Item No. 24202
NACE International Publication 1D199

This Technical Committee Report has been prepared by NACE International Task Group T-1D-46 on Development Strategy for Internal Erosion and Corrosion Monitoring and/or Detection*

Internal Corrosion Monitoring of Subsea Production and Injection Systems

Foreword

The purpose of this technical committee report is to discuss the state of the art of internal corrosion-monitoring techniques for subsea equipment including production and injection systems (e.g., wells, jumpers, manifolds, flowlines, risers, storage systems, pipelines, etc.). It is intended to be useful for engineers involved with subsea production systems.

Corrosion monitoring at the terminus of a pipeline, in the topsides facility, or at the onshore facility is beyond the scope of this report. Information on the techniques and methodology for such facilities, including information on the traditional intrusive techniques—corrosion coupons, linear polarization resistance (LPR) probes, electrical resistance (ER) probes, and potentiodynamic scans, can be found in NACE Publication 3T199.[1]

A distinction between inspection and monitoring of subsea systems exists. Inspection techniques are used infrequently to determine the corrosion condition of a system. Thus, inspection can give information on the wall thickness of the system, telling whether either mild or severe corrosion has occurred. Corrosion monitoring is used frequently or continuously and can therefore be used as a control tool for modifying system parameters. In this technical committee report the main attention is focused on those methods with sufficient sensitivity and frequency of measurements to be classified as corrosion-monitoring techniques. However, inspection techniques that are beneficial for determining the useful life and safety of a system are also described.

This technical committee report was prepared by NACE Task Group T-1D-46 (formerly T-1C-24), a component of Unit Committee T-1D on Corrosion Monitoring and Control of Corrosion Environments in Petroleum Production Operations. It is issued under the auspices of Group Committee T-1 on Corrosion Control in Petroleum Production.

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General

Corrosion monitoring techniques can be divided into intrusive and nonintrusive methods. Intrusive methods are those that access the inside of a system. Nonintrusive systems do not require internal access. This distinction is particularly critical in subsea use because of the difficulty in using intrusive devices in underwater locations, especially at greater depths. Nonintrusive monitoring systems include the field signature method, thin layer activation, and fixed ultrasonic testing (UT). These systems and others are the focus of this technical committee report.

Definition of Terms[(1)]

Anomaly: Any kind of *imperfection* or *defect* that may be present in the wall of a component.

Camera Pig: A configuration *pig* that carries a video or film camera and light sources for photographing the inside surface of a *pipe* on an intermittent or continuous basis.

Corrosion-Resistant Alloy: An alloy that displays substantial resistance to corrosion in the environment of interest.

Data Analysis: The process by which *indications* are evaluated to classify and characterize them as nonrelevant conditions, *pipeline* components, *anomalies*, *imperfections*, *defects*, or critical *defects*.

Defect: An *anomaly* for which an analysis, such as ASME[(2)] B31G,[2] indicates that the *pipe* is approaching failure as the nominal hoop stress approaches the specified minimum yield strength (SMYS) of the pipe material.

Flux Density, Magnetic: The strength of a magnetic field, expressed in flux lines per unit area.

Flux Leakage Field: The magnetic field that leaves or enters the surface of a part as the result of a discontinuity or a change in section.

Imperfection: An *anomaly* in the pipe that will not result in pipe failure at pressures below those that produce nominal hoop stresses equal to the SMYS of the pipe material.

Indication: (1) Any measured signal or response from an *inspection* of a *pipe* above the normal baseline signal. (2) Measurements made during *monitoring* of cathodic protection systems.

Injection System: All portions of the physical facilities through which injected fluids or gases move during transportation, including *pipe*, valves, and other appurtenances attached to the pipe, such as compressor units, metering stations, regulator stations, delivery stations, holders, and other fabricated assemblies.

Inspection: (1) The process of examining a *pipe* using a nondestructive testing technique to look for *anomalies* or to evaluate the nature or severity of an *indication*. (2) The process of running a configuration tool or an in-line *inspection* tool through a *pipe* to detect *anomalies*.

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(1) Words shown in *italics* are those that are defined elsewhere in this section.
(2) American Society of Mechanical Engineers (ASME), 345 East 47th St., New York, NY 10017.

Instrumented Tool or Pig: A vehicle or device, which contains sensors, electronics, and recording or output functions integral to the system, used for internal inspection of a *pipe*. Instrumented tools are divided into two types: (a) configuration *pigs*, which measure the pipeline geometry or the conditions of the inside surface of the pipe, and (b) in-line *inspection* tools, which use nondestructive testing techniques to inspect the wall of the *pipe* for corrosion, cracks, or other types of *anomalies*.

Magnetic Flux: See *flux*.

Monitoring: Measurements or periodic *inspections* made at selected locations.

Pig: A generic term signifying any independent, self-contained device, tool, or vehicle that moves through the interior of the *pipeline* for the purpose of inspecting, dimensioning, or cleaning. (Also referred to as a "scraper.")

Pipe: The steel pipe exclusive of protective coatings or attachments.

Pipeline: That portion of the pipeline system including the *pipe*, protective coatings, cathodic protection system, field connections, valves, and other appurtenances attached or connected to the pipe.

ROV: Remotely operated vehicle.

Subsea Corrosion Monitoring: Present Industry Practice

The complexities of the conditions for subsea oil and gas production as well as changes in the operating conditions have generally resulted in the application of corrosion monitoring. The choice of subsea monitoring equipment is usually the result of considering three vitally important aspects: cost, reliability, and accuracy. Inaccurate data or false indications can be costly to verify. Past experience has shown the reliability of downhole equipment (casing, tubing, subsurface safety valves, mandrels, nipples, etc.) to be of paramount importance because of the cost of subsea workovers. The best method for preventing corrosion-related workovers is proper initial design, with selection of a suitable corrosion-resistant alloy (CRA) or an effective corrosion control system. At present, downhole corrosion monitoring methods are readily available, but have generally not been considered necessary by the industry when proper materials selection is made. A similar argument can be made for subsea equipment such as wellheads, christmas trees, subsea chokes, etc. For production and injection equipment, such as pipelines, flowlines, and risers not constructed from CRAs, monitoring equipment is used in corrosive environments. For production and injection equipment constructed from CRAs, corrosion-monitoring equipment is not typically used.

Corrosion monitoring of subsea systems is still a technology in its infancy. For that reason in-line inspection tools and other methods have been used for the evaluation of subsea production and injection systems, while corrosion monitoring is used at an above-water location topside or onshore. Today, subsea corrosion monitoring is mainly based on inference from data obtained at the line terminus. NACE Publication 3T199[1] describes the techniques and methodology that are relevant for surface corrosion monitoring.

Permanently Installed Monitors

Corrosion monitoring is used in a subsea system to detect, predict, and prevent corrosion failure with its consequent safety and financial implications. Monitoring provides the assurance that the corrosion-mitigation systems, such as inhibitors, are doing their job.[3]

The general philosophy of corrosion monitoring is that multiple techniques are used to both complement and check each other. The overall cost of a complete corrosion-monitoring program is low—it is trivial compared with the cost of undetected corrosion.

A typical approach to defining a corrosion-monitoring program for a subsea application is to:

(a) Consider the various techniques and methodologies available.

(b) Define the type of information required to determine acceptable operation of the corrosion-mitigation system.

(c) Determine the required resolution based on response time.

(d) Define the required system reliability.

(e) Define the location(s) for the probe(s).

A method to verify the information received from a monitoring system is vital because the cost of remedial actions (replacement) can be substantial. Some monitoring devices measure only a small area in comparison with the entire surface area and corrosion in other locations is inferred from those data.

A limitation of traditional corrosion-monitoring techniques in subsea applications concerns communication with the surface. However, with the developments in electronics, signal transmission, and data processing, the availability of subsea corrosion-monitoring techniques