Engineering Standard

SAES-L-133 5 October 2005

Corrosion Protection Requirements
for Pipelines, Piping and Process Equipment

Materials and Corrosion Control Standards Committee Members

Al-Anezi, Mohammed A., Chairman
Al-Rumaih, Abdullah M., Vice Chairman
Abdulhadi, Abdullatif I.
Al-Anizi, Salamah S.
Al-Gahtani, Moraya S.
Al-Ghasham, Tawfiq Y.
Al-Mugbel, Wajdi M.
Al-Nabulsi, Khalid M.
Al-Sannaa, Muhsen S.
Balhareth, Nasser M.
Bash, Fahad M.
Burgess, Brian W.
Choi, Ho J.
Cruz, Ivan C.
Dias, Olavo C.
Kermad, Abdelhak
Lobley, Graham R.
Mehdi, Mauyed S.
Moore, Mark A.
Niemeyer, D.C.
Palmer, Robert E.
Stark, Gregory D.
Tems, Robin D.

Saudi Aramco DeskTop Standards

Table of Contents

1 Scope.. 2
2 Conflicts and Deviations................................. 2
3 References.. 2
4 Definitions.. 4
5 Minimum Mandatory Requirements............... 6
6 Determining Corrosive and
Crack-Inducing Environments...................... 10
7 Corrosion and Cracking Control Measures.. 13
8 Corrosion Control, Water
and Chemical Treatment Subcommittee...... 16

1 Scope

This standard specifies minimum mandatory measures to control internal and external corrosion, and environmental cracking for onshore and offshore pipelines, plant and platform piping, wellhead piping, well casings, and other pressure-retaining process equipment.

Higher temperature corrosion phenomena, > 300ºC (570ºF), are beyond the scope of this document. For higher temperatures, contact Consulting Services Department, Materials Engineering and Corrosion Control Division (CSD/ME&CCD).

The corrosion control measures specified herein are to be applied during design, construction, maintenance, and repair of such facilities.

2 Conflicts and Deviations

2.1 Any conflicts between this standard and other applicable Saudi Aramco Engineering Standards (SAESs), Materials System Specifications (SAMSSs), Standard Drawings (SASDs) or industry standards, codes and forms shall be resolved in writing by the Company or Buyer Representative through the Manager, Consulting Services Department, Saudi Aramco, Dhahran.

2.2 Direct all requests to deviate from this standard in writing to the Company or Buyer Representative, who shall follow internal company procedure SAEP-302 and forward such requests to the Manager, Consulting Services Department, Saudi Aramco, Dhahran.

3 References

The selection of material and equipment, and the design, construction, maintenance, and repair of equipment and facilities covered by this standard shall comply with the latest edition of the references listed below, unless otherwise noted.

3.1 Saudi Aramco References

Saudi Aramco Best Practices

SABP-A-001 — *Materials Selection and Protection Criteria for Austenitic Stainless Steels During Refinery Shutdowns*

Saudi Aramco Engineering Procedures

SAEP-302 — *Instructions for Obtaining a Waiver of a Mandatory Saudi Aramco Engineering Requirement*

SAEP-303	*Engineering Review of Project Proposal and Detail Design Documentation*

Saudi Aramco Engineering Standards

SAES-A-007	*Hydrostatic Testing Fluids and Lay-Up Procedures*
SAES-A-205	*Oilfield Chemicals*
SAES-A-208	*Water Treatment Chemicals*
SAES-A-301	*Materials Resistant to Sulfide Stress Corrosion Cracking*
SAES-H-001	*Selection Requirements for Industrial Coatings*
SAES-H-002	*Internal and External Coatings for Steel Pipelines and Piping*
SAES-L-100	*Applicable Codes and Standards for Pressure Piping Systems*
SAES-L-132	*Materials Selection of Piping Systems*
SAES-L-136	*Pipe Selection and Restrictions*
SAES-L-310	*Design of Plant Piping*
SAES-L-410	*Design of Pipelines*
SAES-L-420	*Scraper Trap Station Piping and Appurtenances*
SAES-L-610	*Nonmetallic Piping*
SAES-L-810	*Design of Piping on Offshore Structures*
SAES-L-850	*Design of Submarine Pipelines and Risers*
SAES-M-005	*Design and Construction of Fixed Offshore Platforms*
SAES-W-010	*Welding Requirements for Pressure Vessels*
SAES-W-011	*Welding Requirements for On-Plot Piping*
SAES-W-012	*Welding Requirements for Pipelines*
SAES-X-300	*Cathodic Protection of Marine Structures*
SAES-X-400	*Cathodic Protection of Buried Pipelines*
SAES-X-500	*Cathodic Protection of Vessel and Tank Internals*
SAES-X-600	*Cathodic Protection of In-Plant Facilities*
SAES-X-700	*Cathodic Protection of Onshore Well Casings*

Saudi Aramco Materials System Specifications

01-SAMSS-016	*Qualification of Pipeline, In-Plant Piping and Pressure Vessel Steels for Resistance to Hydrogen-Induced Cracking*
01-SAMSS-035	*API Line Pipe*
01-SAMSS-038	*Small Direct Charge Purchases of In-Plant Pipe*
01-SAMSS-332	*High Frequency Welded Line Pipe, Class B*
01-SAMSS-333	*High Frequency Welded Line Pipe, Class C*
02-SAMSS-005	*Butt Welding Pipe Fittings*
02-SAMSS-011	*Forged Steel Weld Neck Flanges*
32-SAMSS-004	*Manufacture of Pressure Vessels*
32-SAMSS-007	*Manufacture of Shell and Tube Heat Exchangers*
32-SAMSS-011	*Manufacture of Air-Cooled Heat Exchangers*

3.2 Industry Codes and Standards

American Petroleum Institute

API PUBL 932-A	*A Study of Corrosion in Hydroprocess Reactor Effluent Air Cooler Systems*
API RP 945	*Avoiding Environmental Cracking in Amine Units*

National Association of Corrosion Engineers

NACE RP0170	*Protection of Austenitic Stainless steels and other Austenitic Alloys from Polythionic Acid Stress Corrosion Cracking during Shutdown of Refinery Equipment*
NACE RP0198-2004	*The Control of Corrosion Under Thermal Insulation and Fireproofing Materials – A Systems Approach*

4 Definitions

"Baseline ILI survey": performed on scrapable pipelines prior to commissioning for the purpose of establishing the original condition of the line and to provide a "filter" enabling subsequent surveys to discriminate damage that has occurred in service.

"Caustic Cracking": a form of stress corrosion cracking characterized by surface-initiated cracks that occur in piping and equipment exposed to caustic, primarily adjacent to non-post weld heat treated welds.

"Corrosion": deterioration of a material, usually a metal, that results from a reaction with its environment. For the purposes of this document, corrosion includes general and localized corrosion mechanisms, as well as environmental cracking mechanisms including, but not limited to, stress corrosion cracking (SCC), sulfide stress cracking (SSC), hydrogen induced cracking (HIC) and stress-oriented hydrogen induced cracking (SOHIC).

"Corrosion-critical": piping systems whose failure could present a hazard to humans or to the environment, or where such failure cannot be repaired without disrupting operation. Piping systems in hydrocarbon, hydrocarbon processing, flare, and firewater service are considered corrosion-critical. Piping systems in other services may be defined as corrosion-critical by the operating organization with the concurrence of CSD/ME&CCD.

"Environmental Cracking": brittle fracture of a normally ductile material in which the corrosive effect of the environment is a causative factor.

"Erosion-corrosion": conjoint action of erosion and corrosion in a flowing single or multiphase corrosive fluid leading to the accelerated loss of material. This phenomenon encompasses a wide range of processes including solid particle or liquid droplet impingement, cavitation, and single-phase erosion of protective films.

"Hydrogen **I**nduced **C**racking (**HIC**)**":** the mechanism, related to hydrogen blistering, that produces subsurface cracks parallel to the surface and, sometimes, stepwise cracks in the through-thickness direction.

"In-**L**ine **I**nspection (**ILI**)**":** internal inspection of a pipeline using an in-line inspection tool. Also called *Intelligent or Instrument Scraping.*

"In-Line Inspection Tool": device or vehicle that is designed to travel through a pipeline and survey the condition of the pipeline wall using nondestructive examination (NDE) techniques. Also known as *Intelligent* or *Instrument Scraper.*

"Microbiologically **I**nfluenced **C**orrosion (**MIC**)**":** refers to corrosion mechanisms attributed to microorganisms and their by-products.

"Pipelines": include cross-country and offshore transportation lines, flowlines, trunklines, tie-lines, water supply and injection lines and pipeline branches such as jump-overs. SAES-L-100 defines some of these types of pipelines.

"Piping": includes pipelines, plant piping, and wellhead piping.

"Plant piping": includes above and below-ground piping inside a plant area, as defined in SAES-L-100.

"Plant": includes, but is not limited to, gas oil separation plants (GOSPs), water injection plants (WIPs), water treatment plants, gas processing plants, fractionation plants, refinery, marine or aviation terminals, bulk plants, power plants, tank farms, and pipeline pump stations.

"Polythionic **A**cid **S**tress **C**orrosion **C**racking (PASCC)**":** a form of stress corrosion cracking normally occurring due to sulfur acids forming from sulfide scale, air and moisture acting on sensitized austenitic stainless steels.

"Sensitization": refers to the composition-time-temperature dependent formation of chromium carbide in the grain boundaries of austenitic stainless steels and some Ni alloys; occurs in the 750°F to 1500°F (400°C to 815°C) temperature range.

"Stress **C**orrosion **C**racking (**SCC**)**":** cracking of a metal produced by the combined action of corrosion and tensile stress (residual or applied).

"Stress-**O**riented **H**ydrogen **I**nduced **C**racking (**SOHIC**)**":** is a rare through-thickness type of environmental cracking where a staggered array of small cracks forms, with the array approximately perpendicular to the principal stress. SOHIC occurs in severe wet, sour service and can occur in carbon steel pipe and plate that is resistant to HIC and SSC.

"Sulfide **S**tress **C**racking (**SSC**)**:** brittle failure by cracking under the combined action of susceptible microstructure, tensile stress and corrosion in the presence of water and hydrogen sulfide.

"Wellhead Piping": is the piping between the wellhead wing valve and the plot limit valve of a single or multiple well drilling site or offshore production platform. See SAES-L-410.

5 Minimum Mandatory Requirements

5.1 Use the corrosion-control measures mandated by this standard for all piping and pressure-retaining equipment exposed either internally or externally to one or more of the conditions described in Sections 6.1 or 6.2 of this standard. Use SAES-L-132 for environment-specific materials selection and SAES-L-136 for carbon steel pipe-type selections and restrictions.

5.2 For piping systems that are not corrosion-critical, follow the requirements in the pertinent standards and codes.

Commentary Note:

Some piping systems, not defined as corrosion-critical in this standard, must still be built with corrosion-resistant materials as specified in other standards or codes. Examples are sewer lines, wastewater disposal lines, and potable water lines.

5.3 Normal, Foreseeable and Contingent Conditions

5.3.1 Select appropriate corrosion control methods and materials (see Section 7) for all of the following conditions:

- normal operating conditions, projected over the design life of the system,
- process start up,
- end of run variations and
- foreseeable intermittent or occasional operations, such as hydrostatic test, steam cleaning or carryover of contaminants from an upstream process (e.g., caustic from a stripper).

Commentary Note:

Detailed analysis of the situation may or may not require measures to control general thinning. However, always take measures to prevent sulfide stress cracking, caustic cracking, and other rapid environmental cracking mechanisms.

5.3.2 Select corrosion control and materials for contingent conditions, such as those that may be encountered during construction, start-up, shutdown or process upset operations. Always take measures, as described in Section 7.2, to prevent sulfide stress cracking (SSC), stress corrosion cracking (SCC) such as caustic cracking, SOHIC, and other rapid environmental cracking mechanisms.

Commentary Notes:

(1) Contingency failure requirements will not normally require any special provision for general corrosion, localized corrosion, or hydrogen induced cracking, due to the limited time exposure.

(2) Consideration must be given to potential corrosion of valve trim/seats during hydrotest. The type of hydrotest medium must be considered together with likely exposure time and ambient temperature. Company experience has shown that certain materials (such as 304 SS) used in valve internals suffer from pitting (and in some cases severe pitting) prior to pipelines entering service. Consequently, consideration of hydrotest medium, exposure time and temperature may require an upgrade in valve

trim and seat materials. See SAES-A-007 for specific recommendations for hydrotest fluids and treatment of hydrotest fluids.

5.4 For situations not adequately addressed by codes and standards, use the optimum corrosion and materials engineering practices commonly accepted in the oil and gas industry, with the concurrence of CSD/ME&CCD.

5.5 Each new project or major facility revision shall include a Corrosion Control Plan as part of the detailed design package in accordance with SAEP-303 Attachment 1. Major elements of the Corrosion Control Plan need to be developed early in the project, such as project proposal, to ensure adequate funding. A corrosion control plan should include:

- A materials selection diagram (MSD) in the form of a map, diagram, or table. Deviations from the MSD included in the detailed engineering drawings may only be made with the approval of the Project Management Team Manager, the proponent organization superintendent and the Supervisor, Materials Engineering Unit, CSD.
- The Corrosion Control Plan shall document all design features and operating requirements regarding coatings, cathodic protection, inhibitors and chemical treatment, calculation of corrosion allowances, corrosion monitoring, postweld heat treatment if required, scraping, MIC control, and other relevant corrosion control techniques necessary to comply with this standard.

5.6 Design and provide corrosion-monitoring capabilities for all new corrosion-critical piping systems.

Commentary Note:

For non-corrosive systems, the corrosion monitoring capabilities may be as simple as providing access for ultrasonic surveys. The objective here is to develop a philosophy early in a project so that the philosophy is reviewed and approved and corrosion monitoring equipment may be installed along with any required access platforms.

5.6.1 Provide details of the corrosion monitoring philosophy and design in the Corrosion Control Plan in a separate submittal specifically addressing this topic. The scope shall be submitted as part of the Project Proposal to ensure adequate funding. A detailed submission is required during the detailed design review.

5.6.2 The corrosion monitoring plan shall include the number and approximate location of corrosion monitoring fittings, the provision of safe permanent adequately sized access to each test location, the measurement technique to be employed, the provision of data management software, data transmission, networking, racks, and marshalling cabinets. In cases where multiple engineering contractors are working on various units in a major project, the engineering contractors shall interface to develop one integrated system that maximizes use of existing facilities (computer, etcetera) and avoids unnecessary duplication.

5.6.3 Corrosion monitoring systems may be commissioned subsequently to the signature of the Mechanical Completion Certificate. However, if this occurs, the Project Management Team shall provide sufficient funding for completion and start-up of the corrosion monitoring system.

5.6.4 Corrosion monitoring access fittings used must be approved by the Supervisor, Corrosion Technology Unit, CSD and the facility corrosion engineer. Generally, fittings used in upstream operations will employ Cosasco 2-inch high pressure fittings. Generally, fittings used in refinery operations will be retractable fittings. In selecting fittings, consideration must be given to compatibility with the design of any pre-existing fittings in the plant. On-line retrievable fittings shall not be used on any line where a serious personnel safety risk could result from use of the fittings. On-line retrievable fittings shall not be used in any hydrogen service.

5.6.5 Permanent safe access is required for any location where corrosion probes need to be monitored, serviced, or replaced on-line. The platform size provided for access to 2-inch high pressure fittings shall allow the use of the high pressure access tool and valve within the confines of the platform area. Provision shall be made on elevated platforms to assist in moving the retriever equipment in place.

5.7 In-Line Inspection (ILI) – requirement for pipelines only

In-Line Inspection is a measure to monitor and evaluate the extent of corrosion damage in pipelines. The requirements to install permanent scraping facilities that are capable of accepting ILI tools shall be in accordance with SAES-L-410.

5.8 SAES-A-007 mandates corrosion protection requirements for hydrostatic test water composition and post-hydrotest lay-up procedures

5.9 Follow the requirements for oilfield chemicals in Materials Service Group (MSG) 147000 as defined in SAES-A-205 for first-fill where oilfield chemicals such as corrosion inhibitors, scale inhibitors, anti-foams, demulsifiers, biocides, or neutralizers, are to be used.

Follow the requirements of SAES-A-208 for water treatment chemicals in Materials Service Group (MSG) 147000 provided at first-fill.

In either case (oilfield chemicals or water treatment chemicals), it is highly recommended to check with the Proponent organization to ensure that first-fill chemicals are compatible with existing treatments and that there are no Chemical Alliance agreements in force which may supersede this standard.

5.10 Corrosion allowances

Use corrosion allowance as indicated by design calculations or if it is mandated by industry codes or other Saudi Aramco Standards. If corrosion allowance is used, it shall be a minimum of 1.6 mm. If the calculated required corrosion allowance exceeds 6.35 mm, evaluate alternative measures.

Commentary Note:

Corrosion allowance will not reduce the corrosion rate of the piping material. However, the extra wall thickness of the pipe may provide a longer service life if the mode of attack is uniform general corrosion. Corrosion allowances are not effective against localized corrosion, such as pitting. If pitting rates are well defined from historical data, adequate corrosion allowance can be viable.

6 Determining Corrosive and Crack-Inducing Environments

6.1 Corrosive Environments

For design purposes, an environment that meets any one of the conditions listed below is corrosive enough to require specific corrosion control measures (see Section 7). A piping system or process equipment predicted to be exposed to such an environment during its design life requires measures to control metal-loss corrosion:

6.1.1 Acidic or near neutral pH water phase with an oxygen concentration in excess of 20 micrograms per liter (20 ppb).

Commentary Note:

Acidic or near-neutral pH water that has access to atmosphere will contain up to 8 mg/L dissolved oxygen and is corrosive. Water with a pH of 10 to 12 is considered non-corrosive to steel in many environments.

6.1.2 A water phase with a pH below 5.5 calculated from available data or measured either in situ or at atmospheric pressure immediately after the sample is collected in the field.

6.1.3 A water-containing multiphase fluid with a carbon dioxide partial pressure > 206 kPa (30 psia).

Commentary Notes:

(1) Systems with CO_2 partial pressures between 20.6 kPa to 206 kPa (3 psia and 30 psia) will require corrosion control measures if the expected corrosion rate is high (see 6.4). Systems with partial pressures below 20.6 kPa (3 psia) are usually non-corrosive.

(2) Mixed corrosive systems containing both carbon dioxide and hydrogen sulfide shall be considered to be dominated by the carbon dioxide corrosion mechanism when the ratio $H_2S/ CO_2 < 0.6$. Such corrosion systems are generally called "sweet" when considering general thinning, pitting, and erosion-corrosion. However, note that the systems may contain sufficient hydrogen sulfide to also meet the requirements of sour systems presented in Paragraphs 6.2.1 and 6.2.2.

6.1.4 A service condition that would cause a metal penetration rate of 76 µm/yr (3.0 mpy) or more. The penetration rate may be from uniform corrosion, localized corrosion, or pitting. Determine this service condition jointly by consulting corrosion engineers from the responsible operating organizations and CSD/ME&CCD.

6.1.5 All soils and waters in which piping systems are buried or immersed.

6.1.6 A water-containing fluid stream with flowing solids such as scale or sand, which may settle and initiate corrosion damage.

6.1.7 A water-containing fluid stream carrying bacteria that can cause MIC.

6.2 Crack-Inducing Environments

The environments listed below require control measures if the condition is predicted to occur during the design life of the system.

6.2.1 A piping system or process equipment exposed to an environment meeting any one of the following conditions requires sulfide stress cracking (SSC) control measures:

6.2.1.1 Sour water service with an H_2S concentration above 2 mg/L and a total pressure of 400 kPa (65 psia) or greater.

6.2.1.2 Hydrocarbon service meeting the definition of sour environments in SAES-A-301. Consider an H_2S concentration of 2 mg/L or more in the water phase as equivalent to meeting the NACE criteria. Sour crude systems upstream of a stabilization facility and sour gas upstream of a sweetening or dehydration plant are included as SSC environments.

Commentary Note:

Process engineering calculations based on Henry's Law have shown that environments containing more than 2 mg/L H_2S in the water phase will usually contain more than 0.3 kPa (0.05 psia) partial pressure of H_2S in the gas phase, which is one of the NACE criteria.

6.2.2 A piping system or process equipment exposed to an environment with an H_2S concentration above 50 mg/L in the water phase requires HIC control measures, except that lean and rich DGA systems, other lean amine systems, and caustic systems are not required to meet this requirement.

Commentary Note:

The 50 mg/L criterion and the exceptions for DGA, lean amine, and caustic service are based on Saudi Aramco and industry experience from service and testing.

Amine stripper, its overhead (exit) gas piping, cooler, and overhead receiver shall be fabricated from HIC-resistant materials. Internal cladding with corrosion resistant material releases the requirement of having HIC-resistant material for the cladded part or component.

6.2.3 Environments recognized by other standards or by good engineering practice as potential environments for stress corrosion cracking (SCC) require control measures. CSD/ME&CCD shall be the final arbiter in the resolution of such design questions.

Commentary Note:

Some SCC environments are listed in SAES-W-010 Paragraph 13.3 and SAES-W-011 Paragraph 13.3. The conditions cited in the above standards include, but are not limited to, those listed below:

- *All caustic soda (NaOH) solutions, including conditions where caustic carryover may occur (e.g., downstream of caustic injection points).*
- *All monoethanolamine (MEA) solutions (all temperatures).*
- *All diglycol amine (DGA) solutions above 138°C design temperature.*
- *All rich amino diisopropanol (ADIP) solutions above 90°C design temperature.*
- *All lean ADIP solutions above 60°C design temperature.*
- *Boiler deaerator service (i.e., ambient temperature vacuum deaerators are exempt).*
- *Hydrogen service for P-No. 3, 4, and 5A/B/C base materials.*

- *All diethanolamine (DEA) solutions.*

7 Corrosion and Cracking Control Measures

7.1 Corrosion Control Requirements

For internal corrosion control to mitigate conditions described in Section 6.1, design corrosion-critical piping systems or equipment with at least one acceptable measure of internal corrosion control. A combination of two or more acceptable corrosion control measures for any given environment is preferred whenever economically and technically feasible.

7.1.2 Select the measure(s) to achieve an average metal penetration rate of less than 76 µm/yr (3.0 mpy) and/or select adequate corrosion allowance (e.g., 1.6 mm up to 6.35 mm).

7.1.3 Acceptable corrosion control measures include, but are not limited to, the following:

- Corrosion-resistant alloys
- Corrosion-resistant nonmetallic materials where permitted by Saudi Aramco standards. Coordinate with CSD/ME&CCD for applications not adequately addressed by Saudi Aramco standards such as SAES-L-132 and SAES-L-610.
- Coatings (internal/external) and linings (internal) meeting SAES-H-002.
- Galvanic or impressed current cathodic protection
- Chemical treatment and scraping
- Upstream operations must select inhibitors and chemicals using the methodology of SAES-A-205.

Commentary Note:

Corrosion inhibitor added to the service fluid stream continuously, or introduced in a concentrated slug intermittently is acceptable provided, that the corrosion rate is consistent with the corrosion allowance. Perform periodic pipeline scraping in conjunction with chemical treatment to provide effective corrosion control. Some pipelines should be cleaned using surfactants and/or gels to remove solids.

7.1.4 Protect all buried steel piping against soil-side corrosion by both external coating and cathodic protection. Use coating systems specified in SAES-H-002. Install cathodic protection systems in accordance with SAES-X-400 or SAES-X-600.

7.1.5 For offshore pipelines and platforms, protect all submerged external surfaces by coating as required by SAES-M-005. Use coating systems specified in SAES-H-001 and cathodic protection as specified in SAES-X-300. All casings for offshore wells in non-electrified fields shall be externally coated to increase the effectiveness of the cathodic protection system.

Commentary Note:

Coating of submerged structures is governed by SAES-M-005 and SAES-H-001, however it is mentioned here in SAES-L-133 because failure to coat the structure can adversely affect the ability of the cathodic protection system to adequately protect the submerged piping and well casings under certain circumstances.

7.1.6 Externally protect offshore structures, piping and other static equipment exposed to marine environment (defined in SAES-H-001 and SAES-H-002) including splash zones, either by coating or by sheathing with a corrosion-resistant material. Selection of coating system needs also to comply with SAES-H-002.

7.1.7 Erosion corrosion is mitigated primarily by adherence to SAES-L-132 for material selection and fluid velocity limitations. Similar principles can be applied to cases not specifically addressed in SAES-L-132.

7.1.8 Measures for mitigation of MIC include control of bacteria by application of a biocide chemical, selection of resistant materials, and selection of coatings.

7.1.9 Protect all pipeline jump-overs in crude oil and wet gas service by internal coating that meets SAES-H-002.

7.2 Cracking Control Measures

7.2.1 In the environments defined in Paragraph 6.2.1, use materials that comply with the requirements of SAES-A-301 or meet Saudi Aramco standards and specifications that ensure equivalent performance. Metallic plating, metallic coatings, and plastic coatings or linings are not acceptable for preventing SSC of base metals. Internal coatings may be used to mitigate corrosion, however, this does not eliminate the requirement that the base metal be resistant to SSC.

Refer to SAES-W-010, SAES-W-011 and SAES-W-012 welding standards for welding procedure qualification hardness testing, production weld hardness testing, and restrictions on dissimilar metal welds, for sour service applications.

Commentary Note:

The material requirements in 01-SAMSS-035, 01-SAMSS-038, 01-SAMSS-332, 01-SAMSS-333, 02-SAMSS-005, 02-SAMSS-011 (except for low temperature flanges), 32-SAMSS-004, 32-SAMSS-007, and 32-SAMSS-011 for pipe, fittings, flanges, and process equipment comply with SAES-A-301 or provide equivalent performance, even though the NACE standard is not, and should not be, explicitly referenced in the catalog description or purchase order.

7.2.2 Use seamless pipe, or welded pipe that meets the requirements of 01-SAMSS-016, for all carbon steel piping systems and scraper traps exposed to environments defined in Paragraph 6.2.2. Process equipment steel plates shall also meet the requirements of 01-SAMSS-016.

7.2.2.1 For induction pipe bends and quantities of pipe not to exceed 36 meters (120 feet) in length at any location, when HIC-resistant pipe is not available, use of other pipe with the grade and wall thickness such that the hoop stress does not exceed 25% of the specified minimum yield strength (SMYS) at the maximum allowable operating pressure is permissible with prior written concurrence of CSD/ME&CCD and the operating department. This provision does not preclude or modify the requirement in Paragraph 5.7 to build all new pipelines to allow the passage of ILI tools. Where the internal diameter of a bend or pipe section would be reduced enough to prevent passage of ILI tools, Paragraph 5.7 shall take precedence.

7.2.2.2 For conversion of existing, non-HIC-resistant pipe systems to sour service, the hoop stress must not exceed 25% of the specified minimum yield strength at the maximum allowable operating pressure (MAOP).

Commentary Note:

Operating non-HIC-resistant pipe at 25% SMYS does not result in immunity from hydrogen damage, including blisters, but reduces the probability of a service leak or rupture.

7.2.3 Design sour gas in-plant piping systems and pipelines for resistance to SOHIC by observing the restrictions in SAES-L-136. Note that steels and weldments that are resistant to HIC may be susceptible to SOHIC. Per SAES-L-136, to prevent the probability of SOHIC, welded pipe, e.g., straight or spiral seam, shall not be used in sour gas unless it is stress relieved (e.g., by heat treatment)

7.2.4 Design all corrosion-critical piping systems and equipment for resistance to stress-corrosion cracking (SCC). Possible control measures include material selection, coatings, modification of the environment, post-weld heat treatment, or significantly reduced design stress.

7.2.4.1 Prevent cracking and corrosion in new or repaired amine systems by following the recommended practices of API RP 945 and applying the post-weld heat treatment requirements of SAES-W-010, SAES-W-011 or SAES-W-012.

7.2.4.2 Prevent polythionic acid stress corrosion cracking (PASCC) in potential cracking environments by selecting stabilized materials that resist sensitization. Use welding procedures that minimize sensitization. In systems that have a high potential for PASCC, avoid air and moisture ingress during shutdowns: purge the system with nitrogen. In systems that have a high potential for PASCC but that must be opened to the atmosphere, neutralize polythionic acids by following NACE RP0170 and Saudi Aramco Best Practice SABP-A-001. However, seek input from CSD/ME&CCD on the treatment of poorly draining equipment such as vertical heater coils.

7.2.4.3 Chloride cracking due to impurities in the soda ash wash can represent a major hazard in austenitic materials.

7.2.5 Completely coat the outer metal surface of all 300-series stainless steels that are insulated in order to protect them from pitting and stress corrosion cracking. Follow recommendations of NACE RP0198-2004, Section 4, Table 1. Contact the coatings RSA in CSD/ME&CCD for a list of approved coating products.

8 Corrosion Control, Water and Chemical Treatment Subcommittee

Ivan Cruz	**Coordinator**
Mark Moore	Member
Olavo Dias	Member
Robin Tems	Member
Abdulatif Abdulhadi	Member
Abdelhak Kermad	Member
Robert Palmer	Member
Brian Burgess	Member
Tawfiq Al-Ghasham	Member

Revision Summary

5 October 2005	Major revision. Included process equipment to the document scope, clarified and added references and definitions, added details of corrosion control plan and monitoring requirements, clarified and added requirements for oil field and water treatment chemicals, and rearranged sections to follow logic sequence.