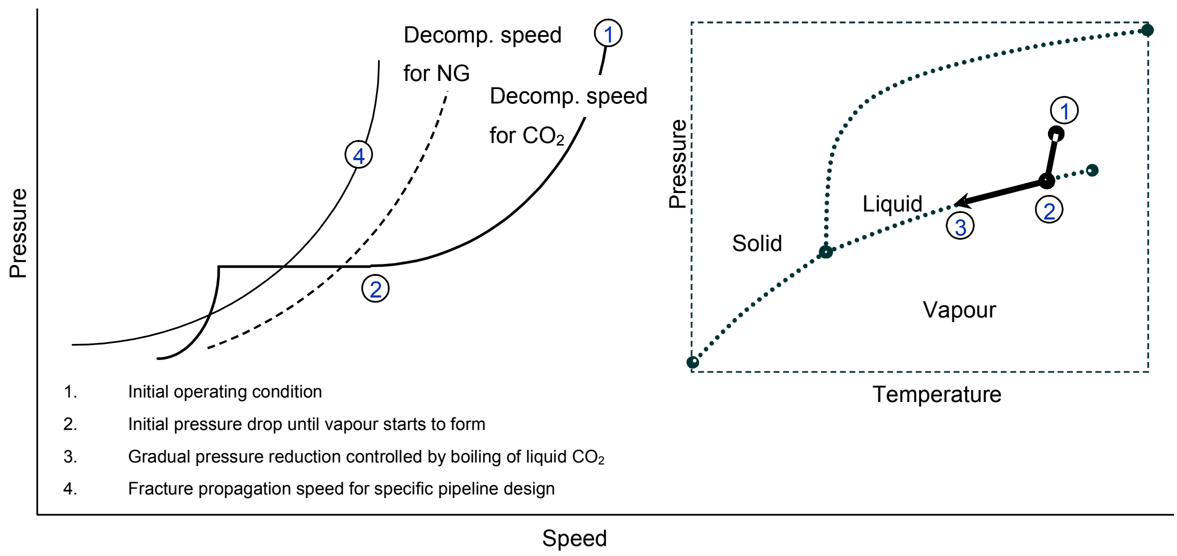

Figure 5-1
Schematic; Particular effects of decompression speed for CO_2 relative to fracture propagation speed of pipe wall; Insert figure shows schematically phase envelope for pure CO_2

The particular issue related to CO_2 is the step change in rapid decompression speed as the pressure drops down to the liquid-vapour line (saturation pressure), ref. Figure 5-1. Compared to natural gas, the decompression speed of liquid CO_2 may be significantly higher. However, as vapour starts to form, the decompression speed of the CO_2 stream drops significantly.

To that extent running ductile fractures is a higher concern for CO_2 pipeline compared to e.g. natural gas pipelines, this needs to be related to the design pressure of the pipeline. For low design pressure (typically less than 150 bar), CO_2 pipelines may come out worse compared to natural gas pipeline. This may, however, not be the case for higher design pressure, ref. Sec.5.5.4.

Decompression speed is influenced by:

— CO_2 composition (effect of other components than CO_2 on liquid-vapour saturation line); Impurities with a lower critical temperature than CO_2, such as Methane, Nitrogen and Hydrogen will increase the toughness required to arrest ductile fracture /6/.
— The initial operating pressure; Higher pressure yields higher decompression speed
— Pipeline operating temperature; Higher temperature yields higher saturation pressure.

A numerical model for prediction of the decompression of outflow behaviour must be capable to deal with a high transient flow and therefore requires tracking of the expansion wave and the propagation as function of time and distance along the pipeline length.

Guidance note:

Different amount of other chemical components in the CO_2 composition will affect the Liquid-Vapour line and subsequently the decompression speed and needs to be considered.

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5.5.3 Fracture control plan

A fracture control plan should be established, and should consider fracture initiation control and fracture propagation control, ref. Figure 5-2.

Fracture initiation control should be considered a first barrier, and propagation control a second barrier.

Guidance note:

It should be noted that there are different mechanisms causing fracture initiation compared to fracture propagation.

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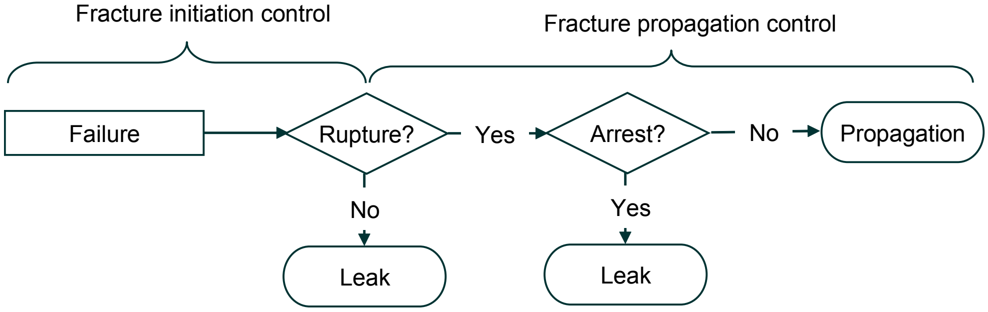

Figure 5-2
Fracture control plan; /A. Cosham, R. Eiber/

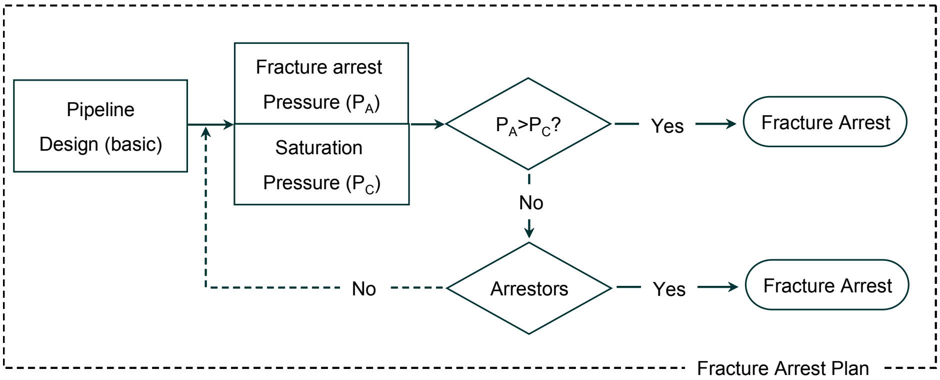

Figure 5-3
Fracture propagation control

5.5.4 Procedure for evaluating fracture propagation control

A coarse assessment of fracture arrest may be performed through the following steps, ref. Figure 5-3:

Step 1: Determine Fracture Arrest pressure (P_A) based on proposed pipeline design in terms of pipeline diameter (D), wall thickness (t) and material specifications.

Step 2: Determine the critical pressure (P_C) based on CO_2 stream composition

Step 3: If $P_A > P_C \rightarrow$ Fracture Arrest

It should be noted that for a CO_2 stream containing a significant fraction of non-condensable gases, such as H_2, the above approach may be non-conservative.

As a consequence of the above approach, low (design) pressure pipeline (thin-walled) will have a lower margin between arrest pressure (P_A) and saturation pressure (P_C), hence be more susceptible to running ductile fractures.

If the coarse assessment described above does not demonstrate sufficient margin between P_A and P_C, the TCM approach, described in Sec.5.5.5 should alternatively be applied.

Guidance note:

High content of non-condensable gases leads to a phase envelope that extends to higher pressure. This needs to be taken into account in terms of at what pressure vapour starts to form during pressure reduction.

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5.5.5 Two curve model approach

If sufficient margin between arrest pressure and saturation pressure can not be documented based on the approach described in Sec.5.5.4, a two curve model (TCM) may be applied (e.g. the Battelle TCM approach)

Applying the Battelle TCM approach the following should be considered:

- Decompression speed for product composition
- Fracture propagation speed.

Guidance note:

The Battelle TCM is an empirically derived parametric model validated for Natural Gas and liquids by large scale tests. Even though a number of tests has been performed for liquids resembling liquid state CO_2, at the time of publication of this RP it has not yet been sufficiently validated with CO_2 as test medium.

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5.5.6 Determination of decompression speed

Determination of decompression speed for CO_2 streams has successfully been performed using transient multiphase solvers, simulating a pipeline rupture. The decompression speed curves are then used as input to the TCM approach together with the fracture propagation speed, ref. Sec.5.5.7.

Guidance note:

The flow solver, Equation of State (EOS) and simulation set-up needs to be able to sufficiently account for the rapid transients occurring during the rupture scenario.

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5.5.7 Determination of fracture propagation speed

Fracture propagation speed for a given pipeline design may be obtained from:

- Empirical correlation to Charpy-V Notch (CVN) impact or Drop Weight Tear tests at operating temperature, including de-rating term for measured CVN>95J
- Burst testing
- FEM Simulations.

Guidance note:

Fast propagating ductile fracture may potentially be evaluated by numerical methods such as FE-simulations as an alternative, or in addition, to empirical based methods (such as the Battelle two curve method). However, this requires a robust and reliable coupling with a description of gas pressure acting on the pipe and the corresponding gas outflow and gas decompression behaviour. If numerical simulations are used, it is recommended to carry out mesh sensitivity studies to evaluate the effect of characteristic element length on the predicted structural behaviour. FE-simulations should be used with great care, and it is recommended to ensure that conservative assumptions are made both for the mechanical properties of the pipeline and the gas pressure.

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Guidance note:

Further R&D work is required to develop validated and robust numerical methodologies for prediction of running ductile fracture, and of decompression flow in CO_2 pipelines in the case of running ductile fracture. At the time of publication of this RP, further R&D work on running ductile fracture was being planned; the designers and developers of CCS CO_2 pipelines should employ the latest knowledge on this subject in the development of the their pipeline systems.

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5.5.8 Fracture arrestors

In case neither fracture initiation control nor fracture propagation control is ensured by other means, fracture arrestors should be installed.

The feasibility and type of fracture arrestors should be documented.

Spacing of fracture arrestors should be determined based on safety evaluations and cost of pipeline repair.

Guidance note:

Use of fracture arrestors in the CO_2 pipelines operated in the United States is considered standard practice /KMCO$_2$/. One operator has provided feedback that they typically install arrestors every 300m (1000') /4/, based on a "spares in stock" philosophy. Some of these pipelines may, however, be constructed from linepipe with lower fracture toughness compared to what is available today.

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Guidance note:

The safety risk associated with a running ductile fracture may not necessarily be significantly worse compared to a local guillotine rupture; safety risk assessment needs to be performed to assess this. The possibility of a running ductile fracture to propagate from a lower to a higher location zone should be considered.

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5.6 Fatigue

5.6.1 Particular aspects related to CO_2

On the condition that no free water is present at any location in the pipeline, fatigue is not considered a significantly higher concern for a CO_2 pipeline than for hydrocarbon pipelines, hence standard design codes may be applied /e.g. DNV OS-F101/.

5.6.2 Particular issues related to off-spec water content

If liquid water in any quantity will be present in the transported medium, the design S-N curve must be established by laboratory testing in an environment similar to the actual operating conditions.

Reference is made to DNV-RP-C203 for fatigue strength analysis, and for guidance on fatigue testing to establish a new S-N curve.

Guidance note:

In the occurrence of free water, corrosion fatigue is a potential concern; however, limited published data are available.

It is recommended to perform further studies to assess the combined effects of dense phase CO_2 and free water.

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5.6.3 Effect of other components

In the presence of free water, the potential effects of other components in the CO_2 stream are listed in Table 5-4.

Table 5-4 Potential effect of other components on fatigue life

Component	*Potential effects related to fatigue*	*Requires Free water*
H_2S	Corrosion assisted fatigue	•
SO_2	Corrosion assisted fatigue	•

5.7 Hydrogen Embrittlement

It is not expected that hydrogen embrittlement is a more sever concern for CO_2 transport than for Natural Gas. Equivalent considerations should be done in accordance with recognized standards.

6. Construction

6.1 General

The construction phase is initiated at the time of ordering the steel on the basis of the selection requirements as provided from design. Components and linepipe for the pipeline system is then to be manufactured and assembled in accordance with the requirements as given from the design.

The requirements with respect to construction have not identified specific needs for CO_2 pipeline systems. The standards referred in this document should give the necessary guidance in combination with the specific design considerations as provided by the previous sections.

In pre-commissioning phase there are some issues that are described in the following section.

6.2 Pre-Commissioning

6.2.1 General

Pre-commissioning activities are performed to prepare the pipeline system to be ready to be put into operation. This requires cleaning of the system (debris) and system testing activities and preparation to fill the pipeline system with the fluid intended for operation.

The standards as referred by this document have guidance on the issue of pre-commissioning activities and relevant considerations. In the following some specific considerations for the pre-commissioning activities are given.

6.2.2 Pressure testing

System pressure integrity shall be confirmed through:

- Strength testing
- Leak testing.

The intension of the strength test is to ensure minimum yield strength (e.g. SMYS).

The intension of the leak test is to confirm that the pipeline system has containment integrity as required.

Standards may deviate as toward the regime implied by pressure testing, e.g. DNV-OS-F101 require pressure strength testing as a mill test of each pipe joint and the pressure leak test on the system level.

For pressure test requirements to onshore pipelines, reference is given to ISO 13623, while for offshore pipelines reference is given to DNV-OS-F101.

Invoking Annex B.6 of ISO 13623, the requirements to pressure test (based on the population density and concentration of people in the vicinity of the pipeline) for category D and E fluids should be applied for onshore pipelines (see Sec.3.2.2).

Fresh water is preferred for pressure testing (i.e. testing with an incompressible fluid).

Air, N_2 and CO_2 may be used in remote areas subject to a risk assessment (ref. guidelines provided in PHMSA §195.306).

Guidance note:

Performing the system pressure leak test with e.g. air or N_2, visual inspection of the entire pipeline length will likely be required to confirm that the pipeline is free of leaks.

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6.2.3 Dewatering and drying

Special attention should be given to dewatering of pipeline system prior to filling with CO_2. The high solubility of water in dense phase CO_2 may be beneficial as to ease the requirement to drying compared to gaseous state. It should, however, be noted that in the initial stage of the first-fill, the CO_2 will be in gaseous phase.

Due to the particular corrosion issues the pipeline should be dried to a dew point of -40 ºC to -45ºC (at ambient pressure) before filling with CO_2 /KMCO$_2$/, /4/.

6.2.4 Preservation

The need for conservation of the pipeline between pre-commissioning and commissioning phases should to be assessed. Gas such as N_2 and dry air may be used for conservation of the pipeline, but the requirement to the gas quality needs to be assessed.

Preservation should be selected with proper consideration toward the commissioning requirements. This may include requirements for internal pressure.

7. Operation

7.1 General

The purpose of this section is to provide minimum requirements for the safe and reliable operation of pipeline systems for the whole service life with focus on pipeline integrity management (PIM).

Integrity management for CO_2 pipelines should be treated differently than for natural gas or hazardous liquid pipelines because CO_2 lines present different operating challenges and they pose different threats and consequences. The following sections cover those aspects of commissioning and integrity management that require additional consideration for CO_2 pipelines relative to other pipelines.

7.2 Commissioning

7.2.1 General

The operator needs to perform the required risk assessment for the particular system and to establish proper commissioning procedures.

The constraints for operation of the pipeline need to be taken into considerations in the commissioning. Assurance that the pipeline is filled with a fluid quality in accordance with the requirements at the receiving end concludes the commissioning phase.

7.2.2 Initial filling with product

Before initial filling, the pipeline is considered to be in the condition as defined by the pre-commissioning.

Mixing of CO_2 and the pre-commissioning substance should be considered as part of this activity. Experience shows that dense phase CO_2 and N_2 do not always mix well and therefore a pig between the two media may be required.

Low CO_2 temperatures shall be considered during first fill operation as the CO_2 stream may have to be throttled downstream the export compressor until a sufficiently high pressure is reached. Risk of forming solid CO_2 as a result of the throttling process shall be considered.

7.2.3 First/initial/baseline inspection

For pig-able pipelines it is recommended to perform a first/baseline/initial intelligent pigging before the pipeline is put into operation. This inspection will determine the condition of the pipeline and be used as a reference for later inline inspections. In addition the results will be used as input to the first inspection plans, see Sec.7.8.

7.3 Integrity management system

7.3.1 General

The basis for a safe and reliable operation of a pipeline is the Integrity Management System or IMS. *IMS* is comprised of many elements and the terminology of the elements may differ in different codes and standards (ref. DNV-RP-F116, API 1160, ASME 31.8S). The operator must be aware about differences between onshore and offshore pipelines with respect to IMS.

Figure 7-1 shows some of the more common elements which are defined in DNV OS F-101 and DNV-RP-F116.

The core of the IMS is the IMP, the Integrity Management Process, ref. Sec.7.7. The IMP includes risk assessments, integrity assessments, inspections, operation, maintenance, repairs, etc. Other parts of the *IMS* support the *IMP,* such as operational controls and procedures, contingency plans etc.

Additional considerations, specific to CO_2 shall be determined and must be addressed in the Integrity Management System and Integrity Management Plan. In this document only the identified CO_2 specific issues will be presented, for general information on company policy, reporting and communicating, management of change, information management and audit and review see DNV-RP-F116.

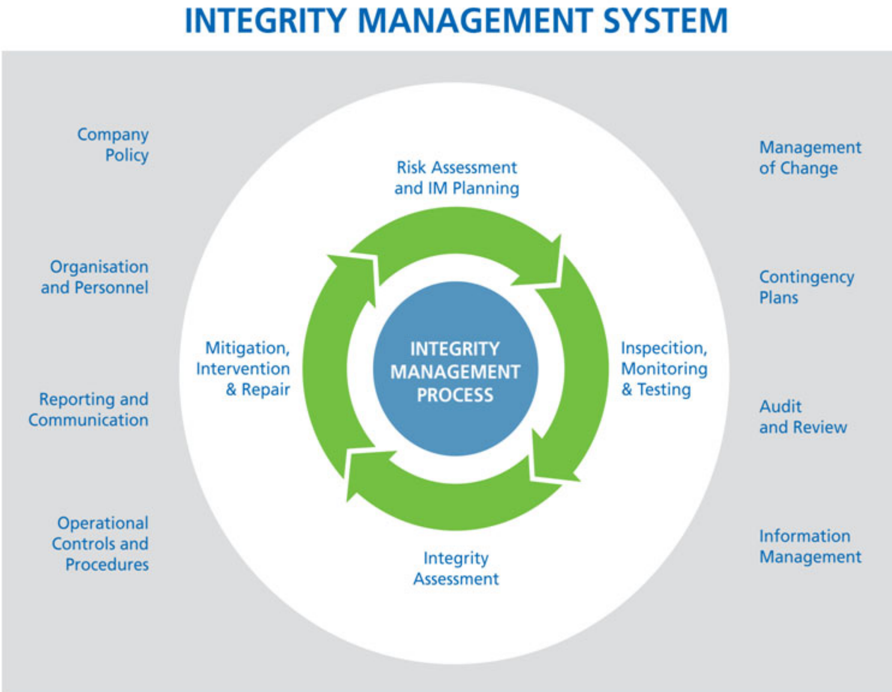

Figure 7-1
Integrity Management System DNV-RP-F116

7.4 Organization and personnel

7.4.1 General

Organization and personnel are defined in DNV-RP-F116.

7.4.2 Training of personnel

The roles and responsibilities of personnel involved with integrity management of the pipeline system shall be clearly defined. Training needs shall be identified and provided for relevant personnel in relation to management of pipeline integrity. Roles and responsibilities, related to safeguarding the integrity of the pipeline system should be clearly defined.

Additional training, above that required for hazardous liquid and natural gas pipelines, may be necessary for personnel working with CO_2 pipelines, also see Sec.7.5.4.

7.5 Contingency plans

7.5.1 General

Contingency plans cover procedures and plans for emergency situations which shall be established and maintained based on a systematic evaluation of possible scenarios. Also contingency repair procedures are a part of contingency plans.

7.5.2 Emergency response plan and procedures

Emergency response plan shall be developed and communicated considering the major accident hazard (MAH) related specifically to CO_2 pipelines.

7.5.3 Pipeline depressurization

Safety issues related to pipeline depressurization need to be considered. Safety zones in the vicinity of the vent stations need to be established and controlled during a vent situation.

Procedures for determining safety zones should be based on the defined depressurization rate and corresponding consequence zones calculated according to recommendations given in Sec.7.6.5.

7.5.4 Safety issues related to pipeline inspection and repair

When working in a pipeline trench (under repair) the O_2 and CO_2 levels shall be monitored inside the trench. Other chemical components in the flow shall also be considered subject to monitoring if these may provide an increased health risk compared to the monitoring and threshold for CO_2 in view of potential leaks.

CO_2 concentration should not exceed 0.5-1% (occupational health limit for 8 hrs day shift).

Guidance note:
For existing onshore CO_2 pipelines, large portable fans are often used to push fresh air into the trench and maintain a non-hazardous environment.

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7.6 Operational controls and procedures

7.6.1 General

Operational controls and procedures are defined in DNV-RP-F116.

7.6.2 Ramp-up and ramp-down of transmission rate

Ramp-up and down should be done manually, with reference to a thermo hydraulic model.

Guidance note:
Ramp-up and down may cause vapour formation at pipeline high points with an increased risk for internal corrosion to occur, depending on the inventory pressure and temperature conditions.

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7.6.3 Leak detection

Computational pipeline monitoring (CPM) is most widely used technique for leak detection. These methods use flow, pressure, temperature and other data provided by a SCADA system, and can be divided into four types:

— Flow or pressure change
— Mass or volume balance
— Dynamic model based system
— Pressure point analysis.

In addition to these methods there are methods that utilize statistical models to validate pipeline data in order to decide if there is an increase in the flow imbalance.

Gas detectors may also be used as part of the risk management strategy for a pipeline. A risk based approach is recommended to determine the need for, and location of, gas (and other) detectors.

Guidance note:

For human detection of leaks from an onshore pipeline release of CO_2 to the ambient conditions, a visible cloud that consists of a mixture of solid CO_2 particles mixed with condensed water ice crystals and condensed water vapour is likely to be formed close to the leak point. Further from the leak point the CO_2 solids will be either sublimed into invisible CO_2 vapour or dropped out onto the ground. The remaining cloud will be condensed water vapour due to the cold CO_2 stream that is condensing the water in the air (see Sec.3.3.6 for details). For subsea releases this may not be the case since the CO_2 is heated to ambient (water) temperature before released to air at the sea surface.

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7.6.4 Pipeline shut-in

A pipeline shut-in procedure should be established.

Pipeline shut-in should be performed carefully and in a controlled manner. The shut-in procedure may depend strongly on the pipeline layout and utility system, hence should be established for each specific pipeline.

During a planned shut-in the pressure in the pipeline should be kept sufficiently high to prevent:

— Vapour from forming
— Risk of forming a free water phase.

Guidance note:

Vapour formation may cause upsets during re-start of the pipeline.

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Guidance note:

Ability of dense phase CO_2 to dissolve water is reduced with reduced pressure.

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In case there is a risk of temperature increase during shutdown, i.e. due to higher ambient temperature, the potential increase in pressure shall be considered with reference to the overpressure protection system.

Guidance note:

This is of particular importance when shutting in a shorter section of pipeline and/or where the shut-in condition is near the critical point.

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7.6.5 Pipeline depressurization

A procedure for planned depressurization should be established. The procedure should consider the pipeline layout in terms of segmentation as well as location, capacity and function of vent stations.

Based on operational experience with existing CO_2 pipelines, one of the main concerns related to pipeline depressurization are the potential risks associated with low temperature effects and formation of solid state CO_2 at low points in the pipeline. The temperature reduction inside the pipeline relates to the pipeline design, operating conditions, ambient conditions and depressurization rate.

The pipeline should be operated to minimize the number of planned depressurizations.

Simulations should be performed to determine the thermo hydraulic response of the pipeline or pipeline segment. The depressurization procedure should document with sufficient margin that:

— Local pipeline temperature less than the design temperature does not occur, including steel pipe as well as internal and external coatings
— Local pressure is maintained above the triple point pressure so as to prevent solid CO_2 formation.

Configuration of vent stations, ref. Sec.4.6.6.

Since the density of solid state CO_2 is higher than liquid state CO_2, formation of solid state CO_2 will not cause internal frost wedging of the pipeline.

Guidance note:

Depressurization of a long pipeline section may take considerable amount of time (e.g. days), and will have impact on the availability of the pipeline. This concern applies both to planned and unplanned depressurization events. Temperature measurement and control should be used for controlling the depressurization rate.

If the temperature becomes low enough, the pipe material may become brittle, in worst case causing pipeline rupture.

If solid CO_2 is formed, a considerable amount of time may be required for the CO_2 to sublimate to vapour. The sublimation time will depend on the ambient temperature and the pipeline insulation properties.

Solid CO_2 deposits will be at pipeline low points which may plug the pipeline.

Re-introduction of dense phase CO_2 into a pipeline which has (or could have) significant solid CO_2 deposits must be avoided. The consequence of the very rapid sublimation of solid CO_2 to vapour, with the corresponding 750 times increase in volume could lead to over pressurization of the containment envelope.

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7.6.6 Thermo-hydraulic model

A thermo hydraulic model for the pipeline should be established and applied as basis for monitoring the pipeline operating conditions. The model should be calibrated with measurements (pressure and temperature) from actual operating conditions.

7.6.7 Flow measurement

Accurate flow measurement may be required for the purpose of leak detection or fiscal metering, Sec.7.9.4.

In relation to CO_2 tax or cap-and-trade regimes the measured amount of CO_2 stored may be required as input to the documentation of the amount of CO_2 released to the atmosphere within the CCS chain. The needed accuracy of the flow measurements should be evaluated, considering that measurement uncertainty of the amount of CO_2 released might have to be incorporated.

7.6.8 Fracture control plan

A fracture control plan and a procedure for evaluating fracture propagation control should be established, see Sec.5.5.3 and Sec.5.5.4 respectively.

7.6.9 In-line inspection procedure

Procedures for launching and receiving an in-line inspection tool should be developed, Sec.7.9.1.

7.6.10 Maintenance valves and sealings

See sections 5.3.4 and 5.3.5 for maintenance and lubrication of

seals, respectively. This must be reflected in the maintenance plan and procedures.

7.7 Pipeline integrity management process

An Integrity Management Process plan (IMP) specific to the CO_2 pipeline system shall be established.

An *IMP* is the specific set of steps and analyses that are conducted to assess and maintain the integrity of a pipeline. The IMP incorporates numerous elements and activities that shall include, but not be limited to, the following:

— Risk assessment activities and integrity management planning (Sec.7.8)
— Integrity assessment activities, including inspections and other activities used to assess the current condition of a pipeline. Also included here are analyses of severity of anomalies or defects in the line and root cause analyses, when appropriate (Sec.7.9, Sec.7.10)
— Response activities, including repairs and mitigation. They also include planning for reassessments and long-term monitoring (Sec.7.11).

The elements of an IMP may differ between pipeline segments and between onshore and offshore applications.

7.8 Risk assessment and IM planning

7.8.1 General

As a part of the *IMP* an operator shall conduct risk assessments based on collected data, identified threats and consequences that could affect the integrity of the CO_2 pipeline system it operates.

The output of the risk assessment gives inspection plans which are the basis for inspections. The first inspection/baseline/initial inspection together with the design, fabrication and installation documentation shall be the input to the first inspection plan.

7.8.2 Data collection

Types of data which may be required in an IMP to evaluate CO_2-specific threats and consequences are shown in Table 7-1.

To the extent practical, the risk assessments should also take into account the results from monitoring (Sec.7.9) and the emergency response plan (ref. Sec.7.5.2).

Data required for the Integrity Management Process specific to the CO_2 pipeline system shall be identified, gathered, aligned, integrated, and reviewed.

7.8.3 Integrity Threat Identification

The likelihood of all threats that could affect the integrity of the CO_2 pipeline system shall be identified and estimated. Each threat is a potential source for failure.

It could be assumed that a CO_2 pipeline would be susceptible to the same threats as a gas or liquid pipeline; however, there are different threats that are specific to CO_2 pipelines as defined in Table 7-1.

Some of the threats listed in Table 7-2 are shown as both “Typical to Any Pipeline” and “Specific to CO_2 Pipelines”, as there are additional or different issues related to these threats for a CO_2 pipeline. The threats are divided into time-dependent, time-independent and operational.

Table 7-1 Data collection CO_2-specific threats and consequences

Data required for IMP	*CO_2-specific threats and consequences*
Design data	The pipeline system has been designed with a set of premises. These premises should be part of the integrity management system. The threats to the system are based on these data, hence the system must operate within the defined limits. Re-assessment activities may change the premises which will change the threats and consequences. Documentation is to be considered as part of the IMP
Attribute Data	Seam weld type (affects surface breaking seam-weld anomalies that may be exposed to CO_2) Pipe manufacturer, manufacturing date, and manufacturing method (similarly affects surface breaking pipe-body anomalies that may be exposed to CO_2) Corrosion allowance on wall thickness
Construction Data	Pressure test/line drying procedure (affects residual water present when line is filled) Inspection reports (identifies types and potential impact of anomalies introduced during construction)
Operational Data	Normal, upset, and maximum allowable water content (along with other components, affects the potential for internal corrosion; water content in a CO_2 pipeline will typically be controlled such that free water, under anticipated operating conditions, does not occur) Hydraulic profile during operations, filling, shut in, shutdown, and decommissioning (affects stresses due to pressure; also affects the ability of dense phase CO_2 to contain water) Temperature profile during normal operations and under upset and shut in conditions (affects mass density/transportation capacity; affects whether CO_2 remains in dense phase) Normal, upset, and maximum allowable levels of other components (affects phase changes that may occur with pressure changes; also impacts safety (exposure to H_2S, SO_2…) and material compatibility (H_2S, O_2,…) Glycol carryover (may affect presence and location of free water) Hydrate formation (hydrate formation is not normally a concern for onshore lines due to their relatively high temperatures, around 60°F, but it may be a concern offshore) Flow control data (affects pressure drops and hydraulic profile along the pipeline) Depressurization history
Internal Corrosion Control Data	Inhibitor usage, including monitoring data Oxygen content pH stabilizers Corrosion monitoring, including but not limited to coupons
Maintenance, Inspection, and Other	In-line inspection data (quantifies the types, locations, and sizes of some anomalies) Monitoring and inspection data related to non-metallic components, such as elastomers Results from leak detection monitoring

Table 7-2 Identified threats to CO_2 pipelines categorized into "CO_2 specific" and "typical for any pipeline"

Threat	*Typical to Any Pipeline*	*Specific to CO_2 Pipelines*
Time Dependent		
External corrosion	●	
Internal corrosion	(●)	●
Stress Corrosion Cracking	●	
Fatigue	●	●
Degradation of materials	●	●
Manufacturing, welding, and equipment defects exposed to CO_2	●	
Stable		
Manufacturing and welding defects not exposed to CO_2	●	
Time Independent		
Third Party Damage	●	
Incorrect Operations	●	
Weather/Outside Force	●	
Equipment defects not affected by CO_2	●	
Equipment Failure	●	●
On-bottom Stability	●	●
Operational		
Repair/Welding Issues		●
Shut in		●
Blow Down/ Depressurization		●

7.8.4 Consequence identification and evaluation

All consequences resulting from failures shall be identified and considered. These consequences and their resulting impact areas are to be used to assess risk and to prioritize inspection, repair, and mitigation activities associated with the IMP.

The consequences of releases due to threats that could affect the integrity of the CO_2 pipeline system it operates shall be identified and estimated.

7.9 Inspection, monitoring and testing

7.9.1 In-Line Inspection

It shall be ensured that the in-line inspection tool to be used is compatible with pressures and CO_2 phases that may be present along the CO_2 pipeline system. Difficulties specific to CO_2 pipelines include but are not limited to those related to material compatibility, high pressures, diffusion of high pressure CO_2 into electronic components, speed control, and cup wear:

Industry experience with inline inspection of CO_2 pipelines is limited to relatively small pipeline diameters and pipeline lengths.

Typical failure modes are:

— Damage to the data recording units due to explosive decompression (i.e. data are lost) when the pig is taken out of the trap
— Wear to the disk plates (cups) or seals due to poor lubrication characteristics of CO_2.

Special polymers are required, i.e. materials that are not susceptible to explosive decompression effects.

Detailed procedures for launching and receiving an in-line inspection tool in a CO_2 pipeline shall be developed, in order to ensure that the compression/blow-down process does not create temperatures damaging to the tool or harmful to nearby personnel.

Guidance note:

Further technology qualification of in-line inspection tool solutions that can run in dense phase CO_2 for linger distances and large bore diameters may be required.

Technology for pigging in a CO_2 environment is expected to adapt to an expanding CCS industry.

Future (European) requirements to Internal Line Inspection (ILI) need to be considered.

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7.9.2 External inspection

Small leakages on buried pipelines containing CO_2 in dense phase can result in a temperature decrease of the surrounding environment resulting in freezing of the humidity in the soil and air, which can be observed as large ice bulbs.

Guidance note:

CO_2 operators in the US that have experienced small leakages from buried pipelines have reported ice bulbs which in some cases may be 1-2 m^3.

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7.9.3 Monitoring of composition and physical properties

For compositional analysis of the CO_2, gas chromatography can be used. This is the same technology that is used in natural gas transport. Which components need to be measured depends on the specification for purity of CO_2. From the compositional analysis it is possible to measure the density of the gas/fluid.

7.9.4 Monitoring of Flow

In the context of CCS fiscal metering will likely become a requirement. The metering station may either be part of the upstream delivery point or pipeline.

Standard flow restriction metering (orifice; Venturi) devices can provide high accuracy, however the precision will depend on the pressure and temperature dependant density. As illustrated in Figure 2-2, a small temperature variation will have a significant effect on the pressure recording. Accurate temperature control in the meter run is therefore of high importance.

Calibration of the flow metering should be performed for each specific CO_2 stream. Virtual metering based on a thermo hydraulic model and input from pressure and temperature sensors may be considered as a fall back option.

Guidance note:

The meter run needs to be equipped with a pressure relief system due to potential temperature induced pressure build-up.

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7.9.5 Monitoring of water content

Instead of a dew point measurement, experience show that it is more suitable to use a moisture analyser to measure the water content. There are several choices of moisture analysers on the market that can be used with CO_2, both contact as well as non-contact.

The precision of the instrumentation shall be considered with respect to the specified margins on water content.

Table 7-3 Techniques for water monitoring

Component	*Available Techniques*	*Sensitivity*	*Accuracy*
Water content	Dew Point and Moisture Analysers	For Moisture Analysers e.g. 0.1-2500 ppm	For Moisture Analysers e.g. 10% of reading

7.9.6 Pressure Testing and dewatering

Related to pipeline repair, see sections 6.2.2 and 6.2.3 for pressure testing and dewatering respectively.

7.10 Integrity Assessment Activities

7.10.1 General

When a damage or abnormality is observed or detected an integrity assessment shall be performed. Typical pipeline defects and those specific to CO_2 pipelines shall be considered and additional inspection, monitoring and testing may be required.

Inspections and overall integrity assessments that address defects specific to CO_2 pipelines may include but are not limited to:

— In-line Inspection, see Sec.7.9.1
— Pressure Testing, see Sec.6.2.2
— Monitoring, see sections 7.9.3 to 7.9.5

Guidance note:

Integrity assessments for CO_2 pipelines should be based on an in-line inspection or a pressure test. Information from on-going monitoring may also be used for part of an integrity assessment, but only in addition to an in-line inspection or pressure test.

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7.10.2 Internal corrosion direct assessment

Internal corrosion direct assessment is a method for determination of the internal corrosion threat mostly for non-piggable onshore pipelines (ref. ASME 31.8s). This method may deviate from ordinary natural gas pipelines.

7.11 Response activities

7.11.1 General

Threats and defects associated with a CO_2 pipeline must be evaluated and addressed in the repair and mitigation program.

7.11.2 Repairs

Repair and modifications of the system should be performed in accordance with accepted industry standards and practices. It is the operator's responsibility to determine the most appropriate repair method.

Some repairs, such as those involving in-service welding, may require additional considerations as a result of being used on a CO_2 pipeline.

Additional considerations may be required when a CO_2 pipeline is depressurized to conduct repairs. This is due, in large part, to possible phase changes in the fluid. During depressurization, CO_2 in pipelines has been known to form dry ice as well as forming a gaseous phase depending on the pressure release. Repair procedures should consider the risk associated with the condition of the fluid.

Guidance note:

Repair procedures should consider the risk associated with the condition of the fluid.

Material qualification shall be evaluated when applying repair solutions to CO_2 pipelines as material compatibility is a concern.

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7.11.3 Mitigation

Mitigation is defined as preventive maintenance related to the condition of the pipeline taken based on the results of the integrity assessment.

CO_2 specific mitigation issues may relate to:

— Pressure restriction and the risk of transition from dense to gas phase
— Flow rate
— Fluid composition, Sec.2.3
— Change in composition of fluid may influence corrosive properties, Sec.5.1
— Change in composition of fluid may influence the behaviour of the dense phase CO_2 flow
— Removal of free water, Sec.4.4

Mitigating internal corrosion shall be primary concern for CO_2 pipelines and may require additional consideration. The operator shall identify and address all known mitigation issues related to CO_2 corrosion to extent practical.

Guidance note:

The following mitigation alternatives are identified to be less promising in relation to CO_2 transport. They are common in use within the industry for transport of other media, but are not identified to be solution in the context of dense CO_2:

— Corrosion inhibitors
— pH stabilizers.

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7.11.4 Intervention

Intervention is defined as corrective actions taken based on the results of the integrity assessment.

Thermal contraction due to depressurization may give the worst case thermal loading scenario for a CO_2 pipeline. The thermal responses of both operational and accidental depressurization should be evaluated. Depressurization scenarios may dominate with respect to intervention requirements.

8. Re-qualification of existing pipelines to CO_2 pipelines

8.1 General

As a potentially feasible option for establishing a pipeline network for transporting CO_2, existing pipeline infrastructure may be taken into use on the condition that the pipelines are re-qualified for CO_2 transportation.

8.1.1 Applicability

Applicability of the recommendations included in this section relates to but are not limited to pipelines where the following parameters are significantly altered:

— Safety issues related to change of product
— Physical properties of the product
— Operating conditions
— Life time.

8.1.2 Basic principle

Re-qualification shall comply with the same requirements as for a pipeline designed specifically for transportation of CO_2. Any deviation identified shall be thoroughly evaluated and concluded whether it is acceptable or not.

For a pipeline re-qualified for the purpose of CO_2 transportation it may, however, not be feasible from either a technical or cost perspective to comply with all recommendations put forward for a purpose built pipeline.

8.2 Basis for re-qualification of existing pipelines to CO_2 pipelines

With reference to the pipeline development process diagram shown in Figure 8-1, the starting point for a re-qualification process is the operation phase of an existing pipeline.

Data from concept, design, construction and operation should provide foundation for the re-qualification.

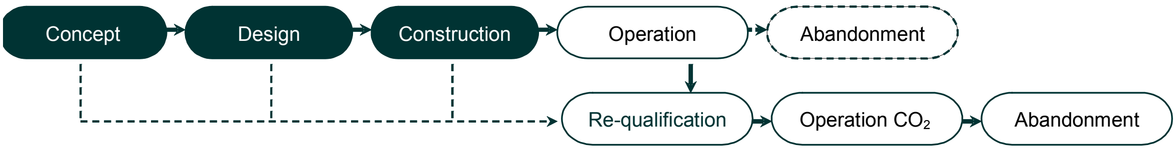

Figure 8-1
Development phases for a pipeline system

When the pipeline is re-qualified for operation with CO_2, the pipeline project enters a new operations phase with new design and operating premises.

Abandonment shall be in compliance with requirements as for the original pipeline and additional requirements for a CO_2 purpose designed and built system.

8.3 Re-qualification process

8.3.1 Process

The re-qualification is initiated by a decision to bring an existing pipeline system or parts thereof into operation with transport of CO_2. This change is primarily identified through change of medium in the pipeline from the original design.

The re-qualification process as defined herein is recognized through the process flow given in Figure 8-2, and described through the steps described in the following sub sections.

8.3.2 Initiation (1)

A decision is taken to evaluate an existing pipeline system for the purpose of CO_2 transport. It is required to perform a re-qualification of the system to ensure safe and reliable operation with CO_2.

8.3.3 Integrity assessment (2)

As a starting point one needs to address the integrity of the pipeline system through assessment of the technical condition. Historical information of how the system has been operated compared with the requirements for operation should be assessed. The information from an Integrity Management Process/ Program as available may be beneficial as support, but this may not necessary provide all information as needed. Identification of materials selections as well as the pressure rating of the pipeline system is key information that needs to be screened as part of the integrity assessment. The SCADA system should be identified and applied as basis for identifying gaps toward the requirements for a CO_2 pipeline.

8.3.4 Hydraulic analysis (3)

A flow assessment should be performed to identify feasibility with reference to transportation capacity and corresponding pressure and temperature distribution along the route. Requirement for modifications of the pipeline system should be identified and evaluated.

8.3.5 Safety evaluation (4)

Safety evaluation of the system should be performed addressing the implications of change of product. The system as it is designed should be evaluated toward the specific safety requirement for CO_2 pipelines. Requirement for modifications of the pipeline system should be identified and evaluated (e.g. additional block valves, leak detection upgrades, etc.).

Particular focus shall be applied to the accidental release consequence analysis due to the change in characteristics of the product. Hazardous distances for CO_2 may be considerably longer that for HC, particularly in valleys or low lying areas, due to the higher release inventory mass and the heavier than air density.

8.3.6 Premises (5)

Premises for CO_2 transport should be defined incorporating the results from the *Hydraulic analysis* as well as *Safety evaluation*. These will define functional as well as system requirements that may deviate from the original design conditions. Requirements to the system should be identified and included as part of a complete premise for the re-qualification.

8.3.7 Re-assessment (6)

Reassessment of the pipeline system may then be initiated. Based on the input from the *Integrity assessment* and the CO_2 transport *Premises*, integrity may be evaluated for the system. Parts of the system that is identified not to be compliant with the integrity requirements will require design *modifications* and reiteration on the *reassessment*. In some cases the required modifications are not feasible e.g. from a cost-benefit standpoint, leading to termination of the re-qualification process.

8.3.8 Modification alternatives (7)

Modification alternatives should be evaluated with respect to feasibility. A re-assessment of the modification alternative will then be performed through documenting the integrity status.

8.3.9 Documentation (8)

Documentation of the system should then be performed. The requirements to the CO_2 pipeline should then be identified together with a status of the system and the requirements to changes of the system to comply with these requirements.

8.3.10 Implementation (9)

Implementation of changes to the system should be performed prior to transition of the system into the new operational mode with CO_2 transport.

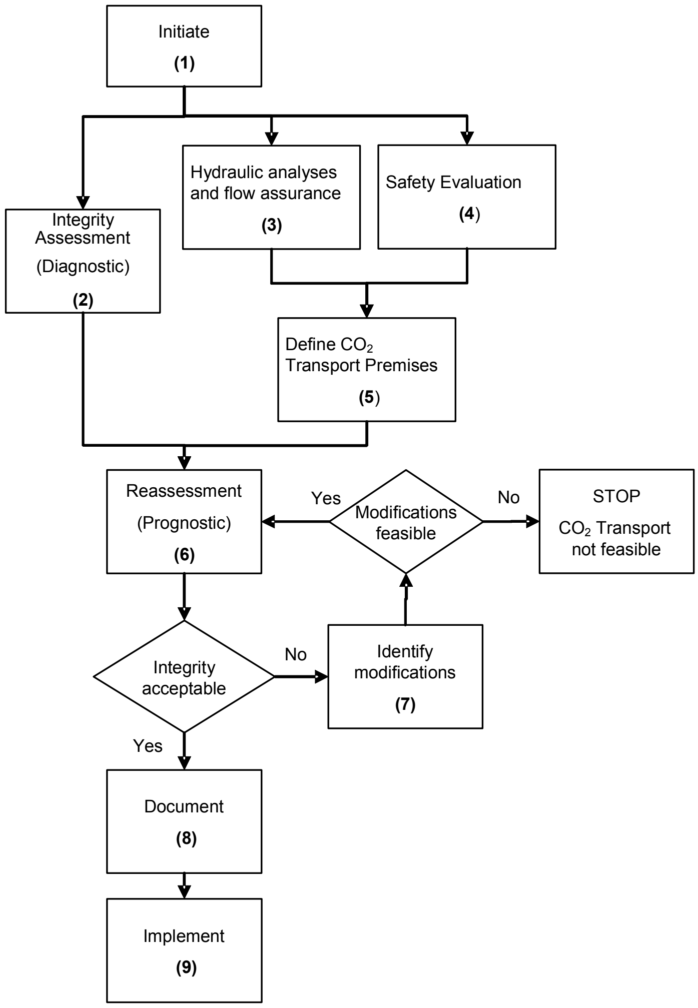

Figure 8-2
Re-qualification process for pipeline system change into CO_2 transport