Sanja Martinez

ISSN 0350-350X
GOMABN 52, 2, 134-143
Stručni rad / Professional paper

ESTIMATING INTERNAL CORROSION RATE AND INTERNAL INSPECTION INTERVAL OF ABOVEGROUND HYDROCARBON STORAGE TANKS

Abstract
Corrosion of aboveground storage tanks (AST) in hydrocarbon service shortens the tank's life cycle and can lead to leaks and release of hazardous materials into the environment. Internal inspection is one of the main means to keep the tank's integrity. Determination of internal inspection interval is imminent for balancing the safe operation requirement and inspection costs. In most instances, the area most vulnerable to corrosion in upright atmospheric AST is the tank bottom. In this paper we present the procedure for calculation of reasonable internal inspection interval based on deterministic method. Calculation and/or anticipation of the key parameter, the bottom plate corrosion rate is discussed. Corrosion rates between 0.1 and 0.9 mm year^{-1} of the thank bottoms that are typically 6.4 mm to 9.5 mm thick show that corrosion is an important concern in the case of long-term storage industrial tanks. It is demonstrated that precise determination of the bottom plate corrosion rate is crucial for the obtaining reliable internal inspection interval.

Keywords: corrosion, aboveground storage tank, crude oil storage

PROCJENA BRZINE UNUTARNJE KOROZIJE I INTERVALA INSPEKCIJE NADZEMNIH SPREMNIKA ZA NAFTU I NAFTNE DERIVATE

Korozija nadzemnih spremnika s naftom i naftnim derivatima skraćuje životni ciklus spremnika i može dovesti do njihova curenja i ispuštanja opasnih tvari u okoliš. Unutarnja inspekcija jedno je od glavnih sredstava za očuvanje integriteta spremnika. Pravilno određivanje intervala unutarnje inspekcije neophodno je za uravnoteženje zahtjeva sigurnog rada i troškova inspekcije. Najugroženije područje s obzirom na koroziju u uspravnim nadzemnim atmosferskim spremnicima je u najvećem broju slučajeva dno spremnika.

U ovom radu smo prikazali postupak za izračun intervala unutarnje inspekcije koji se temelji na determinističkom pristupu. Objašnjen je izračun i / ili procjena brzine korozije dna spremnika koja je ključni parametar za izračun intervala inspekcije. Brzine korozije između 0,1 i 0,9 mm god^{-1} na dnu koje je obično debljine 6,4 do 9,5 mm pokazuju da je korozija važan problem u slučaju industrijskih spremnika za dugotrajnu pohranu nafte i naftnih derivata. Pokazano je da je precizno određivanje brzine korozije dna spremnika ključno za dobivanje pouzdanih intervala interne inspekcije.

Ključne riječi: korozija, nadzemni spremnik, skladištenje nafte

Introduction

With the rapid development of petroleum and chemical industry, storage tank plays an increasing role in the storage of crude oil and its derivatives. The tank interior, and particularly the tank bottom, is prone to corrosion [1, 2]. The thickness of the tank bottom is reduced by both, topside and underside or “soil side“ corrosion [3]. By the internal inspection, the real corrosion rate of tank bottom can be determined, and following repair works can ensure tank’s longtime safe operation in the future. This approach may results in two short-comings for tanks management, under-inspection or over-inspection. On the one hand, there is the risk of environmental damage caused by leaking tanks and the high cost of environmental cleanup, and on the other hand, there is the cost of cleaning tanks and the temporary loss of storage volume or plant operating issues that can be extremely costly. Hence, tanks owners have a keen interest in lengthening the service interval of their tanks to the extent that the minimum thickness of the bottom is attained prior to the next scheduled inspection. The in-service code for atmospheric storage tanks is API STD 653 [4]. The content in API STD 653 covers tank inspection, repair, alteration and reconstruction. Until 1991 when API issued the first edition of Standard 653, estimating the service interval of storage tank bottoms had been based on such factors as visual observations, operating history, and general experience with similar tanks. API STD 653 includes a section on how to determine the service interval of an AST bottom. The API approach is to gather data through an internal inspection and calculate corrosion rates, provide limits on minimum bottom thickness, and establish the schedule for the next internal inspection.

Quantifying the inspection interval can be done by probabilistic or deterministic methods [4, 5]. Probabilistic method uses a statistical approach to extrapolate a relatively small amount of inspection data into a prediction of inspection interval. The deterministic method uses more extensive inspection data to quantify the remaining thickness of the bottom. The key calculation parameters are maximum internal and underside corrosion rates. Current trends appear to be directed toward increased use of the deterministic approach. In-field integrity evaluation of the bottom plate requires a good understanding of inspection techniques, their limitations, and acceptance criteria. In this paper we present the procedure for calculation of reasonable internal inspection interval based on deterministic method.

Corrosion causes of AST bottoms

Crude oil represents a mixture of a large variety (thousands) of organic substances, mainly HCs, with some admixture of oxygen-, nitrogen-, sulphur-containing organic compounds and some inorganic species (metals etc). HCs can be straight and branched, saturated and unsaturated aliphatic, alicyclic, aromatic and polyaromatic compounds [6]. The refinery products are also mixtures containing straight-chain and branched chain hydrocarbons, alkenes, naphtalenes, aromatics, and other compounds [7]. Oil and its derivatives should not be corrosive to metals. The accumulation of water at the bottom of storage tanks is a primary prerequisite for development of corrosion. Generally, it is extremely difficult to avoid the occurrence of water in tanks. The basic sediment and water (BS&W) content of crude oil in storage and transport facilities is usually limited to 0.5 volume percent [8]. However, water and water vapours may ingress into crude oil and its derivatives during storage, transportation, and some other operations [9]. Because of the high polarity of water molecules the water drops separate from the organic phase on the steel surfaces forming a water pillow at the bottom of the tanks and electrochemical corrosion of steel takes place.

Processes of bottom corrosion may proceed even more intensively due to upper inflow of oxygen into the tanks [6]. The solubility of oxygen in hydrocarbons is higher (60 to 70 ppm) than in water (8 ppm). Therefore, oxygen diffuses from the organic phase (hydrocarbons or fuel) to the water phase according to the solubility in each phase, and the concentration gradient increases up to oxygen saturation in the aqueous phase [10]. Concentration cell corrosion may occur when a surface deposit, mill scale, or crevice creates a localized area of lower oxygen concentration [11]. The difference in oxygen concentration between the inaccessible area and the bulk electrolyte creates a concentration cell and may result in significant localized metal loss. The extent of internal corrosion is also influenced by the temperature, CO_2, H_2S and salts (sodium chloride, calcium chloride, and magnesium chloride), light organic acids, etc. Some of the aggressive species are typically separated from crude during production operations performed at low pressure (atmospheric up to 1 bar gauge pressure) or in various technological processes such as desalting and rectification of crude. In the tank, remaining aggressive variables undergo extraction from organic phase into the aqueous phase and may cause a decrease in the pH and increase in the water corrosivity. Even in the absence of abiotic corrosive factors, the bacteria are known to cause severe internal corrosion problems in crude oil storage and transport [6]. Ability of microorganisms to grow both in a water phase and on inter-phase of water/hydrocarbon as well as the generation of products of their metabolism worsen the physical and chemical properties of oils and fuels. Activity of microorganisms promotes an increase of suspended solids content and formation of corrosive sludge at the bottom of tanks. Microbial degradation of HCs and other organic compounds increases the water content in sludge, which can exceed 10%. Pitting corrosion has been observed underneath sludge deposits that are a mix of sand and clay particles, water, and oil products [8].

Fretting-related corrosion may also occur on the bottoms of external floating roof tanks [11]. Repeated, frequent contact between the bottom and the end of the pipe leg when the roof is landed, removes any protective layer of rust scale that may have formed on the bottom surface. When the roof is floated again, water on the tank bottom causes corrosion at the location on the landing plate where the coating and/or any protective rust scale has been damaged. Frequent roof landings over a long period of time causes corrosion severe and localized enough to corrode a hole through the striker plate and the floor plate like a cookie cutter. Most bottom designs require "striker plates" under each roof support leg. When the floating roof is landed, the pipe legs rest on the striker plates supporting the weight of the roof. In some cases, welding can produce large differences in the microstructure of a steel bottom plate resulting in galvanic corrosion. Preferential metal dissolution can occur at the heat-affected zones (HAZ) of the base metal near the welds.

Various corrosion forms at the bottom of ASTs in hydrocarbon service we have encountered in our experience are shown in Figure 1.

Anticorrosion techniques for ASTs

For the interior of ASTs, the following anticorrosion techniques exist: technological measures (such as draining and cleaning), coatings and corrosion inhibitors. For tanks in petroleum service, internal cathodic protection in conjunction with coatings has not gained widespread use [12]. Coatings are the most used technique. The API RP 652 standard recommends two types of coating systems: thin (<500 μm) and thick (>500 μm) based on the two generic types - epoxy and polyesters. For older storage tank bottoms that have corroded both internally and externally, 2,000 to 3,000 μm thick glass reinforced coatings are often used [10]. Requirements for coating material and personal qualification, coating application and inspection can be found in API RP 652, ISO 12944 [13], Norsok M-501 [14], KOC-P-002 Part 2 [15], 09-SAMSS-067 [16] , NACE10SSPC-PA 6 [17] and NACE10SSPC-PA 8 [18]. ISO/CD 16961 entitled "Petroleum, petrochemicals and natural gas industries: Internal coating and lining of steel storage tanks" is currently under development.

Some other recommendation practices which need to be taken in account in corrosion protection of storage tank bottoms are NACE SP0178 [19], API 577 [20] or EN ISO 8501-3 [21] for design, welding inspection and metallurgy and API RP 651 or EN 16299 [22], for cathodic protection of external surfaces of above ground storage tank bottoms in contact with soil or foundations.

Besides coatings, corrosion inhibitors such as nitrites, silicates, and polyphosphates, imidazolines, itaconic salts, oleic acid salts of some amines, and polyalkene glycol esters of oleic acid have been used to control corrosion [23].

The best method of controlling microbial sludge formation and MIC of tank bottoms is through periodical drainage of water and and microbiological control of water and fuel phases [6]. Interestingly, almost the same microorganisms are responsible for oil deterioration storage tanks and the processes related to the bottom MIC [7].

To inhibit or prevent bacterial deterioration of fuels and MIC, bactericides are sometimes injected. The souring caused by sulphate reducing bacteria can be reversed by nitrate additions that act trough biocompetitive exclusion i.e. growth of competing bacterial populations (nitrate reducing bacteria) [24]. If microbial sludge has already formed at the bottom, there is a great chance that bactericides would not prevent the development of MIC.

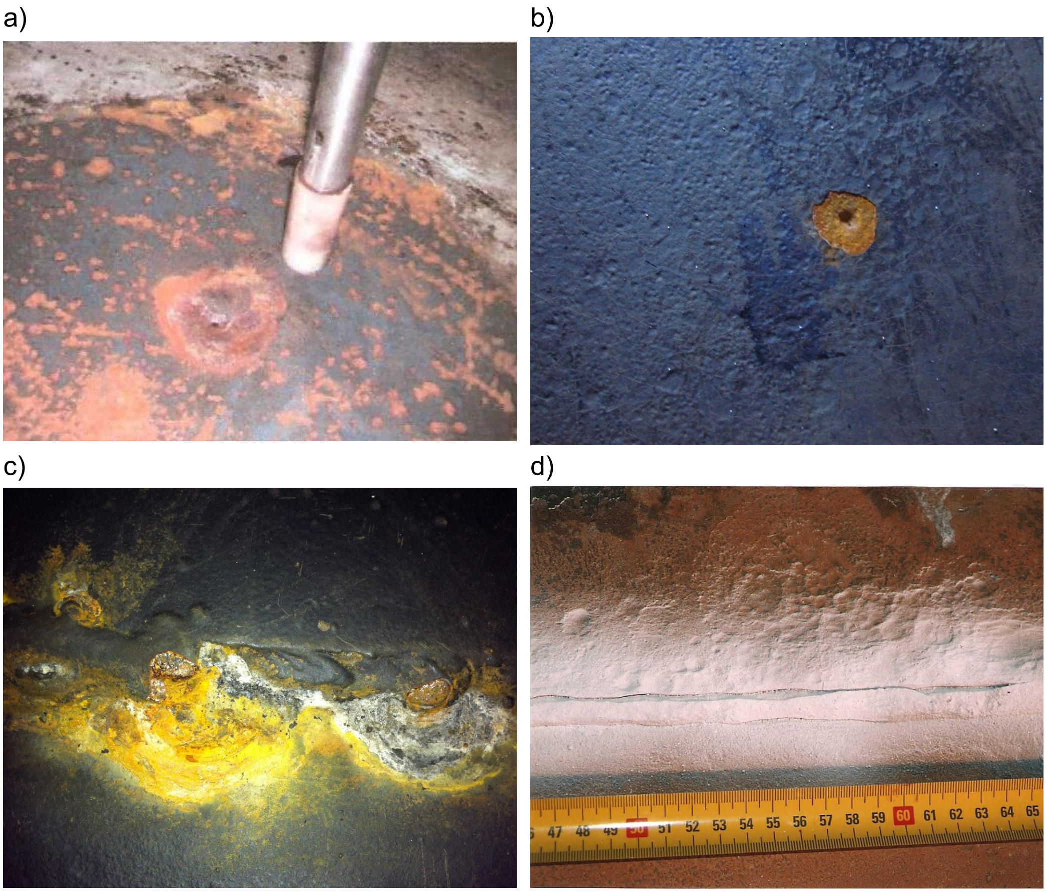

Figure 1: Various forms of corrosion in the interior of a crude oil tank:
a) fretting corrosion below the floating roof legs,
b) pitting corrosion at coating defect,
c) pitting corrosion at poorly coated irregular weld,
d) heat affected zone weld corrosion after abrasive cleaning.

Calculation of corrosion rate from MFL and laboratory measurements

Magnetic flux leakage (MFL) tools are commonly used, along with ultrasonic (UT) thickness measurement tools, to examine the entire tank bottoms [4, 25]. The technique requires that the MFL equipment be set to several fixed thickness loss thresholds (typically 30 %, 60 % and 80 % of the original plate thickness) and the MFL equipment will identify any locations with loss greater than those threshold settings, but it will not quantify the thickness. Under normal conditions, pitting as shallow as 1.8 mm can be detected by MFL in 9.5-millimeter bottom plate (19 % threshold). Scanning rates vary and depend on the general condition of the tank bottom and the number of indications that are found. Newer MFL equipment can distinguish or differentiate corrosion originating at the soil side from corrosion originating at the product side, while older MFL equipment cannot. Ultrasonic thickness measurement techniques are often used to confirm and further quantify data obtained by MFL examination.

A linear decrease in bottom plate thickness, i.e. a constant corrosion rate, *Cr*, is assumed and calculated by the equation:

$$Cr = \frac{Th - Tr}{In - In_0} \tag{1}$$

Tr is the minimum threshold above which defects have not been observed hence *Tr* gives the minimum possible thickness of the plate. *Th* is the original thickness of the bottom plate and *In* is the time interval from the previous internal inspection. Corrosion rate may be underestimated if credit is not given to the protective capacity of tank bottom lining system. The corrosion rate of a tank bottom with an internal lining and bottom side cathodic protection can be assumed to be zero for a period time until coating failures start to appear. E.g. based on the durability of the applied lining In_0 equal to 5 years may be assumed.

Bottom corrosion rate of gasoline tanks equal to 0.04-0.13 mm year^{-1} and of kerosene tanks equal to 0.04-0.1 mm year^{-1} may be found in literature [10, 26]. The average literature value for corrosion rate of: crude oil tanks is 0.3 mm year^{-1}, gas oil tanks is 0.5 mm year^{-1}, diesel oil tanks is is 0.5 mm year^{-1} and fuel oil tanks is 0.28 mm year^{-1}. For crude oil tanks the corrosion rate was also found to vary between 0.1 and 0.9 mm year^{-1} [5], e.g. for a set of 20 crude oil ASTs in similar service the corrosion rate was found to be 0.38±0.19 mm year^{-1}. API 652 states that pitting corrosion of a bare steel tank bottom may occur at a rate as high as 2.0 mm per year. Our laboratory measurements have yielded the value of carbon steel corrosion rate in crude oil tank sludge equal to 0.55±0.05 mm year^{-1}. The appearance of steel samples prior and after the 6 months exposure to sludge is shown in Figure 2. Both uniform and pitting corrosion were observed. Laboratory value was in excellent agreement whit the average corrosion rate obtained in field that equaled 0.52±0.2 mm year^{-1}.

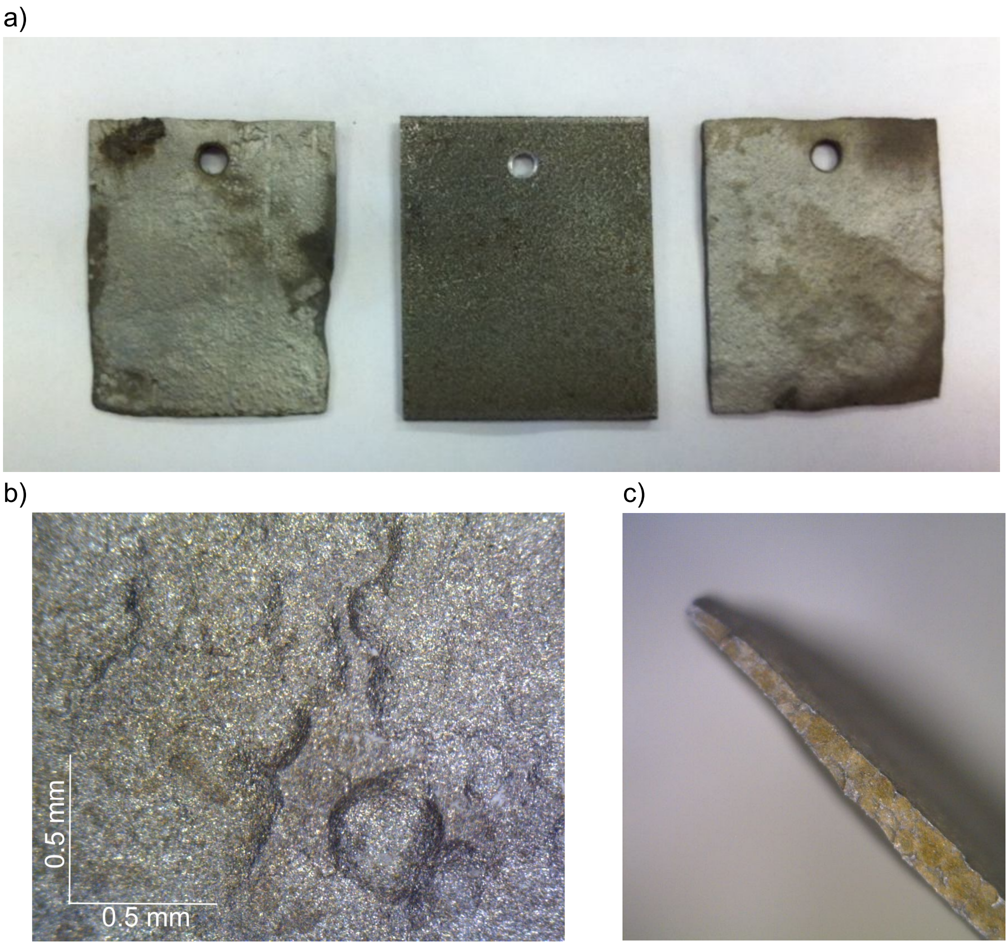

Figure 2: Corrosion of steel samples exposed to AST bottom sludge for 6 months. Duplicate exposed samples are shown in figure a) adjacent to the unexposed sample shown in the middle.

Localized pitting corrosion attack is shown in figure b) and general corrosion visible trough thinning of the specimen is shown in figure c).

Calculating intervals between inspections

Intervals between internal inspections should be determined by the corrosion rates measured during previous inspections or anticipated based on experience with tanks in similar service. We have observed that a reasonable corrosion rate may also be obtained from simple laboratory measurements.

Quantification of the minimum remaining thickness of tank bottoms based on the results of corrosion rate measurement can be done by the equation:

$$MRT = (\text{minimum}\, RT_{bc} \text{ ili } RT_{ip}) - O_r \left(StP_r + UP_r \right)$$

MRT is the minimum remaining thickness at the end of interval O_r. O_r is the in-service interval of operation (years to next internal inspection), RT_{bc} is the minimum remaining thickness from bottom side corrosion after repairs, RT_{ip} is the minimum remaining thickness from internal corrosion after repairs; StP_r is the maximum rate of corrosion on the top side, UP_r is the maximum rate of corrosion on the bottom side.

API Standard 653 recognizes the protective capacity of tank bottom lining system and the cathodic protection system and allows assumption of zero corrosion rate while the lining is still in perfect condition (StP_r = 0) and/or while the cathodic protection system is working properly (UP_r= 0).

The majority of ASTs in the petroleum industry are constructed using steel bottom plate ranging in thickness from 6.4 mm to 9.5 mm. According to API 653, if tank bottom/foundation is designed with means or no means for detection and containment of a bottom leak, the minimum acceptable bottom renewal thicknesses (thicknesses at next inspection) are 1.27 mm or 2.54 mm, respectively. The actual inspection interval shall be set to ensure that the bottom plate minimum remaining thickness at the end of the in-service period of operation is not less than the above stated values for renewal thickness.

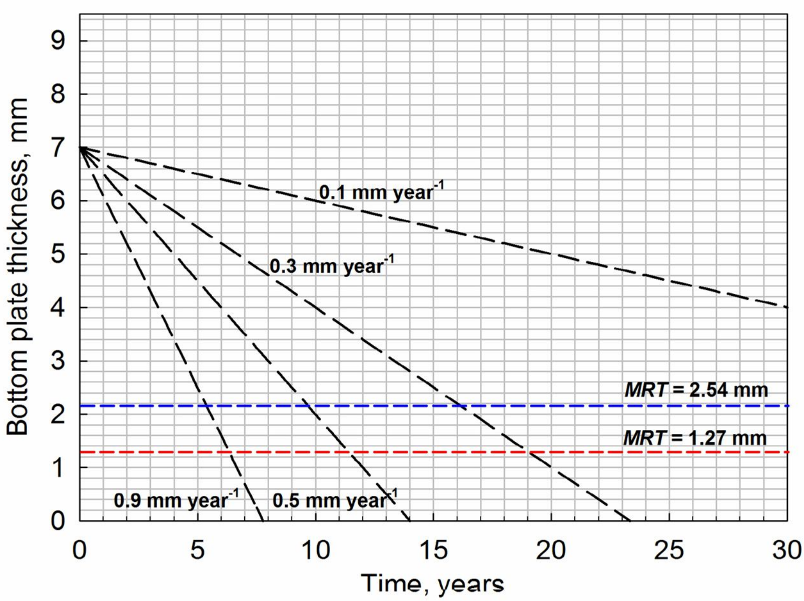

Figure 3: Decrease in bottom plate thickness for various corrosion rates

I.e. for the initial bottom plate thickness of 7 mm and for various corrosion rates, *MRT* as a function of O_r is shown in Figure 3. Maximum inspection interval is determined by the intersection of the line denoting decrease of the bottom plate thickness for a particular corrosion rate and the renewal thickness, *RT*. The significance of precise determination of corrosion rate for calculation of reliable inspection interval is apparent from the graph. According to API 653, the interval from initial service until the initial internal inspection shall not exceed 10 years unless the tank has one of following conditions: bottom thickness 8 mm or greater, cathodic protection or lining. In that case the initial interval may be extended to 12-15 years. For using corrosion rate and (risk based inspection) RBI assessment procedures, maximum intervals must not exceed 20 and 25 years, respectively. For using RBI assessment procedures and tank with a release prevention barrier, maximum intervals must not exceed 30 years. In Chinese code SY/T 5921 [27] the initial interval is set to 5-7 years and the maximum of initial inspection interval for the new tank cannot exceed 10 years. When corrosion rates are not known and similar service experience is not available, the internal inspection interval must not exceed 10 years [4].

Conclusions and recommendations

The accumulation of water at the bottom of ASTs is a primary prerequisite for corrosion to occur. Corrosion is attributed to the deposition of sludge, the presence of aggressive agents in the water phase, and, what is considered to be the biggest threat, the presence of bacterial populations resulting in MIC.

Primary means of keeping the tank's integrity should be application of corrosion protection techniques i.e. properly chosen and installed interior bottom lining, fully functional cathodic protection system of the bottom underside and periodic tank draining. It must be borne in mind that repair works, which often include installation of welded steel patches at the tank's bottom, may lead to stiffening of the bottom plate and subsequent need for bottom replacement.

In corroding tanks, precise determination (measurement or anticipation) of the corrosion rate is done trough serious analysis and correct interpretation of field data and/or performing of supporting laboratory measurements. Knowledge of the true corrosion rate is essential for calculation of the reliable internal inspection interval. Correctly determined inspection interval is prerequisite for successful balancing the safe operation requirement and inspection costs as well as the successful longtime operation of ASTs.

References

1. GROYSMAN A, *Corrosion for everybody*, Springer, Dordrecht, 2010, p. 133-146.
2. GREENWOOD C., *Materials Performance,* **51**, 8, 14.-15., 2012.
3. BARNAWI I.Y., *Materials Performance*, **51**, 3, 3.1-35, 2012.
4. API STD 653, Tank Inspection, Repair, Alteration and Reconstruction, 4th ed., 2009, Includes Addendum 1, 2010, Addendum 2, 2012.

5. SHUAI J., HAN K., XU X., *Journal of Loss Prevention in the Process Industries*, **25**, 10, 166-175, 2012.
6. YEMASHOVA N.A. et al., *Reviews in Environmental Science and Biotechnology*, **6**, 4, 315-337, 2007.
7. ALLSOPP D., KENNETH J.S., GAYLARDE C.C, *Introduction to Biodeterioration*, 2nd ed., Cambridge University Press, Cambridge, 2004, p. 44-54.
8. BEEN J., *Report: Comparison of the Corrosivity of Dilbit and Conventional Crude*, Alberta Innovates – Technology Futures, Alberta, 2011.
9. GROYSMAN A., ERDMAN N, *Corrosion*, **56**, 12, 1266-1271, 2000.
10. GROYSMAN A, *Materials Performance*, **44**, 9, 44–48, 2005.
11. API RP 652, *Linings of Aboveground Petroleum Storage Tank Bottoms*, 3rd ed., 2005.
12. ANSI/API RP 651, *Cathodic Protection of Aboveground Petroleum Storage Tanks,* 3rd ed., 2007.
13. EN ISO 12944, *Paints and varnishes -- Corrosion protection of steel structures by protective paint systems – Parts 1-4 and 6-8*, 1998, *Part 5*, 2007.
14. NORSOK M-501, *Surface preparation and protective coating*, 6th ed., 2012.
15. DOC. NO. KOC-P-002 Part 2, *Internal Lining of Steel Tanks & Vessels: Part 2: Internal Lining of Above Ground Steel Tanks*, Rev. 5, 2011.
16. 09-SAMSS-067: *Qualification Requirements for internal coatings for immersion services*, 2009.
17. NACE No. 10/SSPC-PA 6, *Fiberglass-Reinforced Plastic (FRP) Linings Applied to Bottoms of Carbon Steel Aboveground Storage Tanks*, 2002.
18. NACE No. 11/SSPC-PA 8 *Thin-Film Organic Linings Applied in New Carbon Steel Process Vessels*, 2003.
19. NACE SP0178, *Design, Fabrication, and Surface Finish Practices for Tanks and Vessels to Be Lined for Immersion Service*, 2007.
20. API RP 571, *Damage mechanisms affecting fixed equipment in the refining industry*, 2nd ed., 2011.
21. EN ISO 8501-3, *Preparation of steel substrates before application of paints and related products -- Visual assessment of surface cleanliness -- Part 3: Preparation grades of welds, edges and other areas with surface imperfections*, 2007.
22. EN 16299, *Cathodic protection of external surfaces of above ground storage tank bases in contact with soil or foundations*, 2013.
23. HEIDERSBACH R., *Metallurgy and Corrosion control in Oil and Gas Production*, John Wiley & Sons, Inc., Hoboken, 2011.
24. VOORDOUW G., *Current Opinion in Biotechnology*, **22**, 401-405, 2011.
25. O'CONNELL M., *Journal of Protective Coatings & Linings*, 56-63, MARCH 1997.
26. GROYSMAN A., SISO R., *Materials Performance*, **51**, 2, 52-56, 2012.
27. SY/T 5921, *Code for repair of vertical cylindrical welded steel crude oil tanks*, 2000.

Author:

Prof. dr. sc. Sanja Martinez, dipl. ing. (sanja.martinez@fkit.hr)
University of Zagreb, Faculty of Chemical Engineering and Technology, Department of Electrochemistry, Zagreb, Croatia

Received: 27.02.2013.

Accepted: 04.06.2013.