Using industry data to compare performance of different risk-based methods for the management of corrosion under insulation

Dr. Clare Watt[1], Dr Chi-Ming Lee[2], Steve Paterson[3], Mr Antony Jopen[4]

[1]*KAEFER Isoliertechnik, Bremen, Germany, dr.clare-louise.watt@kaefer.com*
[2]*TWI Ltd, Cambridge, United Kingdom, chi.lee@twi.co.uk*
[3]*Arbeadie Consultants Limited, Banchory, United Kingdom, steve.paterson@rbd247.com*
[4]*TWI Ltd, Cambridge, United Kingdom, antony.jopen@twi.com*

Abstract

Corrosion Under Insulation (CUI) is currently the subject of increased focus for the upstream and downstream oil and gas and petrochemical industries. Despite the publication of guidance and standards and often substantial control spend, there continue to be CUI failures, many of which are significant in terms of safety, cost and reputation.

Effective detection of CUI for critical equipment is expensive; while cost reduction is a well-justified focus of topical research, this may not address the problem of high impact failures. Little work has been carried out to explore the limitations of risk-based methods used to manage CUI. This paper uses industry experience and data to illustrate gaps and weaknesses in a number of different risk-based methodologies. The data are being used to revisit the required groundwork for an "optimum" approach to reduce the risk of serious failure.

Existing risk-based methods are likely to remain relevant for the development of evolving lower cost CUI control technologies and their integration into reliable assurance schemes. This work also highlights the benefits of more widespread CUI data sharing and opportunities for further research because the performance limitations of CUI controls that have been in use for many years are still not fully understood (e.g. quality coatings, insulation design, Non-Intrusive Inspection (NII) technologies).

Keywords

"Risk-based assessment pitfalls", "CUI", "plant data", "knowledge gaps", "industry experience"

1. Introduction

Corrosion Under Insulation (CUI) is a key focus area for the oil & gas, refining and petrochemical industries. Operators continue to experience serious incidence of CUI in their facilities, often in late life and in many cases after having assigned significant resources to manage this form of corrosion. There is also increasing attention from Regulators who have concerns about inconsistent management of CUI across the industry which has led to major safety events directly related to this mechanism. This has occurred despite the publication of guidance and standards in the industry.

For carbon steel equipment, inspection is still the only reliable method of preventing CUI failures and inspection resource is prioritised by adjusting timing and/or inspection coverage and technique. This almost always employs a semi-quantitative risk assessment methodology developed in-house, referencing one or several of the industry guidance and standards. The primary quantitative method based on API 581 is complex to apply and suffers from inadequate transparency of data used to underpin it.

In this paper published industry guidance and data have been reviewed together with a number of in-house risk-based assessment methods. Some key improvement areas have been identified that could help to both minimise critical equipment failures and optimise CUI inspection costs.

A new set of marine CUI data is presented to illustrate that more widespread sharing of CUI related data would be beneficial for the oil & gas, refining and petrochemical industries in terms of further refinement of risk based methodologies, and the promotion of key technology development areas such as coating, insulation, and non-intrusive inspection.

As an illustration of the opportunities for improvement, only carbon steel will be covered in this paper, although many of the points raised will be relevant for stainless steels, for which we have less overall prediction knowledge.

2. CUI Challenges

The primary concern of CUI in safety critical equipment is the potential consequence of a significant failure leading to a major safety event. CUI can give rise to catastrophic rupture failure if left undetected. Experience has shown that most critical failures occur in later life and should be preventable.

Inspection is currently the only method of preventing CUI failures of carbon steel. Frequent cycles of 100% effective inspection coverage of all critical equipment, (e.g. three yearly), would very likely prevent all CUI failures but the cost and effort are prohibitive and often unnecessary. Prioritizing inspection timing and workload is essential but risk-based methods can be prone to error.

3. Comparison of published and in-house RBA methods

Published guidance.

The following guidance, spanning the last 15 years, was reviewed for this paper:

- 2006 API 570 piping inspection code
- 2008 UK Energy Institute corrosion management guidance
- 2008 EFC55
- 2009 API 581 2nd edition risk based inspection technology
- 2010 NACE SP0198
- 2011 DNV RP G101
- 2013 UK Health & Safety Executive SP018
- 2014 API 583, EFC55 2nd edition, UK Energy Institute thermal insulation system guidance
- 2015 FESI Document 10
- 2016 API 581 3rd edition

The review highlighted some key gaps and inconsistencies:

- There is only one published risk based assessment method (API 581 [1]) which delivers risk based inspection interval and effectiveness guidance based on use of coating life and corrosion rate adjustments to determine time to failure.
- There is no published semi-quantitative risk-based assessment method.
- Plant data and basis of guidance is not referenced.
- Key guidance all recommends the use of plant data to form the basis of CUI prioritization methods, but not what to do if there is no data.
- Influential CUI probability parameters vary both in terms of number and definition.
- Reliability of Non-Intrusive Inspection (NII) methods is only cautioned by EFC55 [2], other guidance provides extensive information on techniques but not for reliability.
- Construction of multilayer inspection schemes which can be very effective is only addressed in the UK EI guidance [3]. Furthermore, while some guidance [3, 4] clearly drives appropriately timed 100% insulation removal for the highest risk equipment, other guidance [5, 6] does not provide such a clear message.
- Inspection interval guidance is only clearly given in two documents and can vary significantly for some equipment conditions [2, 5].
- Evaluation of inspection results and adjustment of probability for inspection cycles after the first inspection is not addressed in detail.
- There is very little guidance on coating maintenance strategies.

<u>In-house methods</u>

Eight in-house risk-based assessment methods for CUI from the upstream industry were reviewed; they were created 2006-2017 during which period much of the published guidance was issued or revised.

General observations are as follows:

- All methods adopt a semi-quantitative approach by weighting CUI influencing factors.
- All methods evaluate probability and consequence of failure in different ways and all make use of risk categories to direct priorities.
- The strategy underpinning methods is not clear, particularly for points scoring methods.
- Inspection interval output varies, for example thorough inspections are performed at 5-15 or 10-25-year cycles or fixed at 12 years or shorter intervals. The determination of the inspection interval is mostly qualitative. Several methods use plant data to justify extended intervals at some temperatures.

Examples of flaws and blind spots of the in-house models are as follows:

- Three methods give no guidance for interval or inspection effectiveness.

- Four methods do not drive an effective inspection for any highly critical equipment at any age; this is because they do not employ an ageing factor for equipment operating at temperatures within the less severe categories of the CUI temperature range, though this equipment can fail over longer exposure periods.

- Several methods do not drive an effective inspection for some highly critical equipment operating within the CUI temperature range because the methods reduce probability for combinations of influential factors that are less reliable, including:
  - Insulation type
  - Visual "Good" or "Average" cladding condition
  - Relatively dry environment and/or higher temperatures assumed to have less severe CUI, without the back up of regular close visual inspections to verify no persistent water sources.

- The temperature thresholds defining different CUI severity ranges vary significantly and not all methods require dead leg and/or heat tracing temperature to be considered.

- Seven methods do not reference plant data, or how the method was constructed based on the guidance referenced.

- One method employs rigid inspection intervals which do not vary with risk.

- Two methods employ extended inspection intervals for Thermally Sprayed Aluminium (TSA) coatings in a marine environment, whereas some guidance is more cautious [comparing 2 and 7 for example]. It is unclear if the (unpublished) good experiences with this coating are applicable to all conditions.

4. CUI Plant Data

Published Information

Only four shared carbon steel CUI datasets [3,4,5,6] were found in the literature, yet they all contribute significantly to current fundamental global CUI knowledge, each providing something different:

- The influence of temperature on corrosion rate.

- Time-based failure patterns shared by three petrochemical plants in similar climate locations with conventional paint coatings, where 90% failures appear preventable by effective inspection before 16-20 years.

- Insulation type (closed cell vs mineral fiber) has little influence on failure patterns.

- Higher corrosion rates for certain types of geometric design feature (e.g. column rings).

Knowledge gaps

There are some key factors limiting the relevance and interpretation of the data:

- Insufficient information to characterize the plants (location and operating processes) and/or how the data were collected (e.g. whether the corrosion rate includes coating life, definition of the sample population size, whether past inspection altered the rates or quoted failure data).

- There are no data for:

  - climates close to the equator,
  - upstream marine plant,
  - chemical/refinery plants in confirmed marine locations,
  - long-term performance of quality coating systems (e.g. TSA),
  - improved insulation system cladding design,
  - unusually early or severe CUI failures.

<u>New plant data which illustrates knowledge gaps</u>

KAEFER recently sponsored the analysis of a large quantity of CUI data provided by the Operator of a 25-year-old upstream gas processing plant located in a marine coastal, temperate climate, 0.5-1km inland, with conventional paint coating for insulated piping. The data which relate to CUI observed in carbon steel piping have been analysed in detail and compared to previous published CUI data. Some examples of the key insights from this analysis are as follows:

(a) Different CUI failure patterns for different plants as indicated in Figure 1.

The different leak datasets were not directly comparable because the marine plant executed highly effective inspection for many piping systems from 11-16 years age, whereas the petrochemical data was not influenced by this. The marine data were corrected to add "prevented" leak numbers to the actual leak numbers. This was done by projecting all plant CUI anomalies and around 30% of the plant non-anomalous CUI wall loss data points to failure, assuming a corrosion rate based on a 5-year coating life and failure at 30% of the general wall loss hoop stress calculated minimum thickness.

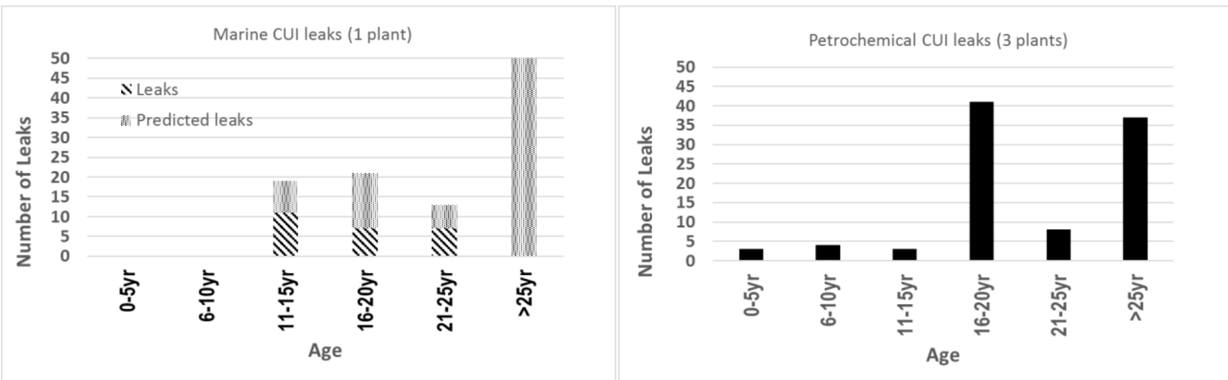

Figure 1. Marine plant CUI leak data compared with published petrochemical plant data [5]

The data sets share the same bimodal characteristic, but the marine plant step increase in failures commences earlier (11-15 years) compared with the petrochemical plants (16-20 years), and there are more of them per plant. The reasons for the differences could be due to different plant temperature/wall thickness combinations and/or exposure to higher chlorides. It is believed the petrochemical plants are located close to estuaries but 5-60km from the open coast in the US and UK.

(b) Influence of temperature on marine leak data

CUI failures and predicted failures during the first 25 years of plant operation were dominated by the 50-110°C temperature range. The 150-230°C range contributions are thought to be due to dead legs, and only one reported CUI leak at ambient temperature at 20 years.

The total marine insulated piping length was dominated by three static operating temperature ranges 0°C & ambient, 50-110°C and 150-230°C and there is highest confidence in actual leak data comparisons at these temperatures.

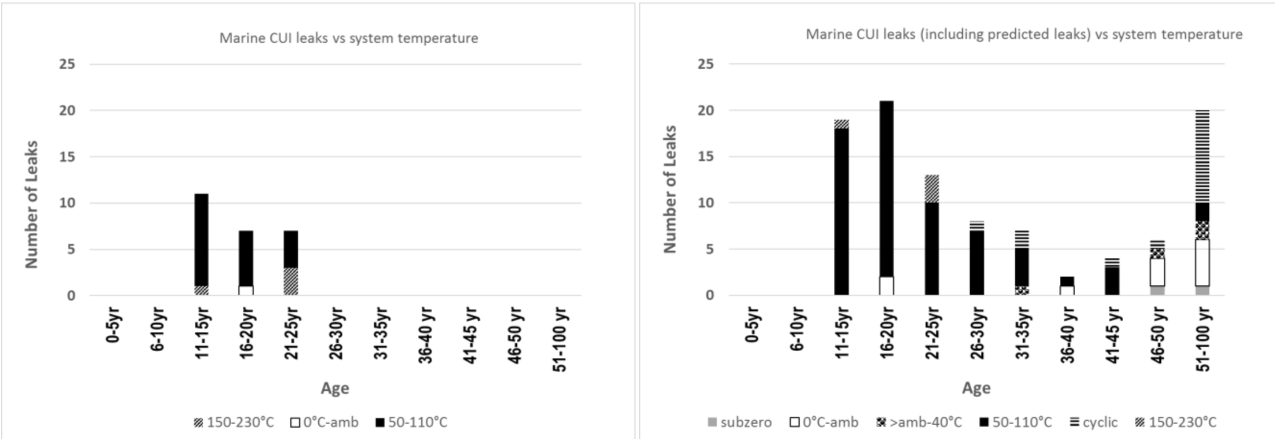

Figure 2. Marine plant leaks and projected leaks versus system temperature.

(c) Relevance for critical systems vs thin walled lower criticality systems.

All twenty-five leaks occurred on lower pressure (thinner wall) low consequence of failure systems.

Around ten critical CUI findings found by early effective inspection on highly critical thicker-walled hydrocarbon equipment were predicted to have failed during the period 16-25 years with a similar pattern for production critical process systems.

(d) CUI corrosion rate data vary significantly for individual plants and locations.

Figure 3 reveals strong agreement between the marine upstream plant data and one published dataset believed to originate from a petrochemical plant in the US [8]. The observed corrosion rates obtained from a refinery [9] are significantly lower, especially at higher temperatures.

(e) API 581 underpredicts the marine CUI wall loss and other [8] data especially at higher temperatures. Measured corrosion rate data points all lie above the API581 marine maximum prediction curve in Figure 3; the majority of the marine data points are not relevant for the pipe support penalty or Corrosion Under Pipe Supports (CUPS) adjustment.

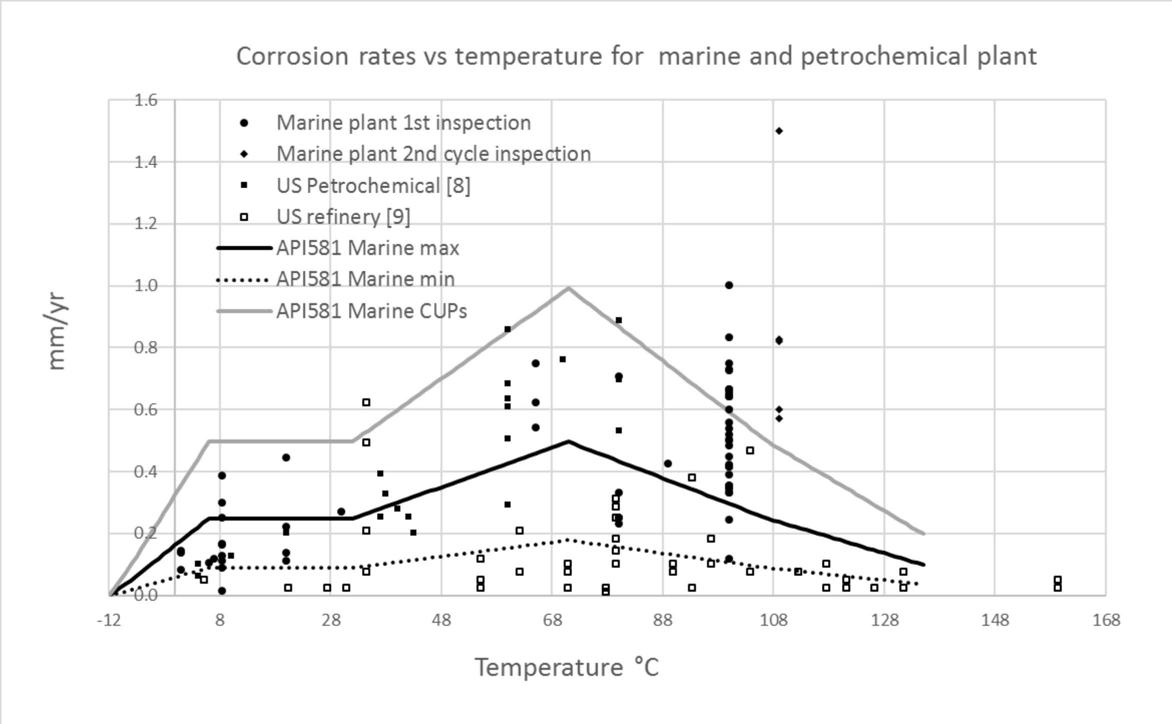

Figure 3. Comparison of CUI corrosion rate versus temperature from different plant datasets.

Figure 4 shows the effect of the API581 underprediction on the plant wall loss versus age data (using the API581 5-year coating life).

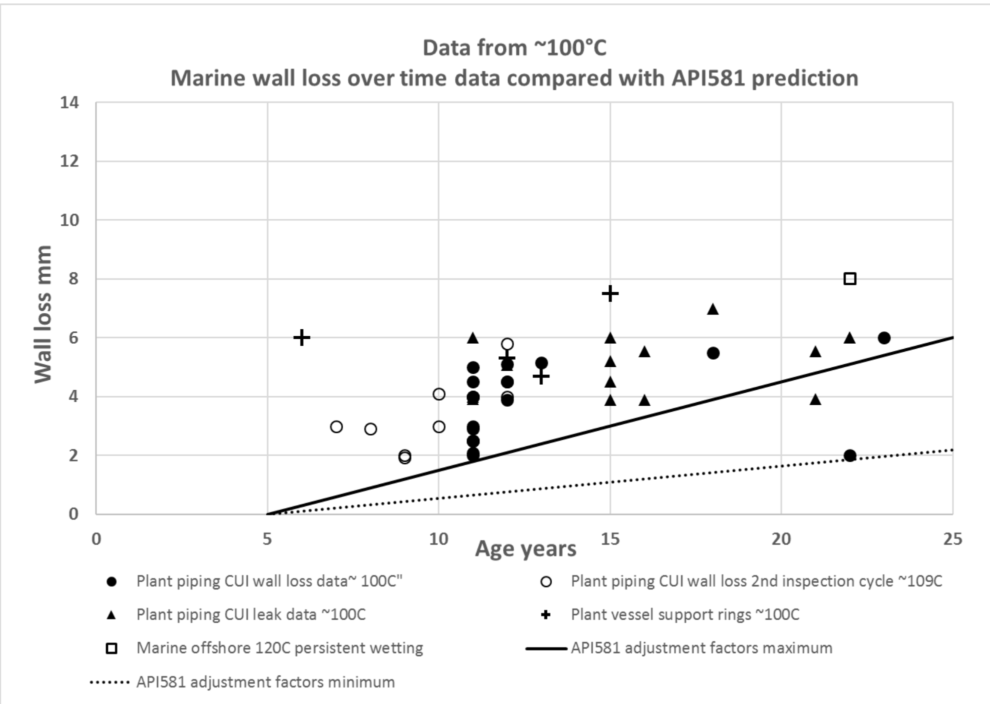

Figure 4. Comparison of marine wall loss versus age with API 581 prediction.

It is useful to look for patterns in data, but difficult to have confidence in adjustment factors that the reported data does not confirm (complexity, cladding condition, metal crevice/contact, insulation type). Plant data characterization and quality do not allow this level of analysis and there are other reasons for the differences

As an example, one of the reasons for the higher marine plant ambient temperature metal losses could be galvanic enhancement of top of line small bore attachment CUI due to contact between 316 cladding and the painted carbon steel substrate. It is believed that this influences initiation more than rate. Most of the CUI data relating to the higher temperature systems was for the main piping, not the SBC connections.

(f) Extent of occurrence of CUI locations was measured as a total of 8% by length, or 240m from a sample of 100% inspected 3.1km piping. It was dominated by extensive CUI on long straight piping runs on elevated pipe racks, elsewhere often <1% length was affected (Figure 5).

This may explain why sample inspection can often lead to a false sense of security and why 100% inspection coverage is necessary for confident detection. It also illustrates the potential problem of field-testing new CUI technologies with small-scale field trials.

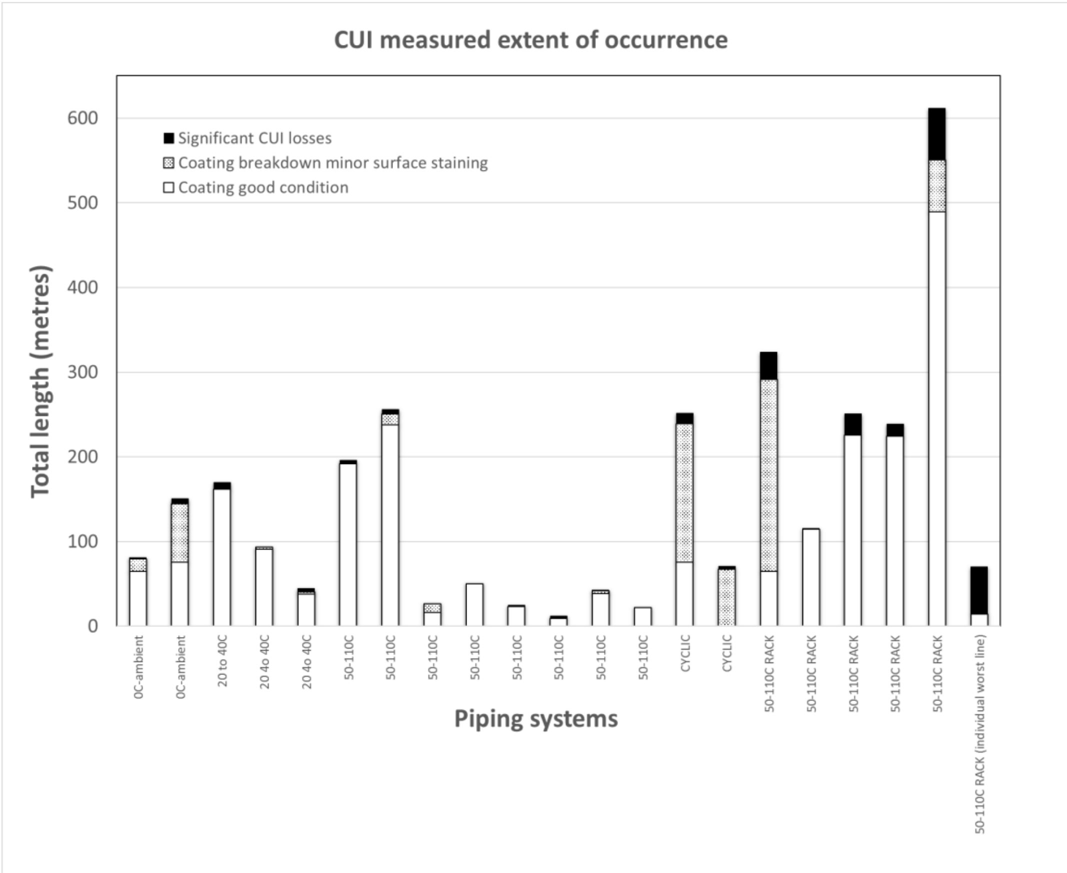

Figure 5. Measured marine plant CUI extent of occurrence.

5. General industry experience

Other experience from the industry illustrates the importance of some of the gaps detected in the in-house risk-based assessment methods.

Unexpectedly severe CUI at high system temperatures in relatively dry locations

There are several marine examples of very severe corrosion on piping operating above 120°C, and in a relatively dry location with no obvious source of water ingress. In one case persistent wetting caused by water dripping from above led to ~1mm/year of corrosion. In another case ingress of water under the insulation of vertical piping was associated with water that had collected in an exposed location several decks up; the effect of wetting might not have been as severe had the piping not been a dead-leg, where the temperature was within the most severe CUI range. This event would not have been predicted by API 581 or some of the semi-quantitative in-house methods.

Unexpectedly severe CUI at ambient temperature in climates close to the Equator

There are reports of widespread early severe CUI (5-10 years) for equipment operating at ambient temperature, small bore connections in plants located in humid climates close to the Equator where sweating and large day/night temperature variations occur, sometimes with little rainfall.

Early severe CUI

There are some examples of early failures or near-miss failures on plant from 5-10 years age where significant losses more than 8mm have been recorded. The examples are in the UK/Europe and mostly relate to combinations of the most severe CUI temperature range, severe geometries such as vessel insulation support rings and welded supports, persistent sources of water ingress particularly at height for onshore plant, in some cases relating to TSA coatings in a marine climate. Such early damage appears to have low frequency of occurrence.

General industry issues contributing to delayed effective inspection

- Published guidance does not appear to include a thorough review of all the other existing guidance to explain differences or apparent contradictions. Is there really a need for more than one published guidance?
- The resource demands on personnel responsible for creating in-house risk-based assessment methods means that not all guidance can be reviewed, and this can result in key errors or gaps, depending on which guidance is consulted.
- Organisational structures often do not support the necessary multidiscipline resource required to plan inspection programs in the office and implement them in the field. Control of CUI is suited to dedicated project management and budgets.
- Early investment in the above can be difficult to justify because undetected CUI critical equipment failures or near-miss failures often occur in later life and the economics are not always obvious in consideration of the fact that the prevention of just one high safety or production critical failure often justifies the cost of the entire CUI inspection scheme for the whole plant.

- Without understanding CUI extent of occurrence, many plants can believe they are managing CUI effectively by sample inspection.
- When CUI risk-based assessment methods and management strategies are improved or put in place for older plant, age must be considered, and the concept of significantly overdue inspection recognised. There are many examples of CUI catch-up campaigns that do not commence work on the highest risk equipment and consequence of failure is the best place to start (or pressurised gas and volatile liquid inventories).

6. Key observations

- Inspection remains the main barrier to CUI and ALARP risk management for critical carbon steel equipment.
- Published guidance is inconsistent and API581 represents the only published risk based CUI method that can drive inspection plans but it is both too complex and difficult to apply.
- All in-house methods reviewed were simple and semi-quantitative, there is no published method to follow and they all varied.
- All (complex and simple) CUI risk-based inspection planning tools reviewed contained flaws that would severely limit their effectiveness.
- Most importantly, existing guidance is based on very limited plant experience; yet it underpins all inspection management throughout the industry.
- Detailed consideration of just one additional CUI operational data set calls into question key prediction assumptions in existing guidance. API581 significantly underestimates marine, temperate climate CUI severity at higher temperatures, whereas other guidance [5] may be too conservative at lower temperatures.
- Similar plant types and climatic locations appear to follow similar CUI ageing patterns but different combinations can be very different and there is no published data for some.

7. Recommendations

- Existing published guidance ought to be revised and aligned.
- The number of case studies on which guidance is based should be significantly expanded to increase confidence in its conclusions. This will require industry cooperation in the short run, but has the potential to significantly reduce both inspection cost and HSE risk in the long run.
- Large catch-up campaigns on older plant provide an opportunity to collect data.
- Plant data collection or case studies must characterise the plant type, operating process and temperature insulated inventory size/length or data population, coating,

effect of inspection history regime, proximity to marine coasts, explain assumptions regarding coating life. For temperate climates data should span 20+ years.

- Key areas of interest are:-
  - marine vs non-marine
  - temperate vs climates close to the equator
  - upstream vs petrochemical plant
  - long-term performance of quality coating systems (e.g. TSA)
  - improved insulation system cladding design
  - unusually early or severe CUI failures.

- The following interim advice is proposed to maximise ALARP risk management and which could reduce inspection costs in marine temperate climates;-
  - Semi-quantitative in-house methods should provide clear interval and inspection effectiveness guidance considering equipment age.
  - A multilayer inspection approach (interim visual and extended thorough) is effective where, the intervals and required inspection coverage should both be driven by risk.
  - Use a consequence of failure method that prioritises the HSE and finance concerns separately and where the SHE priorities clearly focus on inventories with high stored energy (pressurised gas and volatile liquids).
  - Inspections are defined as combinations of timing and effectiveness. For example shorter interval interim close visual inspection can identify obvious cladding damage and water sources, longer intervals for insulation removal campaigns.
  - For highly critical equipment 100% coverage by insulation removal is required to provide assurance, as supported by the possible low extent of occurrence of CUI.
  - Include equipment age in the probability/likelihood assessment and acknowledge overdue inspection.
  - If significantly overdue, pressure system inventories with high stored energy (gas and volatile, flammable liquids) are more likely to fail catastrophically [d]
  - Be cautious of *reducing* probability or likelihood of failure based on influential factors that are less reliable (at least for highly critical equipment):
    - Cladding visual condition is acknowledged to be difficult to rely on to provide assurance of no water ingress.
    - Insulation type has little influence on CUI failure patterns according to published data.
    - System complexity is difficult to define and marine plant data shows that the most severe CUI for piping occurred on the simplest geometries, although in a location difficult to insulate.

    - Relatively dry locations can be reasonably identified, but frequent visual inspection is needed to verify and prevent non-obvious water sources such as dripping from above, deluge, delivery of liquids under insulation by attached piping that collects water from a more wetted location.
    - Temperature assessment must consider dead legs, which can be at maximum ambient temperature for less than ambient temperature services, or, in the most severe CUI range for any temperatures exceeding this range. Heat tracing temperature should be used if higher than the system temperature.
    - Sweating influence will vary considerably for different climates.
    - Do not reduce CUI probability based on inspection results to extent intervals or reduce coverage.
    - Do not assume that % inspection is sufficient assurance for highly critical equipment.
    - Do not replace insulation removal with NII for highly critical equipment unless it has been extensively field tested.
- The marine, temperate climate dataset provided suggests the following:
    - Do not follow API581 marine prediction for temperatures above 70°C and consider CUI rates can be high at least up to 130°C.
    - UK Regulator inspection timing guidance of ~10 years is considered reasonable for the most severe temperature range for CUI.
    - At ambient temperatures and below, however, it could be effective to extend thorough inspection intervals for thin-walled critical equipment to beyond 20 years with interim 100% small bore attachment coverage.
    - Using an experienced and qualified insulator to aid visual inspection may increase the chance of preventing “unusually” early failures of critical equipment in temperate marine climates. They typically involve heavy wetting; higher temperatures, persistent water source, obvious cladding defects, height, support rings and water trapping vessel support rings and attachments, galvanic cladding landing points and difficult to insulate locations.
- Sweating in climates close to Equator may drive a very different order of priorities especially for equipment at ambient temperature, or that regularly passes through it, especially including small bore connections, may present the highest initial priority with very short intervals i.e. 5 years.

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