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DAMAGE MECHANISM AND BARRIER IDENTIFICATION ON HYDROGEN PRODUCTION UNIT USING INNOVATIVE METHODOLOGY FOR RISK ASSESSMENT

IDENTIFIKACIJA MEHANIZAMA OŠTEĆENJA I BARIJERA PRIMENOM INOVATIVNE METODOLOGIJE ZA PROCENU RIZIKA NA PRIMERU POSTROJENJA ZA PROIZVODNJU VODONIKA

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- barijere

Abstract

In the oil and gas industry hydrogen is used in a large number of processes, mostly in hydroprocessing units such as hydrotreating, hydrocracking and other refining processes that increase the hydrogen-to-carbon ratio. To satisfy the need for H_2, refineries usually have a dedicated Hydrogen Production Unit (HPU). Given the wide range of processes that HPU supplies and the fact that cost of operation of this kind of unit is rather high, it stands to reason that any kind of interruption in unit operation will affect the whole refining process. From Risk Based Inspection (RBI) point of view, HPU can be a very challenging unit to deal with, primarily due to the wide range of operating processes conditions as well as different operating fluids. As a result of applying the innovative methodology for risk assessment, it is shown that significantly higher number of damage mechanisms are identified in regard to the number of damage mechanisms that would be identified by applying traditional methodology, due to the fact that both active and passive damage mechanisms are identified. Concept of barriers such as measures that are able to restrict, reduce or preferably eliminate damage mechanisms identified in HPU are introduced and discussed. Innovative methodology was successfully applied in the case of a refinery in the Middle East.

Izvod

Vodonik se u naftnoj i gasnoj industriji koristi u velikom broju procesa, najviše u postrojenjima za preradu vodonika kao što su hidro-prerada, hidrokreking i drugi preradni procesi koji povećavaju odnos vodonika i ugljenika. Kako bi se zadovoljila potreba za H_2, rafinerije obično imaju posebno postrojenje za proizvodnju vodonika (HPU). Imajući u vidu širok spektar procesa koje HPU snabdeva i činjenicu da je trošak rada postrojenja ovakvog tipa prilično visok, može se zaključiti da će bilo kakav prekid u radu postrojenja imati uticaja na ceo proces prerade. Sa stanovišta Analize zasnovane na rizicima (RBI), HPU predstavlja vrlo izazovno postrojenje usled činjenice da je prisutan širok spektar radnih procesnih parametara kao i različitih radnih fluida. Kao rezultat primene inovativne metodologije za procenu rizika prikazaće se da je broj identifikovanih mehanizama oštećenja značajno veći u odnosu na broj mehanizama koji bi bio identifikovan primenom tradicionalne metodologije, usled činjenice da se identifikuju i aktivni i pasivni mehanizmi oštećenja. Takođe, biće prikazano definisanje i razmatranje koncepta barijera, kao mera za ograničavanje, smanjenje ili uklanjanje mehanizama oštećenja identifikovanih u HPU. Inovativna metodologija je uspešno primenjena na slučaju rafinerije na Bliskom istoku.

INTRODUCTION

Components, equipment and systems used in the oil and gas industry are subjected during their operation to chemical, electrochemical and physical factors which may deteriorate their integrity. Such integrity deterioration results in deformation, defects, performance degradation or damage, thereby reducing the ability of the asset to perform its required function efficiently and effectively whilst protecting health, safety and the environment. Some of the most common deterioration mechanisms are corrosion, fatigue, creep, erosion, hydrogen related cracking, wear, overload, temperature expansion and contraction. These degradation mechanisms represent a major hazard in the oil and gas industry as these failures may pose, if not monitored or mitigated properly, serious threats to human life, the environment and financial investment. It is important to note that components, equipment and systems may fail following the onset of these degradation mechanisms even though all the necessary rules and practices are followed during the design and fabrication stages. Ensuring their integrity is paramount to maintaining plant integrity and its safe operation.

Risk Based Inspection (RBI) is a risk based, multidisciplinary, decision support process with a goal of determining and documenting an optimum cost-effective inspection plan for pressure equipment while in compliance with safety regulations. The RBI method defines the risk of pressure equipment failing as the product of two factors: the Likelihood or Probability of Failure (PoF) and the Consequence of Failure (CoF) /1, 2/. Failure is defined as a termination of the ability of a system, structure, equipment, or component to perform its required function of fluid containment (i.e. loss of containment) which can result as a leakage of fluid into the atmosphere, or a full rupture of the pressure component. The likelihood and consequences of failure are determined for each item through qualitative assessment or, in some cases, a more rigorous semi-quantitative or quantitative assessment. The assessment should be based on identified degradation mechanisms, design data, process data, inspection and operating history, and equipment location relative to human and environmental influences. Following documents on which a part of the risk assessment is based are presented:

– ASME PCC-3: Inspection Planning Using Risk-Based Methods /3/;
– API RP 571: Damage Mechanisms Affecting Fixed Equipment in the Refining Industry /4/;
– API RP 580: Risk-based Inspection /1/
– API RP 581: Risk-based Inspection Methodology /2/;
– API RP 584, Integrity Operating Windows /5/;
– API RP 970: Corrosion Control Documents /6/.

HYDROGEN PRODUCTION

‘Hydrogen is required in refineries for a large number of hydrotreating and hydrocracking processes, to remove sulphur, nitrogen, and other impurities from hydrotreater feed and to hydrocrack the heavier gas oils to distillates. A limited quantity of hydrogen is produced in the catalytic reforming of naphtha, but generally the quantity is insufficient to meet the requirements of hydrocracker and hydrotreating units. As hydrogen production is capital intensive, it is always economical to recover hydrogen from low-purity hydrogen streams emanating from hydrotreating and hydrocracking units and minimize production from hydrogen units. In the absence of hydrogen recovery, these streams end up in fuel gas or are sent to flare. Most refinery hydrogen is produced by the steam reforming of natural gas. The conventional hydrogen production in refineries involves the following steps:

– natural gas desulphurization;
– steam reforming;
– high- and low- temperature shift conversion; and
– trace CO and CO_2 removal by methanation.’ /7, p. 153/

A typical hydrogen production unit is shown in Fig. 1, and is fully taken from API RP 571 /4/ with suggested damage mechanisms.

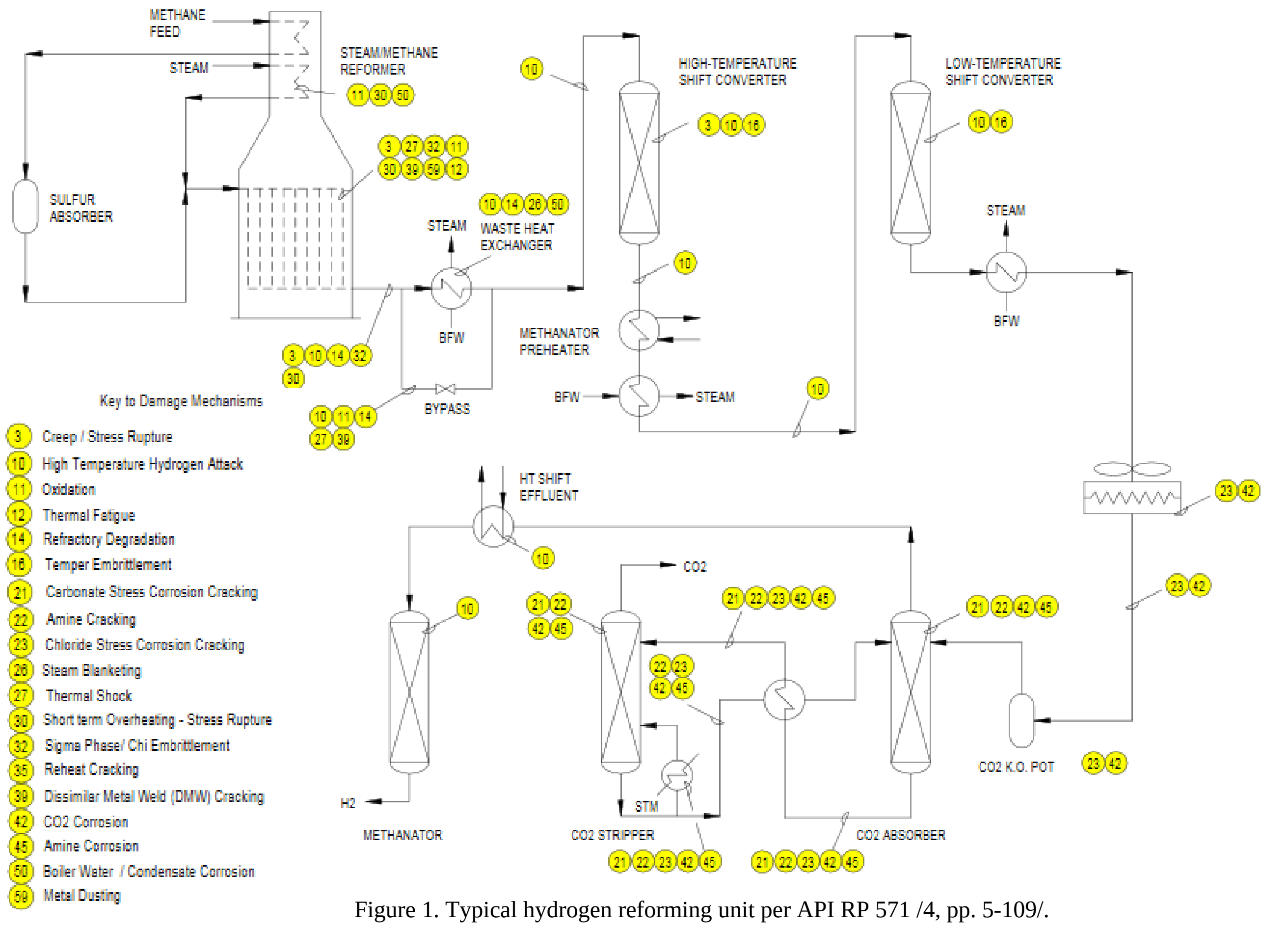

Figure 1. Typical hydrogen reforming unit per API RP 571 /4, pp. 5-109/.

The CO_2 striper, CO_2 absorber and methanator, shown in bottom part of Fig. 1, can be replaced with Pressure Swing Adsorption (PSA) unit, which is the case for the modern refinery in question. The reasons for using PSA unit are given in the following subsection.

Process description

The Hydrogen Production Unit (HPU) provides the total hydrogen requirement for hydrotreating units, e.g. Diesel Hydrotreater (DHT) unit, Kerosene Hydrotreater (KHT) unit, Atmospheric Residue Desulphurization (ARDS) units, Hydrocracker (HCR) unit, Naphtha Hydrotreater (NHT) unit and etc. The HPU utilizes steam reforming to generate hydrogen. Hydrogen produced in the HPU also covers requirements in various hydrotreating units in the refinery. In addition to the nominal capacity of the HPU, the plant produces some extra hydrogen as required for recycling and mixing with the feed to the HPU when operating on feedstock with insufficient hydrogen content as compared to requirement for hydrogenation of the process feed. A PSA unit is used to obtain the desired product hydrogen purity of minimum 99.8 vol% hydrogen.

The HPU consists of the following sections:
– desulphurization of process feed by hydrogenation and H_2S absorption on ZnO;
– pre-reforming;
– parallel steam reforming and heat exchange reforming;
– medium temperature shift conversion;
– process gas heat recovery and cooling;
– gas purification by pressure swing adsorption.

Pressure swing adsorption

'The pressure swing adsorption (PSA) route is simpler than the conventional route, in that the low-temperature CO conversion, CO_2 removal by liquid scrubbing, and methanation to catalytically remove the remaining oxides of carbon are replaced by a molecular sieve system. This system works by adsorbing CO_2, CO, CH_4, N_2, and H_2O at normal operating pressure while allowing hydrogen to pass through. The molecular sieve is regenerated by lowering the pressure and using some of the product to sweep out the desorbed impurities. Due to this pressure cycling, it is commonly referred to as pressure swing adsorption system.' /7, p. 162/.

According to /8/, there are five general features of the PSA system that to a large extent explain both the advantages and limitations of the technology and hence determine the suitability for a given application:
1. product purity;
2. yield or fractional recovery;
3. concentration of trace impurities;
4. energy requirements;
5. scaling characteristics.

Operating procedures, material selection and other considerations

In the following paragraphs, operation procedures for upset and/or start-up/shut-down conditions, which may have an impact on subsequent criteria for damage mechanism identification, are presented:
– the hydrogen required for desulphurization is contained in the ARDS membrane Tail Gas used as part of the process feed or hydrogen product recycled to the feed gas compressor;
– hydrogen requirement for the desulphurization during start-up is delivered from outside;
– during short time operation at start-up or shut-down with only steam flowing to the pre-reformer it is required to add hydrogen to the process steam. This hydrogen is supplied from an emergency hydrogen storage.

The following considerations apply in regard to material selection for the equipment and piping:
– for vessels, design is kept to carbon steel with appropriate corrosion allowance for the service well under creep range and without presence of CO/CO_2 and water, with corresponding corrosion allowances between 1 mm (for 'clean' service) and 3 mm;
– for the higher temperature services containing hydrogen, materials of choice are low and medium alloyed carbon steels (1.25% Cr - 0,5% Mo, up to 2.25% Cr - 1% Mo) with similar corrosion allowances, 1-3 mm;
– for the parts of the systems containing CO/CO_2 and/or wet gas (water), material of choice has been set to SS 304L/H, SS 316L up to SS 321H for high temperature service. Due to the highly corrosive nature of the fluid, even for stainless steels, the corrosion allowance is set to be between 1 to 2 mm (NOTE: L stainless steel grades - with low carbon content are usually used in highly corrosive environment where intergranular corrosion is possible; H stainless steels grade - with high carbon content are usually used at temperatures above 500°C, for long-term creep service);
– for the high temperature hydrogen service, the limits of the steel applicability have been determined based on so-called 'Nelson curves', given typically in API RP 941 /9/. Due to recent failures (since 2010) where High Temperature Hydrogen Attack (HTHA) has been identified as a source of failure, the technology for investigating HTHA susceptibility and inspection methods for detection and assessment of HTHA are being developed. As per API RP 581 /2/, it has led to significant revision/lowering of the overall values of the Nelson curves and of removal of 0.5Mo steels altogether from the list of materials to be used in hydrogen service. Additionally, it is suggested that the most current edition of API RP 941 /9/ should be consulted for guidance.

Table 1 shows possible fluid composition, while Table 2 shows characteristics, properties and additional information of the considered operating fluid.

Table 1. Composition of working fluid in the shift converter part of the HPU.

Substance	vol %
H_2	55 - 62
methane	4 - 7
water	15 - 19
CO_2	12 - 15
CO	1 - 5

NOTE: Sum should always be 100%

Table 2. Operating characteristics of working fluid in the shift converter part of the HPU.

Working Fluid	$H2O/HC/H_2/CO/CO_2$	
Phase	Vapor/2-Phase	
MDMT*	°C	-3
Operating temperature	°C	45 - 319
Operating pressure	bar	21,7 - 23
Design temperature	°C	360
Design pressure	bar	27.1
Possible free water during normal operation	Yes/No	Yes
Possible free water during upset operation	Yes/No	Yes
Hydrogen service	Yes/No	Yes
Material of construction		SS 304L/1.25Cr-0.5Mo
Corrosion allowance	mm	1.5/3
PWHT	Yes/No	Yes

* Minimum design metal temperature

DAMAGE MECHANISM AND BARRIER IDENTIFICATION

The extension of the Innovative approach from the one shown in the ASME PCC 3 /3/ is to identify both active and passive (potential) damage mechanisms and the conditions under which passive (potential) can be activated. For the purpose of distinguishing the two proposed types of damage mechanisms, the principle of Integrity Operating Windows (IOWs) will be used. Another extension of the Innovative approach is introduction of the barriers principle. Criteria for damage mechanism identification based on the Innovative approach are presented in /10/. Same methodology and principles are being applied in this case with the variation for the criteria taken from API RP 970 Annex B /6/, shown in Table 3. Definition of the Corrosion Loops (CLs) is also applied. In order to facilitate the readers' understanding of the further steps, the principles for the identification of damage mechanisms are presented below:

1. categorize/classify equipment in CLs;
2. analyse fluid and operating condition;
3. analyse possible operating modes of the system (normal condition, upset conditions, downtime, etc.)
4. apply criteria for damage mechanism identification per ASME PCC-3 /3/ by conditions defined in previous points;
5. apply criteria for damage mechanism identification per API RP 970 Annex B /6/, Table 3.

For the whole HPU, the following damage mechanisms have been identified:

1. High Temperature Hydrogen Attack (HTHA)
2. Creep/stress rupture
3. Oxidation
4. Thermal fatigue
5. Temperature embrittlement
6. Thermal shock
7. Short term overheating
8. Reheat cracking
9. Boiler water / condensate corrosion
10. Metal dusting
11. Sigma phase / chi embrittlement
12. Sour water corrosion (presence of water and H_2S)
13. CO_2 corrosion (presence of CO_2 in the stream)
14. High temperature creep
15. High temperature corrosion
16. Corrosion under Insulation (for insulated parts)
17. Atmospheric corrosion (for not insulated parts)
18. Erosion – droplets
19. Erosion / erosion corrosion
20. Brittle fracture
21. Mechanical fatigue

As stated in the section regarding hydrogen production, HPUs are considered to be fairly large and complicated due to the presence of numerous operating fluids (according to the RBI methodology, when a significant change occurs either in process or chemical parameters, then it is considered to be a different operating fluid in question).

Table 3. Important criteria for damage mechanism identification as per operating and process conditions /6, Table B.1/.

High temperature damage mechanisms (> 230°C)
b) Is there a potential for brittle fracture (e.g. hydrogen embrittlement, temper embrittlement, 0.5Mo steel) of heavy wall hydro processing equipment from rapid heating/cooling or pressurizing below the minimum pressurization temperature?
c) Is there a potential for accelerated creep from operating outside of the operating window (e.g. higher temperature or pressure or both)?
f) Is there a potential for accelerated sulphidic corrosion from gradual increase of sulphur content, temperature or inadvertent increase of other sulphur species such as H_2S or mercaptan content?
j) For alloys operating above about 370°C, are there any high temperature aging embrittlement phenomena that might lead to brittle behaviour when equipment is pressurized at lower temperatures?
k) Is there a degradation effect due to metal dusting, carburization, nitriding, etc.
l) Is there hot spot due to refractory lining failure or any other overheating?
Low temperature (aqueous) corrosion and stress corrosion cracking damage mechanisms
b) Is there a potential for rapid corrosion at or downstream of injection or process mixing points due to heating/cooling, condensation/evaporation, reaction, between the injecting and mixing streams, etc.?
d) Is there a potential for rapid corrosion due to change in flow rates, changes in flow regime, e.g. vaporization, flashing, or other multiphase flow conditions?
f) Is there a potential for rapid localized corrosion at hot spots as a result of direct contact between heat tracing and process piping, e.g. lack of standoff or improper use of heat transfer material?
q) Can solids be present causing increased erosion-corrosion (i.e. catalyst carryover, accumulation of corrosion products, etc.)?
r) Is there a potential for increased corrosion or cracking beyond piping spec breaks due to process changes or upsets?
s) Is there potential for increased corrosion in the inlet zone or at a vapour/liquid interface?
v) Is there a potential for inadvertent process contamination that could cause stress corrosion cracking? (e.g. wet H_2S, caustic, amines, chlorides, polythionic acids)?
External damage mechanisms
c) Can changes in process conditions lead to increased corrosion under insulation (CUI), e.g. idling of normally hot equipment, equipment in cyclic service above and below 120 °C, or exposure of stainless steel equipment to external chloride cracking?
d) Is CUI possible?

Identification of damage mechanisms and possible barriers shall be oriented only to a section of the HPU process recognized as critical due to the possibility of condensation appearance. The chosen section includes parts of the unit from shift conversion, through the PSA, up to the hydrogen product and product offgass lines. Condensation in the selected part of the HPU is regarded as extremely dangerous in respect to the construction material primarily due to the increased corrosion rate induced through CO_2 corrosion. Also, there is a very small possibility that the line can be contaminated with H_2S if the desulphurization process is not operating within normal parameters, thus activating the sour water corrosion damage mechanism. Operating process conditions are as shown in Table 3.

Active damage mechanisms

Based on the principles for damage mechanisms identification as per Innovative approach, the following active damage mechanisms have been identified for the selected section:

1. CO_2 corrosion (presence of CO_2 in the stream)
2. High temperature corrosion
3. Corrosion under insulation (for insulated parts)
4. Atmospheric corrosion (for not insulated parts)
5. Erosion – droplets
6. Mechanical fatigue
7. Thermal fatigue

Passive damage mechanisms

The following passive or potential damage mechanisms, which can become active due to changes in any number of observed parameters or conditions (e.g. change in fluid composition, change in process parameters, change in material, etc.) have been identified, based on the Innovative approach for the selected section:

1. Sour water corrosion (presence of water and H_2S)
2. High temperature hydrogen attack (HTHA)
3. Erosion/erosion corrosion
4. Brittle fracture

Barriers

Identification of passive damage mechanisms is carried out by using a *what if* analysis where realistic consequences of barrier failures, which are taken into account in order to prevent the occurrence, or reduce the impact of active damage mechanisms, are observed. A barrier can be defined as a measure, either introduced subsequently or via initial design, which restricts, reduces or preferably eliminates a damage mechanism. A barrier can be physical in nature (selected material of construction, addition of corrosion allowance, etc.) or not (various process controls, heat treatment and etc.). A number of systems or procedures can also be defined and used as barriers, as long as they reduce or remove effects of damage mechanisms. The identified barriers for part of the HPU are shown in Table 4.

Four barriers can be regarded as essential for the analysed section of the HPU:

1. Material of the structure; can be viewed as a barrier that eliminates almost all failure modes because it used with intention to avoid occurrence of damage mechanisms altogether.
2. Corrosion allowance; a form of barrier that is primarily used to reduce effects of corrosion. It is a highly effective barrier, but only when the system is working within normal parameters.

Table 1. Identified barriers for the analysed part of the HPU.

Barrier	Properties			
	Used for failure mode	Remarks	Efficiency in service	Barrier degradation
Material of structure	all	primarily to avoid DM* altogether	highly effective	NA
Design	all	primarily to avoid DM altogether	highly effective	NA
Installation	fabrication DM		highly effective	NA
Corrosion allowance	corrosion/thinning		highly effective	yes, corrosion rates
Heat treatment	metallurgical, cracking	ensure metallurgical structure, stress relief	highly effective	depends on operation periods outside IOWs
Post weld heat treatment	cracking	stress relief, avoid cracking	highly effective	depends on operation periods outside IOWs
Temperature control	all	avoid critical conditions for DM	mostly effective	depends on operation periods outside IOWs
Pressure control	all	avoid critical conditions for DM usually by reducing stress[1]	mostly effective	depends on operation periods outside IOWs
Flow control	corrosion/thinning	avoid critical conditions for DM	mostly effective	depends on operation periods outside IOWs
Fluid composition control	all	avoid critical conditions for DM	mostly effective	depends on operation periods outside IOWs
Coating	corrosion/thinning/cracking	prevent contact between material and fluid	highly effective	Yes, coating aging
Tracing	corrosion/thinning	electrically or steam tracing - to maintain fluid temperature to prevent i.e. condensation	mostly effective	depends on time in operation and operating philosophy

* DM – damage mechanism

1) continuous cyclic service due to pressure alteration as the result of PSA process

3. Pressure control; a barrier that can be especially important for the selected section of the HPU due to the continuous cyclic service caused by pressure alteration as the result of PSA process. Appearance of condensation is also possible when reducing pressure, as a part of the PSA's operation process, if traces of water are present in the stream.
4. Tracing; a barrier that can be introduced in order to remove the possibility of condensate forming. In other words, tracing makes sure that all other barriers stay active and effective.

All other barriers should not to be neglected or regarded as less important. In essence, for the normal operation of the HPU it is required that all barriers perform as intended. Some of the barriers are time dependent (corrosion allowance, coating, tracing and etc.) and this statement should be noted, and inspection should be planned in accordance to anticipated barrier's end-of-life.

CO_2 corrosion is the damage mechanism that is expected to be active during the service of the HPU due to the nature of the process, and it can be regarded as the most aggressive of the active damage mechanisms. CO_2 corrosion results when CO_2 dissolves in water to form carbonic acid. At least three conditions are required to be fulfilled for this damage mechanism to be active: presence of CO_2, water and material susceptible to damage mechanism. The first condition cannot be influenced by anything available (within reasonable limits) – operating fluid in the selected part of the HPU has a chemical composition that includes CO_2 in medium amount. The third condition is easily influenced by material selection, which can be, and is regarded as a barrier. Finally, to completely remove CO_2 corrosion, one should make an effort to preclude the situation where water is present in the operating fluid, condensates. CO_2 corrosion appears as localized thinning and is somewhat easily reduced by introduction of Tracing (either steam or electrical, depending on the resources at hand). For the period of operation of 10 years, with the postulated barrier efficiency, the damage equivalent expected to be found on the equipment is of the same amplitude as the system operating without the barriers for a period of half a year to one year. Taking into account this damage mechanism in such limited manner, previous estimations of corrosion rates have to be further adjusted/increased to include these factors.

As mentioned, some of the barriers are time dependent, meaning that their efficiency will either significantly drop after a period of time or a barrier will completely stop performing its purpose. Corrosion allowance or tracing are typical examples that can illustrate this statement. After a corrosion allowance is removed by the effects of damage mechanisms, vessel and/or pipping will be subjected to increased risk of failure. After 10 years or more of service, the tracing barriers usually have increasing failure rates – leaking of steam tracing tubes is a frequent failure mode after a period of service. Both outcomes are expected, but interconnection between barriers and expected failures is something that it is important and to be noted.

Leakage of steam tracing tubes can lead to increased corrosion rates due to the Corrosion under Insulation (CUI). The time frame when frequent leakage in the steam tracing system starts to happen is around 10 years. At the same time, the applied coating would start to degrade, thus increasing the equipment's susceptibility to the CUI. With the increased leak frequencies from the tracing system combined with the progressive degradation of the coating, one can deduce that the CUI would become one of the major concerns in keeping the integrity of the equipment and especially interconnecting piping systems.

Inspection guidelines example

As an example of application of innovative method, one can take the example of CO_2 corrosion and tracing system case applied to future inspection planning. Detailed inspection plan cannot be established at this stage, but guidelines and rules for the inspection can be established. The following guidelines can be applied for the previously mentioned example:
1. During the operation, the shutdown times have to be recorded, especially without steamout or passivation (N_2 purging), as they might cause the CO_2 corrosion to be active during the shutdown periods;
2. During the operation, the time periods where steam tracing was not operational or having degraded performance should be recorded (i.e. due to steam loss due to leakage in the steam coils);
3. Time periods from points 1 and 2 should be summed up – it should also be considered that these periods have CO_2 corrosion as an active mechanism – and based on that postulate, the corresponding corrosion rate and maximal possible loss of wall thickness i.e. using corresponding technical module from API RP581 /2/;
4. If the times or estimated losses are significant according to the judgement of the qualified inspector, or if the expected wall thickness loss exceeds 75% of the corrosion allowance, full visual (internal) inspection followed by wall thickness measurements in the identified corroded areas of the equipment or piping should be planned. Also, it should be considered that the loss of wall thickness is expected to be highly localized.

As already discussed, the barrier failure, steam coil leakage, would also be a potential source of the CUI. The piping system and the equipment are however coated correspondingly, so for the first couple of turnarounds, only spot testing and external visual inspection of the insulation would suffice to identify the potential spots where CUI might be expected. However, after a period after the expected coating life – normally 10 years or more, more detailed inspection of the external of the equipment should be planned. To this purpose, the exact locations and durations of steam coil leakages should be recorded/documented and coupled with the coil repair activities, the potential CUI damage spots should be visually inspected, thickness measured and if possible, coating reapplied. A special consideration should be given to the possible spots of moisture accumulation according to API RP 583 /11/ and EFC 55 Guideline /12/.

CONCLUSION

As a consequence of the dynamic behaviour of damage mechanisms and barriers, one has to note that the measured and expected corrosion rates might have to be adjusted after certain periods of time - i.e. after the points where the barrier has been 'spent' or operates with decreasing efficiency. In other words, although operating under same conditions in the future, one cannot take for granted that the expected damage rate - corrosion rate in this case - will remain constant but rather has to be re-evaluated. Further, the inspection methods applied, and inspection scopes have to be revised and adjusted according to the newly assessed severity of damage mechanisms, mostly due to the failure or degradation of the installed damage barriers.

Taken as an example, the failing steam tracing system leading to an increase of the CUI, one can note that in some cases the barriers might, in the long run, result in the aggravation or introduction of additional damage mechanisms in the system. With the integrative approach as suggested in this paper, this type of interaction might be more apparent or easier to recognize and, in the end, managed appropriately.

To conclude, the most commonly used RBI approach of 'set it and forget it' might be in a number of cases misleading - the re-assessment and re-evaluation of the RBI is required periodically in the full extent. With the proposed method, one can setup the system that documents the dynamics of the damage mechanisms and installed barriers, also taking into account the degradation or failure of the barriers thus automatically triggering the RBI review in the cases when certain barrier degradation levels are reached or when certain IOWs are not being upkept in service.

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