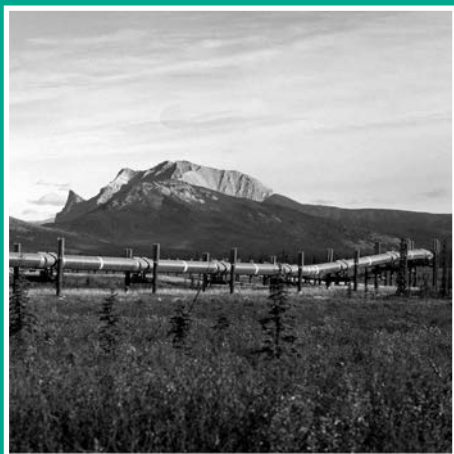




European Federation of
Corrosion Publications
Number 64

Recommended practice for corrosion management of pipelines in oil and gas production and transportation

Edited by
Bijan Kermani and Thierry Chevrot

European Federation of Corrosion Publications
NUMBER 64

Recommended practice for corrosion management of pipelines in oil and gas production and transportation

Edited by
Bijan Kermani and Thierry Chevrot



Published for the European Federation of Corrosion
by CRC Press
on behalf of
The Institute of Materials, Minerals & Mining

 **CRC Press**
Taylor & Francis Group
Boca Raton London New York

CRC Press is an imprint of the
Taylor & Francis Group, an **informa** business


The Institute of Materials,
Minerals and Mining

 **Documents**
Document Sharing Hub

Published by Maney Publishing on behalf of the European Federation of Corrosion
and The Institute of Materials, Minerals & Mining

First published 2012 by Maney Publishing

Published 2017 by CRC Press
711 Third Avenue, New York, NY 10017, USA
2 Park Square, Milton Park, Abingdon, Oxon OX14 4RN

© 2012, European Federation of Corrosion

The authors have asserted their moral rights.

This book contains information obtained from authentic and highly regarded sources. Reprinted material is quoted with permission, and sources are indicated. Reasonable efforts have been made to publish reliable data and information, but the editors, authors and the publishers cannot assume responsibility for the validity of all materials. Neither the editors, authors nor the publishers, nor anyone else associated with this publication, shall be liable for any loss, damage or liability directly or indirectly caused or alleged to be caused by this book.

All rights reserved. No part of this book may be reprinted or reproduced or utilised in any form or by any electronic, mechanical, or other means, now known or hereafter invented, including photocopying and recording, or in any information storage or retrieval system, without permission in writing from the publishers.

Trademark notice: Product or corporate names may be trademarks or registered trademarks, and are used only for identification and explanation, without intent to infringe.

ISBN: 978-1-907-97533-2 (pbk)

ISSN 1354-5116

Contents

	<i>Series Introduction</i>	<i>iv</i>
	<i>Volumes in the EFC series</i>	<i>vi</i>
	<i>Preface</i>	<i>xi</i>
	<i>Acknowledgement</i>	<i>xii</i>
1	Introduction	1
2	Pipeline register and description	12
3	Corrosion assessment	19
4	Corrosion mitigation	34
5	Corrosion monitoring and data management	46
6	Inspection	53
7	Review and feedback	58
8	Change of duty and implementation of change	62
Annex A	Flexible pipelines	65
Annex B	Clad, liners and CRA pipelines	74
Annex C	Guidance on pig trap inspection and maintenance	83
Annex D	Manifolds	85
Annex E	Catenary risers	89
Annex F	CO ₂ Injection lines	93
Annex G	Steam injection lines	97
Annex H	Injection lines	101
Annex I	Definitions	109

European Federation of Corrosion (EFC) publications: Series introduction

The EFC, founded in 1955, is a Federation of 33 societies with interests in corrosion and is based in twenty-six different countries throughout Europe and beyond. Its member societies represent the corrosion interests of more than 25,000 engineers, scientists and technicians. The Federation's aim is to advance the science of the corrosion and protection of materials by promoting cooperation in Europe and collaboration internationally. Besides from national and international corrosion societies, universities, research centres and companies can also become Affiliate Members of the EFC.

The administration of the Federation is in the hands of the Board of Administrators, chaired by the EFC President, and the scientific and technical affairs are the responsibility of the Science and Technology Advisory Committee, chaired by the STAC Chairman and assisted by the Scientific Secretary. The General Assembly approves any EFC policy prepared and presented by the BoA. The Federation is managed through its General Secretariat with three shared headquarters located in London, Paris and Frankfurt.

The EFC carries out its most important activities through its nineteen active working parties devoted to various aspects of corrosion and its prevention, covering a large range of topics including: Corrosion and Scale Inhibition, Corrosion by Hot Gases and Combustion Products, Nuclear Corrosion, Environment Sensitive Fracture, Surface Science and Mechanisms of Corrosion and Protection, Physico-chemical Methods of Corrosion Testing, Corrosion Education, Marine Corrosion, Microbial Corrosion, Corrosion of Steel in Concrete, Corrosion in Oil and Gas Production, Coatings, Corrosion in the Refinery Industry, Cathodic Protection, Automotive Corrosion, Tribo-Corrosion, Corrosion of Polymer Materials, Corrosion and Corrosion Protection of Drinking Water Systems, Corrosion of Archaeological and Historical Artefacts. The EFC is always open to formulating new working parties in response to the demands brought about by developing technologies and their ensuing corrosion requirements and applications.

The European Federation of Corrosion's flagship event is EUROCORR, the most important Corrosion Congresses in Europe, which is held annually in a different European country in September of each year. To date, 27 EUROCORR conferences have taken place in 12 different countries and they have gained a reputation for their high technical quality, global perspective and enjoyable social programme. Another channel for the EFC's valuable transfer of knowledge is the EFC "green" book series which are the fruit of the collaboration and high scientific calibre within and amongst the EFC working party members and are emblematic of the EFC editorial policy.

EFC Offices are located at:

European Federation of Corrosion, The Institute of Materials, Minerals and Mining,
1 Carlton House Terrace, London SW1Y 5DB, UK

Fédération Européenne de la Corrosion, Fédération Française pour les sciences de la Chimie, 28 rue Saint-Dominique, F-75007 Paris, France

Europäische Föderation Korrosion, DECHEMA e.V., Theodor-Heuss-Allee 25,
D-60486 Frankfurt-am-Main, Germany

- 1 **Corrosion in the nuclear industry**
*Prepared by Working Party 4 on Nuclear Corrosion**
- 2 **Practical corrosion principles**
*Prepared by Working Party 7 on Corrosion Education**
- 3 **General guidelines for corrosion testing of materials for marine applications**
*Prepared by Working Party 9 on Marine Corrosion**
- 4 **Guidelines on electrochemical corrosion measurements**
*Prepared by Working Party 8 on Physico-Chemical Methods of Corrosion Testing**
- 5 **Illustrated case histories of marine corrosion**
Prepared by Working Party 9 on Marine Corrosion
- 6 **Corrosion education manual**
Prepared by Working Party 7 on Corrosion Education
- 7 **Corrosion problems related to nuclear waste disposal**
Prepared by Working Party 4 on Nuclear Corrosion
- 8 **Microbial corrosion**
*Prepared by Working Party 10 on Microbial Corrosion**
- 9 **Microbiological degradation of materials and methods of protection**
Prepared by Working Party 10 on Microbial Corrosion
- 10 **Marine corrosion of stainless steels: chlorination and microbial effects**
Prepared by Working Party 9 on Marine Corrosion
- 11 **Corrosion inhibitors**
*Prepared by the Working Party on Inhibitors**
- 12 **Modifications of passive films**
*Prepared by Working Party 6 on Surface Science**
- 13 **Predicting CO₂ corrosion in the oil and gas industry**
*Prepared by Working Party 13 on Corrosion in Oil and Gas Production**
- 14 **Guidelines for methods of testing and research in high temperature corrosion**
Prepared by Working Party 3 on Corrosion by Hot Gases and Combustion Products

- 15 **Microbial corrosion: Proceedings of the 3rd International EFC Workshop**
Prepared by Working Party 10 on Microbial Corrosion
- 16 **Guidelines on materials requirements for carbon and low alloy steels for H₂S-containing environments in oil and gas production (3rd Edition)**
Prepared by Working Party 13 on Corrosion in Oil and Gas Production
- 17 **Corrosion resistant alloys for oil and gas production: guidance on general requirements and test methods for H₂S service (2nd Edition)**
Prepared by Working Party 13 on Corrosion in Oil and Gas Production
- 18 **Stainless steel in concrete: state of the art report**
*Prepared by Working Party 11 on Corrosion of Steel in Concrete**
- 19 **Sea water corrosion of stainless steels: mechanisms and experiences**
Prepared by Working Party 9 on Marine Corrosion and Working Party 10 on Microbial Corrosion
- 20 **Organic and inorganic coatings for corrosion prevention: research and experiences**
Papers from EUROCORR '96
- 21 **Corrosion-deformation interactions**
CDI '96 in conjunction with EUROCORR '96
- 22 **Aspects of microbially induced corrosion**
Papers from EUROCORR '96 and EFC Working Party 10 on Microbial Corrosion
- 23 **CO₂ corrosion control in oil and gas production: design considerations**
*Prepared by Working Party 13 on Corrosion in Oil and Gas Production**
- 24 **Electrochemical rehabilitation methods for reinforced concrete structures: a state of the art report**
Prepared by Working Party 11 on Corrosion of Steel in Concrete
- 25 **Corrosion of reinforcement in concrete: monitoring, prevention and rehabilitation**
Papers from EUROCORR '97
- 26 **Advances in corrosion control and materials in oil and gas production**
Papers from EUROCORR '97 and EUROCORR '98
- 27 **Cyclic oxidation of high temperature materials**
Proceedings of an EFC Workshop, Frankfurt/Main, 1999
- 28 **Electrochemical approach to selected corrosion and corrosion control**
Papers from the 50th ISE Meeting, Pavia, 1999
- 29 **Microbial corrosion: proceedings of the 4th International EFC Workshop**
Prepared by the Working Party on Microbial Corrosion
- 30 **Survey of literature on crevice corrosion (1979–1998): mechanisms, test methods and results, practical experience, protective measures and monitoring**
Prepared by F. P. Ijsseling and Working Party 9 on Marine Corrosion

- 31 **Corrosion of reinforcement in concrete: corrosion mechanisms and corrosion protection**
Papers from EUROCORR '99 and Working Party 11 on Corrosion of Steel in Concrete
- 32 **Guidelines for the compilation of corrosion cost data and for the calculation of the life cycle cost of corrosion: a working party report**
Prepared by Working Party 13 on Corrosion in Oil and Gas Production
- 33 **Marine corrosion of stainless steels: testing, selection, experience, protection and monitoring**
Edited by D. Féron on behalf of Working Party 9 on Marine Corrosion
- 34 **Lifetime modelling of high temperature corrosion processes**
Proceedings of an EFC Workshop 2001 Edited by M. Schütze, W. J. Quadackers and J. R. Nicholls
- 35 **Corrosion inhibitors for steel in concrete**
Prepared by B. Elsener with support from a Task Group of Working Party 11 on Corrosion of Steel in Concrete
- 36 **Prediction of long term corrosion behaviour in nuclear waste systems**
Edited by D. Féron on behalf of Working Party 4 on Nuclear Corrosion
- 37 **Test methods for assessing the susceptibility of prestressing steels to hydrogen induced stress corrosion cracking**
By B. Isecke on behalf of Working Party 11 on Corrosion of Steel in Concrete
- 38 **Corrosion of reinforcement in concrete: mechanisms, monitoring, inhibitors and rehabilitation techniques**
Edited by M. Raupach, B. Elsener, R. Polder and J. Mietz on behalf of Working Party 11 on Corrosion of Steel in Concrete
- 39 **The use of corrosion inhibitors in oil and gas production**
Edited by J. W. Palmer, W. Hedges and J. L. Dawson on behalf of Working Party 13 on Corrosion in Oil and Gas Production
- 40 **Control of corrosion in cooling waters**
Edited by J. D. Harston and F. Ropital on behalf of Working Party 15 on Corrosion in the Refinery Industry
- 41 **Metal dusting, carburisation and nitridation**
Edited by H. Grabke and M. Schütze on behalf of Working Party 3 on Corrosion by Hot Gases and Combustion Products
- 42 **Corrosion in refineries**
Edited by J. D. Harston and F. Ropital on behalf of Working Party 15 on Corrosion in the Refinery Industry
- 43 **The electrochemistry and characteristics of embeddable reference electrodes for concrete**
Prepared by R. Myrdal on behalf of Working Party 11 on Corrosion of Steel in Concrete

- 44 **The use of electrochemical scanning tunnelling microscopy (EC-STM) in corrosion analysis: reference material and procedural guidelines**
Prepared by R. Lindström, V. Maurice, L. Klein and P. Marcus on behalf of Working Party 6 on Surface Science
- 45 **Local probe techniques for corrosion research**
Edited by R. Oltra on behalf of Working Party 8 on Physico-Chemical Methods of Corrosion Testing
- 46 **Amine unit corrosion survey**
Edited by J. D. Harston and F. Ropital on behalf of Working Party 15 on Corrosion in the Refinery Industry
- 47 **Novel approaches to the improvement of high temperature corrosion resistance**
Edited by M. Schütze and W. Quadackers on behalf of Working Party 3 on Corrosion by Hot Gases and Combustion Products
- 48 **Corrosion of metallic heritage artefacts: investigation, conservation and prediction of long term behaviour**
Edited by P. Dillmann, G. Béranger, P. Piccardo and H. Matthiesen on behalf of Working Party 4 on Nuclear Corrosion
- 49 **Electrochemistry in light water reactors: reference electrodes, measurement, corrosion and tribocorrosion**
Edited by R.-W. Bosch, D. Féron and J.-P. Celis on behalf of Working Party 4 on Nuclear Corrosion
- 50 **Corrosion behaviour and protection of copper and aluminium alloys in seawater**
Edited by D. Féron on behalf of Working Party 9 on Marine Corrosion
- 51 **Corrosion issues in light water reactors: stress corrosion cracking**
Edited by D. Féron and J.-M. Olive on behalf of Working Party 4 on Nuclear Corrosion
- 52 **Progress in Corrosion – The first 50 years of the EFC**
Edited by P. McIntyre and J. Vogelsang on behalf of the EFC Science and Technology Advisory Committee
- 53 **Standardisation of thermal cycling exposure testing**
Edited by M. Schütze and M. Malessa on behalf of Working Party 3 on Corrosion by Hot Gases and Combustion Products
- 54 **Innovative pre-treatment techniques to prevent corrosion of metallic surfaces**
Edited by L. Fedrizzi, H. Terryn and A. Simões on behalf of Working Party 14 on Coatings
- 55 **Corrosion-under-insulation (CUI) guidelines**
Prepared by S. Winnik on behalf of Working Party 13 on Corrosion in Oil and Gas Production and Working Party 15 on Corrosion in the Refinery Industry
- 56 **Corrosion monitoring in nuclear systems**
Edited by S. Ritter and A. Molander

57 **Protective systems for high temperature applications: from theory to industrial implementation**

Edited by M. Schütze

58 **Self-healing properties of new surface treatments**

Edited by L. Fedrizzi, W. Fürbeth and F. Montemor

59 **Sulphur-assisted corrosion in nuclear disposal systems**

Edited by D. Féron, B. Kursten and F. Druyts

60 **Methodology of crevice corrosion testing for stainless steels in natural and treated seawaters**

Edited by U. Kivisäkk, B. Espelid and D. Féron

61 **Inter-laboratory study on electrochemical methods for the characterisation of CoCrMo biomedical alloys in simulated body fluids**

Edited by A. Igual Munoz and S. Mischler

This recommended practice (RP) is a compendium of current best practices and state-of-the-art knowledge by major operators, engineering contractors and service companies involved in hydrocarbon production and transportation. It is intended to contribute to continued and trouble-free operation of pipelines. This enables the improved integrity of operations, safety and security of people whilst minimising the adverse impact on the environment and enabling security and business success.

The RP incorporates some minimum operational requirements and practices to ensure that when managing corrosion in pipelines, fundamental principles are followed. It covers management of corrosion for pipelines carrying hydrocarbons, injection water and/or produced water from design to decommissioning. It is structured to follow the logical steps of a basic corrosion management process and makes references to relevant and available international standards and/or recommended practices. This RP is intended for use by personnel from the petroleum industry having knowledge of corrosion and materials.

In the context of this RP, pipeline is defined as a line which carries fluids in upstream hydrocarbon production operations from wellheads or production sites to process sites (including platforms, reception plants, and downstream facilities) and vice versa. It excludes wells, vessels, rotating equipment and process pipeworks.

The recommendations set out in this RP are meant to provide flexibility and must be used in conjunction with competent technical judgements. Nevertheless, it remains the responsibility of the user of the RP to judge its suitability for a particular application or context.

If there is any inconsistency or conflict between any of the recommended practices contained in the RP and the applicable legislative requirement, the legislative requirement shall prevail.

Every effort has been made to ensure the accuracy and reliability of the data and recommendations contained in this RP. However EFC, its subcommittees, and individual contributors make no representation, warranty, or guarantee in connection with the publication or the contents of this RP and hereby disclaim liability of responsibility for loss or damage resulting from the use of this RP, or for any violation of any legislative requirements.

Pipeline Corrosion Management Working Group (WG) of the EFC Working Party (WP) 13 on Corrosion in Oil and Gas Production held its first meeting in June 2009 in Paris. Since then, several meetings were held to capture industry-wide recommended practices in corrosion management of pipelines transporting fluids, in hydrocarbon production. The organisation of the WG was undertaken by representatives from worldwide operators, engineering contractors and service companies.

In achieving the primary objective parameters affecting corrosion of pipelines, their mitigation and management were discussed during the WG meetings. These aspects formed the core of the present RP, sections of which have been prepared by the WG members. The RP was put together by Bijan Kermani of KeyTech through a joint industry project (JIP) to manage, collate inputs and prepare the document. The JIP was sponsored by BG Group, BP, ConocoPhillips, Shell, Statoil, Technip, Total, Wellstream and Wood Group Integrity Management (WGIM).

The chairmen of the WG and WP would like to express their appreciation to all who have contributed their time and effort to ensure the successful completion of this RP. In particular, we wish to acknowledge significant input from these individuals and their respective companies:

BG Group	Richard Carroll
BP	Alan Crossland
	Ammer Jadoon
	Lee Smith
ConocoPhillips	Mike Swidzinski
Shell	Sergio Kapusta
Statoil	Trygve Ringstad
	Helen Sirnes
	Bernt Slogvik
Technip	Carol Taravel Condat
	Elias Remita
Wellstream	Richard Clements
Wood Group Integrity Management (WGIM)	George Winning
	Chris White

Many members of EFC WP 13 also contributed to the development, review and specific sections of the RP whose significant contributions are recognised. In particular, efforts in reviewing the document from Mohsen Achour (ConocoPhillips), Mehdi Askari (Pars Oil and Gas Co), Ilson Palmieri (Petrobras), Ulf Kivisakk (Sandvik), Sytze Huizinga (Shell), and Michel Bonis (Total) are highly appreciated.

Finally, one editor (BK) wishes to thank JIP members for their financial support allowing development and production of this publication.

It is hoped that this RP will prove to be a key reference document for engineers, suppliers and contractors working in the oil and gas industry, paving the way for corrosion-free operation of pipelines with the ultimate goal of improving safety, security and minimising the impact on the environment.

Bijan Kermani	Thierry Chevrot
KeyTech	Total
Chairman of Working Group	Chairman of EFC Working Party
Pipeline Corrosion Management	Corrosion in Oil and Gas Production

Pipeline corrosion management (PCM) is defined as that part of the overall pipeline management system (PMS) and operating practices which is concerned with the development, implementation, review and change of corrosion policy. In this recommended practice (RP), PCM covers the management of corrosion from design to decommissioning, for upstream pipeline systems carrying hydrocarbons, injection water and/or produced water. While numerous instances of pipeline leak and failure are reported annually, the challenge to managing their occurrences has not been reflected in the production of many international standards. This Chapter focuses on introducing the subject, outlines the objectives encompassing the scope of the RP and the benefits from the implementation of the PCM programme. It underlines necessary management commitment and competency requirements.

1.1 Foreword

Pipeline integrity is key to maintaining operational success, safety and security and minimising harm to the environment. Several industry surveys [1,2] have shown that corrosion is a dominant contributory factor to failures, leaks and integrity threat in pipelines. Therefore, its optimum control within an integrity management framework is paramount for the cost effective design of facilities and ensuring continued, uninterrupted and safe operations within the expected design life.

This RP is developed to improve and manage corrosion in upstream pipeline systems. It focuses on corrosion exclusively; both internal and external. However, other integrity threats should be considered and addressed within an appropriate Asset Integrity Management (AIM) programme to enable integrity and reliability assurance.

The risk of internal or external corrosion becomes real once an aqueous phase is present and able to contact the pipe wall, providing a ready electrolyte for corrosion reactions to occur. The inherent corrosivity of this aqueous phase is then heavily dependent on the pipeline materials of construction, environmental conditions (temperature, pressure, presence of bacteria, etc.) and levels of dissolved corrosive species (acid gases, oxygen, organic acids, etc.) which may be present.

Development, implementation and continual updating of a successful corrosion management framework are key components of operating a pipeline throughout its production life, whatever the operating conditions. As a consequence, it is important that an adapted and tailor-made corrosion management programme is put in place to actively manage corrosion from the earliest stages through to the end of pipeline life to ensure trouble-free operations. Such an approach needs to be taken on board and implemented in the technical/commercial assessment of new field developments, in prospect evaluation, and for operating existing pipeline systems.

The RP provides overview of elements, steps and measures necessary to manage corrosion of pipelines in oil and gas production and transportation. It has been developed from feedback of operating experience, research outcomes and operating

companies' in-house studies and practices. It has captured extensive inputs from operating companies, manufacturers, engineering contractors and service providers.

This RP is intended for use by personnel from the petroleum industry having knowledge of corrosion and materials and the necessary competency described throughout this document.

In the context of this RP, pipeline is defined as a line which carries fluids from wellheads or production sites to process sites (including platforms, reception plants, and downstream facilities) and vice versa, excluding wells, vessels, rotating equipment and process pipework.

This RP is not intended to provide a prescriptive framework for PCM, but only to outline, without going into details, the techniques, steps or measures which have been demonstrated as successful in the identification and management of the corrosion threats to oilfield pipeline facilities. It will also make reference to existing and recognised international standards whenever possible, without further details of their contents.

Furthermore, the present RP only provides a partial answer focused on corrosion threats of what needs to be developed within a broader theme of AIM.

By following the procedures outlined in this RP, confidence can be gained that the levels of corrosion control and management are appropriate for safe and trouble-free operations.

1.2 Objectives of this RP

This RP aimed to produce a reference document to achieve the following objectives:

- To capture and compile into a comprehensive document industry-wide information in relation to PCM.
- To define and outline common practices in PCM available amongst oil and gas operating companies and engineering design houses to:
 - ease discussions with projects' partners worldwide
 - deal with third party tie-ins.
- To agree with engineering design houses on processes and approaches necessary to define and characterise corrosion management requirements at the design stage.

The RP should be treated as an integral part of a pipeline management system (PMS).

This RP includes:

- i. Recommendations for registering essential and/or useful pipeline data for implementing adequate corrosion management programmes.
- ii. An overview of corrosion threats and their respective assessment practices.
- iii. Recommendations for defining and implementing corrosion mitigation actions.
- iv. An overview of corrosion monitoring data capture and full analysis.
- v. An explanation for the need of adequate inspection programmes and their contribution to PCM programme.
- vi. Guidelines for an overall review process based on points (i) to (v) above.
- vii. Guidelines for change of duty if necessary from the review in step (vi).

The recommendations set out in this RP are meant to provide flexibility and must be used in conjunction with competent technical judgement. It remains the responsibility of the user of the RP to judge its suitability for a particular application.

Throughout this RP, the terms ‘should’ is used to indicate recommendations as opposed to prescriptive requirements.

1.3 Scope

1.3.1 General

This RP covers requirements and gives recommendations for managing corrosion from design to decommissioning in pipeline systems carrying hydrocarbons, injection water and/or produced water. It incorporates some minimum operational requirements and practices to ensure that fundamental principles are followed when managing corrosion in pipelines. It is intended for use in the technical/commercial assessment of new field developments, in prospect evaluation, design and construction, and for operating existing pipeline systems.

Table 1.1 and Fig. 1.1 summarise the scope of this RP, and present a list of excluded items/equipment where applicable. It should be noted that items within this RP include pig launchers and receivers.

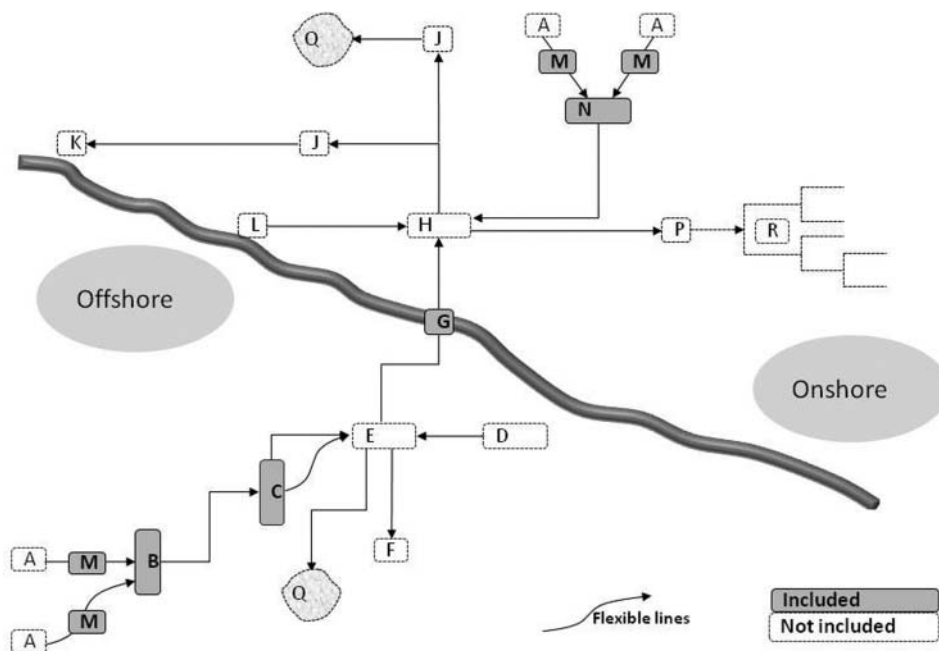
Table 1.1 Scope of this RP

Items covered by this RP ^{1,2}	Excluded items
Risers, transportation pipelines and trunklines for liquids, gases and multiphase fluids	• Lines handling gas prepared for domestic use (gas distribution systems) • Lines handling processed products • Valves and rotating equipment • Subsea templates • Pressure vessels • Topsides/surface facilities • Compression stations • Utility lines/umbilicals/chemical injection lines • Drain lines • Non-metallic materials • Slug catchers³
Flowlines and gathering lines	Crude oil storage, handling facilities, vessels and rotating equipment, heat exchangers, field facilities and processing plants
Manifolds and pipeline end manifolds (PLEMs)	Wellhead template
Catenary/dynamic risers	J tube, Caissons
Pig launchers and receivers	Valves
Flexible pipelines	
Corrosion-resistant alloy (CRA) and CRA clad/lined and non-metallic lined pipelines	
Injection lines (CO ₂ injection, steam lines)	Pumps, chemical injection lines, steam generation, CO ₂ removal plant

¹ In the context of this RP, flowlines, gathering lines and trunklines are considered as pipelines.

² Items within this RP include pig launchers and receivers.

³ While slug catchers are designed within the pipeline codes, they are project specific and therefore not included in this RP.



1.1 A schematic diagram of typical pipeline systems covered by this RP.

Solid lines: Items included within the scope of this RP.

Dashed lines: Items excluded from the scope of this RP.

Items within the scope of this RP include pig launchers and receivers.

A, Individual producing well. B, Subsea manifold. C, PLEM. D, Subsea template.

E, Offshore producing/processing facilities. F, WI/WAG wells. G, Landfall. H,

Onshore processing facilities. J, Compressor station. K, Export terminal. L,

Import terminal. M, In-field flowlines. N, In-field manifolds.

P, Let-down station. Q, Gas storage field. R, Gas distribution network

1.3.2 Contents

The approach adopted in this RP follows the systematic steps taken by most operating companies in the implementation of PCM. It follows the logical steps of a basic corrosion management process and is structured accordingly. This includes assessment, mitigating measures, design and implementation, monitoring and inspection, review and change of duty. It makes reference to relevant international standards and/or recommended practices when available.

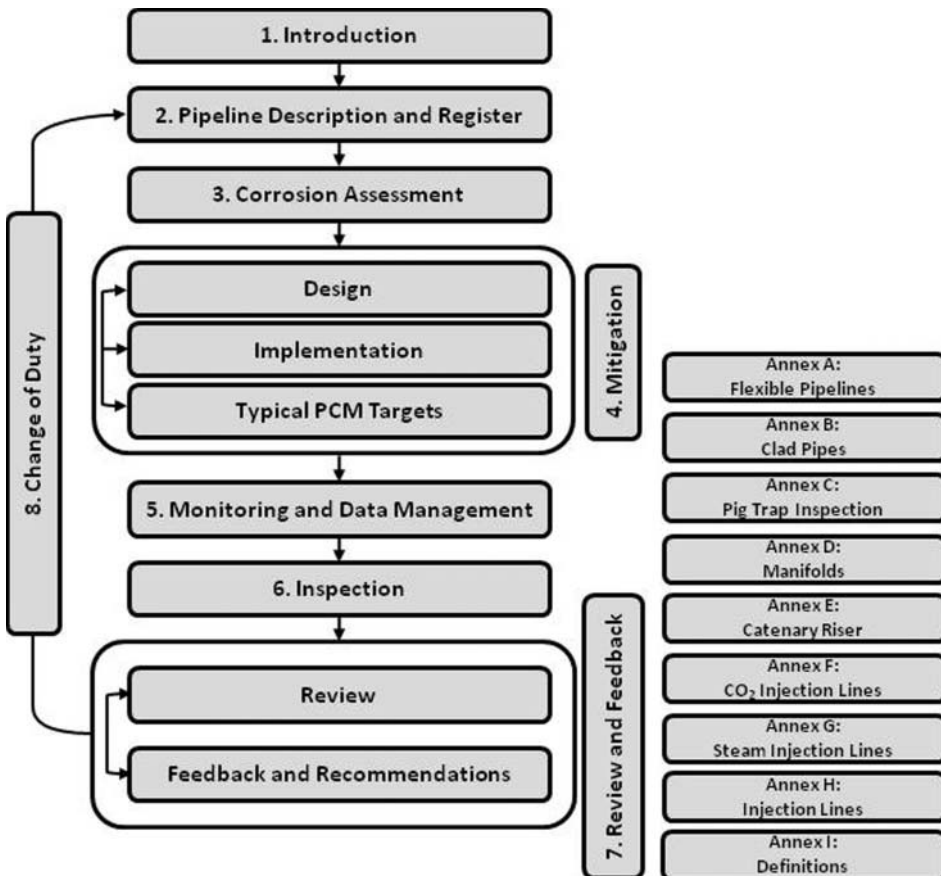
The structure of the document is captured in Fig. 1.2 with a brief description of each section summarised in Table 1.2. At the end of each Chapter or Annex, a section is assigned to relevant bibliography where additional detailed and pertinent information can be found. A more detailed description of each topic is given at the start of each Chapter or Annex.

1.4 Purpose of Pipeline Corrosion Management (PCM)

A 'live' PCM programme will act as an effective way to control the corrosion threats in pipelines. The purposes of developing, implementing and continuously updating the PCM programme are to:

- Prevent loss of containment caused by corrosion.
- Provide a management directive with the purpose of controlling corrosion threats and costs over the lifetime of the pipeline systems.
- Ensure that adequate corrosion control programmes are in place and reviewed systematically.
- Define clear responsibility, accountability and ownership of corrosion management throughout the operating life of pipelines.

In addition, a PCM programme should ensure compliance with national and international laws and regulations.



1.2 Structure of this RP

1.5 Benefits of PCM programme

Development and implementation of a structured corrosion management programme will ensure continued and safe operations of pipelines. In addition, key benefits arising from the development and implementation of PCM programme include but are not limited to:

- balancing capital expenditure (CAPEX) and operating expenditure (OPEX)
- optimising materials selection and corrosion control measures

6 Recommended practice for corrosion management of pipelines

- minimising any adverse effect on the environment
- providing safety and security
- understanding of corrosion activities in pipeline systems by:
 - providing an early warning of active corrosion which enables cost-effective and early intervention
 - directing towards mitigation and monitoring/inspection measures
 - confirming effectiveness of remedial measures
- enabling better-informed integrity, maintenance and repair planning decisions
- providing feedback on operational conditions leading to corrosion and tailoring corrosion modelling activities.

Overall, PCM together with risk-based assessment (RBA) methodologies within the context of AIM will lead to minimising loss of containment, as well as optimising future repairs and inspection needs. This can result in potential cost savings.

Table 1.2 Contents of this RP

Chapter/section	Description
Chapter 1	Introduction outlining the scope, purpose of PCM, objectives, benefits and applicability of this RP
Chapter 2	Pipeline description and register covering basic design data required for assessing and managing corrosion in pipeline systems
Chapter 3	A description of information required to assess corrosion, competency level required to carry out such assessments, types of threats and overview of corrosion assessment methodologies
Chapter 4	Key elements of mitigation actions for internal and external corrosion control
Chapter 5	Necessity and means for corrosion monitoring and data gathering
Chapter 6	Necessity for inspection and its contribution to PCM
Chapter 7	Highlighting steps, measures and manners to review and provide feedback
Chapter 8	Change of duty and implementation of change
Annex A	Covering specific reference to corrosion management of flexible pipelines
Annex B	Covering specific reference to corrosion management of clad pipes, liners and corrosion-resistant alloy (CRA) lines
Annex C	Covering specific guidance on pig trap inspection and maintenance
Annex D	Covering specific reference to corrosion management of manifolds
Annex E	Covering specific reference to corrosion management of catenary risers
Annex F	Covering specific reference to corrosion management of CO ₂ injection lines
Annex G	Covering specific reference to corrosion management of steam injection lines
Annex H	Covering specific reference to corrosion management of injection lines
Annex I	Definitions

1.6 Management commitment

The implementation, use, and maintenance of a suitable PCM programme require adequate resources and therefore, management commitment.

Typical ways of demonstrating management commitment may include, but are not limited to:

- The preparation of multi-annual budgets dedicated to the PCM to enable middle/long term planning.
- Regular (annual) management reviews of the effectiveness of the PCM as part of the overall AIM programme.
- The formal approval of a corrosion management policy.
- The maintenance of competencies and skill levels in the team responsible for PCM, which can be encouraged by:
 - rewarding career path
 - establishing adequate continuity through succession plans
 - recognising the expertise of key personnel
 - ensuring the implementation of specific competency development programmes.

1.6.1 Responsibilities/accountabilities

Corrosion management in general is an activity requiring the involvement of several disciplines. In the case of PCM, it is necessary that responsibilities and accountabilities of the different entities and personnel involved are clearly defined and documented to ensure that:

- all activities required by the PCM are adequately addressed and carried out
- the interfaces between the different entities are clear
- the PCM programme is followed rigorously and efficiently, thereby avoiding duplicated tasks
- each task related to the PCM programme is carried out by personnel with adequate qualifications and experience.

The easiest and most reliable way of documenting responsibilities and accountabilities is to produce an interface matrix such as the template presented in Table 1.3. This is typically represented in a 'Responsible Accountable Consulted Informed' (RACI) format. This RACI describes the participation of various personnel in completing tasks or deliverables for a particular pipeline system. This is particularly useful in clarifying roles and responsibilities in cross-functional/departmental projects as well as processes involved in PCM.

1.6.2 Corrosion management policy

A corrosion management policy is essential to clearly document:

- management and personnel commitment towards the PCM
- high level objectives of the PCM
- performance targets
- means and resources to achieve these objectives.

The corrosion management policy can be complemented by other documents giving more detailed information and directives about the various tasks to be achieved and procedures to be followed. An example of such documents are outlined in the Bibliography Section (Section 1.10). These may be related to a variety of topics which may, for example, include: corrosion assessments, corrosion monitoring, chemical treatment, maintenance of protective coatings, etc.

Table 1.3 A typical RACI template

	The Leadership Team	Engineering Authority	Technical Authority	Field Operation	Others
Business planning					
Corrosion strategy & planning					
Corrosion management programme implementation					
Assessment and reporting of corrosion management programme results					
Conformance with corrosion management programme					
Exception to corrosion management strategy					
Exception to corrosion management programme					
Others					

1.7 Optimisation and use of corrosion modelling

The philosophy behind this RP is to reinforce the importance of methodologies, corrosion mitigation actions, acquiring feedback and using operating company’s experience to achieve effective PCM. It is therefore recognised that, while useful for corrosion assessment, corrosion models in isolation cannot be relied upon solely to implement a satisfactory PCM programme. In this context, corrosion models should be used bearing in mind corrosion monitoring/inspection data, historical events, operational trends, past experience and field data.

Furthermore, corrosion models should be used by personnel having an overall understanding of corrosion management, to take into account their limits and their relevance with regard to field conditions and experience.

1.8 Competency of personnel

The competency of personnel involved in corrosion management activities is of paramount importance to the success of PCM. While this will normally be handled through the corporate policy of the operating company, the following aspects should be underlined:

- It is recommended that key positions are identified in the PCM programme to ensure that they are staffed on a permanent basis, and that a multi-annual recruitment and training plan is made available.
- Personnel should have received adequate training to undertake the tasks they will be assigned to in the PCM programme. Training should be adapted to these tasks and should involve courses and/or on the job training.

- It is of importance that all personnel involved in PCM, in whatever capacity, spend sufficient time in the field. This should be either through an assignment or site visits to become familiar with operational practices. It is reinforced that PCM should not solely be a ‘paper exercise’, as many deficiencies can only be identified on site through operational involvement.
- It is also important that personnel involved in PCM are suitably motivated. This will generally be covered by corporate policies. Achievements in preserving pipeline integrity contribute to the operating company’s business objectives and public image. This should be recognised adequately if the operating company wants to maintain sufficient expertise and experience in their PCM personnel.

1.9 Abbreviations

AC	Alternating Current
AIM	Asset Integrity Management
ALARP	As Low As Reasonably Practicable
BOL	Bottom of Line
C-steel	Carbon and Low Alloy Steel
CA	Corrosion Allowance
CAPEX	Capital Expenditure
CCS	CO ₂ Capture and Storage
CI	Corrosion Inhibitor
CIS	Close Interval Survey
CP	Cathodic Protection
CRA	Corrosion-Resistant Alloy
CUI	Corrosion Under Insulation
DC	Direct Current
DCVG	DC Voltage Gradient
ECDA	External Corrosion Direct Assessment
EMAT	Electromagnetic Acoustic Transducer
ER	Electrical Resistance
FAT	Factory Acceptance Test
FPCM	Flexible Pipeline Corrosion Management
GAB	General Aerobic Bacteria
GLR	Gas Liquid Ratio
GnAB	Gram-negative anaerobic bacteria (<i>GNAB</i>)
GOR	Gas Oil Ratio
GPS	Global Positioning Systems
HDD	Horizontal Directional Drilling
HDPE	High-Density Polyethylene
HE	Hydrogen Embrittlement
HIC	Hydrogen Induced Cracking
HV	High Voltage
ILI	Inline Inspection
JIP	Joint Industry Project
KPI	Key Performance Indicator
LPR	Linear Polarisation Resistance
MAOP	Maximum Operating Pressure
MAWT	Minimum Allowable Wall Thickness

MDEA	Methyl-Di-Ethanol-Amine
MFL	Magnetic Flux Leakage
MIC	Microbial Induced Corrosion
NDE	Non Destructive Evaluation
OPEX	Operating Expenditure
Ox Sca	Oxygen Scavenger
P	Pressure
PA	Polyamide
PCM	Pipeline Corrosion Management
PE	Polyethylene
PEX	Cross-Linked Polyethylene
PIM	Pipeline Integrity Management
PIMS	Pipeline Integrity Management System
PIP	Pipe in Pipe
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
PMS	Pipeline Management System
ppb	Parts per billion
ppm	Parts per million
PWHT	Post Weld Heat Treatment
RACI	Responsible Accountable Consulted Informed
RBA	Risk Based Assessment
RBI	Risk Based Inspection
RIM	Riser Integrity Management
RP	Recommended Practice
SCC	Stress Corrosion Cracking
SCR	Steel Catenary Riser
SOHIC	Stress Oriented Hydrogen Induced Cracking
SRB	Sulphide Reducing Bacteria
SSC	Sulphide Stress Cracking
SWC	Stepwise Cracking
T	Temperature
TDS	Total Dissolved Solid
TOLC	Top of Line Corrosion
TR	Transformer Rectifier
UT	Ultrasonic
VOC	Volatile Organic Compounds
WG	Working Group
WI	Water Injection
WP	Working Party

Bibliography

- UK Health and Safety Executive, 'A guide to the pipelines safety regulations, guidance on regulations', 1996.
- Energy Institute, 'Guidance for corrosion management in oil and gas production and processing', May 2008.
- Canadian Association of Petroleum Producers (CAPP), 'Mitigation of internal corrosion in sweet gas gathering systems', June 2009.

- Canadian Association of Petroleum Producers (CAPP), 'Mitigation of internal corrosion in sour gas pipeline systems', June 2009.
- Canadian Association of Petroleum Producers (CAPP), 'Mitigation of internal corrosion in oil effluent pipeline systems', June 2009.
- Canadian Association of Petroleum Producers (CAPP), 'Mitigation of internal corrosion in oilfield water pipeline systems', June 2009.
- UK Health and Safety Executive, 'A guide to the pipelines safety regulations', 1996.
- 'Pipeline risk management manual – ideas, techniques and resources', 3rd edn, (ed. W. K. Muhlbauer), 2004, Elsevier.

References

1. P. Zelenak, H. Haines and J. Kiefner: 'Analysis of DOT reportable incidents for gas transmission and gathering system pipelines, 1985 through 2000', PR218-0137, Kiefner and Associates Inc. for the Pipeline Research Council International (PRCI), 2003.
2. <http://events.nace.org/library/corrosion/pipeline/pipeline-failures>

An essential first step in managing corrosion in any pipeline system is to compile an exhaustive inventory of relevant information into a pipeline register. Such a list characterises the pipeline and should include (i) all details related to the pipeline location, field and history, (ii) design details including pipe configuration, materials data, (iii) operating parameters covering types of fluid and environment (burial, atmospheric, marine, immersed, soil if known, etc.), operating conditions, acid gas content and water chemistry, (iv) internal and external corrosion mitigating measures covering operational pigging, chemical treatment, type of cathodic protection (CP) system, coatings, and (v) inspection strategy including pigging capacity and other related information. This chapter (see Fig. 2.1) outlines necessary information required to capture the full inventory of pipeline systems, their compilation into the pipeline register and provides a snapshot of steps and elements in this process.

2.1 Introduction

An overriding parameter in pipeline corrosion management (PCM) is full knowledge of pipelines for which an operating company is responsible. In some instances, this inventory and register are required by local legislations. This knowledge is gained through development and updating of a full pipeline register containing all related physical, logistical and operational parameters and information. Such information will also contain the basic data necessary to carry out and implement the respective corrosion management programme.

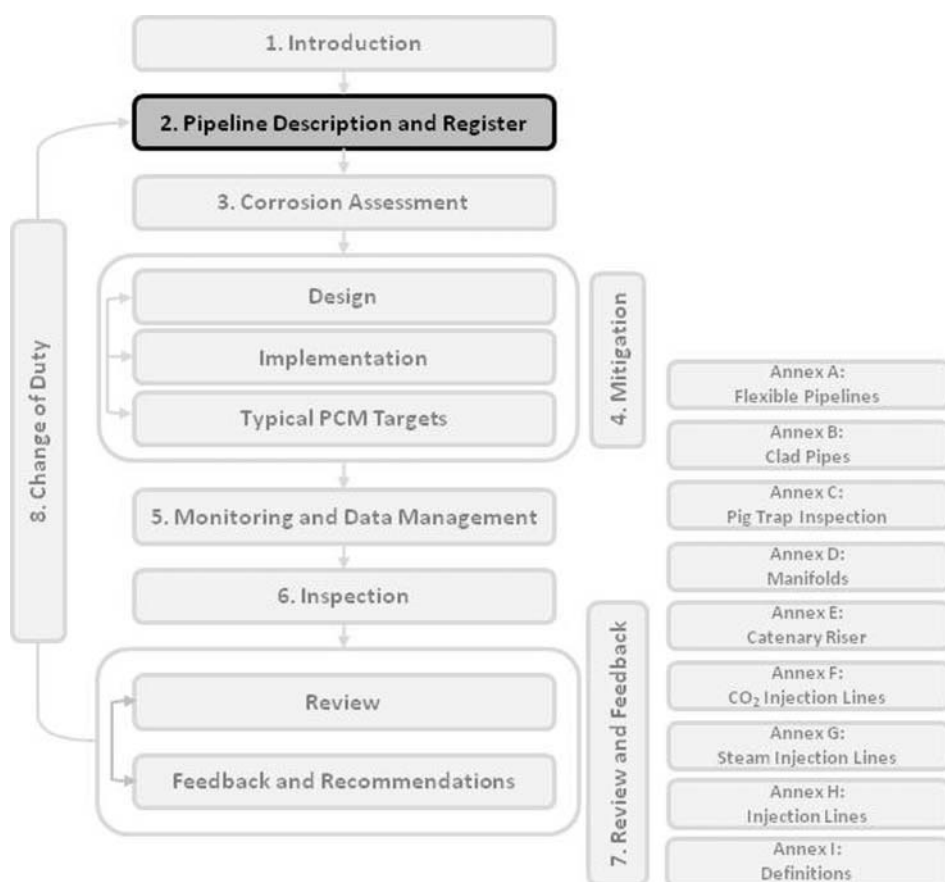
2.2 Basic pipeline register (the system)

The basic pipeline register aims to document a full list of pipelines for which an operating company is responsible for their corrosion management. It should be noted that this may also include pipelines not necessarily owned by the operating company, for example, in the following cases:

- The pipeline or part thereof, is owned by a third party which delegates its operation to an operating company/contractor.
- The pipeline or part thereof, is owned by a consortium comprising the operating company and has clearly delegated its corrosion management to the said operating company.
- While the pipeline or part thereof is operated by a third party, its corrosion management has been delegated – such a case may apply to third party tie-ins which may include complementary requirements and additional information.

The pipeline register should contain basic information required to document the characteristics of the lines ('hardware'), as well as the responsibility of the operating company with regard to corrosion management with a specific attention to interfaces when relevant.

The information listed in the basic pipeline register should include, as a minimum but may not be necessarily limited to those outlined in Table 2.1.



2.1 Position of Chapter 2 within the structure of this RP

2.3 Physical characteristics register

Basic design and construction data need to be documented in the pipeline register. This is necessary to assist in any remaining life evaluation by corrosion assessments. The accuracy of such information is paramount, since the remaining life of a pipeline is substantially affected by critical aspect such as materials, nominal wall thickness, type of coating, or the method used for CP.

The basic design and construction data which should be documented comprises, but may not be limited to those outlined in Table 2.1.

In some specific cases, additional information may be documented such as the names of the linepipes' supplier(s), welding and/or field joint coating application contractor(s), design and installation contractor(s), etc. This type of information may be particularly useful in the case of very long pipelines where several contractors may have been involved.

Table 2.1 Typical content of pipeline register/inventory

Type of data	Information	Essential (Yes/No)
Pipeline system	Name of the owner	Yes
	Name of the operating company	Yes
	Battery limits	Yes
	Entity responsible for corrosion management	Yes
	Country, field, sector, asset	Yes
	Type (rigid, flexible, pipe in pipe (PIP))	Yes
	Departure and arrival points	Yes
	TAG Number	No
	Offshore, onshore, or both	Yes
	Diameter and length	Yes
	Year of commissioning	Yes
	Share of production of asset/operating company	No
	Design life	No
Physical characteristics	Land ownership	Yes
	Material & grade	Yes
	Wall thickness	Yes
	Design pressure	Yes
	Maximum operating pressure (MAOP)	Yes
	Minimum allowable wall thickness at MAOP	Yes
	Type and thickness of external coating	Yes
	Type and thickness of internal coating	Yes
	Type and thickness of field joint coating	Yes
	Internal or external cladding & thicknesses	Yes
	External cementing	Yes
	Type of cathodic protection system	Yes
	Operational pigging capabilities	Yes
	Topography	No
	Inline inspection (ILI) capabilities	Yes
	Permanent/temporary pig traps	No
	Laying (soil, seabed, trenched, buried, etc.)	Yes
	Landfalls	Yes
	Linepipe supplier(s)	No
Operating conditions	Welding & field joint coating contractor(s)	No
	Design & installation contractor(s)	No
	Physical operating conditions	
	• <i>Inlet & outlet pressures</i>	Yes
	• <i>Inlet & outlet temperatures</i>	Yes
	• <i>Oil, gas, condensate, water flowrates</i>	Yes
	• <i>Ambient temperature</i>	Yes
	Fluid characteristics	
	• <i>Type of fluid</i>	Yes
	• <i>Gas oil ratio</i>	Yes
	• <i>Inlet & outlet water flowrates</i>	Yes
	• <i>CO₂, H₂S contents (gas phase)*</i>	Yes
	• <i>Dissolved O₂ content</i>	Yes
	• <i>Typical water composition</i>	Yes
	• <i>Organic acid content</i>	Yes
	• <i>Solid content</i>	Yes

Table 2.1 Continued

Type of data	Information	Essential (Yes/No)
Inspection data	Inspection policy (prescriptive, risk based inspection (RBI), etc.)	Yes
	Date and type of previous inspection	Yes
	Date and type of next inspection	No
	High level summary of last inspection results	Yes
	Repairs (composite repair, clamps)	Yes
	Pipeline section replacement	
Others	Physical treatments & level of confidence	
	• <i>De-aeration</i>	Yes
	• <i>De-carbonation</i>	Yes
	• <i>De-sulphuration</i>	Yes
	• <i>De-hydration</i>	Yes
	• <i>Operational pigging</i>	Yes
	Chemical treatments & level of confidence	Yes
	• <i>Corrosion inhibition</i>	Yes
	• <i>pH stabilisation</i>	Yes
	• <i>Biocide treatments</i>	Yes
	• <i>Oxygen scavenging</i>	Yes
	• <i>Anti scale treatment</i>	Yes
	• <i>H₂S scavenging</i>	No
	• <i>Demulsifiers</i>	No
	• <i>Wax/asphaltene inhibitors</i>	Yes
	• <i>Elemental sulphur solvent</i>	Yes
	• <i>Mode of treatment</i>	Yes
	• <i>Dosage rate</i>	Yes
	• <i>Name of supplier</i>	No
	Corrosion monitoring	
	• <i>CP data, close interval survey (CIS), DC voltage gradients (DCVGs), etc</i>	No
	• <i>Monitoring type & technique</i>	No
	• <i>Locations</i>	No
	• <i>Monitoring frequency</i>	No

* CO₂ and H₂S contents are the respective values of the last or next gas phase in equilibrium with the aqueous phase, i.e. the content at the last separator for any liquid circuit downstream, or the content at the bubble point for any hydrated oil upstream.

2.4 Operating conditions

The pipeline register should document the basic operating conditions of each pipeline to provide a sound basis for performing corrosion assessment. Operational conditions will also enable corrosion engineers to identify potential corrosion threats, their significance, and their implications in terms of mitigation actions and monitoring.

Operating conditions should be updated on a regular basis to reflect changes in pipeline operations so that the corrosion assessment remains valid with time. Therefore, the pipeline register becomes a live document.

The operating conditions can be divided into two parts as follows:

2.4.1 Physical operating conditions

As most corrosion mechanisms are affected by or sensitive to the operating pressures and temperatures (both internal and environmental), these parameters need to be documented in the pipeline register. Furthermore, the type of external environment (burial, atmospheric, marine, immersed, etc.) needs to be documented to ensure that a complete external corrosion assessment can be performed. Respective parameters are outlined in Table 2.1.

Further information, such as soil properties, ambient temperature or seawater currents may be useful to document for specific applications.

2.4.2 Fluid characteristics

These are of paramount importance for carrying out corrosion assessments, defining mitigation actions and monitoring of corrosion. They should be captured and incorporated into the pipeline register including those outlined in Table 2.1.

Organic acids are important both in terms of system corrosivity and especially for determining the risk of top of line corrosion (TOLC). The presence of solids as sand, mineral scales, etc.) also needs registering.

More details on fluid characteristic are given in Chapter 3.

2.5 Inspection policy and data

PCM is an integral part of integrity management and, as such, it cannot be dissociated from the prevailing inspection policy. Furthermore, the availability of inspection data will impact the corrosion assessment, or even the definition of mitigation and monitoring actions to a large extent.

It is therefore, recommended to clearly document in the pipeline register, both the inspection policy followed for each pipeline, as well as the main results obtained from inspection activities.

When doing so, one should remember that inspection activities are different from corrosion monitoring activities, i.e. they aim at obtaining data on the physical status of the pipeline, rather than evaluating fluid corrosiveness or corrosion inhibition effectiveness as described further in Chapters, 4, 5 and 6.

The pipeline register should therefore document those information outlined in Table 2.1. The type and methods of previous and next inspections should include ILI, excavations, visual inspections of risers, etc.

A summary of the results of previous inspections, although useful, is not required in the pipelines register. However, these should be easily accessible within the operating company's company document management system so that they can be accessed if required during corrosion assessments and reviews, as well as during the definition of mitigation and monitoring actions. More details of inspection policy are given in Chapter 6.

2.6 Complementary information

The following information may be documented so that it is readily available for corrosion assessments and corrosion reviews. If the information is not documented

in the pipeline register, then it will need to be readily available elsewhere and gathered or summarised before performing any corrosion assessment or corrosion review. These include the following three series of parameters:

2.6.1 Physical treatments

The existence of physical treatment upstream of the pipeline inlet such as de-aeration, de-carbonation, de-sulphuration, or de-hydration will have a positive impact on system corrosivity as long as these processes are reliably and correctly operated. The use of such treatments and the confidence in their availability and reliability can be documented in the pipeline register but will in any case need to be readily available. This information is outlined in Table 2.1 and further details of such treatments are given in Chapter 4.

2.6.2 Chemical treatment

Similarly, any chemical treatment used for mitigating corrosion can be included in the pipeline register or be readily available elsewhere. These may include but not limited to those outlined in Table 2.1.

Furthermore, when documenting chemical treatments, additional information reflected in Table 2.1 should include the following:

- Is the treatment continuous, by regular batch, or occasional?
- Was the chemical tested and selected in the laboratory?
- What is the availability of the treatment on site?
- What is the dosage rate?
- Is the treatment monitored in terms of injection follow-up, and/or corrosion monitoring, and/or dedicated laboratory analyses?
- What are the chemicals suppliers and product types?

Documentation of the above will allow determination of an overall level of confidence in the mitigating actions when performing corrosion assessments.

Some chemical treatments such as demulsifier, wax and asphaltene removers can increase fluid corrosivity by promoting water wetting.

More details on chemical treatments are given in Chapter 4.

2.6.3 Corrosion monitoring data

Corrosion monitoring data (coupons, probes, bioprobes, cathodic protection performance, coating degradation, sample collection and analyses) constitutes another essential series of information necessary for corrosion assessments and corrosion reviews. While a brief summary or anomaly reporting may be included in the pipeline register, exhaustive documentation of corrosion monitoring data may be too large to be included, but will need to be readily available in a separate dedicated company data management system.

However, it will be possible to document in the pipeline register whether corrosion monitoring is used. In this case, the necessary information should include those outlined in Table 2.1.

Further details on corrosion monitoring are given in Chapter 5.

2.7 Key messages

Table 2.1 gives the typical and brief content of the pipeline register recommended in this RP. The final register used by the operating company may include other information, depending on local regulations, operating company integrity assurance policy, and availability of data.

Information considered as essential is suggested in the table, but the responsibility to include in the register all of the required data is ultimately the responsibility of the operating company.

Pipelines experience many types of corrosion damage, internally and externally including general and localised corrosion. These damage mechanisms are influenced and governed by physical, chemical and hydrodynamic aspects of the pipeline system. Identification of key corrosion threats is a fundamental step in pipeline corrosion management (PCM) and is an iterative process throughout the design, operation and service life of pipelines. This chapter (see Fig. 3.1) covers types of corrosion threat, information required to carry out corrosivity assessments, hotspot identification and system corrosivity evaluation for both routine and non-routine operations. In addition, the chapter includes considerations on competency levels required for carrying out corrosivity assessment.

3.1 Introduction

Recognition of corrosion threats yields key information allowing effective and pertinent mitigating actions. In assessing corrosion, the type of damage, and its initiation and development throughout service life are important considerations in ensuring implementation of PCM. Information necessary to perform a corrosion assessment is wide ranging and the subject of many documents and standards as outlined in the Bibliography.

3.2 Relevant corrosion threats

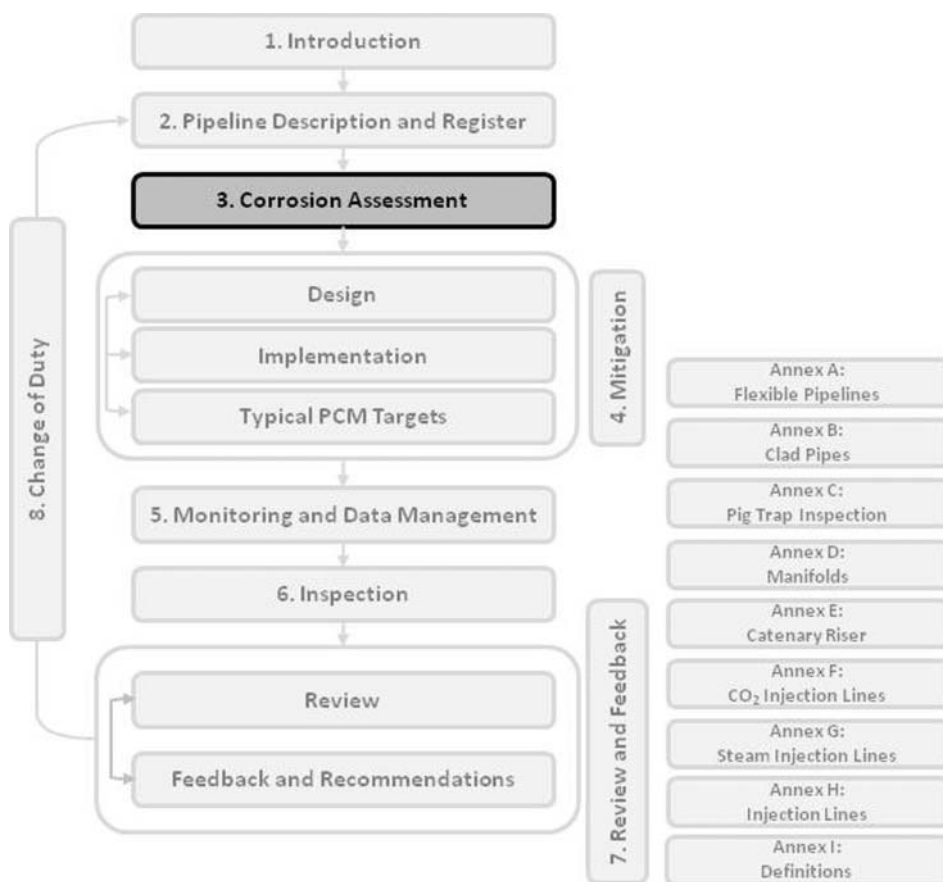
The main corrosion threats in pipeline systems are outlined in Tables 3.1 and 3.2 with relevance to service and primary influencing parameters, for internal and external corrosion, respectively. The threats listed in these tables are broadly in line with time dependence threat categorisation described in ASME B31.8S. Further details can be found in the Bibliography.

3.3 Gathering data input

Before undertaking the corrosion assessment, a list of key data should be gathered. The most commonly used information for corrosion assessment includes those data outlined in Tables 3.3 and 3.4 for internal and external corrosion, respectively.

It is important to recognise that any sample taken is only representative of the process stream at the point where it has been taken. Changes in the fluid chemistry between the inlet and sampling point, or during the time between sampling and analysis should be understood and accounted for in interpreting the results.

During the operating life of a pipeline, the fluid chemistry and gas content may vary with process upsets and/or operational requirements. Therefore, the frequency of water and gas sampling programmes needs to be adequate and representative and their trends with time recognised.



3.1 Position of Chapter 3 within the structure of this RP

Data relating to external condition tend to be collected less frequently, but are no less important and should still be subject to regular update and analysis. These may include but not limited to the soil and groundwater conditions, environmental conditions, and location (risers, landfalls, etc.).

3.3.1 Fluid chemistry

Representative water chemistry should be made available. This is critical for an effective internal corrosion threat assessment.

Key components in water chemistry for CO₂ and/or H₂S corrosion and for water injection lines are outlined in Table 3.3.

The following should be considered when carrying out fluid chemistry analysis:

- pH measurements made on fluids in the field on depressurised samples should be taken with caution. CO₂ evolves from the solution rapidly when the fluid is depressurised into a sample vessel. Therefore, the measured pH is not representative of the in-situ conditions.

Table 3.1 Internal corrosion threats

Type of threat	Relevance to service	Primary influencing parameters
Microbiologically influenced corrosion (MIC)	Oil and produced/ injection water	Sulphate, nutrients, bacteria type, pH, flow rate, salinity, temperature
CO ₂ corrosion	Oil, gas and PW/PG injection	P&T, acid gas content, in-situ pH, flow regime, water cut
H ₂ S + CO ₂ corrosion	Oil, gas and PW/PG injection	P&T, acid gas content, in-situ pH, flow regime, water cut, acid gas ratio, microbial activities
Top-of-line corrosion (TOLC)	Stratified wet gas	T, organic acid content, water condensation rate
Oxygen corrosion and other oxidants	Water injection	O ₂ content, T and flow rate, residual chlorine
Under-deposit corrosion	Oil and produced/ injection water	Solids, scales, flow rate
Preferential weld corrosion	Oil, gas and PW/PG injection	Weldment metallurgy, flow regime, type inhibitor, water salinity
Crevise corrosion	Oil, gas and PW/PG injection	Joint design and configurations, oxygen content
Galvanic corrosion	Water injection	Dissimilar joints, oxygen content
Erosion and corrosion–erosion	Oil, gas and PW/PG injection	Solids, flow regime
Corrosion and cracking from injected chemicals ¹	At chemical injection point	Design of injection point, chemical dose rate, acid type, oxygen concentration ²
Sulphide stress cracking (SSC)	Oil, gas and PW/PG injection	In-situ pH, H ₂ S, T, steel metallurgy, stress level
Hydrogen induced cracking (HIC)	Oil, gas and PW/PG injection	In-situ pH, H ₂ S, T, P, steel cleanliness and metallurgy
Corrosion-fatigue	Dynamic risers	Cyclic stress, system corrosivity

¹ Injected chemicals may contain contaminants that exacerbate the corrosion process, e.g. hydrate inhibitor may result in sufficient oxygen contamination to pose oxygen related damage in produced fluid lines.

² In highly aggressive environments, can also be a corrosion threat downstream of hydrate inhibitor injection points for wet gas/multi-phase systems, particularly where synergy with other corrosion threats is possible.

- Presence of some production chemicals may affect water chemistry. If anticipated, water samples should be taken upstream of injection point, before batch treatment or after injection has ceased for sufficient time.
- For samples taken during well tests, care should be taken to look for contamination with drilling fluids. High levels of ions such as Zn²⁺, Ca²⁺, Br⁻, Ba²⁺, Sr²⁺, B³⁺ or K⁺ may indicate contamination and therefore affect water chemistry.
- The organic acid content (or associated organic species) may interfere with bicarbonate analysis – a key point when carrying out water chemistry analysis. Care should be taken not to overestimate in-situ pH and bicarbonate level in the presence of organic acids.

Table 3.2 External corrosion threats

Type of threat	Relevance to service	Primary influencing parameters
Microbiologically influenced corrosion (MIC)	Buried pipelines	Soil type, coating, cathodic protection (CP) inefficiency, anaerobic conditions
Crevice corrosion	Above ground pipe support, flanges	Joint and support design
Galvanic corrosion	Flanges, couplings, fittings, insulating joints	Dissimilar joints, water wetting
Soil corrosion	Land lines	Soil type, coating, CP inefficiency
Atmospheric corrosion	Above ground lines	Coating, environment
AC-induced corrosion	Buried land lines	Third party infrastructures, telluric activities
Corrosion under insulation (CUI)	Above ground insulated lines	Type of insulation, the environment
Stray current corrosion	Buried land lines	Third party infrastructures
Stress corrosion cracking (SCC) – high pH	Buried land lines	Soil conditions, T, coating degradation, CP, pH, cyclic stress
Stress corrosion cracking (SCC) – neutral pH	Buried land lines	Coating degradation, CP, pH, cyclic stress
Corrosion-fatigue	Submarine lines	Cyclic stress
Hydrogen embrittlement	Submarine lines	CP overprotection, coating, steel/weldment hardness

- Sulphides may be measured in the aqueous fluid samples taken. However, H₂S can evolve from the sampling vessel on depressurisation and oxidise when exposed to oxygen. Therefore effective preservation of samples must be ensured. This is usually achieved by using a stabilising agent such as sodium hydroxide or zinc acetate [2].
- Operational procedures with regard to open and closed drains may lead to bacterial activities, water quantity and compositional changes – these should be taken on board.
- In the presence of Fe²⁺, a suitable sampling and preservation (acidification or chelating agents) procedure should be used to prevent iron precipitation.
- It is recommended to drain the sample point for a sufficient period of time before collecting the fluids to ensure representative sampling.

3.3.2 Gas composition

The gas analysis should include the percentage of the acid gases (CO₂ and H₂S) and O₂. In the case of liquid pipelines, these are the values measured or predicted from the associated gas phase of the liquid/gas equilibrium immediately upstream.

3.3.3 Flow regime

Understanding the flow regime within the pipeline can help to assess system corrosivity, partitioning behaviour of an inhibitor, the likelihood of water wetting, under

Table 3.3 Summary of information for assessing internal system corrosivity

Parameter	Essential	Comment
Type of service	√	Oil, water, gas or multi-phase including any process changes
CO ₂ content	√	In the associated gas
H ₂ S content	√	In the associated gas
Elemental sulphur	√	Very high corrosion rates can be experienced
O ₂ content	√	Dissolved oxygen
Operating pressures	√	Range, maximum values
Bubble/dew point	√	
Operating & ambient temperatures	√	Range, maximum values
Oil API gravity		
Throughput/day gas	√	Profile throughout service life if available
Throughput/day oil	√	Profile throughout service life if available
Throughput/day water	√	Profile throughout service life if available
GOR/GLR		Profile throughout service life if available
Sand production and content		An important consideration for erosion and under deposit corrosion and considered essential for high flow rate conditions
Line internal diameter	√	
Flow regime		From modelling or meters/service knowledge
Water type & composition:	√	Condensed/formation water
HCO ₃ ⁻	√	
Organic acids and other organic species	√	e.g. acetate, formate, butyrate, etc. needed for CO ₂ , TOLC and MIC assessment
Cl ⁻		This is essential for flexible risers and CRAs
SO ₄ ²⁻		This is essential for MIC assessment
Fe ²⁺		
Ca ²⁺		
TDS		
Salinity		
pH	See footnote	Predicted and measured*
Bacterial count		For oil, multi-phase or water lines only
Operating life	√	
Wall thickness	√	
Remaining operating life		
Chemical treatment		Meeting key targets in operation or are targets realistic in design?
injection reliability		
Production chemicals applied		Meeting key targets in operation or are targets realistic in design?
Continuous or batch treatment	√	Meeting key targets in operation or are targets realistic in design? In the event of batch, frequency should be noted
Chemical residual content		Meeting key targets in operation or are targets realistic in design? This includes biocide, oxygen scavenger and corrosion inhibitor

GOR, gas oil ratio; GLR, gas liquid ratio; TDS, total dissolved solids; TOLC, top of line corrosion.

* It is essential that the pH is correctly measured or predicted to allow accurate system corrosivity assessment.

deposit corrosion and MIC. This is normally achieved by flow dynamic modelling bearing in mind operational parameters.

3.3.4 External assessment

Influential parameters affecting external corrosion of pipelines are summarised in Table 3.4.

The data should be gathered through a site survey covering variations along the pipeline. An initial desktop topographical, geological and environmental survey may be used to identify regions with fluctuations in water table, soil type and industrial activity. From this review, specific locations should be selected for site surveys and collection of samples for analysis or in situ measurement.

Soil resistivity is a key parameter and on its own, can provide a good assessment of the potential corrosivity of an environment. Typical values and guidance on the aggressiveness of the soils are given in Table 3.5. Resistivity measurements are described further in the Bibliography.

Preservation of soil samples taken in the field for analysis is no less critical than for fluid samples. Soil samples should not be contaminated or permitted to dry out, samples for bacterial analysis should be kept anaerobic, or sulphide reducing bacteria (SRB) tests conducted in the field should be stored under appropriate temperature conditions.

Table 3.4 Summary of information for assessing external system corrosivity

Parameter	Essential	Comment
Environment	√	Above ground, buried, submarine, splash zone, trenched. Landfall, crossings [1]
Geographical location and water depth	√	For sealines only
Exposure temperatures	√	Above and below pipe – winter and summer
Soil type/backfill	√	Consolidated, sand, gravel, etc.
Soil water content	√	
Bacteria level		SRB content per gram; aerobic, anaerobic
Coating/insulation/heating type	√	
Coating condition		Essential if condition unsatisfactory
Soil/electrolyte resistivity	√	
Soil pH		
Alkalinity		
Cl ⁻		
SO ₄ ⁻		
AC source interference	√	Railway, HV power, etc.
DC source interference	√	DC railways, other CP systems, industrial DC users
Cathodic protection type	√	Impressed current, sacrificial anode
Anode condition	√	
Pipe support design		
Mechanical type defects		Buckling, free-span, etc.

AC, alternating current; DC, direct current; HV, high voltage; SRB, sulphide reducing bacteria.