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## Reconciling Measured Versus SME-Determined Corrosion Rates in DMR/RBI Development

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# Reconciling Measured Versus SME-Determined Corrosion Rates in DMR/RBI Development

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## Introduction

Identifying the type of corrosion to be expected (general, localized, pitting) and providing a valid supported estimate of the future corrosion rate is an essential outcome of the damage mechanism review (DMR) as this is required knowledge to be translated into the risk-based inspection (RBI) program. As a long-time corrosion/materials/inspection subject matter expert (SME) being charged with supporting a DMR for a plant unit, one of the most frustrating tasks in supporting the DMR is using and reconciling plant corrosion rate data taken from the plant inspection data management system (IDMS). This article discusses this issue and lessons learned that may help in completing this task but also highlights the ongoing need for our industry to improve the entire thickness management process (TMP).

## Background

As part of a thorough DMR, identification of credible corrosion damage mechanisms that exist within a particular system or corrosion loop is the first step. This article focuses on thinning corrosion mechanisms; obviously, other degradation issues are included within the DMR but are not part of this discussion.

The DMR may start with generic process unit exposures given in references, but the role of the SME is to use their wisdom, which includes a thorough understanding of the unit process operation, past, present, and future, to flesh out the generic damage mechanisms and possible severity within the specific plant [1-3]. This is usually done via a process overview review with site operations and process technical personnel explaining the plant operation, any significant changes to the plant (including any projects and management of change (MOCs)), plus providing specific plant process operation conditions and laboratory test data as requested by the SME. The other essential element to ensure a thorough understanding of damage mechanism exposure is a review with inspection/MI personnel, using the plant history inspection findings, including loss of containment (LOC) and any needed replacement issues reported, as this may reveal corrosion exposures, corrosion rates, and historical changes not readily explained by a generic identification of damage mechanisms.

Ideally, the DMR should be included and documented within a unit corrosion control document (CCD) and associated with identified integrity operating windows (IOWs). This allows for providing a credible, foundational, documented reference basis used for identifying corrosion mechanisms, types of corrosion, and usable corrosion rates for the DMR. A plant may want to jump into a standalone DMR to support rapid implementation of RBI and request the SME to provide estimates of corrosion rates and to save time and

money by limiting the supporting documentation that provides the basis of the damage mechanisms and corrosion rates provided. Too often, when requested to revalidate/update this type of DMR, this lack of documentation for this sort of previous damage mechanism review, and particularly the corrosion rate basis from that assessment, is frustrating with little or no basis provided. It also requires significantly more work to try to recreate the basis. It is strongly recommended that for plants that opt into a standalone DMR, some form of documentation must be included by the SME that provides the basis for the assessment provided. This will also usually necessitate some initial identification of process conditions and IOWs used to support the assessment. It really is quite difficult to decouple a DMR from the IOWs needed to validate the basis for corrosion rates.

## Reconciliation

So now comes the crux of the matter for this article: how the SME can specify credible corrosion rates associated with the identified corrosion damage mechanisms using their SME expertise/wisdom and corrosion prediction tools (when available) and critically reconcile this against the equipment/circuit measured corrosion rates using plant thickness monitoring and reported in the plant IDMS.

## Vessels

For equipment (vessels), reconciliation is relatively easy for corrosion rate assessment, as internal inspection histories are usually available and are key in identifying reported internal corrosion findings (location, type, and depth of corrosion loss), which are documented over time. Too often, the IDMS point-based corrosion rates for the equipment item using the external CML point thickness data across the equipment may not reflect these internal findings. CMLs may not monitor the locations where corrosion is found, or the type of monitoring needed for the type of corrosion (pitting is particularly problematic), or there is considerable inconsistency (measurement variability, depth of losses) from one internal inspection to another [4]. To help reconcile this issue, looking at the reported corrosion losses over the last internal inspections (two) can help determine active corrosion metal loss over time in a particular location in the vessel that then can be used to calculate the corrosion rate.

## Heat Exchangers Tubes

Heat exchangers (airfin and bundle tubes) may or may not be subject to specific DMR or RBI programs, but often the plant will request the SME to identify DMR damage mechanisms and corrosion rates to help the plant address exchanger reliability and inspection planning. Again, the IDMS data for assessing corrosion

rates on exchanger tubes may be missing entirely or poorly reflect the maximum wall loss reported in tube NDE reports or the fact that replaced bundles are not inspected [5]. A review of the latest tube NDE report, if available, can confirm whether bundles have been replaced, what the maximum wall loss reported is, and whether 100% coverage or sampling is reported, which should be adjusted to define a recent maximum corrosion rate. It is important to determine whether this latest corrosion loss occurred over the short term or the long term, as heat exchanger tubes may be highly susceptible to subtle changes to operating conditions. This may require delving further into past tube inspection data and confirming the exposure to operating conditions over time.

## Piping

By far the most problematic reconciliation issue and the primary reason for this article is how to deal with the IDMS piping corrosion rates. Piping does not benefit from alternative inspections, such as vessels and heat exchangers, and usually relies solely on the plant's TMP, which collects and stores thickness data within the plant's IDMS database. The IDMS usually tracks and reports single condition monitoring location (CML) thicknesses and calculated short-term (STCR) and long-term (LTCR) corrosion rates at each location within a given piping circuit. Depending on the sophistication of the IDMS used, circuits may be divided into subloops (main piping, deadlegs, mix or injection points), provide statistical estimates such as a circuit average corrosion rate, and possibly a measure of the variance of the circuit corrosion rates (e.g., coefficient of variance) within the circuit or subloop. Though there are some significant tools available for statistical analysis of circuit thickness data, too often these have had limited penetration into a plant's piping TMP and IDMS [6]. Further complications may exist when piping for a given corrosion loop exposure may have multiple identified IDMS system piping entries that have not been combined within a given corrosion loop to provide circuit corrosion rate information or, worse, the piping circuit includes sections that belong in different corrosion loops with different damage mechanism exposures.

Unfortunately, there are so many ways that the plant's piping TMP can generate questionable information that the plant IDMS corrosion rate information may have poor credibility, and the SME is tempted to ignore this and use their wisdom or prediction tools for providing corrosion types and estimated corrosion rates [7]. Given that the plant has spent considerable resources in obtaining the thickness data, and there are often hidden gems of real findings, the IDMS should be interrogated regardless. This can be used to substantiate the SME estimates used or, more importantly, identify some outlier corrosion that may be real and not be readily understood or predicted. Usually, the SME will not have the time or resources to do a thorough review of all the plant IDMS corrosion rates for a given project and will need to prioritize the review using plant-based information identifying real past and current issues with potential high corrosion losses and secondly, prioritize using the SME initial assessment of where high potential corrosion damage mechanisms exist for the unit. The proposed steps for doing this analysis can include extracting the following information in order of priority, which are discussed separately:

1. Loss of containment (LOC) database for piping issues
2. List of piping replacements in recent history (e.g., last two run lengths)
3. Extraction of IDMS high corrosion rates (e.g., > 25 mpy)
4. Extraction of IDMS short remaining lives (e.g., < 2 unit run lengths)
5. Review of the IDMS data and piping isometric of the top high-potential corrosion rate exposure based on SME wisdom

## Piping Loss of Containment

Obviously, where a piping LOC has occurred due to corrosion, this provides an obvious source of identified corrosion issues. In a well-developed TMP program, these LOC issues should be accompanied by some form of root cause analysis (RCA) that helps the SME use the plant's assessment of contributing direct and programmatic causes for the LOC. This may directly provide corrosion rate information and whether any actions were taken to address the contributing cause(s) that created the LOC, including any programmatic changes made by the plant. Unfortunately, if a plant RCA has not been performed, the SME needs to spend some priority time delving into the LOC issue and identifying the direct corrosion root cause(s) here. This may often point out some form of operation not fully discovered by the TMP monitoring program in collecting/analyzing the data.

## Piping Replacements

Piping replacements represent the next opportunity in identifying corrosion problems found by the plant that warrant replacements in whole or in part for a particular corrosion loop. This, combined with a simple query of the plant operations and inspection personnel to specifically list their top known piping concerns, is essential to root out issues that may not be readily apparent from an IDMS interrogation. A replacement list must be sorted for those attributed to internal corrosion versus other reasons, such as CUI or process design changes. This often is difficult to unravel via the IDMS database alone, particularly with partial replacements that have occurred, and the point thickness data will be hard to unravel without extensive review using isometrics and discussions with inspection. Often, piping replacement may be accompanied by additional thickness data collection to support the replacement, but this data may not be fully captured in IDMS, and this data may be valuable in confirming the driving corrosion rate issue.

## Piping High Corrosion Rates

Though it is easy to interrogate IDMS to extract high corrosion rate information, this will usually require some significant screening to understand if actual, meaningful corrosion is occurring. Firstly, which corrosion rates to use, including short-term (STCR), long-term (LTCR), or, depending on the IDMS used, some form of statistically based circuit-based analysis such as circuit average (CACR)? Secondly, what constitutes a high corrosion rate threshold to use for this interrogation?

Point-based (CML) corrosion rates usually can have a significant amount of noise for a variety of reasons, including NDE quality variation, degree of local thickness variation due to component thickness variation, corrosion loss variation, even due to uniform corrosion, but particularly for non-uniform corrosion mechanisms, and too short an interval between repeated thickness testing at the location. Often without proper NDE management, a past thickness data survey is found to be biased high/low and may be discounted by the site. Point-based data collection that relies on single-point readings taken only at the point and recorded in IDMS is highly susceptible to local variation that can masquerade as corrosion. The short interval problem is often a particular source of unrealistic corrosion rates, as a common response to an initial high corrosion rate reported is to repeat the thickness inspection at the single point on too frequent a basis which will often exacerbate the data variation noise, generating unrealistic corrosion rates.

It is the author's experience that an initial screening using an IDMS data dump of point based STCR and LTCR greater than 25 mpy is a starting point for several reasons. Though the STCR can be the most susceptible to the variance noise per the previous discussion, it has the advantage of representing both the most recent operation corrosion exposure, but more importantly, it may be an indicator of a real potential outlier corrosion issue. In addition, screening the LTCR as well may provide some signs of a longer-term issue. Care must be taken with this data as the LTCR basis may often only be based on an original nominal thickness versus a true baseline thickness, which may over- or underestimate true wall losses. Using 25 mpy as a threshold is usually sufficient to be a true signal above the high signal-to-noise ratio in point-based corrosion rates, as discussed previously, and to avoid a much larger amount of lower-level variance noise. This enables the SME to focus the review on a workable amount of data where further in-depth analysis is required. This analysis should include various aspects further discussed here.

Of course, initial screening should confirm if the high single CML STCR/LTCR is real. The SME should confirm whether the plant has implemented a response mechanism built into its TMP when a high STCR is initially reported. Too often this may not be the case, or the response is simply to repeat the point thickness measurement in a short interval without further investigation which, though a good validation of the wall thickness, this kind of response will significantly increase corrosion rate variation. Hopefully, the response includes expanding the CML coverage to confirm the scope of the apparent high corrosion rate. This may not have been the case, or the expanded coverage may not be recorded in IDMS. This should be initially reviewed with site inspection to confirm their reaction and understanding of these high corrosion rates reported. This may reveal TMP issues that they are aware of and possibly any ad-hoc information available but not reported within the IDMS.

With this information in hand, what are the SME's next steps to further unravel truth from fiction? For the corrosion loop piping in question, it is usually necessary to obtain both the thickness monitoring isometric and the complete IDMS CML data for the piping in question to support answering these questions.

What is the distribution of all the other CML corrosion rates within the given corrosion loop? There are two potential outcomes in answering this question.

1. Firstly, does this high corrosion rate stand out alone as a significant outlier well above the distribution of the other corrosion rates reported? If not available, a quick way to analyze for this is to calculate the coefficient of variance ( $CV = \text{STDEV}/\text{MEAN} \times 100$ ) of the entire set of CML corrosion rates (excluding the single high reading), and if less than 10%, this would be a strong indicator that this is a significant outlier. A recycle with the plant per the initial screening discussion is warranted to confirm whether the thickness data used to generate this high corrosion rate is credible. If deemed credible, proceed to the damage mechanism confirmation step.
2. On the other hand, if there are additional elevated (> 10 mpy) CML corrosion rates within the corrosion loop, this may support an increased credibility that this may be a real indication of a corrosion problem and that the measured corrosion rates may be useful. This usually requires some SME eyeballing analysis, though there are tools (e.g., probability plots) that can help in quantifying this assessment. This then supports going directly to the damage mechanism confirmation step.

Once the credibility of the reported measured corrosion rate(s) has been determined, the SME must then investigate the reason for the higher measured corrosion rates. Is the identified corrosion damage mechanism(s) for this service capable of generating high potential corrosion rates for the given operational service information provided, including IOW compliance or operational upsets? This requires considering the identified damage mechanism's corrosion morphology, particularly as many mechanisms can generate localized corrosion losses in terms of where along the piping the damage may occur (shear stress locations, deadlegs (settling corrodent, vapor breakout), mix or injection points) and how the loss morphology (pitting, local corrosion) may occur at these suspect locations.

A crucial element of this review is to confirm whether the CML allocation (locations) and NDE used are representative and sufficient for detecting the expected damage mechanism morphology (see API 570 Section 5.6). This investigation is the most crucial element of reconciling the measured corrosion rate with the SME's knowledgeable review of the potential corrosion mechanisms and potential corrosion rates for the service. The SME can avail themselves of various tools for estimating corrosion rates or may have to rely on empirical experiences that relate to the system under review.

The result of this investigation can usually fit a range of outcomes. The best outcome is where the CML allocation and type of NDE used are adequate for the damage mechanism, and the high measured corrosion rate reported can be the basis for the DMR corrosion rate. A second outcome may be that the measured high corrosion rate is credible for the damage mechanism expected, but there may be insufficient allocation or NDE type coverage to validate whether this may be sufficiently conservative to represent

the highest potential corrosion rates through the corrosion loop. The measured corrosion rate is a warning that the damage mechanism is active and may require the SME to put forward a higher estimated DMR corrosion rate to help drive further investigation or implement enhanced inspection effectiveness coverage for the damage mechanism within this piping. The most concerning outcome may be that a credible isolated high corrosion rate is difficult to explain for a corrosion loop's expected damage mechanism unless there has been an issue with operation (IOW concern, operational upsets). It is tempting to ignore this data point, but if the corrosion rate passes the prescreening credibility analysis, the SME must decide whether to use this or an SME-based corrosion rate. This issue should be documented, and the SME should provide recommendations to investigate further, with a more in-depth RCA-type approach outside the current DMR project. Often, the scope of the DMR/RBI project only allows time to use the SME estimated corrosion rates, but it is important to identify and recommend that the plant reconcile any high corrosion rates within their database. This should already be a fundamental part of their plant thickness management program.

### Piping Short Remaining Life

Another IDMS database screening tool would be extracting piping system information with a short remaining life (ranging from one to two unit run lengths). This may be considered an overlap with the corrosion rate based assessment, but it may unearth some hidden issues that may be representative of a longer term, lower corrosion rate issue. Often, this may reveal issues with thinner wall components (initial thin schedule or small bore piping) that may require flagging by the DMR but may not necessarily change the corrosion rate to be assigned to the piping system.

### Piping High Potential Damage

During the DMR, there may be a few corrosion loops that identify damage mechanisms with the potential to cause high corrosion rates but are not reported by the plant to be an issue via the LOC, replacements, and IDMS database review. This needs a reverse reconciliation to confirm whether a higher SME-defined corrosion rate should be used. Ideally, the operations review may determine that the plant has adequate current corrosion control practices (process limits, water wash, chemical injections) in place that have been successful in reducing the corrosivity potential of the assigned damage mechanism. The assigned DMR corrosion rate can make use of the measured corrosion rates but is subject to including documentation of the control practices/limits in place (e.g., IOWs) that should be in place to justify using the measured corrosion rate. If there are few apparent control practices in place that would support the use of lower corrosion rates, a more in-depth review of the piping TMP should be undertaken to confirm if the CML allocation and NDE coverage used to produce the IDMS measured corrosion rates are able to detect the higher potential corrosion of a specific damage mechanism. In these cases, the higher SME corrosion rate should be used with recommendations to increase the inspection effectiveness for the type of damage mechanism reported.

### SME Estimates

A final word on the use and determination of SME corrosion rate estimates is warranted.

1. There are a few corrosion mechanisms that do have credible basis for estimating corrosion rates including Sulfidic Corrosion (API RP939C) and NH<sub>4</sub>HS (alkaline sour water) Corrosion (API RP932B) subject to understanding the range of operating exposure information available.
2. API RP 581 Annex 2.B does include a few corrosion rate tables for some corrosion mechanisms, though it is the author's experience that these require some considerable SME experience and wisdom to evaluate and use [8].

Regardless, it is recommended that the basis including any assumptions for the SME estimated corrosion rates where provided are clearly documented.

### Conclusion

The reconciliation between IDMS-measured corrosion rates and SME-based estimates of corrosion rates is an essential element of a damage mechanism review (DMR). Some guidance is provided to help the SME in performing the reconciliation. It is recommended that the basis for the selected corrosion rates used within the DMR is well documented, with the basis for using SME estimates or IDMS measured corrosion rates explained. This article demonstrates the potential pitfalls in the plant thickness management process (TMP) that contribute to difficulties in this reconciliation. This again demonstrates the opportunity for plants to improve their TMP to improve reporting credible corrosion rate information that can be used directly by the plant in DMR and RBI programs. ■

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