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Safe and Compliant Process Unit Operation

Assignment 1 of 1
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1. Declaration of Authenticity

This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.

Signed:

Date:

2. Acknowledgments

Firstly, I would like to thank Kelvin Lake not just as a project mentor but for teaching me how to analyse and solve a problem as an engineer would. Without the knowledge gained across certain modules I feel I would have not understood and capitalised on the full potential of the problem discussed in this report. I would also like to individually thank Andrew Thorn for teaching me to make better use of tools to identify, solve and improve real life maintenance issues, Marie Pitson for helping me present my reports far more professionally and I also want to thank each and every member of staff at UWSTD Swansea who have taught me these past three years as each and every one of them have had some input in my continued development as an emerging engineer.

To the members of the Inspection and Engineering team at Valero Pembroke, I am truly grateful for all of their help, guidance and inspiration with a special thanks to Geoff Martin, (Senior Reliability Engineer for the Refining Complex).

At the Pembroke plant I would also like to thank my two line managers I have had whilst attending university, for understanding the pressures of balancing work with additional studies and giving me the much needed flexibility with working hours thus allowing me to complete the project even within a new role.

Finally from a professional work standpoint I would like to show my upmost respect and appreciation to Tony Jevons, my first line manager when I came to Pembroke as staff. Without his encouragement I would have not achieved my full potential and this journey would have never even started.

I would like to show my appreciation for my fellow classmates and peers who have been an important part of my life these last three years, some even longer. Without the peer pressure, competition and support from one another, I very much doubt I would of made it this far.

Perhaps and most importantly I would like to thank my amazing family. My partner Ellen for putting up with me, for sometimes being sat in our office all day and night revising or writing assignments. Without her support and encouragement I would have been lost. My two fantastic children Jake and Sasha thanks to them for understanding that the hard work I have done is not always fun for them but it will contribute to our future. I look forward to supporting them both through their studies when the time comes. Finally I would like to thank the rest of my family for giving me continuous encouragement and support every step of the way.

3. Abstract

This report gives an understanding of how the Pembroke plant achieved continuous process safety. Through scheduled inspections, inspection advice notes are issued when defects are found within pressure containing equipment such as piping and pressure vessels.

Oil refineries and other similar process plants are highly regulated and must follow strict guidelines and codes of practice otherwise they face large fines or even be forced to close down. Process safety is the number one priority, as a loss of containment could result in an environmental or personnel safety concern, which is to be avoided at all costs.

The report shows what actions are taken when an inspection advice note is issued to the business and how it is acted upon. In this case a section of line has been highlighted to maintenance, suffering from atmospheric corrosion and action is needed.

Using guidance from applicable ASME and API codes, the author in the roll as integrity coordinator together with a cross function team concludes that, a temporary repair as per ASME-PCC2 temporary repair instruction is the best method of repair and maximises asset uptime safely. Using a risk matrix to understand the present level of risk it becomes apparent one repair is needed urgently and the other poses a lesser risk and can be completed as planned maintenance.

After approving the first method of temporary repair the author then moves focus to further assessment of the remaining defects. From forming a cross functional team several possibilities are drawn up and explored. Some defect locations are removed from the problem by proving they pass a fitness for service assessment which then in turn reduces the potential work scope.

Using cost estimating to help aid the decision process, the author then determines that live line patch repairs conform to the applicable temporary repair codes are the best course of action. During the report it becomes apparent that several recommendations can be made for future work. The author also deduces after using a root cause analysis tool that the IAN could have perhaps been preventable. To justify these recommendations the author attempts to put a timescale and cost to each one whilst quantifying the potential payback.

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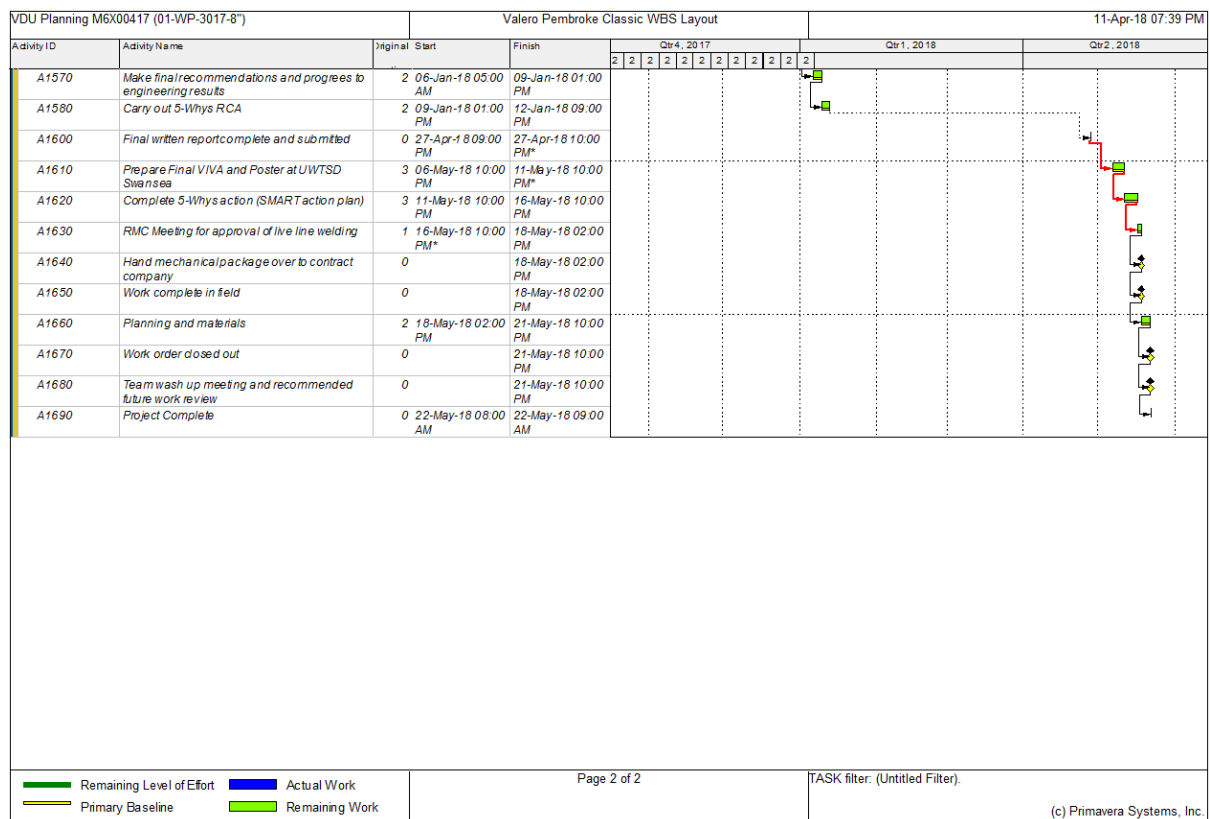
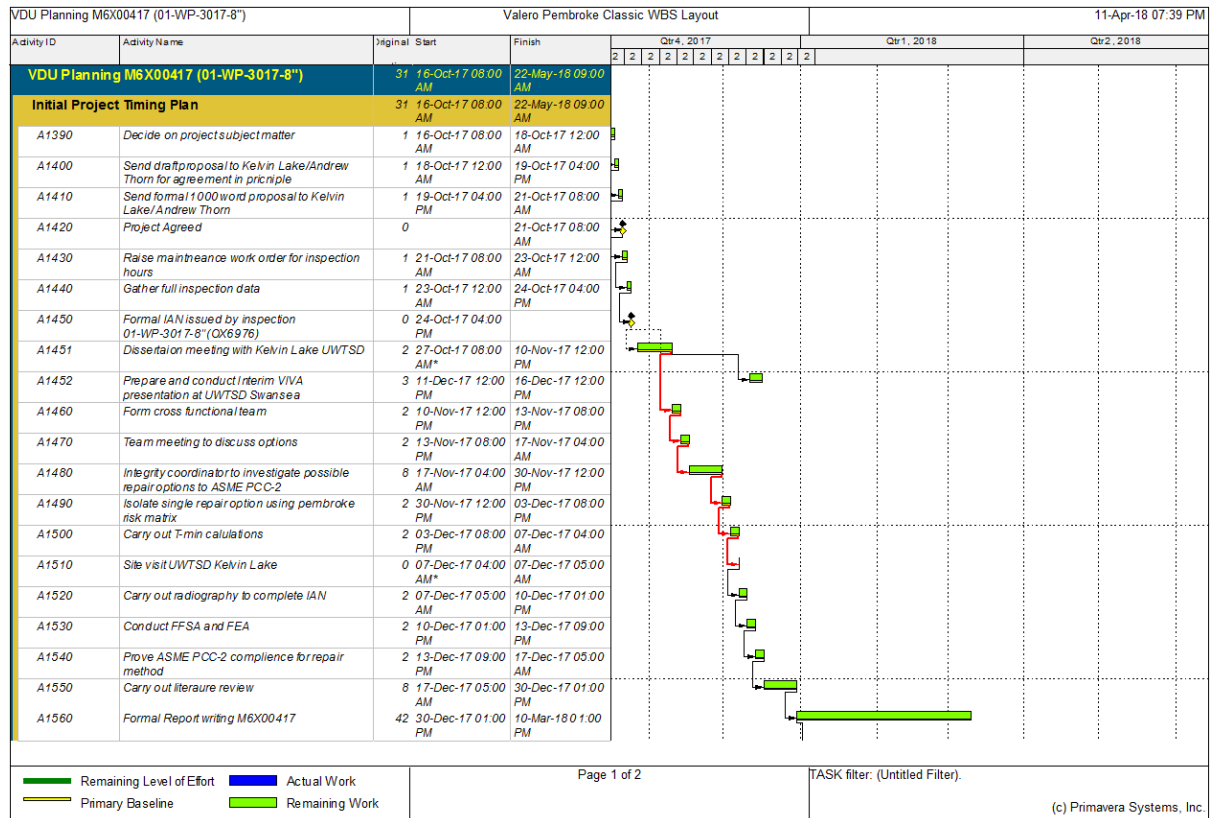
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6. Project Plan



7. Acronyms and Abbreviations

API	Control Of Major Accident Hazards
ASME	American Petroleum Institute
COMAH	American Society Of Engineers
CSA	Cross Sectional Area
CTEMS	Commitment To Excellence Management System
CTP	Critical Thickness Profile
ETQ	Engineering Technical Query
FFSA	Fitness For Service Assessment
GA	General Arrangement
GEMS	General Engineering Material Specifications
HSE	Health And Safety Executive
HVGO	Heavy Vacuum Gas Oil
IAN	Inspection Advice Note
LPO	Loss Prevention Observation
LPS	Loss Prevention System
LTA	Local Thin Area
LVGO	Light Vacuum Gas Oil
MAWP	Max Allowable Working Pressure
MOC	Management Of Change
MPY	Mils Per Year
NDT	Non-Destructive Testing
NLI	Near Loss Investigation
OSS	Out Of Service
P&ID	Piping And Instrumentation Diagram
PFD	Process Flow Diagram
PMPT	Pembroke Minimum Pipe Thickness (3mm)
PPM	Parts Per Million
RAMS	Risk Assessed Method Statement
RCA	Root Cause Analysis
RIDDOR	Reporting of Injuries, Diseases and Dangerous Occurrences Regulations
RMC	Risk Management Committee
RTS	Returned to Service
RTS	Remaining Strength Factor
RWT	Remaining Wall thickness
SMART	Smart Measureable Achievable Realistic Time Bound
SME	Subject Matter Expert
SWS	Sour Water Stripper
TURNAROUND	Term Used To Describe a Maintenance Shutdown or Outage
UKAS	United Kingdom Accreditation Service
UOP	Universal Oil Products (Regulatory body for refining operating licences)
USTM	Ultrasonic Thickness Measurement
UWTSD	University Wales Trinity Saint David's

8. Introduction

Opened in the mid nineteen sixties and employing over one thousand people, Pembroke oil refinery is still a thriving successful plant and one of very few left still operational in the UK. Run by the San Antonio Texas based Valero Energy Ltd, the refinery turns either light or heavy raw crude feedstocks into more saleable transportation fuels. Producing sixty percent gasoline, the plant is one of the largest and most complex refineries in Western Europe and its recent success and continued operation is mainly down to its excellent investment in people throughout each of its departments, both locally and corporately. Profit margins vary due to economics but are generally small so throughput has to be maintained at a high rate at the plant and unplanned shutdowns are to be avoided. Whereas the previous owners of the, Chevron Oil have both upstream and downstream assets, Valero do not and are only in the business of refining oil and not extraction or expedition. This forces Valero to pay great attention to its efficiency in processing crude oil into fuels. Unplanned downtime directly effects profit and the company have even gone as far in the past as closing unreliable plants. Within the Pembroke refinery there are several departments, these are as follows;

Human Resources

- HR Team
- Public Relations and Community Team

Operations

- 01-Refining
- 02- Blending and Shipping
- 03- Cracking and Olefins

Centralised Maintenance

- Rotating Equipment
- Fixed Equipment (Of which the author makes up part of the team)
- Instrumentation and Electrical
- Civil Support Services

Procurement

- Warehousing
- Contracts
- Purchasing Team

Safety

- Safety Team
- Environmental and Industrial Hygienist
- Fire Department
- Quality Control Laboratory

Technical Department

- Engineering
- Inspection

Each department plays a major part in the day to day running of the plant and if one element were missing, the plant would struggle to maintain its high level of efficiency.

As seen in the above, the operations section is split up into three teams, complex one, two and three. These effectively are three different businesses within the refinery, it can also be seen that maintenance is a central service of which in this department the author takes up the role of refining integrity coordinator. Central maintenance is something that was implemented in 2012 and has proved to be a great success due to labour resources working on site priorities

and not the area priority. This has minimised unnecessary overtime and disruption to other planned work by moving resources to reactive breakdowns. The plant has over twenty processing plants and each are interconnected in some way. Taking a unit offline in isolation usually results in some form of production rate cut on other units and this is avoided if possible.

Due to the nature of the processes that take place the plant is highly regulated. The site is a top-tier COMAH site, this is due to the substances consumed and produced and the potential severity of an accident or incident if one were to occur. (Hse.gov.uk, 2018) give a general statement of the upper tier, as taking all necessary measures to prevent major accidents involving dangerous substances and limit the consequences to people and the environment of any major accidents which do occur. The refinery also operates under licence from several other regulatory bodies and without these in place the business would close.

Process safety and the environment are of the highest priorities therefore, correct practices, codes and standards are mandatory at Pembroke across every department whether it be the health and safety at work act or the UOP operating guidelines of a particular process unit. The regulations must be followed or penalties maybe sanctioned on the plant and potentially in the worst case, the plant may be forced to shut down temporally or even close. This report plans to study the maintenance of the refinery in more detail and the applicable codes it must follow. In order to run each process unit safely, the inspection department play a major role in assessing piping and pressure vessels and issuing recommendations where necessary. The department is one of the most highly regulated on site and must inspect all equipment to API 510 and 570 standards whilst complying with UKAS ISO/IEC 17020. Dependant on its findings, any work scope generated from inspection is then actioned by the complex manager and fixed equipment engineer. These actions often require a cross functional team to implement the best possible outcome with regards to safe running of the plant and to the business. The work taking place at this stage is of particular interest as the author in the position of integrity coordinator plans to look in more detail the most effective way of repairing a certain piece of equipment. When an inspection advice note (IAN) is issued to the business unit, the complex manager is to respond with what action is to be taken and assign a due date. Examples of this would include; shutting the equipment down immediately for repair, installing a temporary repair or carrying out further assessment to prove safe operation of the plant. All of which would be done in accordance of ASME-PCC2 which is the standard in place at the refinery regarding asset integrity repair and maintenance. This code does not give a specific repair method but offers different options that can be implemented. This will be assessed in great detail throughout the report and this code is not to be deviated from unless a formal risk assessment is to be completed and management of change (MOC) be logged.

When an IAN is issued time is of the essence as there is potential of shutting the plant down to action a repair. This will then more than likely result in a loss of production or other cost to the business, something that Valero want to avoid. Repairs need to be efficient if the business is to succeed but there is a bigger picture and strategy. This is to be discussed with regards to inspecting pressure containing equipment more frequently. This area needs to be examined further so that some sound recommendations can be made. It will be more than likely that, due to repair options given within ASME recommendations, more than one solution to choose when investigating any repair options, solid justification must be in place before pursuing any such like repair. Process safety and reliability will be key to decision making when it comes to a repair and best options are to be always assessed.

9. Problem Statement

During a scheduled routine inspection of a 32m section of vertical pipeline 01-WP-3017-8" within the refining complex's vacuum distillation unit (01-VDU), **EXTERNAL** corrosion has been identified and the line has been found to be below 3mm which is Pembroke's minimum pipe thickness (PMPT) . The recognised failure mechanism/mode is recorded as, breakdown of surface coating leading to external corrosion. A total of sixteen locations have been found below 3mm (PMPT) and have led to a new IAN (OX6976) being issued to the business unit. The action to be taken calls for repair or replacement of the line in accordance with TEC/SPI/109. The document also advises that there are a further twelve locations that cannot be assessed due to severe pustular corrosion and that the current inspection method is deemed inconclusive with the line in its current state.

The line runs from top to bottom of the unit's sour water stripper tower and is part of the equipment that facilitates removal of harmful ammonia and hydrogen sulphide (H₂S) from process water. Some of the locations documented on the IAN state a thickness of below 2.0mm, this is of particular concern and is to be addressed with immediate action. Process safety is the highest priority at the plant and this IAN must be mitigated as an urgent priority.

The goal of this project is to reach the most effective outcome of continuing safe plant operation. The next planned outage for the equipment would be either 2020 or 2023 dependant on current economics, so taking the equipment OOS now would be an unplanned event. There are a number of ways in which this can be achieved and the author being in the position of integrity coordinator plans to investigate these possible options.

Finally, once safe unit operation has been achieved it is the author's intention to investigate whether or not any learnings can come from this. This investigation will take place using the sites root cause analysis (RCA) 5-whys tool.

Problem Statement;

'Define the best possible method conforming to ASME-PCC2 for continued safe plant and unit operation'.

10. Research and Literature Review

10.1 VDU operation

The Vacuum Distillation Unit (VDU) shown in **appendix A**, is also referred to as Unit (01), is located within the refining complex and first came online whilst under Texaco ownership in 1982. The purpose of the VDU is to separate atmospheric residue into individual fractions of diesel, light vacuum gasoil (LVGO) and heavy vacuum gasoil (HVGO) and vacuum residue.

(Valero, 2018) Describes as; distillation under vacuum is used to reduce the heat and hence energy input necessary to retrieve the high value products from boiling atmospheric residue. This results in decreased fuel gas and hence energy costs. If distilling atmospheric residue at atmospheric pressure the required temperature would be in the order of 500°C at which point most hydrocarbons would thermally crack. Through the reduction of pressure, the fractionation can be achieved with heater outlet temperatures in the region of 425°C.

This gives a general overview of how the whole unit operates. The hydrocarbon process is important to understand as these processes produce sour water as an unwanted by-product.

Within the VDU boundaries is a sour water stripper system (SWS), it carries out the task of removing unwanted substances from process water, which is achieved by using steam to remove these components turning them into gas to be burnt as off-gas in the VDU unit's two furnaces.



Figure 1 Location of 01-VDU within Refinery

10.2 Description of Sour Water Stripper System

Sour water is water that has been in direct contact with a hydrocarbon stream. This water contains Hydrogen Sulphide (H_2S), Ammonia (NH^3) and a small amount of hydrocarbon. The SWS is designed to reduce the concentration of these unwanted substances before the water is sent to the Waste Water Treatment Plant (WWTP). The H_2S and NH^3 are stripped through use of steam from the top of the SWS column 01-F-302 as acid gas. These then flow to the SWS acid gas knock out pot (01-F-305) to remove any entrained liquid. From 01-F-305 it is sent to 01-H-101/201 furnaces to be burned.

(Do, Oil and Center, 2018) also state that this can also be sent to a refineries sulphur plant for further treatment to allow for an emissions compliant incineration.

VDU Sour water is primarily formed in a vacuum distillation column overhead system. Additional sources are sent to the SWS from other process units and also from the blending and shipping complex tanks 20-D-52 and 20-D-53. The system is capable of processing 50m³/hr of sour water and this operation happens continuously every twenty four hours and processes the sour water from all three business complexes.

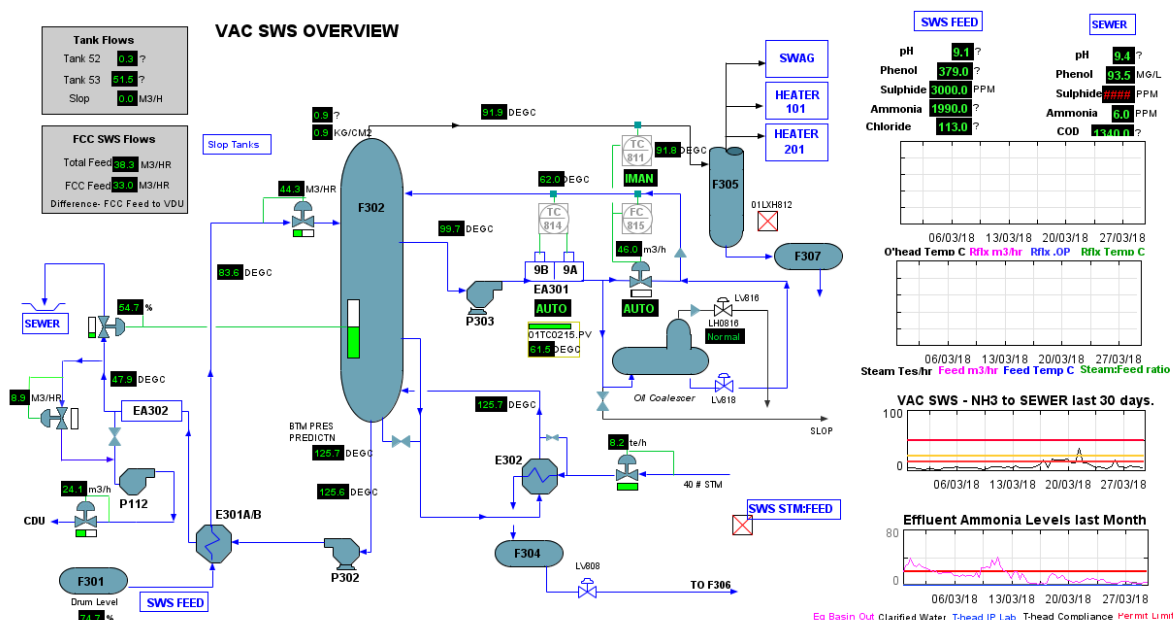


Figure 2 Overview of Pembroke Refinery Sour Water Stripper

The process flow diagram (PFD) as seen in (figure 2) shows the SWS feed, which in this instance is 44m³/hr and is close to max rate for the system. The system currently here is also processing sour water from each complex. The SWS is an integrated system for the whole refinery and to take the equipment out of service would require careful planning. Without this equipment available, hazardous liquids would have to be put to store in tanks and be processed raw by the sites WWTP. Hydrogen Sulphide is an extremely harmful substance which in low concentrations up to 100ppm has an odour of rotten eggs, above this human senses become numbed and this level becomes fatal, levels above 500ppm will result in sudden death if exposed to for just short duration. **Appendix B** highlights the dangers of H_2S and gives guidelines of this.

The 32m section of line with new IAN issued 01-WP-3017-8" runs from the oil coalescer to the top of the SWS with reflux water. The principle of this is to further remove any H₂S still entrained in the process water and the H₂S levels in this line could be up to 50ppm. This can be found on P&ID 01-AA-523 on the highlighted part in **appendix C (a)** and a general overview can be found in **appendix C (b)**

10.3 Initial Assessment of 01-WP-3017-8"

Corrosion is a form of damage mechanism and is found in many forms. To correctly categorise the exact damage mechanism and to enable engineers to mitigate against it, full guidance can be found throughout the contents of API 571. This is the applicable code used by refineries to firstly categorise the observed damage mechanism and then treat the cause to allow for future prevention. For API standards, corrosion is measured with the unit as mils per year (MPY), a simple measurement calculating the losses observed in millimetres per year.

Some examples of corrosion rates would be;

- Severe marine environments 20 MPY
- Industrial environments containing acids or sulphur compounds 5-10 MPY
- Inland locations exposed to moderate rain and humidity 1-3 MPY

From the critical factor section 4.3.2.3 of the API code it lists key points on what can effect corrosion rates in MPY. The factors that apply to the line discussed are as follows;

- Corrosion rates increase with temperature up to about 250°F (121°C)
- Airborne contaminates from cooling water towers
- Geographical location of the equipment in relation to the coastline and the presence of salts in the air blown off the coast line by the wind.

In this instance, for line 01-WP-3017 after review of API 571, two failure modes could potentially be found directly from the contents of the code;

- **Erosion/Erosion corrosion-** This is internal thinning of the line due to the movement/velocity of the internal solid, liquid or gas, which in this case has not been observed. Confirmed by inspection reports of RWT is close to nominal.
- **Atmospheric Corrosion-** General or local corrosion caused by accelerants. Corrosion rate depends on severity of accelerant and current control measures in place.

(Dobis, J., Cantwell, J. and Prager, M, 2004). Show that according to the information provided and the information stated in the IAN, the correct category of corrosion found in this instance is atmospheric corrosion. This corrosion found occurs from moisture in atmospheric conditions, marine, coastal environments and moist polluted industrial environments. Notably airborne contaminants are most severe and are by far the largest accelerant of atmospheric corrosion. For specifically this line, fits this criteria operating in the temperature danger zone and due to the fact it is the most westerly located process unit subjected to the prevailing winds from the Pembrokeshire coastline which can also be seen in (**figure 1**) image. The wind in turn carries the spray off of the sea which contains much higher concentration of salts than

normal rain water. One other contributing factor may be that with the correct wind direction, mist from the refineries cooling towers may find its way to the SWS equipment. Carbon steel is also listed in API 571 as one of the materials most susceptible for this damage mechanism.

(Dobis, J., Cantwell, J. and Prager, M, 2004) state the appearance can be found to be general or localised, dependant on whether or not the moisture is trapped. Localised coating loss or damage promotes corrosion and a distinctive iron oxide (red rust) scabbing will be observed. API 571 can later be used when making future recommendations in this report.

With the present hazard taken into consideration, action is immediately required to mitigate this risk. The IAN has confirmed this line is below PMPT and 3mm min RWT. Work needs to be done to understand all of the facts presented in IAN 0X6976 shown in **appendix D**. The first action to be taken, using the Pembroke risk matrix (**table 2**) to understand what the current level of risk is in order to categorise the priority of this IAN being progressed quicker than others. From the authors experience the consequence of failure of a line in this service is high due to it containing dangerous levels of H₂S. Before progressing to calculating the hazard of the thinned sections of line some analysis is to take place to establish the minimum required thickness for pressure containment T_{min}.

Valero Energy is an American company and adopt their own process of 'commitment to excellence management system' (CTEMS), this enforces all of its sites across the world to adopt the American standards such as ASME and API. These codes are also accepted by UK inspection board and the UK Health and Safety Executive (HSE). Directed by CTEMS section 5.0 the Pembroke site uses ASME B31.3 for assessment of pipework and pressure vessels, this is shown in **appendix E**. (Process piping, 2011) shows that under section 304.1.2 the formula of calculating T-min in straight pipe under **internal** pressure is as follows;

$$t = \frac{PD}{2(SEW + PY)}$$

- Where;
- T_{min}= Minimum thickness
- P= Internal design pressure
- D= Outside diameter of pipe as listed in tables or as measured
- S= Stress value from table shown in **appendix F (a)**
- E= Quality factor from table shown in **appendix F (b)**
- W= Weld Joint strength reduction factor as shown in **appendix G (a)**
- Y= Coefficient from **appendix G (b)** where t= <D/6 and for materials shown. For t= >D/6 use;

$$Y = \frac{d + 2c}{D + d + 2c}$$

This formula can be used to establish minimum remaining wall thickness for 01-WP-3017-8" to understand whether or not the line is capable of withstanding internal design pressure. To use this formula the unknown values must be found and are tabulated below.

Table 1 Showing required values to establish T_{min} for 01-WP-3017-8"

T_{min} = Unknown	This is the unknown in the equation
$P=13.97\text{Kg cm}^2\text{ g (1.37MPa)}$	Max design pressure stated in on IAN. ASME B31.3 specifies use of design pressure not max operating when calculating minimum thickness
$D= 219.1\text{mm (0.2191m)}$	Taken from pipe spec PJ164 shown in appendix H (a)/(b)
$S= 20\text{ KSI (137.9 N/mm}^2\text{)}$	Taken from table show in appendix F (a) Note that 20 KSI used due to max design temperature of 149°C
$E=1$	Taken from appendix F (b) for seamless pipe
$W=1$	No welded joints therefore a value of 1
$Y=0.4$	Taken from table in appendix G (b) as $t= D/6$

All of the above design conditions as stated on the front cover of the IAN are verified and can be used in the above formula to show T_{Min} , this formula relates back to thin cylinder theory where ratio of thickness compared to internal diameter is $<1/20$ and hoop stress is $\sigma_h = \frac{PD}{2T}$. All units have be converted into Si units.

$$T_{Min} = \frac{1.37 \times 0.2191}{2 (137.9 \times 1 \times 1) + (1.37 \times 0.4)}$$

$$T_{Min} = 1.0861 \times 10^{-3} \text{ m}$$

This API formula can also be validated using the above mentioned thin cylinder theory. It can be said that hoop stress is twice that of longitudinal stress. Therefore hoop stress is the limiting factor and due to this, the following formula can be used. $\sigma_h = \frac{PD}{2T}$. In this case T will equal the calculated T_{min} to help understand the max allowable hoop stress that can be observed on the system. So;

$$\sigma_h = \frac{1.37 \times 202.72}{2 \times 1.08}$$

$$\sigma_h = 128.57 \text{ N/mm}^2$$

This is close to the max allowable stress as seen in **appendix F (a)** ASME B31.3 table A-1 for A106 GR.B carbon steel pipe at the specified temperature. However as wall thinning is localised it is not the entire circumference that has thinned. Over ninety percent of the normal thickness remains around the circumference. To calculate for a more realistic actual value for hoop stress T_{min} can be replaced by nominal wall thickness where $T=8.18\text{mm}$ shown (**appendix H (b)**). So;

$$\sigma_h = \frac{1.37 \times 202.72}{2 \times 8.18}$$

$$\sigma_h = 16.97 \text{ N/mm}^2$$

Therefore it can be said for 01-WP-3017-8", that using the above formula as per design code ASME B31.3, minimum thickness required for pressure containment based on the design conditions stated on the front cover of the IAN is 1.08mm.

With $T_{\min}$ now established it can be seen that location 12 has a remaining wall thickness (0.5mm) which is below what has been calculated for pressure containment. Although this is based on design pressure and not maximum operating pressure which is much lower this still poses a significant risk and can be risk assessed using the Pembroke matrix (table 2).

From studying this information the question is asked why failure has not occurred when a small section of the line is below $T_{\min}$. Theoretically a pinhole leak should have been observed at location 12. The reason there has been no loss of containment, is because the formula used in API calculations specifies the use of design conditions and not actual operating conditions. This is a more conservative approach and allows processing plants to operate safely.

To help understand the difference, the same calculation can be made by using the maximum operating pressure the actual equipment is subjected to. It should be noted however this is **not to API code** and is purely for observation and theory.

Where maximum operating pressure = 0.765 MPa

$$\text{Theoretical Minimum Thickness } \mathbf{NOT} \text{ to API Code} = \frac{0.765 \times 0.2191}{2(137.9 \times 1 \times 1) + (0.765 \times 0.4)}$$

$$\text{Theoretical } T_{\min} = 0.6\text{mm}$$

Although location 12 is still marginally below this figure it could be said that the accuracy of using USTM to measure wall loss could according to (Advanced-ndt.co.uk, 2018) is stated as +/- 0.1mm for a similar device used at Pembroke.

This information helps the author to better understand why a small pinhole leak has not been observed.

Table 2 The Pembroke risk matrix

Consequence											
Business	Environment	Community	Safety								
>\$100 Million	Catastrophic - Serious contamination of ground water or water course, extensive loss of aquatic life.	Public Evacuation or National Media Coverage	>10 Fatalities On Site or Multiple Fatalities Off Site	VI	TR	Level 1	Level 2	Level 3	Level 4	Level 4	Level 5
	Major - Serious toxic effect on beneficial or protected species, significant fish kill over a five mile range.	Public Evacuation or County Media Coverage.	2 to 10 Fatalities On Site or One Fatality Off Site	V	TR	TR	Level 1	Level 2	Level 3	Level 4	
	Severe - Hazardous material into water course with half mile effect, e.g. Viable Fish kill	Shelter in Place or County Media Coverage	Permanent Disabling Injury (e.g. Amputation) to Single Fatality	IV	BA	TR	TR	Level 1	Level 2	Level 3	
>\$1MM to \$10MM	Significant - Strong or offensive odours or noise, major breach of permitted emissions	Shelter in Place or Local Area Media Coverage	Serious Injury to Permanent Injury (e.g. Burn)	III	BA	BA	TR	TR	Level 1	Level 2	
>\$10K to \$100K	Noticeable - Nuisance off site, discernible odours, minor breach of permit conditions	Community Warning or Local Media Coverage	Recordable to Lost Time	II	BA	BA	BA	BA	TR	Level 1	
<\$10K	Minor - Nuisance On site only, No off site effects	No to minor Impact to people or No Media Coverage.	Minor to First Aid	I	BA	BA	BA	BA	BA	TR	
				Likelihood ➡	AAA	AA	A	B	C	D	E
				Qualitative description	Rare - equivalent to being killed by a lightning strike.	Remote, has occurred once or twice in the Industry	Unlikely that the event will occur at this facility.	Conditions may allow the event to occur within industry using similar technology	Conditions may allow the event to occur at this facility during its lifetime	Likely to occur at this facility once every 10 years	likely to occur
				Scenario frequency per annum	10-7 to 10-6	10-6 to 10-5	10-5 to 10-4	10-4 to 10-3	10-3 to 10-2	10-2 to 10-1	10-1 to 1
Legend: Level 2, 3, 4 and 5 Unacceptable Risk. Must be reduced regardless of cost - Short term, interim risk reduction required. Long term risk reduction plan must be developed and implemented, to reduce the risk. If the consequence is "IY" or higher and the risk cannot be reduced to "TR" or at least "Level 1" due to the cost of controls being disproportionate, then the activity must be abandoned. Level 1 - Undesirable risk. If the consequence is "IY" or higher and the risk cannot be reduced to at least "TR" due to the cost of controls being disproportionate then the activity can only be continued with appropriate manager sign off at Level One authority providing a robust ALARP demonstration is made. This may involve a quantitative risk assessment e.g. LoPA/ QRA with a CBA - Contact PSM personnel for advice. If the consequences are between "I" and "III" then a qualitative risk assessment can be used for ALARP demonstration, e.g. Team review - What more can we do? Why aren't we doing it? TR - Risk is tolerable if ALARP Further control measures must be investigated and implemented if reasonable to do so. If the consequences are "IV" or higher an ALARP demonstration may be required to determine what is reasonable. Contact PSM personnel for advice. If the consequences are between "I" and "III" then a qualitative risk assessment can be used for ALARP demonstration, e.g. Team review - What more can we do? Why aren't we doing it? BA - Broadly Acceptable The risk is acceptable if all controls are in place and recommended good practice is followed.											

Using this matrix the following could be said for continuing to operate the line with location 12 of 0.5mm RWT in its current condition.

Consequence Safety/Environment (III) x Likelihood (E) = Level 2 (Unacceptable risk must be reduced). There is also an element of business risk owing to the fact that if the line were to fail completely and the unit would have to be shut down there would be a loss of profit opportunity due to the downtime. This will be investigated further in the relevant section.

After using the formula and risk matrix, it is clear that immediate action is to be taken. For locations above T_{min} further assessment will be required but the action is not an urgent priority. In the interim period in case of a pinhole leak developing the area is cordoned off. Continuous gas monitoring is active at the equipment and in the event of a minor leak the unit alarm will sound.

If no further action were to be taken although not the case, in the highly unlikely event that a catastrophic failure were to occur even with no personnel present due to unit restrictions using barrier control, a large release of sour water would be a stewardable event to both the HSE and corporate headquarters. A release of this kind would be a RIDDOR and COMAH reportable event and through similar investigations at other plants and factories, large fines have been observed and in some cases had their operating licences suspended or void. Two examples in (**table 3**) are shown below to quantify the type of penalty that can be sanctioned by a regulatory body;

Table 3 Showing examples researched of industrial incidents leading to large fines

Company and Incident	Fine
(Applebey, 2018) Syngenta Chemicals - Release of over 3.5 tons of dangerous chemicals to atmosphere	£213,041
(Press.hse.gov.uk, 2018) Tata Steel - Release of large vapour cloud of flammable benzole	£970,000 + £70,000 in court fees

These examples although not oil refineries give a clear indication of the potential financial loss in the event of a catastrophic failure. Although due to the exact damage mechanism to 01-WP-3017 this scenario is highly unlikely this research helps to put the magnitude of loss into perspective.

It should also be noted at this point that the refinery go above and beyond recommended guidelines for monitoring of H_2S as every member of personnel on the refinery wear a personal H_2S monitor that alarms at just 5ppm. An example of this monitor is shown in (**figure 3**).



Figure 3 Example of H2S monitor worn by all personnel at the Pembroke plant

10.4 Further Investigation and Research

The author acknowledges the fact that this is a bespoke problem and further reading is only available in the form of applicable codes such as;

- Valero CTEMS section 5.0
- ASME PCC-2 Repair of pressure equipment
- ASME B31.3-2010 Code for process piping
- API 570 Piping inspection code
- API 579-2016 Fitness-for-service
- API 571-2011 Damage mechanisms affecting fixed equipment in the refining industry

These must not be deviated from without a formal risk assessment conducted by the senior staff engineer. Other reading or educational material can only be used to build knowledge around the subject matter, in order to find the best solution for the IAN.

The IAN states that there are a further 12 locations that have not been inspected due to excessive pustular corrosion and scale found. The current inspection method to take piping thickness readings are ultrasonic thickness measurement (USTM). This form of non-destructive testing (NDT) involves a hand held device that measures soundwaves by the time it takes for the soundwave signal to bounce back indicating the material thickness, this is very effective on good material but inconclusive for heavy corrosion. Not knowing these remaining thicknesses due to heavy scabbing on the line presents a potential similar hazard to that of location 12. It would not be best practice to remove the scabbing while the line is pressured up in case a leak were to develop from the process of mechanical descaling. The scabbing shown in (**figure 4**) can however be inspected with an alternative means of NDT.



Figure 4 showing scabbing to 01-WP-3017-8"

Radiography can be used to assess RWT. This is not the routine approach to scheduled pipe inspection due to the resource required to carry out the work. This work is also classed as a

hazardous activity due to radiation present from the X-rays. When carrying out this work a thirty meter perimeter has to be cordoned off to allow for the radiation. This will stop any maintenance work nearby for the duration of the NDT work. For work of this type, a later investigation will be conducted to discuss whether or not radiography should be a mandatory requirement when inspecting equipment with this damage mechanism as there is almost a certainty that this will be required.

Results of USTM are usually null and void measuring heavy external corrosion and radiography unless corrosion is removed is un-avoidable. Therefore in this case the area inspection engineer is requested to and completes this work with the in-house NDT contractor. **(Figure 5)** shows two rad shots taken of blisters found at locations 27 and 28 these show remaining wall thickness above T_{min} and in location 28 above PMPT. From the radiography taken it is shown that location 33 has the least RWT of 2.2mm, the thickest was found to be virtually nominal thickness of approximately 8mm. From this information it has become apparent that the unknown areas of the line pose no greater risk than that of location 12.

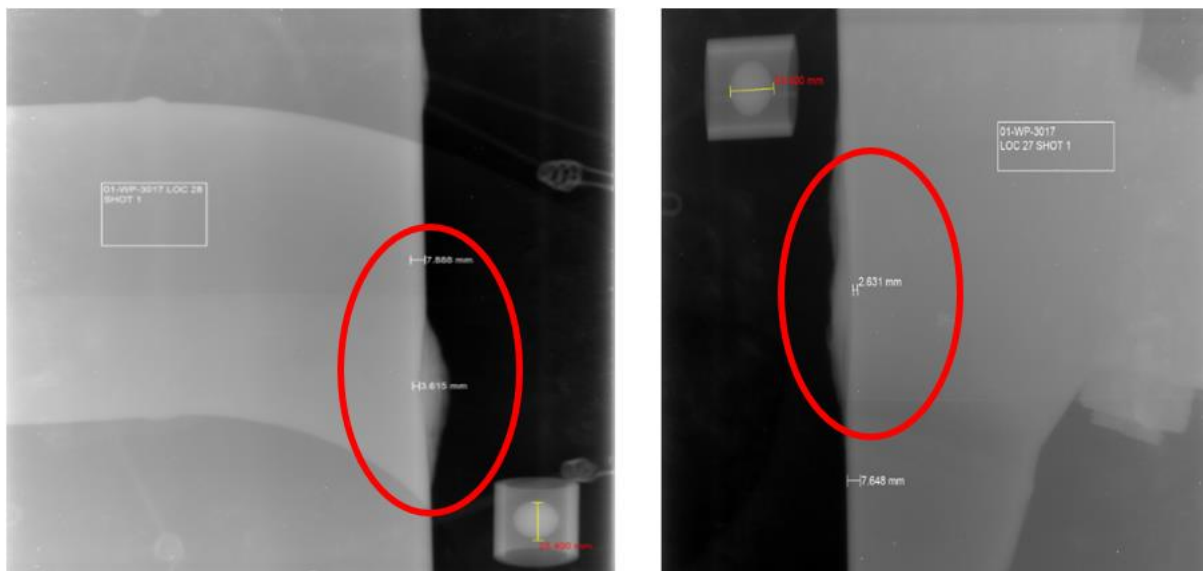


Figure 5 Radiography carried out at locations 27/28 showing remaining wall under pipe blisters

With all required information now established this report can now progress to making decisions on how to mitigate the IAN. Knowing immediate action is required for location 12 and further work required for the twenty seven other locations there are options to discuss in order to achieve safe continued operation on the VDU. These options must consider safety and environment before cost and will use that methodology to make some key decisions. A cross functional team is set up to decide on a logical approach to solving the problem and making recommendations. This team is as per organogram shown in **(table 4)**. Some useful information provided by the author of this report as pre-read before a formal meeting of the below group takes place would be to quantify the cost associated to an unplanned shutdown of the equipment if the line were to fail.

To approach this the author in the role of the integrity coordinator will liaise with the blending and shipping (Complex 02) operations superintendent, who is responsible for running of the tank farm and all of the oil movements in the field. This information will prove crucial to decision making both in the immediate future for the section of line at 0.5mm RWT and other areas of concern.

After the author's discussion with the complex 2 tank farm superintendent it is apparent that sour water, in the event of unit upset, is routed to crude tanks 52 or 53. These tanks have a crude capacity of 28,000m³ which is a considerable volume. However crude does not mix well with process water high in H₂S. It is not desirable to send untreated process water to a crude tank for any long period of time. From the discussion up to 10m³ in a full tank would be acceptable dependant of concentration of H₂S but any more would cause issues when entering the crude processing unit. In this case if the SWS had to be shut down in emergency and the remaining process units remained on then 50m³/hr of sour water would have to be sent to tankage. This would be sent to whichever tank was at its lowest level and could no longer be used for crude storage until the sour water were moved from the tank. With further discussion sour water can only be processed at 2m³ at the sites WWTP, this is due to the ammonia in the water killing the organic media used to biologically break down other compounds. Using the WWTP therefore, does not offer an alternative to the SWS in the event of routing sour water around the unit. The only option that remains is to bypass the process of the SWS and route sour water to tankage. To understand the financial implications this would set on the business, a previous study highlighted by the operations superintendent has been used. Chevron LPO control number 241101/6 is an observation made when in 2006 the SWS tower 01-F-302 suffered from a weld failure on a vacuum support ring. An unplanned shutdown resulted and within thirty minutes the whole refinery's sour water produced was routed to tank 11, which is a large crude tank. The down time suffered from planning and reactively repairing the column was long enough to fill the whole crude tank. The observation and investigation as per LPO 241101/6 seen in **appendix P** concluded that the cost of not having the flexibility of crude storage and the damage that sour water imposes on tank floors bare a cost to this business of £5k/day. In that case the sour water took almost 12 months to process back through the system resulting in a lost profit equivalent of £1.5m. This information is useful for this project as the following could be said;

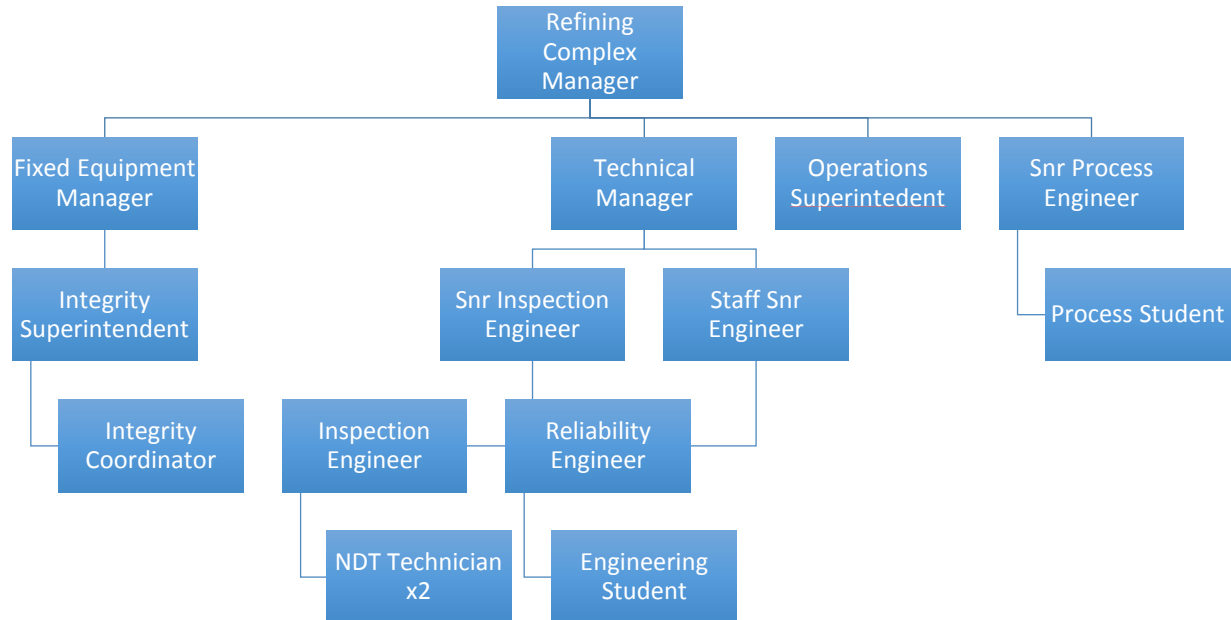
50m³/hr of sour water processed = 1200m³/Day

Therefore 1day downtime = £5000

This is particularly useful for decision making when repair methods are discussed in the team show in (**table 4**). The information can also be used as above in the Pembroke risk matrix (**table 2**) to risk assess the business risk which was presumed lower from the outset.

Business (I) x Likelihood (E) = Level 1 (Undesirable risk)

Table 4 Organogram of team set up to action IAN



11. The Project

11.1 Project Team and Meeting

As seen in (**table 4**) a large team is required to decide the best possible action to take with regards to action an IAN of this magnitude. Although each member will not be fully involved in the process, each member's expertise will be required to look at the potential options. After an IAN pre-read has been conducted a meeting takes place where a cross functional team to discusses options for SME's to investigate. The role of the integrity coordinator is key as this member of the team will be responsible for coordinating any work or actions that are generated by the meeting. Whereas it is the fixed equipment manager and complex manager to formally respond and agree to the actions needed for the IAN, the integrity coordinator is mainly responsible for making sure these actions are completed within the due date set.

Due to the urgency of topic one, an immediate meeting is called. There are two topics to discuss;

- **Topic one-** Action required for location 12
- **Topic two-** Options to action all other locations

From this meeting for **topic one**, it was decided a temporary repair as per ASME-PCC2 would be installed to mitigate the immediate risk posed by the section below T_{min} . This was to be measured, designed and installed on urgent basis. From discussions in the team, a mechanical clamp was the only option due to the fact design temperature was above the 125°C temperature rating of a composite wrap. Installing a wrap would not conform to ASME PCC-2. Other options were not given more thought, due to the time scale and cost. From the experience within the group to 'swoop down' and route the sour water to storage and carry out a quick but permanent repair, it was estimated that for operations to prepare the line for hot work the pipe section be replaced, inspected and RTS it would take approximately 3 days. This repair would be in the region of £10k plus the LPO of £15k caused by sending sour water to tankage. **Topic two** the remaining defects listed in the IAN were discussed by all parties. It was decided that using the matrix from (**table 2**) the risk of running with these defects came out at tolerable risk (TR). The advised action from the matrix recommends action to be taken to lower this score. Within the meeting using repair methods deduced from ASME PCC-2 the following options were decided to be explored for suitability;

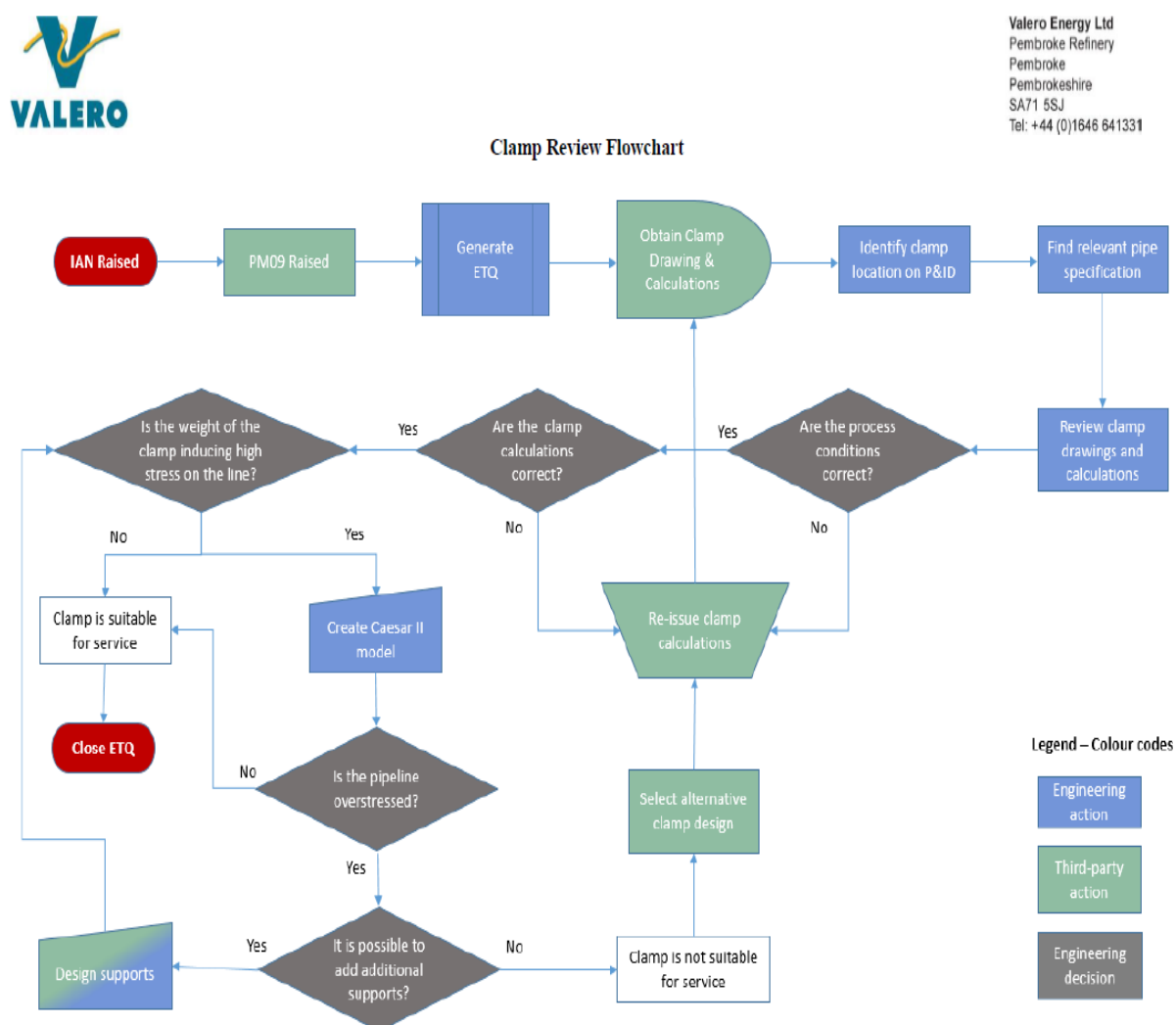
- 1) **Carry out FFSA 1 or 2-** This would involve further work than calculating pressure containment but to assess the mechanical strength of the line taking into account condition of supports, vessel nozzles and condition of the line.
- 2) **Install further temporary repairs-** Install mechanical enclosures to locations listed in IAN. Investigate the extra loading this would add to the remaining line.
- 3) **Take the equipment out of service-** Investigate the potential difficulties in taking the equipment out of service (OOS) in order to carry out a full line replacement.
- 4) **Live line welding-** Weld patches over the defects in accordance with ASS-PCC2 guidelines.

Each of these options, all endorsed by the whole team, are to be investigated with the integrity coordinator. It is possible for one or more of these options to be implemented.

11.2 Immediate Action

As discussed in section 11.1, **Topic one** requires immediate action. The decision of fitting a mechanical enclosure (repair clamp) to mitigate location 12 of the IAN is to be actioned as an urgent priority due to the risk of operating with a line below T_{min} . At the time, from the author's point of view the process of installing a temporary repair was not clearly defined. To aid the author and with guidance from the engineering team a flow diagram was constructed using MS Visio of which can be seen in (**table 5**). This shows the workflow process that has to take place in order to install the mechanical clamp.

Table 5 Pembroke temporary repair clamp procedure



Once the line has been measured up in the field at location 12 by the leak sealing specialist Team-Furmanite, this information will then be used by their own offsite engineering house in Holland to design a suitable enclosure for the line. This is then to be reviewed via the engineering technical query process (ETQ). As per PCC-2 guidelines a repair clamp is to be manufactured to ASME-VIII. This code is the code for vessel construction and any proposal received from a leak sealing contractor is to be checked for approval of conformity against that code. This effectively classes the repair clamp as a standalone pressure vessel and not

pipework, this makes some subtle differences to the designs when it comes to materials for construction and (**Figure 6**) shows the pipe defect at location 12.



Figure 6 Corroded section of 01-WP-3017-8" at location 12 with 0.5mm remaining wall thickness

11.3 ETQ Process for Team Furmanite Clamp (T26131)

For the ETQ to take place certain criteria must first be met, this includes;

- PM09 SAP work order raised
- Confirmed process conditions
- Landing areas for clamp to be inspected for acceptable thickness (>5mm)
- P&ID of line
- Pembroke piping specification for line
- CAD drawing and control sheet from Team-Furmanite showing clamp design
- Completed and signed temporary repair form

With all of this criteria met the ETQ process can now review the clamp for approval or rejection. Details of information sent from Team-Furmanite shown in **appendix I**

Taken from ASME VIII the following assessments have been made to check the enclosure is fit for purpose.

Bolting As per ASME-II part D table 3 (A193 Studs B7M and 2HM Nuts)

Control Calculation- (Taken from TEMA bolting chart (Groysman, 2017))

Core Diameter ($\frac{3}{4}$ " UNC) = 15.75 mm (db)

fbolt (taken from control sheet) = 137.9 N/mm²

$$F \text{ Bolt maximum} = \frac{\pi}{4} \times db^2 \times fbolt$$

$$\frac{\pi}{4} \times 15.75^2 \times 137.9 = 26866.8N$$

Therefore total bolt strength = 26.9KN or 2.7 Ton

Bolt Force required due to internal pressure chamber

Surface area of internal pressure supplied by contractor shown in (*figure 35 appendix I*) = 9768.00mm²

Design Pressure as per IAN = 1.37 MPa

Calculated Pressure =1.37MPa

Bolt Force Fb1 = Calculated Pressure X Surface Area

9768 x 1.37=13382.16 N or 13.KN

Bolt Force required due to internal pressure on peripheral seal

Surface area of peripheral seal supplied by contractor shown in (*figure 35 appendix I*) = 667.00mm²

Design Pressure as per IAN = 1.37 MPa

Injection Pressure percentage=5%

Calculated Pressure =5.00 MPa (assuming this pressure when injecting sealant)

Bolt Force Fb2 = Calculated Pressure X Surface Area

667 x 5 = 3335 N or 3.3KN

Total Bolt Force

Bolt Force Total = Fb1 + Fb2

3335 +13382.16 = 16717.16N

Bolt Stress

$$\text{Bolt stress} = \left(\frac{F_{b\max}}{0.25 \times \pi \times db^2} \right)$$

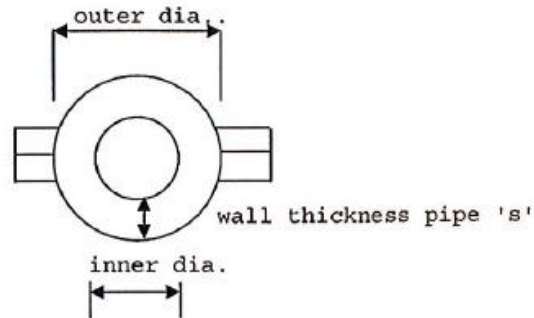
$$\left(\frac{16717.16}{0.25 \times \pi \times (15.75 \times 15.75)} \right) = 85.81 \text{ N/mm}^2$$

This shows that the 3/4" UNC bolting is acceptable for application where allowable stress is 137.9 N/mm², stress calculated in this clamp bolting only sees a maximum of 86 N/mm².

Control Wall Thickness SHELL

ACC. ASME UG 27

scheme:



Min. wall thickness:
acc. UG27

$$t_{\min} = \frac{P_i \times R}{S \times E + z \times P_i}$$

Figure 7 ASME VIII UG27

Taken directly from ASME VIII section UG27 the above calculation in (**figure 9**) gives the correct formula to calculate $T_{\min}$ for clamp shell wall, where;

Table 6 Values required to calculate minimum required wall thickness

P=13.97Kg cm ² g (1.37MPa)	Max design pressure
Pi= 13.97Kg cm ² g (1.37MPa)	Calculated pressure
D= 219.1mm (0.2191m)	Taken from pipe spec PJ164 shown in appendix H (a)/(b)
S= (137.9 N/mm ²)	Max Stress
E=0.6	Taken from ASME VIII UW12
Z=-0.60	ASME VIII (UG-27)
Ri=132.00	Inner radius excluding corrosion allowance
R=133.30	Inner radius including corrosion allowance

$$\text{Therefore } T_{\min} = \frac{1.37 \times 133.3}{(137.9 \times 0.6) + ((-0.6) \times 1.37)}$$

$$T_{\min} = \underline{2.23\text{mm}}$$

Actual wall thickness taken from team CAD drawing = 8mm.

To help validate this information again thin cylinder theory can be applied. Although $T_{\min}$ is established for the cylindrical clamp, stresses could be better understood from either transposing the above equation or using the previously seen formula $\sigma_h = \frac{PD}{2T}$.

$\sigma_h = \frac{1.37 \times 133.30}{2 \times 2.229}$ Therefore hoop stress at $T_{\min}$ is calculated through this at 40.96 N/mm². This result even at minimum thickness is far below the max allowable stress of 137.8 N/mm².

Control Wall Thickness ENDPLATE**CONTROL ENDPLATE ACC. ASME VIII DIV.1 UG34:**

formula: $d = D_{\min} \times \sqrt{\frac{Z \times C \times P_{inj.}}{E \times f_{eind.}}}$

Figure 8 End plate formula taken from ASME VIII UG-34

Table 7 Figures required to calculate endplate thickness

d= min endplate thickness	Unknown and to be calculated
$D_{\min}=264.0\text{mm}$	Smallest span
$D_{\max}=264.0\text{mm}$	Biggest span
$Z= 3.4-(2.4 \times D_{\min}/D_{\max}) = 1$	ASME formula
$C=0.33$	As per UG-34
$P_{inj}= 1.37\text{MPa}$	Design Pressure
$E= 0.6$	Joint efficiency as per AMSE VIII table UW12
$F_{eind}=137.9 \text{ N/mm}^2$	Max allowable stress on endplate
$CA= 1.3\text{mm}$	Corrosion allowance 1.3mm

$$d = 264 \times \sqrt{\frac{1 \times 0.33 \times 1.37}{0.6 \times 137.9}}$$

$$d = \underline{19.51\text{mm}}$$

Minimum endplate thickness required is 19.5mm and actual endplate thickness taken from CAD drawing (**appendix I**) is 40mm.

From these standard calculations taken from sections of ASME VIII, the proposed Team-Furmanite clamp is deemed acceptable and fit for purpose as a temporary repair. To further support these findings a solid works model has been constructed using the CAD drawing and FEA has been completed to back up the calculations. As seen in the FEA study (**figure 9**) the maximum Von-Mises stress observed shows 19.13N/mm^2 , this appears acceptable although well below 137.9N/mm^2 that is specified as maximum allowable stress as per ASME B31.3 table A-1 **appendix F (a)**. The actual thickness is far above the minimum thickness so the clamp will not appear to be overly stressed. It should also be noted that the operating temperature of 149°C has not been accounted for in this static study, neither has any of the forces acting on the clamp from the bolting. The justification for the FEA for this report is to just assess whether or not higher stresses than previously calculated are present which in this case they are not. An SAP work order (5055707) has been entered to progress this clamp which can be seen in **appendix K (a)**.

Model name: George Bagley P148139 Clamp TEST
Study name: Static 1(-Default-)
Plot type: Static nodal stress Stress1
Deformation scale: 2387.23

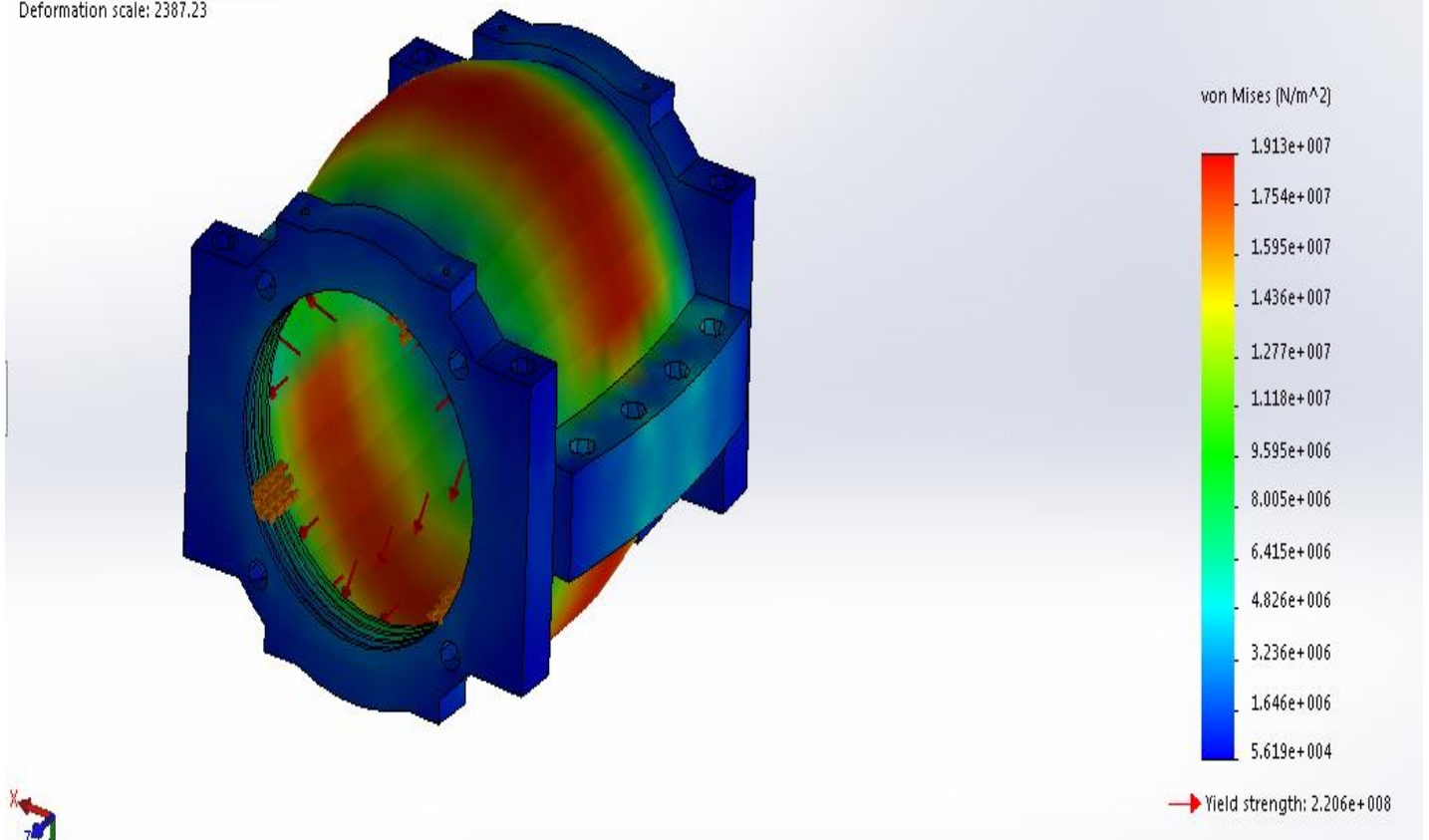


Figure 9 Solid works static study used to validate clamp design calculations

The FEA shown above is set up by fixing the endplate sealing faces to the pipe and applying internal pressure of 1.37MPa to the internal cylinder.

11.4 Clamp fitting

With this in installed as per (**figure 11**) risk has been mitigated and the likelihood of a hazard occurring has been reduced to (**Consequence III x Likelihood AA = BA broadly acceptable**). As this is a temporary repair this has been logged in the plant condition monitoring system (PCMS) which is shown in (**figure 10**). A turnaround SAP work order shown in **appendix K (b)** has also been entered to capture the future line replacement at the next outage opportunity. The total cost of this work was as per SAP work order in **appendix K (a)**;

- £372.96- Site labour for installation support
- £11,376.43- Team-Furmanite engineering costs, clamp fabrication, delivery and installation (with urgent priority surcharge)

Total cost =£ 11,740.39

Fitting of the clamp involved the following work;

- Unit crane to land the hardware at location
- 2x leak sealing technicians to loose bolt the clamp to defective location, torque all bolting and inject perimeter seal with sealing compound
- All work done in breathing apparatus as a precaution taken in case leak developed

The screenshot shows the PCMS interface for a temporary repair clamp. The breadcrumb trail at the top indicates the location: IWR > 01 > PIPE-CAT 2 > 01-WP-3017 > 01-CC-079 > 0X7030 /0X6976.

Identification:

- IWR No.: 0X7030 /0X6976
- Component: 01-WP-3017
- Circuit: 01-CC-079
- IWR Type: TEMP
- Headline: 01-WP-3017 331-LS-402545 8" Clamp

Reference:

- Event: [Dropdown]
- Event Rpt Category: [Dropdown]
- Schedule: [Dropdown]
- ☐ Permanent Template

General:

- Req. Completion Date: [Dropdown]
- Priority: PM04
- Work Type: Temp Box
- M.O.C. No.: [Text]
- Criticality: (N/A)
- Work Constraint: (N/A)
- Addressee: (N/A)
- Add Date: 12/09/2017
- Last Change Date: 14/09/2017
- Latitude: [Text]
- Longitude: [Text]

Status:

- IWR Status: Approved
- Released for Approval: ☒
- Opened By: Bagley, George
- Date: 12/09/2017
- Approved By: James, Neil
- Date: 14/09/2017
- Closed By: [Text]
- Date: [Text]

Figure 10 PCMS data for temp repair clamp fitted to location 12



Figure 11 Clamp installed at location 12 of IAN (Clamp No. T26131)

11.5 Topic 2 Discussion

Now that the immediate risk has been lowered from the application of a mechanical clamp to location 12 and no further defects have a RWT less than calculated for pressure containment, attention can be focused towards the rest of the defects highlighted in the IAN. As previously shown, the cross functional team discussed four possible methods of mitigation to lower the present risk. These will now be discussed.

11.5.1 Fitness for service

According to API 579 which is the enforced fitness for service code to be used as per CTEMS, there are three levels in which this assessment can be carried out. For this particular assessment the defects have been categorised as localised metal loss referred to in the standard as local thin area (LTA). For the assessment to be carried out section 5.2.4 must also be satisfied, for this the sites materials SME must confirm the line does not operate in the creep range. The final pre-requisite for the assessment is that the equipment has originally be designed to applicable codes which in this case is API 570 and ASME B31.1. All of which are satisfied.

(Fitness-for-service, 2007) for localised metal loss defects only states;

- **Level 1 FFSA-** The only load considered is the internal pressure applied to one single thickness.
- **Level 2 FFSA-** This allows for a better assessment of the thinned area and takes into account bending moment of a cylindrical object and considers the structural integrity. Taken credit for any structural supports or guides.
- **Level 3 FFSA-** This would normally be carried out by a third party and precisely considers structural metal loss. This would involve a combination of analysis of numerical stress calculations and detailed computational methods in the form of FEA using a program such as CAESAR.

01-WP-3017-8" Assessment

Firstly, to assess each location on in its own merit, the IAN has been updated to include the two additional locations found during the radiography inspections carried out, this now brings the total amount of defects to seventeen. Each location has now been further inspected to highlight the exact extent of the metal loss. Although severe paint breakdown was evident the actual surface area of the localised metal loss has to be quantified to allow for the FFSA procedure to take place. This has been completed for each of the defect locations in accordance with (**figure12**)

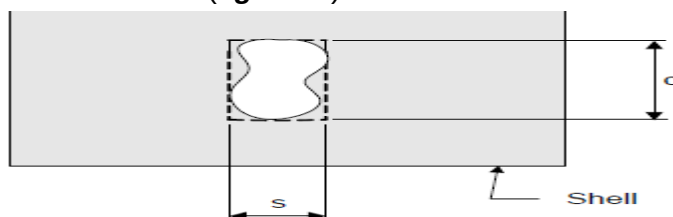


Figure 12 API 579 Assessment criteria for FFSA

This shows the shell or wall of a cylinder/pipe and correct method of sizing of the exact defect later to be used in the assessment calculations. Further USTM inspection is to be completed to compile this data for each location stated on the IAN. With this data known a level 1 FFSA can be completed for each location.

Level 1 FFSA for 01-WP-3017

API 579 Part 5 has been selected as per **appendix J**. This is to assess local metal loss and nothing more.

The procedure requires steps to be met before continuing through the assessment. If a step is not satisfied, the defect fails a level 1 assessment and a level 2 or 3 will be required. As the corrosion is external, the level 1 also assumes, if the defect is to pass, that corrosion is arrested immediately. This is achieved by preparing and repainting the line.

Location 20- This location is at PMPT but has active corrosion present. This as per 5.3.3.1 of the code requires only for corrosion to be arrested and surface protection put in place. Therefore this requires no further action but coating.

Locations 14- This defect has been chosen first to assess, due to it maintaining the largest RWT. The assumption made here is that all of the defects are of similar size so that if this location were to fail a level 1 assessment all others would fail also.

Step by step Assessment.

Nomenclature for this assessment is found in **appendix L**

Step 1- This requires critical thickness profile (CTP) to be determined this refers to (**figure 14**) and establishing the S and C values.

S=20mm

C=22mm

Step 2- Determines wall thickness to be used in calculations

$t_c = t_{rd} - \text{FCA}$ (Future corrosion allowance of 0.163mm calculated from inspection data)

Step 3- Show minimum measured wall thickness in the LTA, t_{mm} and dimension S

LTA= 2.8mm

t_{mm} = 6.3mm

S= 20mm

Step 4 determines remaining thickness ratio and longitudinal flaw length using the following equations;

$$R_t = \frac{t_{mm} - FCA}{t_c} \quad \text{So; } R_t = \frac{6.3 - 0.163}{6.3} \text{ and } \lambda = \frac{1.285 \times 20}{\sqrt{202.72 \times 6.3}}$$

$$\lambda = \frac{1.285}{\sqrt{Dt_c}} \quad R_t = 0.974 \quad \lambda = 0.719$$

Step 5 states the criteria for the flaw size that must be met for the assessment to continue

$$R_t \geq 0.20$$

$$t_{mm} - FCA \geq 2.5 \text{ mm (0.10 inches)}$$

$$L_{msd} \geq 1.8\sqrt{Dt_c}$$

For this case;

$$R_t = 0.974$$

$$t_{mm} = 6.3 \text{ mm}$$

$$L_{msd} = 1.8\sqrt{202.72 \times 6.3} \text{ therefore } L_{msd} = 64.32 \text{ mm}$$

All of the above meet the criteria for the assessment to continue.

Step 6- For LTA type thinning this step is not required

Step 7- determine max allowable working pressure (MAWP) using thickness from step 2.

This has already been established as part of the t_{min} calculated earlier in the report however this formula can be transposed to confirm MAWP is acceptable

$$P = \frac{t \times 2(SEW) + (P\gamma)}{D}$$

$$\frac{2.7 \times 2(20 \times 1 \times 1) + (1.37 \times 0.4)}{219.08} = 3.401$$

Therefore using this formula shows with 2.7mm RWT MAWP would be 3.4MPa (Max Design = 1.37MPa)

Step 8- States proving the equipment operates below MAWP calculated and the following table is used and results for values R_t and λ give reading above the curve in **(figure 13)** the equipment passes a level 1 FFSA.

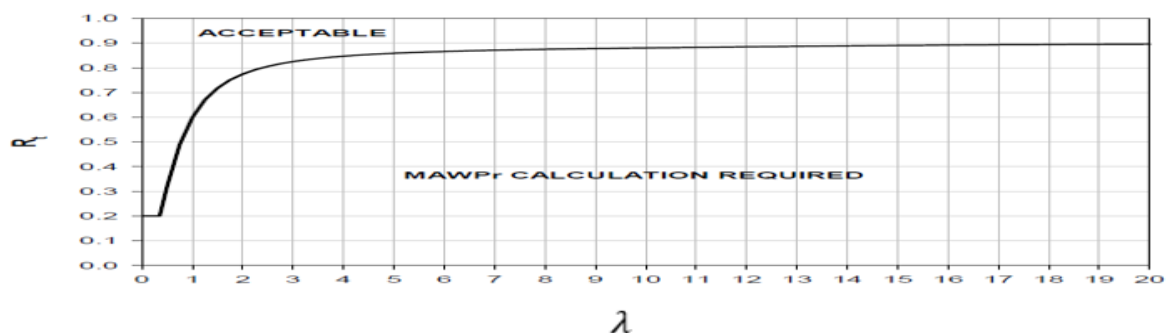


Figure 13 API level 1 FFSA assessment criteria

For corrosion found at this location the following values were calculated $R_t = 0.974$ $\lambda = 0.719$ and using this data with the above table it would be clear to state that the defect at location 14 passes a level 1 FFSA. It should be noted that, during this calculation, it was discovered by the author that step 5 requires a RWT of above 2.5mm which includes FCA. This is particularly interesting due to the amount of locations listed in the IAN that are below 2.5mm RWT. The above level 1 FFSA was carried out for each location that satisfied step 5 criteria and each location passed a level 1 FFSA. A pre-read of a level 2 FFSA later also shows that the same criteria must be met in order to continue with that assessment also. Knowing this information, another method of mitigation must be found for the remaining defect locations.

Further Assessment

To help understand further the condition of the remaining defects some calculations can be made outside of the API579 assessments. These can be used to understand mechanical stress on the line under certain conditions. The worst case scenario will be assumed for this assessment. The 32m line will be assumed to be filled with water and the thinnest section will be calculated at the top of the line. Rather than localised metal loss, complete circumferential loss will be assumed.

Locations 23 and 11 have the largest observable metal loss with a RWT in patches of just 1.5mm although these are not at the top section of the vertical line. This will be assumed to give the worst case. This model is set up by using the following

$$STRESS = \frac{FORCE}{AREA}$$

The calculated stress can then be compared back to the max allowable stress stated per ASME table –A1 seen in **appendix F (a)**. For this calculations the following values have been used;

- Force= from pipe data pro **appendix H (b)** weight of line is 74.77kg/m line is 32m in length and gravity taken as 9.81. ($74.77 \times 32 \times 9.81 = 23471N$)
- Area- Cross sectional area of pipe (CSA) where OD 204.22 (ID+ Remaining wall as per IAN) and ID is 202.72

$$\frac{\pi D^2 - \pi d^2}{4}$$

$$\frac{131022 - 129105}{4}$$

Remaining CSA= $4.79 \times 10^{-4} \text{ m}^2$

So;

$$\sigma = \frac{23471}{4.7941 \times 10^{-4}}$$

$$\sigma = 48.9 \text{ N/mm}^2$$

These calculations can be supported by using an FE solver such as solid works CAD simulation package. The results below validate the previous calculations. (**Figure 14**)

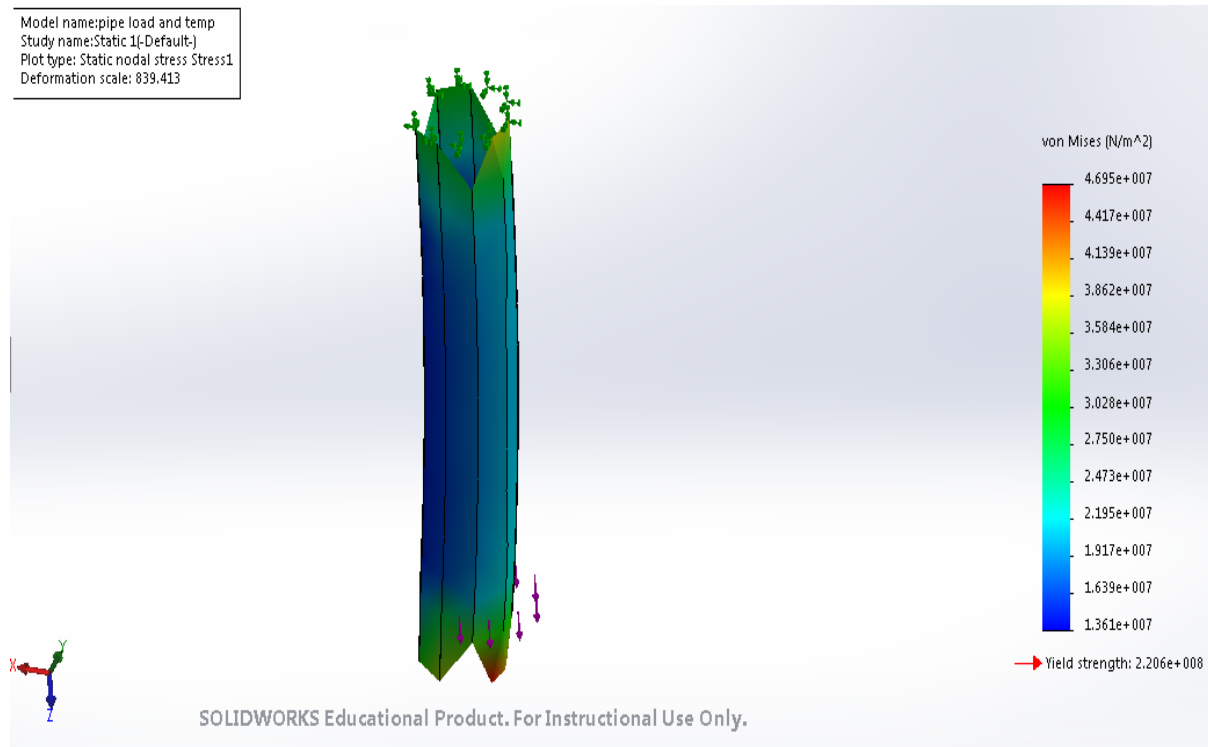


Figure 14 Validation of calculations using solidworks simulation

In this study the line has been modelled by creating a 32m section with a uniform thickness of 1.5mm the same as IAN locations 23 and 11. For the simulation, the model has been fixed at the top with a load of 23kN applied throughout acting downwards. The FEA delivers some very similar numbers to that of the basic calculations. 46950000 N/m^2 which converts to 46.95 N/mm^2 . Due to some rounding errors and the fact solid works assumes material properties, this FEA study helps to validate the information calculated for the problem. What is of particular interest in this model is that, if further conditions are applied to the problem, the material shows signs of failure. If design pressure and temperature as stated on the IAN are applied to the same model the material is close to its yield strength and a considerable amount beyond the max allowable stress as stated in API 579. This will later be considered when making recommendations.

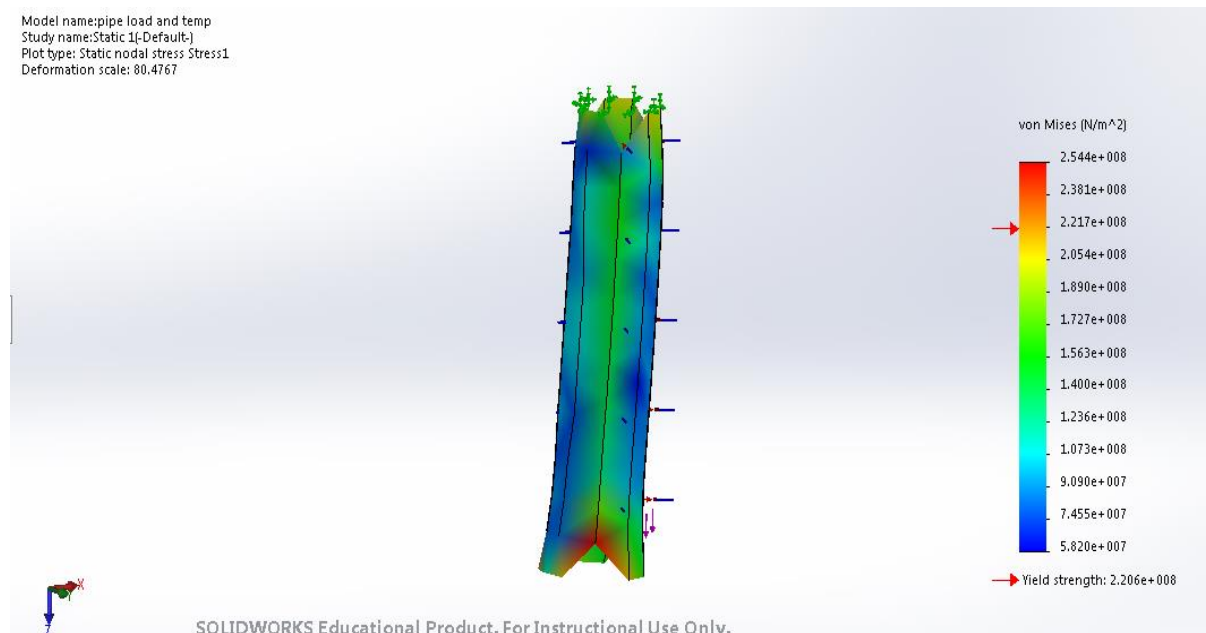


Figure 15 FEA study with design pressure and temperature applied

Fitness for service results

From the studies above it can be concluded that each location with 2.6mm RWT passes a level 1 FFSA. This has helped limit the work potentially required to satisfy the recommendations of the IAN. For all areas including and below 2.5mm further actions will have to be taken. **Appendix M** shows updated information regarding a pass or fail of FFSA. A total of six locations meet API 579 and are deemed fit for purpose leaving eleven areas to still action. It should be noted that although six locations have passed FFSA this does not mean no further action is required as CTEMS section 5.0 states that, whether or not a line is fit for safe continuous use, if it falls below PMPT it must be replaced at the next maintenance opportunity. For this to happen a turnaround work order is to be raised to have the sections of line replaced at the next interval the equipment is planned to be offline. An immediate action that must also be satisfied, is to arrest and paint the active corrosion. This can be completed with simple hand tools, treated with a rust inhibitor solution and then coated with a suitable hand paint.

The results show that sections at and below 2.5mm would fail a formal API 579 fitness for service of any level. It is however, interesting to observe that with the use of FEA and basic hand calculations, even taking into account the worst case for remaining thickness, the line can still cope with the stresses potentially subjected to it. For a level 3 FFSA assessment to take place a highly detailed assessment would have to take place and would require very precise modelling of the line. In this author's experience, the costs of this would be in the region of £50k. For the external services and utilising internal resource to gather the required information would be approximately £10k. This is something that could be considered after looking at the other options discussed previously in the team.

11.5.2 Installing Further Temporary Repairs

Another logical approach for continued safe operation would be to install additional repair clamps to the line. There are some considerations to be made however. Firstly, the line already has three clamps installed. The one at location 12 from this report and two prior to this. There are a remaining eleven locations to address that do not meet FFSA and although from some basic FEA the line did not appear to be stressed, the extra weight should be taken into consideration. The clamp fitted to location 12 weighed approximately 50kg if it was assumed a further eleven clamps were to be fitted then the line should be modelled accordingly with an additional weight of 550kg added. Without incurring further costs from Team-Furmanite measuring and designing these clamps a sound estimate can be made to aid the decision making process. The clamp fitted at location 12 was invoiced to the work order for approximately £12k this was a basic clamp but was engineered and installed on an urgent basis. Premium manufacturing costs around 50% more than planned so it could be said that each clamp would cost in the region of £6k bringing the total cost of fabrication and installation of the eleven clamps to £66k. It is duly noted that this is not a permanent repair and these clamps will have to be removed at the next maintenance outage planned for 2020 or 2023 as per ASME PCC-2 guidelines. The IAN will remain open but mitigated by the clamps until that date. Costs of removing the clamps will be similar to the cost of the line replacement minus the chemical cleaning and losses suffered from sending sour water to store.

11.5.3 Taking the equipment out of service

From a maintenance perspective, taking the equipment OOS for a full repair would be the most logical option. The line would be cut out and replaced like for like and then returned to service with no further action required but to paint the remaining tie-in field welds. This, although the best method of repair, comes at a cost to the business. Firstly, to understand how long the work would take will help to calculate the true cost, using industry norms and to ASME b31.3. The cost to the business of a complete line replacement this is shown in (**table 8**).

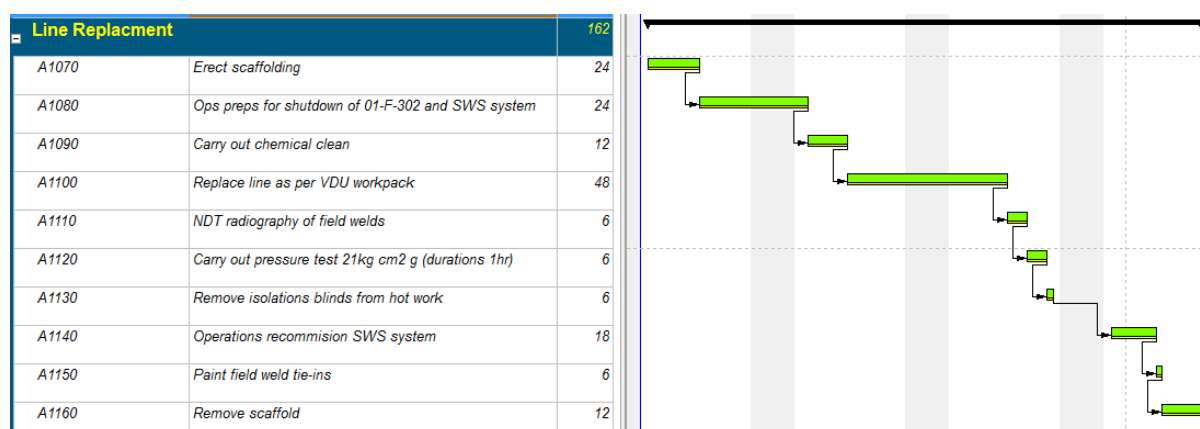


Figure 16 Timing plan for replacement of 01-WP-3017

From studying this plan it can be seen that, to take the unit offline to carry out the line replacement, would be a duration of five days from start to finish. There is a direct cost of labour and materials for this work but there is also cost of chemical cleaning to prepare the system for maintenance as 'sweetening' of the unit is required before mechanical work

commences due to the potential residual high PPM H₂S. To support the plan shown in (**figure 16**) a cost estimate has been completed this also considers the cost of sending sour water to storage. As previously discussed.

Table 8 Estimated cost of line replacement

Description	Cost
Scaffold Services	£9,900
Painting Services	£5,500
Crane Services	£1,320
Mechanical Labour Requirements	£13,200
Inspection	£330
Operations Support	£2,300
Chemical Cleaning	£18,000
Materials and Fabrication	£30,000
Cost of Sour Water to Store	£25,000

Using the site average for cost of labour estimated from the job plan (**figure 18**) above estimates the total cost to the business of £105,550. The big advantage of completing this work is that no further action is required and the IAN could be closed.

11.5.4 Live Line Repairs

Live line welding is an acceptable practice at the Pembroke refinery this involves welding on in service equipment. This practice is highly risk assessed and controlled with detailed risk assessed method statements, operating instructions and weld procedures.

ASME PCC-2 list a number of different methods of repair for this, which are;

1. External Weld Overlay-Building up of metal loss using welding
2. Welded Box Repair- Welded box similar to a bolter clamp
3. Partial Encirclement Reinforcing Sleeves- Sleeve less than half pipe diameter
4. Full Encirclement Reinforcing Sleeves- Restoring structural integrity to pipeline
5. Fillet Welded Patches- To address localised metal loss where weld overlay is not acceptable.

To carry out any one of these repairs, the refineries risk management committee RMC would have to be informed of intended repair method. Once informed, the committee would then hold a meeting to review all of the safety procedures and the proposal method. A pre-requisite of carrying out live line repairs is that the RWT is $>5\text{mm}$. With this being the case, weld build up by overlay welding would not be possible. This immediately discounts option one. It should also be noted that sleeve repairs which equal half the pipe diameter or more are classed as a temporary repair. Again, if work of this magnitude is to be carried out it is not desirable to be installing a temporary repair for it later to be removed at next outage. This leaves one possible solution of live line patch repairs. A final check to comply with API 570 section 8.1.4.1 is that the max allowable stress of the line is not above 275 N/mm^2 . Which in this case it is not and for this line is 137.9 N/mm^2

11.5.5 Live line patch repairs

ASME boiler and pressure vessel code. (2015) states in article 2.12 that this type of repair is best suited to vessel or pipe walls subject to localised metal loss. It involves fillet welding of a size on size fitted patch equal to or exceeding the original thickness of the parent component and of the same metallurgy. The patch must be designed assuming through wall conditions from the parent pipe surface and be designed for full pressure containment. An example of a repair patch installation is show below in (**figure 17**).

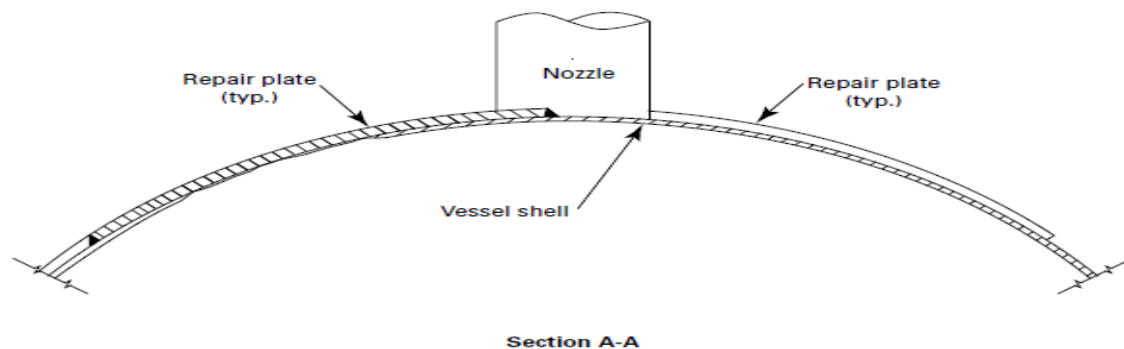


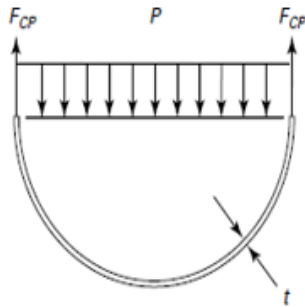
Figure 17 ASME PCC-2 welded repair patch

Section 3.2 of the code states that credit can be taken for both the patch and the remaining pipe wall. For this report if it were assumed that the thinnest location be taken for worst case, this would be the nominal wall thickness supplied by the patch plus the RWT of the pipe

8.18mm (Nominal) +1.5mm (Lowest RWT) = 9.68mm.

From the previous FFSA this would be acceptable thickness but can be checked with the specified PPC-2 Calculations as shown (**figure 18**) this is to be checked as the calculation specifies the midpoint and not the full thickness.

(1) Circumferential Load. Unit forces in hoop direction:



$$F_{CP} = \frac{PD_m}{2} \quad (1)$$

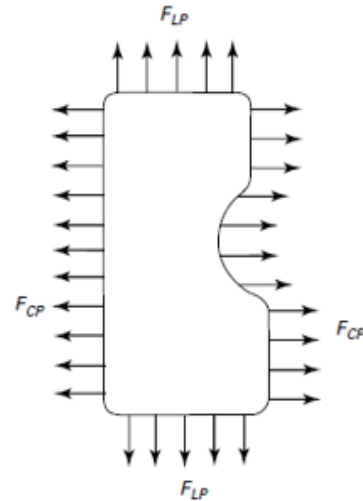
where

D_m = diameter at mid-wall of component, mm (in.)

F_{CP} = circumferential force due to internal pressure, N/mm (lb/in.)

P = internal design pressure, kPa (psi)

(2) Longitudinal Load. Unit forces in longitudinal direction:



$$F_{LP} = \frac{PD_m}{4} \quad (2)$$

where

F_{LP} = longitudinal force due to internal pressure, N/mm (lb/in.)

Figure 18 PCC-2 section 3.2 internal pressure load calculations

Using the above equations the following is calculated;

$$F_{CP} = \frac{1.37 \times 212.4}{2}$$

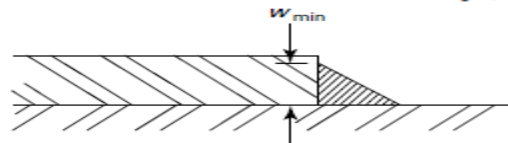
$$F_{LP} = \frac{1.37 \times 212.4}{4}$$

$$F_{CP} = 145.494 \text{ N/mm and } F_{LP} = 72.747 \text{ N/mm}$$

One final check for application of patches is maximum load on the fillet weld. This stipulates that the perimeter weld is to exceed the allowable load of both circumferential and longitudinal loads. This is given by formula in (**figure 19**).

3.4 Allowable Load on Perimeter Fillet Weld

(a) The perimeter weld shall be sized such that the allowable load on the weld exceeds the longitudinal and circumferential loads in accordance with eq. (4).



$$F_A \geq w_{\min} E S_a \quad (4)$$

where

- E = weld joint efficiency factor (0.55)
- F_A = allowable force on fillet welds, N/mm (lb/in.); $F_A > F_C$ and F_L
- S_a = allowable base metal stress, MPa (psi)¹
- $w_{\min}$ = minimum weld leg dimension, mm (in.)

Figure 19 Patch fillet weld joint deficiency calculation

Calculations can be made to help understand whether or not the welds of the patch have sufficient strength to cope with the yield strength as specified in ASME B31.3 table A-1 (**appendix F (a)**) of 137.9 N/mm²

Using the above formula, the following is established. Note that for this calculation a 6mm fillet ($w_{\min}$) is selected due to the authors experience in welding procedures and techniques.

$$F_a > w_{\min} E S_a$$

$$F_a = 6 \times 0.55 \times 137.9$$

$$F_a = 455.07 \text{ N/mm}^2$$

This far exceeds F_{CP} and F_{LP} , therefore the mechanics of this application to install welded patches seems acceptable providing a suitable welding procedure is put in place and approval is given by the RMC. It may also be noted the fillet may be much smaller than 6mm if required.

Now that the application is deemed fit for purpose the costs can now be discussed. For this to be completed, using estimated costs generated from industry norms and after discussion with the Pembroke fixed equipment planning department shown in (**table 9**), estimated cost is just £30k which includes in-situ painting of the line to arrest any further corrosion. Unlike the line replacement, there is no requirement to shut the system down as this would be completed on the run as live line welding. Therefore there is no requirement for operations support or chemical cleaning. Inspection and painting costs are higher due to the fact that the line will be painted in the unit and not in the fabrication shop.

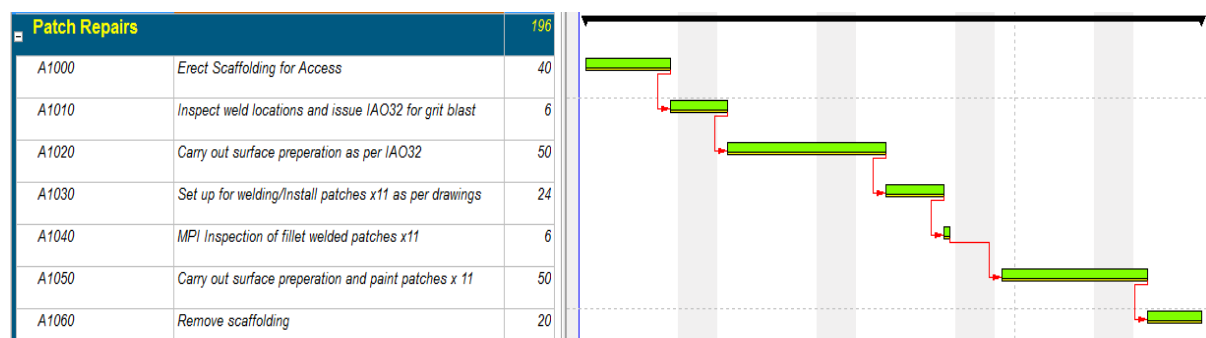


Figure 20 Timing plan for patch repairs

Table 9 Cost of ASME PCC-2 live line patch repairs

Description	Cost
Scaffold Services	£9,900
Painting Services	£11,000
Mechanical Labour Requirements	£5,280
Inspection	£1,320
Materials and Fabrication	£2,500

Unfortunately although this is a welded repair, it has been discovered that under API 570 section 8.1.4.1. Initially the author assumed that if the patch was less than half the pipe diameter, the repair would be classed as permanent. This however from working with the engineering team, was highlighted not to be the case as the code states in the relevant section (Process piping. (2011) a temporary repair may be made by fillet welding a properly designed split coupling or plate patch over a pitted or locally thinned area. (**Figure 21**).

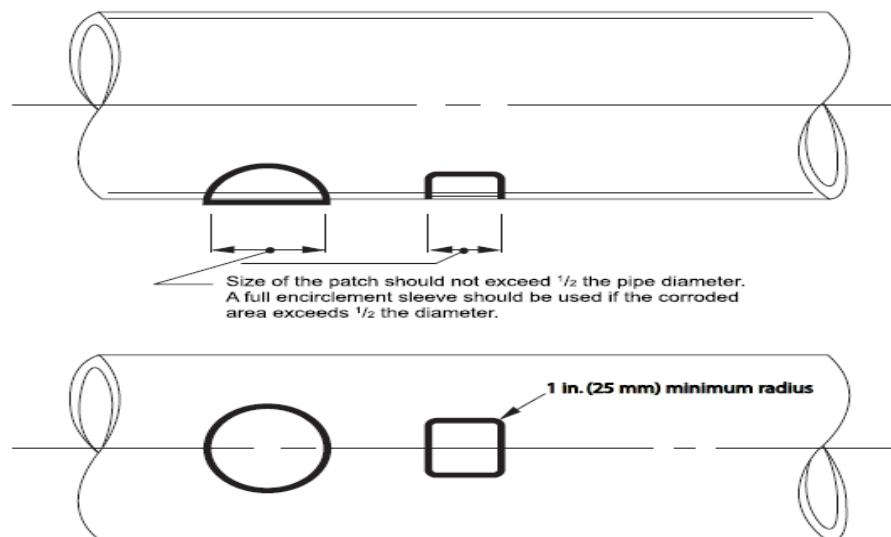


Figure C.2—Small Repair Patches

Figure 21 API 570 Example of a welded repair patch

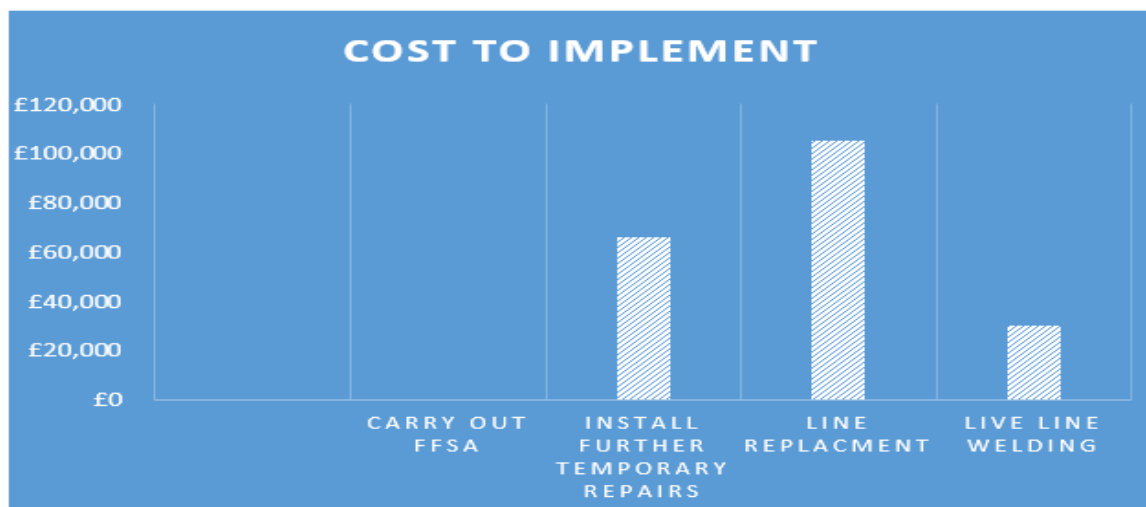
12. Summary of results

As originally discussed by the cross functional teams, four possible options were to be explored and given merit. The four options have each now been discussed. Before any recommendations are to be made the findings are to be tabulated below for better interpretation. The risk matrix used in (**table 2**) has also been used to categorise how each option would lower the current risk.

Table 10 Showing different risk scenarios dependant on repair method

Method	Cost To Implement	Class Of Repair	Hazard Score After Completion
Carry Out FFSA	£0	Temporary	III x B = TR
Install Further Temporary Repairs	£66,000	Temporary	III x A = TR
Line Replacement	£105,550	Permanent	III x AAA = BA
Live Line Welding	£30,000	Temporary	III x AA = BA

Table 11 Cost to implement each repair strategy



From this data, if the complete line were to pass a FFSA it would be the most cost effective way to continue with running the equipment in the short term. However, as this is only temporary, cost would be incurred at next outage. Unfortunately as proved, not all sections passed this assessment. It's also shown as zero cost due to the fact the author, with guidance of the engineering team, has carried out this work with no external services required. The most cost effective repair from the four options would be the live line patch repairs but this is classed as a temporary repair. It does however lower the risk to BA with one score lower in likelihood of failure compared to that of a clamp. These Results are to now be discussed and recommendations made.

13. Discussions of Results and Work Completed

13.1 Project Learnings and Outcomes

Firstly, the project has guided the author to a much better understanding of ASME and API practices at a much more professional level. This has been achieved by using the Valero risk matrix and applicable codes to solve a real life engineering issue, including sound understanding of how to establish minimum RWT of a line in service using approved API T_{min} Calculations.

After understanding T_{min} , the approval and application of the urgent repair clamp was completed. In conducting this work it was learnt that repair clamps are designed to ASME VIII and not piping code. Maximum design process conditions were specified from the data given in the IAN and used in conjunction with standard formula from the ASME code. The clamp was approved and fitted to the line and the likelihood of a hazard occurring was immediately lowered.

During this stage it was noted the figures used for calculation were maximum design figures and not to the actual maximum operating temperature and pressure values. T_{min} was calculated at 1.08mm but a small patch of the line was found to be just 0.5mm. The question was asked why a pin hole leak was not observed if this was the case. This was then understood better by highlighting the difference in values not for just the design pressure but actual maximum operating pressure, using thin cylinder theory it helped to show how conservative the API codes are in order to make processing plants operate safely.

From further study it was later shown that lines fail a FFSA 1 or 2 if only 2.5mm RWT is present and that a further level 3 assessment would be required if no repairs were carried out. As there is a high cost to this assessment and the potential of the assessment being unsuccessful and failing, temporary repairs and permanent ones were then considered.

One final interesting point that was observed, was the effect of temperature on the A106 grade B carbon steel pipe and how it behaves mechanically, dependant on temperature. Where further assessment is made this should be considered.

13.2 Fitness for service

This process looked the information supplied by the IAN in an attempt to understand whether or not the equipment was still fit for service even with the RWT. This was carried out by using standard assessment criteria in the form of API 579. The positives that came from this assessment were that 6 locations passed a level 1 FFSA due to further investigation of the exact defects using more accurate NDT. This reduced the work scope of actual repairs to eleven locations requiring a physical repair. The level 1 assessment assumes the line is not subjected to structural loading. In this case the line is not supporting another components for example valves, platforms and tie in points. The line is purely just required to support its own weight. A level 2 assessments would have been required if this were not the case. In this instance a level 3 assessment could have been carried out for the sections that failed to meet the criteria of a level 1 or 2 but, due to the cost of the assessment, the team decided this was not economical due to other methods available. Interesting observations were made during the assessment when it came to some theoretical modelling of the line using simulation

software in solid works. A worst case assessment was set up to help support numerical reasoning and, in this case, the results were very similar. The most noticeable observation, however the model changes, were dramatically when design temperature and pressure is applied. In this case the line was actually simulated to fail, which is something a level 1 or 2 assessment would not be able to identify. For this a level 3 assessments would definitely be requested if the line was to be left in its current state. The cost of the level 1 assessment on each area was deemed negligible as no external services were required and all work was done within the team.

13.3 Install further temporary repairs

Further temporary repairs were discussed but concerns were made regarding the extra 550kg of weight that would be added to the line. An assumption made during the assessment was that the top and bottom nozzles the pipework ties into are structurally sound and able to support the weight of the line. If material loss was also observed on these, then a further assessment would have to be made. Cost was also considered for this method and was in the region of £66k. As this would be a temporary repair and because of the extra loading to the line, this repair method was not deemed suitable unless there were no other options.

13.4 Taking the equipment out of service

Understating the cost to the business with regards to taking the equipment OOS was key for this study. After discussion with the operations representatives outside of the core team it was necessary to understand the full implications of routing sour water to storage to be later processed has a direct cost. The cost estimate also assumed no delays in each phase of the plan shown. Assumptions are also made that the sour water sent to store is reprocessed immediately when the equipment is back online to limit the damage to the tank floor. Possible delays could come in the form of inspection of the line and failures of welding picked up during radiography. Although this repair offers the safest operation after being carried out it is also the most expensive. This is potentially offset however, by the fact the repair is permanent and the IAN could be closed.

13.5 Live line repairs

As guided by ASME PCC-2 welded patches installed while equipment is still on line were discussed as an option of repair. Although temporary, from the costs explored these were seen to be a cost effective repair compared to that of a clamp. Calculations were checked as per PCC-2 and the strength given to the line by the patches were acceptable. Further checks were carried out, checking the weld had sufficient strength compared to max allowable stress as per line spec. The cost of carrying out this work was also determined and was approximately one third cheaper than a full line replacement.

13.5 Conclusion of Results

After careful consideration of the summary of results in section 12 and the explanation of work done for each repair method, it can be seen that a live line patch repair is the most cost effective way to allow for safe continued operation of the SWS. This method also brings the risk back down to broadly acceptable. Although temporary, this repair, once installed, can be left in place until either 2020 or 2023. The cost of the permanent repair will not be as high during an outage, as the complete unit is chemical cleaned and no sour water is produced, therefore no process water is routed to tankage. The cost of the patch repair is just £30k but the true cost of the repair is the immediate cost plus the permanent one. This cost has been calculated as follows.

Live Line Patch Repair + (Line Replacement - (Chemical cleaning and tankage penalties))

$$30,000 + (105,550 - (25,000 + 18,000)) = 62,550$$

True Estimated Cost of Repair = £62,550

This repair method has had full endorsement by the complex manager and with this information it is now known the IAN can be set a due date for completion.

This is then agreed upon by the entire team.

The activity of live line welding presents its own hazards which are to be identified and control measures put in place. The main hazard to be considered is burn through during the welding process. This is to be carefully controlled via use of recognised welding procedures. In the past the Pembroke culture has not favoured live line welding over installing clamps. However through justification of cost and careful control of processes and procedures the author has helped towards a culture change, in staff accepting live line welding as a suitable and safe method of practice. This is partly down to demonstrating several live line packs completed safely.

The process of implementing the patch repairs is as follows;

1. Work order raised by Integrity coordinator
2. Engineering services to create drawings and design for each patch location
3. Integrity Coordinator to complete RMC meeting request paperwork and book meeting, forms shown in **appendix O**
4. Chosen contractor to complete risk assessed method statement (RAMS)
5. Planning department to complete job package and order materials
6. Integrity Coordinator once in receipt of RMC approval complete live line welding request form
7. Mechanical work to be completed
8. Follow up work
9. Work order sign off

The intention of this report is to prove and justify that the option of live line welded patches is the most suitable and cost effective. The physical work in the field will be carried out as future recommended work by the integrity coordinator/author.

14. Route Cause Analysis 5-WHYS

As discussed in the workgroup when assessing which method would be potentially suitable to explore further, another requirement requested by the complex manager was to understand how the loss occurred. As already stated, external corrosion is preventable therefore these costs of repair are seen as an avoidable loss to the business. The direct loss being £62550. A loss of this magnitude is categorised as a minor loss as under £250k. However this was deemed as a sizable amount and if lesson's can be learned to prevent similar losses, then this should be investigated. As this type of problem is likely to occur again with other equipment the investigation was given merit. Using the Pembroke loss prevention system (LPS) the loss stated is reported as an entry under the second highest categorised due to it not being a loss >£250k

The near loss investigation (NLI) is entered to state the problem and not the solution. It is the nature of the tool to find a suitable solution by analysing why the loss has occurred. (**Figure 22**) shows this entry along with the time, date and potential value of the loss in US dollars.

IPS

Incident Prevention System

The screenshot displays the '1. LI/NLI Info' section of the Incident Prevention System (IPS) interface. The top navigation bar includes links for gbwk, Worklist, QNLR, LI/NLI, LPO, Form Search, Reports, My Defaults, and Print. The left sidebar lists various investigation steps from 1 to 12, with '1. LI/NLI Info' selected. The main form area contains the following details:

- Control Number:** 2296117
- Status:** Initial
- Responsible Organization:** Turnaround Manager
- Initiator's Organization:** Turnaround Manager
- Severity Classification:** ?
- Actual (LI Only):** [Dropdown menu]
- Potential (NLI & LI):** Cat I
- Sensitive Info or Commercial Incident?:** No
- Costs Impacting Valero:**

Costs	US\$	100000.00
Total Costs:	US\$	100000.00
- Loss/Near Loss Date:** 12/Sep/2017 (DD/Mmm/YYYY)
- Loss/Near Loss Time:** 12:00 (hh:mm in 24 hour format)
- Loss/Near Loss Location:** Vacuum Distillation Unit (VDU)
- Loss/Sub Loss Type(s):**
 - ☒ NLI/NMR
 - ☐ Abnormal Freight
 - ☐ Abnormal Supply Occurrence
 - ☐ Additive Injection (Ext)
 - ☐ Additive Injection (Int)
 - ☐ Agency Warning
 - ☐ Agency Warning - Air
 - ☐ Agency Warning - Health & Food
 - ☐ Agency Warning - UST
- * Loss/Near Loss Description:** IAN 0X6976 for line 01-WP-3017-8" issued identifying several locations below PMPT (3mm) all caused by external corrosion. NLI raised to investigate cause.

Figure 22 Loss prevention NLI investigation for root cause analysis of why IAN was issue

The second part of the IPS tool helps the inputter drill down to the root cause of the original problem statement. The tool requires for the problem statement to be re-entered and then

asks a series of why's until reaching a conclusion that could follow on with a solution that prevents the problem from occurring. Six why's have been used in this case to find the root cause of the IAN being issued. Seen in (**figure 23**) the root cause has been established as the equipment is ageing and, due to poor older painting processes no longer used, the paint has broken down and allowed the bare pipe to be exposed to the elements causing external corrosion.

The Solution for this problem has been actioned upon the author. This is to consider the cost of additional inspection resource vs the cost of unplanned reactive repairs. Lines are inspected to schedules and only corrosion allowances are taken into consideration and not external corrosion. For this damage mechanism, lines would have to receive a non-routine inspection and this in turn would firstly require resource to identify the at risk lines and then inspect them. To track this solution the author plans to construct a SMART action plan by the deadline specified for the solution date. A SMART action plan is again another tool developed to measure certain areas and is an acronym for;

Specific-**M**easurable-**A**greed-**R**ealistic-**T**ime bound = **SMART**

Using this tool as stated by (Yourcoach.be, 2018) it can be used to measure and track pre-agreed realistic goals. An example of the template used is seen in **appendix N** and if the cost to benefit ratio of employing extra resource to inspect at risk lines were positive this tool and its use would be a huge advantage.

12. Solution

Control Number: 2296117
Status: Initial

Root Cause		Control Number: 2296117	Status: Initial
No.	* Describe in Detail WHY the Loss/Near Loss Occurred	1273 Characters left	
1	WHAT? IAN raised for external corrosion to 01-WP-3017-8". Multiple locations are below PMPT with one below t-min Why? Line inspection was only scheduled as per corrosion rate and not taking into account poor paint condition Why? Paint should provide adequate protection to line but in this case it has not Why? Because paint has broken down and failed to offer protection and the pipe has been exposed directly to the elements Why? Potentially poor application or incorrect painting process Why? Because in the past when equipment was new, the importance of paint and protective coatings was not as carefully controlled as it is now Why? Equipment was newer and these type of failures where less likely to occur	☐ Select	
Add		Delete	
Solution(s): How to Prevent Loss/Near Loss from Recurring			
No.	Factor	1810 Characters left	
1	2. Lack of or inadequate procedures	☐ Select	
Person Responsible		Due Date	Compl.Date
Bagley, George (GBWK)		30/Aug/2018	
Supervisor V&V Date			
*Solution:		Investigate current inspection strategy for at risk piping and consider additional inspection <u>resource</u> for non-routine inspections. Develop SMART action plan to measure and track progress.	
Action Taken:(optional - see Help)			

Figure 23 5-WHYS analysis and solution to problem

15. Recommended Future Work

Below are seven key points the author recommends to be carried out as future work. It is recommended that a cross functional team is formed to score each key point in its own merit. These recommendations are to be made time based in the category of, short, medium and long term targets. Each will have an estimated cost and be disseminated to key stakeholders as discussed.

Short Term (0-6 Months)

- **Install welded patches-** The report has only gathered the information analysed and concluded the best possible repair solution. No physical work has been completed other than installing a temporary repair to location 12. For continued safe operation the welded patches must be installed. Although already planned, it is recommended that the current area integrity coordinator carries this work out. The findings of this report are to be shared with the coordinator at the soonest opportunity. The cost of this work has been identified in the report as (£62550) which includes the coating of the line for further protection.
- **SMART action plan-** Emerging from the 5-whys RCA a need to develop a process to better inspect lines that have been identified as having poor painting process's applied. A SMART action plan should be implemented to track this progress and the area integrity coordinator be tasked with overseeing the SMART plan. External corrosion is preventable and the use of this tool will allow for tracked improvement of current processes. This action plan should be considered within six months of issuing this report. The cost of setting up the plan is minimal due to the fact this is part of an integrity coordinators base business to improve work flow processes. In this case no cost has been put to the action.
- **Level 3 FFSA-** The line studied in this report discusses level 1 and 2 FFSA. Whereas some locations passed a level one, others did not meet the criteria for level 1 and 2 due to the fact that taking FCA into account were either below or would be below 2.5mm RWT. It was shown, using some simple mathematical hand calculations and basic FEA that the line was structurally sound according to API codes but when temperature was applied the material was past its max yield point for A106 gr B Pipe. However due to the complexity and the fact a level 3 FFSA is to be done by an external source, a level 3 has not been considered. This assessment is a possibility for the line as the defects are not full circumferential and credit in the FEA or calculations are not given to the RWT around the remaining circumference of the pipe. Therefore a level 3 FFSA could be future work. This information will be passed on to the senior mechanical engineer for further thought. The cost of this analysis can be >£50k

Medium Term (0-18 Months)

- **Temperature-** It is clear from calculations made, that the difference in mechanical properties observed from a pipe at ambient temperature and the actual design temperature of 01-WP-3017-8" vary considerably and should be investigated. This can again be done in house and it is recommended that this be undertaken by current or future engineering students. To be carried out in-house, costs are again negligible.

Long Term (0-60 Months)

- **Paint processes-** As identified, the root cause was failure of coating leading to external corrosion. It is a future recommendation to carry out a survey of all equipment on the SWS to identify similar breakdown of protective coatings and carry out repairs when necessary. This will be set out by the SMART action plan seen in the short term goals. Firstly this will be investigated by the integrity coordinator but the final findings will have to be assessed by either the integrity superintendent or the fixed equipment manager. From the authors experience it would take in the region six months for two additional staff to formulate a method of inspection strategy and carry out the initial assessment of at risk lines. Once in operation this would then form part of a rolling program. Total cost of two additional members of staff to oversee and determine a process initially would be calculated by;
 - Approximate hourly rate =£30
 - Hours worked per week =38
 - No of weeks =26
 - Total cost for two additional staff = £59280

As discussed this would only be the initial set up and further costs would be incurred. This will be discussed further in the next recommendation.

- **Additional Inspection Resource-** If non-routine line inspections were more frequent, bad actors would be identified sooner allowing for immediate action being carried out to arrest external corrosion. It is recommended that the cost of extra inspection resource vs the cost of replacing pipework reactively be examined in greater detail. Moving on from the SMART action plan and the initial assessments, this section considers how to make the complete program sustainable in order to give a valued amount of payback. This recommendation potentially will require endorsement from the technical and maintenance director as this may require a complete team of new employees to make this successful. As an estimate the author has suggested the members of a team that would execute work of this type. Using a similar estimating method as above the total to implement this team per year would be in the region of £300k. These findings are to be discussed in greater detail with key stakeholders. The potential payback of this at this stage is un-quantifiable but this will need to be clear before discussing. 01-WP-3017-8" is just one 32m section of line and the cost of replacement is over £100k if hundreds more of at risk lines are identified the cost to benefit ratio would be considerable.



Figure 24 Organogram showing theoretical team required to inspect at risk pipelines

- **Clamp optimisation-** During the assessment of the Team-Furmanite proposal of the mechanical clamp fitted to location 12 stated on the IAN, calculations highlighted the

fact the pressure containing end plate was double the required thickness and the clamps shell wall was over four times thicker than required. API/ASME code does not specify a safety factor for these dimensions therefore, any more material than stated for pressure containment other than for FCA is unnecessary. Recognising this, there is an opportunity for topology optimisation of future clamps and this could be discussed with the current leak sealing contractor Team-Furmanite. This information has already been passed to the fixed equipment manager, including the observations made in the calculations for the clamp installed at location 12. This work should, in theory, have zero cost to the business and any improvements made could be expected as part of the service provided by Team-Furmanite.

For each of these recommendations to be passed to the correct stakeholder it has been decided that the author will conduct a series of meetings and presentations in order to satisfy that these recommendations are to be put to good use. The factual information generated throughout the report will aid each stakeholder to make formal decisions when deciding whether or not to act upon them.

For each category or goal the author plans to discuss in the following groups;

Short Term Goals 0-6 (months)

- Fixed equipment engineer
- Senior inspection engineer
- Integrity superintendent
- Integrity coordinator

Medium Term Goals (0-18 months)

- Senior reliability engineer
- Senior staff engineer
- Student engineering team leader

Long Term Goals 0-60 (months)

- Fixed equipment engineer
- Maintenance director
- Technical director
- Team-Furmanite contracts manager

16. Conclusion

The entire objective of this report was to maintain process safety at all times at the Pembroke refinery. This clear objective has been achieved and a number of other valuable recommendations have been made, in the hope to prevent similar scenarios from occurring.

During the project the author in the roll of integrity coordinator, was responsible for coordinating the safest and most efficient method of achieving excellent process safety.

Firstly, the importance of a timing plan to work to was identified and then later constructed so that the report and project both had a formal structure. Without this in place, the author or other members of the team would have not had any clear objectives to work to and deadlines would be unknown.

A quality review of applicable codes and practices have been essential throughout the entire project in order to make any assessments, judgments or recommendations. Mainly API and ASME codes as these are the exact codes oil refineries operate to. When analysing the IAN issued for the defective line it has been clear there are different elements of risk present due to the varying thickness found during the initial inspection. It was shown that all work carried out would be as an action created from assessing risk, using the Pembroke risk matrix as seen in (**table 2**). This table was essential to allow the cross functional team to understand what risk was actually facing them.

From the initial assessment of line 01-WP-3017-8" it was clear from research the author as integrity coordinator was dealing with atmospheric corrosion. This was a frustration shared by the team as the internal process was not the damage mechanism but breakdown of surface coating and the location of the equipment with respect to the elements such as the sea and the rain were the main contributing factors to the failure mode.

From reviewing the IAN and using minimum thickness calculations in accordance with API code, it was discovered that immediate action was required at location 12. It was an interesting observation made to try and understand why the component had not already failed. This analysis was undertaken and due to inaccuracy of USTM and the API use of values, the report highlighted that the component had not failed as it was perhaps marginally above actual theoretical T_{min} . This however, was of no great advantage due to the fact this would not been in compliance with the code.

Had no action been taken and a failure had have occurred potential penalties could have been sanctioned similar to those already highlighted in industry using (**table 3**).

With the minimum thickness of the line below code, a mechanical clamp was decided the best immediate action, along with perimeter barriers and permanent gas monitoring. This was decided by the cross functional team after seeing the advantage of analysing figures from a previous study, this helped the team quantify the cost of sending sour water to storage. The clamp proposal was received from Team-Furmanite and assessed by the author for application. Through research and guidance from the Pembroke engineering department the author learned that mechanical enclosures are built in accordance to ASME VIII, which is the design code for pressure vessels and not piping. Using this code allowed the report to use standard calculations as per that code to make a judgment on whether or not the clamp was fit for purpose, which, in this case, it was.

From both the T_{min} and clamp assessment calculations it was interesting to observe that, although the calculations were more conservative, they still both related back to a more simple theory and the formula of thin cylinder theory. This was highlighted through simple calculations to validate the more complex ASME and API formula. The simple thin cylinder theory was perhaps even more useful to understand max allowable stresses observed.

The author using knowledge of CAD and FEA verified these hand calculations and very similar results were shown. This gives confidence in both the formula used and the quality of the FEA boundary conditions. When using the FEA for the pipe section it was discovered the results were very similar for both methods. However when simulating the same conditions in the FEA but adding the max design temperature, which is something not accounted for in the formula, with the RWT assumed at just 1.5mm the study then looked at what difference temperature made. In this case for A106 GR B pipe the difference was significant and although formula predicted the line fit for purpose, the FEA suggested that the material was above ASME b31.3 max allowable stress and very close to the max yield stress of the material chosen in solid works. In the authors opinion this led to a good recommendation for future work to summarise and understand the effects of temperature on carbon steel pipe.

Further assessment was also carried out to the pipe, in the form of a level 1 FFSA. This passed off six locations as fit for service, reducing the overall work scope. The largest and most significant observation made here was that for level 1 and 2 FFSA if a line is below 2.5mm that it will automatically fail the assessment. This is valuable learning for both the author and a large part of the cross functional team. For the assessment to have continued, a much more in-depth and complex level 3 FFSA would have been required which potentially would have been a costly exercise if it still were to fail.

The report has considered process safety as the number one priority throughout but it has also used costings to help make secondary judgements. After meeting to discuss possible actions it was the integrity coordinator who was to go and investigate possible methods of repair and analysing the true cost. In using reliable costing methods and plan scenarios it became apparent that one method was more suitable than others. Although deemed as per ASME-PCC2 as a temporary repair, there was justification of carrying out the live line welding repair over an equipment shutdown, due to the fact it would still of worked out cost effective to install the immediate repair and then complete a permanent repair at a later date. The author has completed several live line welding tasks which has helped instil confidence among the safety and risk management committee. The change in culture moving towards live line welding as opposed to mechanical enclosures is a welcomed one among many departments at Valero Pembroke.

Finally to conclude, using the RCA tool available at the refinery to help analyse why the failure had occurred in the first place, led to a recommendation to treat the root cause of the IAN. This then led into some other recommendations being made that align with the same topic. These other recommendations, originally not apparent until the report and study evolved were also noted. The author feels that further opportunities are apparent from this report and that the report only attempts to solve just the process safety element, which in this case it has succeeded.

From the recommendations it is clear that work needs to be done in and around the topic of identifying at risk lines and equipment. It is clear that the weather and location of the refinery in relation to the sea air has a huge impact. This is even more evident from studying the photograph taken of the temporary repair clamp installed at location 12 (**figure 11**). This was only installed just 4 months prior to the author's photograph and already, due to limited weather protection, the bolting and the clamp have begun to show signs of corrosion.

Although there is currently a team working on equipment preservation at the refinery, pipelines do not perhaps get the focus they deserves and this needs to be addressed if future prevention of external corrosion is to be achieved.

17. References

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18. Appendices

Appendix A (General lay out of VDU and sour water stripper column)



Figure 25 01-VDU Shown from east side of unit



Figure 26 General arrangement of SWS

Appendix B (Overview of the effects of H₂S on the human body)

Table 12 Effect of H₂S on the human body

Health Hazards

Hydrogen sulfide gas causes a wide range of health effects. Workers are primarily exposed to hydrogen sulfide by breathing it. The effects depend on how much hydrogen sulfide you breathe and for how long. Exposure to very high concentrations can quickly lead to death.

Short-term (also called acute) symptoms and effects are shown below:

Worker Exposure Limits	Concentration (ppm)	Symptoms/Effects
NIOSH REL (10-min. ceiling): 10 ppm	0.00011-0.00033	Typical background concentrations
OSHA PELs: General Industry Ceiling Limit: 20 ppm General Industry Peak Limit: 50 ppm (up to 10 minutes if no other exposure during shift) Construction 8-hour Limit: 10 ppm Shipyard 8-hour limit: 10 ppm	0.01-1.5	Odor threshold (when rotten egg smell is first noticeable to some). Odor becomes more offensive at 3-5 ppm. Above 30 ppm, odor described as sweet or sickeningly sweet.
NIOSH IDLH: 100 ppm	2-5	Prolonged exposure may cause nausea, tearing of the eyes, headaches or loss of sleep. Airway problems (bronchial constriction) in some asthma patients.
IDLH: immediately dangerous to life and health (level that interferes with the ability to escape) (NIOSH)	20	Possible fatigue, loss of appetite, headache, irritability, poor memory, dizziness.
PEL: permissible exposure limit (enforceable) (OSHA)	50-100	Slight conjunctivitis ("gas eye") and respiratory tract irritation after 1 hour. May cause digestive upset and loss of appetite.
ppm: parts per million	100	Coughing, eye irritation, loss of smell after 2-15 minutes (olfactory fatigue). Altered breathing, drowsiness after 15-30 minutes. Throat irritation after 1 hour. Gradual increase in severity of symptoms over several hours. Death may occur after 48 hours.
REL: recommended exposure limit (NIOSH)	100-150	Loss of smell (olfactory fatigue or paralysis).
	200-300	Marked conjunctivitis and respiratory tract irritation after 1 hour. Pulmonary edema may occur from prolonged exposure.
	500-700	Staggering, collapse in 5 minutes. Serious damage to the eyes in 30 minutes. Death after 30-60 minutes.
	700-1000	Rapid unconsciousness, "knockdown" or immediate collapse within 1 to 2 breaths, breathing stops, death within minutes.
	1000-2000	Nearly instant death

Appendix C (a) (P&ID 01-AA-523 showing line 01-WP-3017)

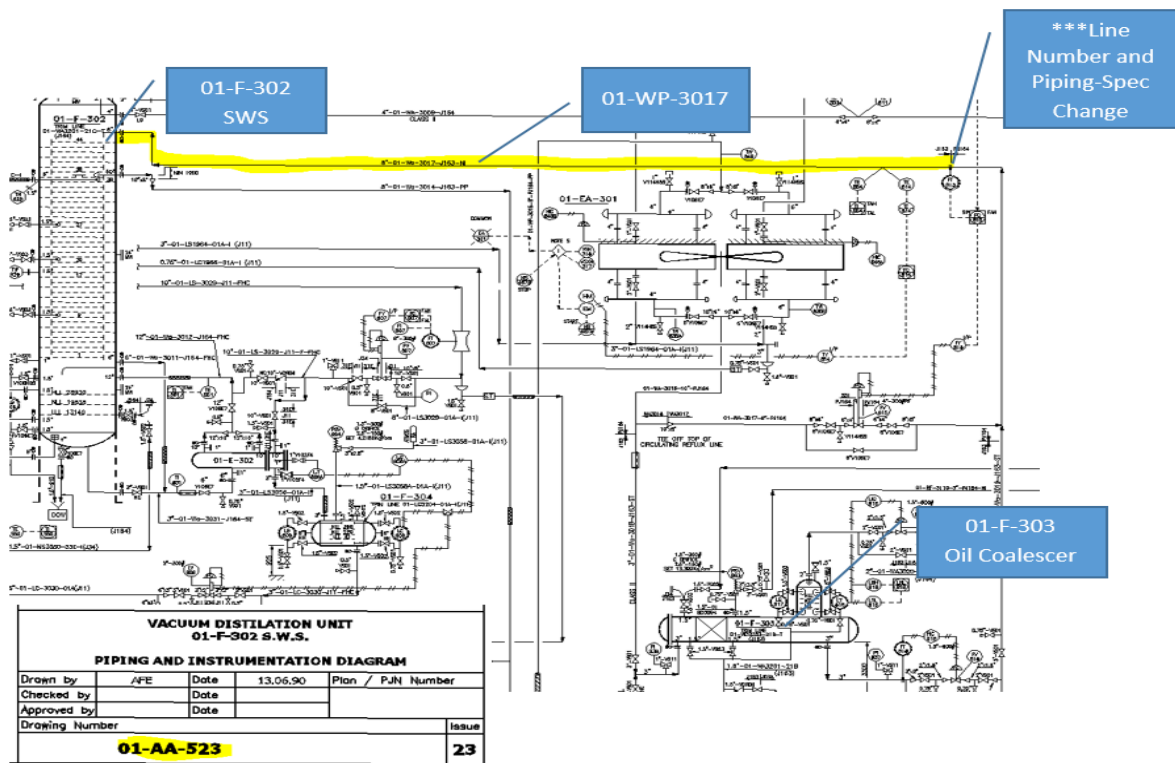


Figure 27 P&ID 01-AA-523 showing line 01-WP-3017

Appendix C (b) (General arrangement of SWS and defective line)

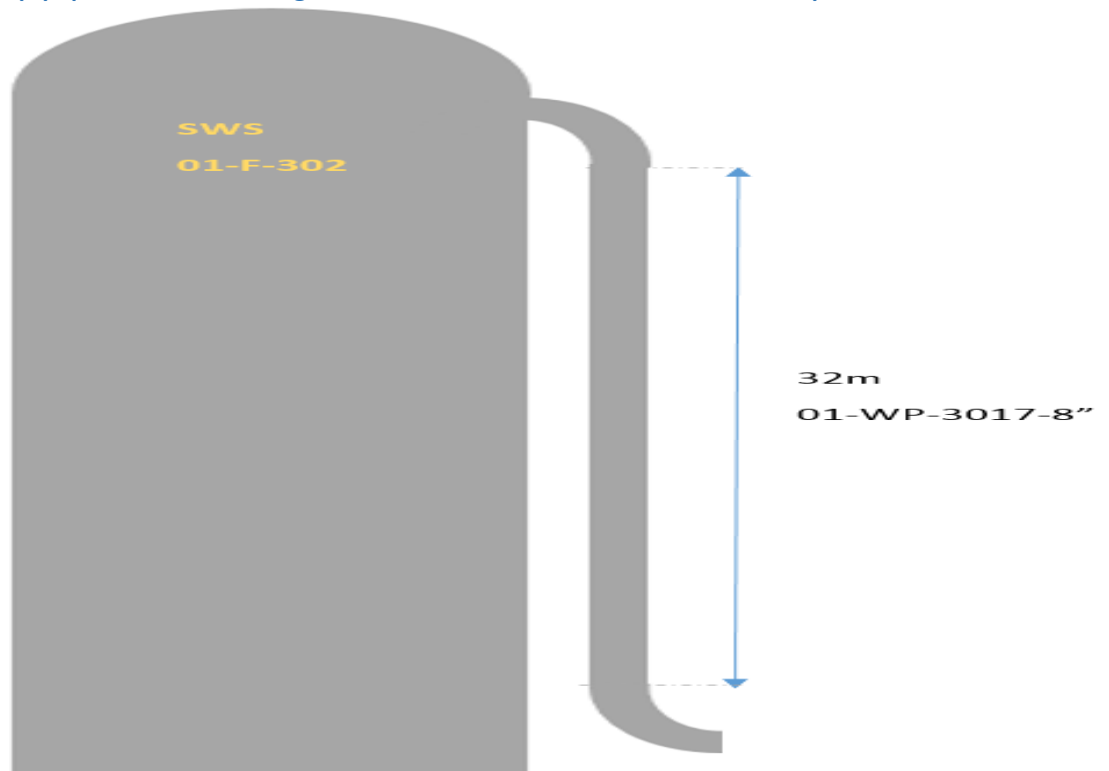


Figure 28 GA of SWS and 01-WP-3017-8"

Appendix D (Inspection advice note cover sheet 0X6976)

TEC/SPI/506, Appendix 2.

IA 020, Issue 17, 22nd January 2016.

Valero Energy Limited - Pembroke Refinery
 Inspection Department
 UKAS Accredited to ISO 17020
 BIS Appointed User Inspectorate for PER

**INSPECTION ADVICE NOTICE No: 0X6976**

Written Scheme No	01/007	Equip. No	01-WP-3017-8"
Description	Severe external corrosion identified in multiple locations (EPP)		
To	Malcolm White	Refinery Business Manager	

Design pressure	13.97kg/cm ²	Design temp	149°C
Operating pressure	7.8kg/cm ²	Operating temp	86°C
Phase, Gas/Liquid	Liquid	Process fluid	SWS Reflux (water)
Etc.			

Observation(s):

- External inspection of pipe work has identified multiple areas of severe external corrosion

Location (CML)	Nominal Wall	Corrosion Loss	Remaining Wall Thickness	PMPT
Location 1: Level 16	5.6mm	4.0mm	1.6mm	3.0mm
Location 2: Level 16	5.6mm	3.5mm	2.1mm	3.0mm
Location 6: Level 16	6.0mm	4.0mm	2.0mm	3.0mm
Location 7: Level 16	5.7mm	3.5mm	2.2mm	3.0mm
Location 8: Level 16	5.7mm	3.5mm	2.2mm	3.0mm
Location 9: Level 16	5.7mm	4.0mm	1.7mm	3.0mm
Location 11: Level 14	6.0mm	4.5mm	1.5mm	3.0mm
Location 12: Level 14	6.0mm	5.5mm	0.5mm	3.0mm
Location 13: Level 14	6.0mm	3.5mm	2.5mm	3.0mm
Location 14: Level 14	6.3mm	3.5mm	2.8mm	3.0mm
Location 18: Level 12	6.2mm	3.5mm	2.7mm	3.0mm
Location 20: Level 11	6.5mm	3.5mm	3.0mm	3.0mm
Location 23: Level 10	6.0mm	4.5mm	1.5mm	3.0mm
Location 31: Level 9	6.2mm	3.5mm	2.7mm	3.0mm
Location 32: Level 9	6.2mm	3.5mm	2.7mm	3.0mm
Location 33: Level 8	6.2mm	4.0mm	2.2mm	3.0mm

- Additional corroded locations are present on the pipe work but above PMPT. (See Isometric below in Figure 2). It should be noted that a number of these fall marginally above PMPT and should be considered for inclusion in the scope for repair. (All photos of the locations can be found in the inspection reports folder)
- All Locations listed in the table above fall below or are at PMPT.
- All Locations either fail a Level 1 FFSA and/or an assessment against TEC/PRO/25.
- A further 12 locations have active corrosion scale present which has not been removed due to the severity of corrosion present.**

Figure 29 IAN 0X6976

Appendix E (Valero CTEMS landing page)

myVALERO

insideValero page scheduled to be migrated to myValero in the future

Search Contacts, Documents

5.0 Technical Excellence & Knowledge Management

Safe, stable and reliable operation begins with excellence in design and is maintained by ensuring that our technical knowledge is available, retained, and shared.

5.1 Facility Design, Construction and Commissioning

5.1.1 The Project Development and Execution Process (PDEP) is in place to incorporate health, safety, environmental, reliability, operability, maintainability, and loss prevention standards requirements into the selection, development, and execution of the projects.

5.1.2 A process to develop and use engineering standards is in place. Deviations from design engineering standards are permitted only after review and appropriate approval and are fully documented.

5.1.3 Process hazard analyses (PHAs) are conducted for new facilities and for the purpose of identifying, evaluating and recommending controls of the hazards involved in the process.

5.1.1 PDEP

- PDEP

5.1.2 Engineering Standards

- Engineering Standards

5.1.3 Process Hazard Analysis

- PHA Standard

5.2 Incident Investigation and Sharing Lessons Learned

5.2.1 An Incident and significant near-miss reporting and investigation process is in place and the corporate-wide tracking system is used to ensure timely sharing of information and closure of corrective actions.

- Both internal incidents and industry-wide alerts are included in the process
- Trends are periodically reviewed to identify procedure, process or design changes

5.2.1 Incident Investigations

- Incident Investigation Standard

Elements & Expectations

- 1. Leadership Accountability
- 2. Protecting People & Environment
- 3. People & Skills Development
- 4. Operations Reliability & Mechanical Integrity
- 5. Technical Excellence & Knowledge
- 6. Change Management
- 7. Business Competitiveness
- 8. External Stakeholder Relationships
- 9. Assurance & Review

Contacts

- Refinery Ops Contacts
- PSM
- Safety
- Environmental
- Operations Directors
- Maintenance Directors
- Technical Directors

Figure 30 Example of Valero CTEMS

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Appendix F (a) (ASME B31.3 table A-1)

Table 13 Stress value S where $20 \text{ KSI} = 137.9 \text{ N/mm}^2$

ASME B31.3-2010

(10) **Table A-1 Basic Allowable Stresses in Tension for Metals¹ (Cont'd)**
 Numbers in Parentheses Refer to Notes for Appendix A Tables; Specifications Are ASTM Unless Otherwise Indicated

Material	Spec. No.	P-No. or S-No.	Grade	UNS No.	Notes	Min. Temp., °F (6)	Specified Min. Strength, ksi		Min. Temp.		
		(5)						Tensile	Yield	to 100	200
Carbon Steel											
Pipes and Tubes (2)											
A 285 Gr. A	A 134	1	...	...	(8b)(57)	B	45	24	15.0	14.7	14.2
A 285 Gr. A	A 672	1	A45	K01700	(57)(59)(67)	B	45	24	15.0	14.7	14.2
Butt weld Smls & ERW	API 5L	S-1	A25	...	(8a)	-20	45	25	15.0	15.0	14.7
	API 5L	S-1	A25	...	(57)(59)	B	45	25	15.0	15.0	14.7
...	A 179	1	...	K01200	(57)(59)	-20	47	26	15.7	15.7	15.3
Type F	A 53	1	A	K02504	(8a)(77)	20	48	30	16.0	16.0	16.0
...	A 139	S-1	A	...	(8b)(77)	A	48	30	16.0	16.0	16.0
...	A 587	1	...	K11500	(57)(59)	-20	48	30	16.0	16.0	16.0
...	A 53	1	A	K02504	(57)(59)	B	48	30	16.0	16.0	16.0
...	A 106	1	A	K02501	(57)	B	48	30	16.0	16.0	16.0
...	A 135	1	A	...	(57)(59)	B	48	30	16.0	16.0	16.0
...	A 369	1	FPA	K02501	(57)	B	48	30	16.0	16.0	16.0
...	API 5L	S-1	A	...	(57)(59)(77)	B	48	30	16.0	16.0	16.0
A 285 Gr. B	A 134	1	...	...	(8b)(57)	B	50	27	16.7	16.5	15.9
A 285 Gr. B	A 672	1	A50	K02200	(57)(59)(67)	B	50	27	16.7	16.5	15.9
A 285 Gr. C	A 134	1	...	...	(8b)(57)	A	55	30	18.3	18.3	17.7
...	A 524	1	II	K02104	(57)	-20	55	30	18.3	18.3	17.7
...	A 333	1	I	K03008	(57)(59)	-50	55	30	18.3	18.3	17.7
...	A 334	1	I	K03008	(57)(59)	-50	55	30	18.3	18.3	17.7
A 285 Gr. C	A 671	1	CA55	K02801	(59)(67)	A	55	30	18.3	18.3	17.7
A 285 Gr. C	A 672	1	A55	K02801	(57)(59)(67)	A	55	30	18.3	18.3	17.7
A 516 Gr. 55	A 672	1	C55	K01800	(57)(67)	C	55	30	18.3	18.3	17.7
A 516 Gr. 60	A 671	1	CC60	K02100	(57)(67)	C	60	32	20.0	19.5	18.9
A 515 Gr. 60	A 671	1	CB60	K02401	(57)(67)	B	60	32	20.0	19.5	18.9
A 515 Gr. 60	A 672	1	B60	K02401	(57)(67)	B	60	32	20.0	19.5	18.9
A 516 Gr. 60	A 672	1	C60	K02100	(57)(67)	C	60	32	20.0	19.5	18.9
...	A 139	S-1	B	K03003	(8b)	A	60	35	20.0	20.0	20.0
...	A 135	1	B	K03018	(57)(59)	B	60	35	20.0	20.0	20.0
...	A 524	1	I	K02104	(57)	-20	60	35	20.0	20.0	20.0
...	A 53	1	B	K03005	(57)(59)	B	60	35	20.0	20.0	20.0
...	A 106	1	B	K03006	(57)	B	60	35	20.0	20.0	20.0
...	A 333	1	6	K03006	(57)	-50	60	35	20.0	20.0	20.0
...	A 334	1	6	K03006	(57)	-50	60	35	20.0	20.0	20.0
...	A 369	1	FPB	K03006	(57)	-20	60	35	20.0	20.0	20.0
...	A 381	S-1	Y35	...	...	A	60	35	20.0	20.0	20.0
...	API 5L	S-1	B	...	(57)(59)(77)	B	60	35	20.0	20.0	20.0

Appendix F (b) (ASME B31.3 table A-1B)

Table 14 Basic quality factors E

Table A-1B Basic Quality Factors for Longitudinal Weld Joints in Pipes, Tubes, and Fittings, E_j These quality factors are determined in accordance with para. 302.3.4(a). See also para. 302.3.4(b) and Table 302.3.4 for increased quality factors applicable in special cases. Specifications, except API, are ASTM.				
Spec. No.	Class (or Type)	Description	E_j (2)	Appendix A Notes
Carbon Steel				
API 5L	...	Seamless pipe	1.00	...
		Electric resistance welded pipe	0.85	...
		Electric fusion welded pipe, double butt, straight or spiral seam	0.95	...
		Furnace butt welded	0.60	...
A 53	Type S	Seamless pipe	1.00	...
	Type E	Electric resistance welded pipe	0.85	...
	Type F	Furnace butt welded pipe	0.60	...
A 105	...	Forgings and fittings	1.00	(9)
A 106	...	Seamless pipe	1.00	...
A 134	...	Electric fusion welded pipe, single butt, straight or spiral seam	0.80	...
A 135	...	Electric resistance welded pipe	0.85	...
A 139	...	Electric fusion welded pipe, straight or spiral seam	0.80	...
A 179	...	Seamless tube	1.00	...
A 181	...	Forgings and fittings	1.00	(9)
A 234	...	Seamless and welded fittings	1.00	(16)
A 333	...	Seamless pipe	1.00	...
		Electric resistance welded pipe	0.85	...
A 334	...	Seamless tube	1.00	...
A 350	...	Forgings and fittings	1.00	(9)
A 369	...	Seamless pipe	1.00	...
A 381	...	Electric fusion welded pipe, 100% radiographed	1.00	(18)
		Electric fusion welded pipe, spot radiographed	0.90	(19)
		Electric fusion welded pipe, as manufactured	0.85	...
A 420	...	Welded fittings, 100% radiographed	1.00	(16)
A 524	...	Seamless pipe	1.00	...
A 587	...	Electric resistance welded pipe	0.85	...

Appendix G (a) (ASME B31.3 weld joint factors)

ASME B31.3-2010

Table 302.3.4 Longitudinal Weld Joint Quality Factor, E_j

No.	Type of Joint	Type of Seam	Examination	Factor, E_j
1	Furnace butt weld, continuous weld 	Straight	As required by listed specification	0.60 [Note (1)]
2	Electric resistance weld 	Straight or spiral	As required by listed specification	0.85 [Note (1)]
3	Electric fusion weld			
	(a) Single butt weld (with or without filler metal) 	Straight or spiral	As required by listed specification or this Code Additionally spot radiographed in accordance with para. 341.5.1 Additionally 100% radiographed in accordance with para. 344.5.1 and Table 341.3.2	0.80 0.90 1.00
	(b) Double butt weld (with or without filler metal) 	Straight or spiral [except as provided in 4(a) below]	As required by listed specification or this Code Additionally spot radiographed in accordance with para. 341.5.1 Additionally 100% radiographed in accordance with para. 344.5.1 and Table 341.3.2	0.85 0.90 1.00
4	Specific specification			
	(a) API 5L Submerged arc weld (SAW) Gas metal arc weld (GMAW) Combined GMAW, SAW 	Straight with one or two seams Spiral	As required by specification	0.95

NOTE:

(1) It is not permitted to increase the joint quality factor by additional examination for joint 1 or 2.

Appendix G (b) (ASME B31.3 temperature differentials)

Table 304.1.1 Values of Coefficient Y for $t < D/6$

Materials	Temperature, °C (°F)					
	≤ 482 (900 & Lower)	510 (950)	538 (1,000)	566 (1,050)	593 (1,100)	≥ 621 (1,150 & Up)
Ferritic steels	0.4	0.5	0.7	0.7	0.7	0.7
Austenitic steels	0.4	0.4	0.4	0.4	0.5	0.7
Other ductile metals	0.4	0.4	0.4	0.4	0.4	0.4
Cast iron	0.0	...	...	...	...	...

Figure 32 Coefficient values for Y

Appendix H (a) (Pembroke GEMS pipe specification for 01-WP-3017)

Table 15 Pembroke pipe spec for 01-WP-3017-8"

PMSS

**Piping and Material Service Specification
Pembroke Plant**

PJ164

Rev. 10

**CLASS 150 RF, Carbon steel, PWHT (Selected Services)
0.125" C.A. for 1½" & Smaller and 0.187" C.A. for 2" & Larger**

Process Water (WP)

Hydrocarbons & Rich Amine (OMAR)

Hydrocarbons & Lean Amine (OMAL)

Chemicals-Rich Amine (MAR)

Chemicals-Lean Amine (MAL)

Chevron Limited, Pembroke Plant
General Equipment and Material Specification (GEMS)
Piping and Material Service Specification (PMSS)

Page 2
Pembroke GEMS PJ164-10
App'd GTDM, Feb 11

SERVICE:	Process Water (WP) Hydrocarbons & Rich Amine (OMAR) Hydrocarbons & Lean Amine (OMAL) Chemicals-Rich Amine (MAR) Chemicals-Lean Amine (MAL) Blowdown (BD) Butane (O) Acid Gas (AG) Relief Flare (RF)	MATERIAL: DESIGN CODE:	ASTM A106 Gr B Carbon Steel ANSI ASME B31.3, Latest Edition
RATING CLASS:	150# Raised Face	MATERIAL GROUP:	Group 1.1, ASME B16.5
TEMPERATURE LIMIT:	-28.9°C / 204.4°C	STRESS RELIEF:	Post Weld Heat Treated (PWHT) (Selected Services Only - Note 01 & 35)
NOMINAL CORROSION ALLOWANCE:	0.125" - 1½" & Smaller 0.187" - 2" & Larger	EXAMINATION:	Per ASME B31.3
HYDROTEST @ AMBIENT:	29.4 barg	VALVE TRIM:	13% Cr, 316SS

PRESSURE - TEMPERATURE RATINGS

TEMP F	-20 to 100	200	300	400			
TEMP C	-28.9 to 37.8	93.3	148.9	204.4			
psig	285	260	230	200			
barg	19.6	17.9	15.9	13.8			
kg/cm ² g	20	18.3	16.2	14.1			

ITEM	NOTES	NPS (in)	SCH/RAT	ENDS	DESCRIPTION	TAG NO.
PIPE	01 & 35					
Threaded	02	1 & SMLR	XXS	THRD	CS, SMLS, A106 GR B	
Socket-weld		1½ & SMLR	160	SW	CS, SMLS, A106 GR B	
Butt-weld		2	160	BW	CS, SMLS, A106 GR B	
Butt-weld		3 - 6	80	BW	CS, SMLS, A106 GR B	
Butt-weld	14	8 - 24	CALC	BW	CS, SMLS, A106 GR B	

Appendix H (b) (Pipe data pro for 8" standard schedule pipe)

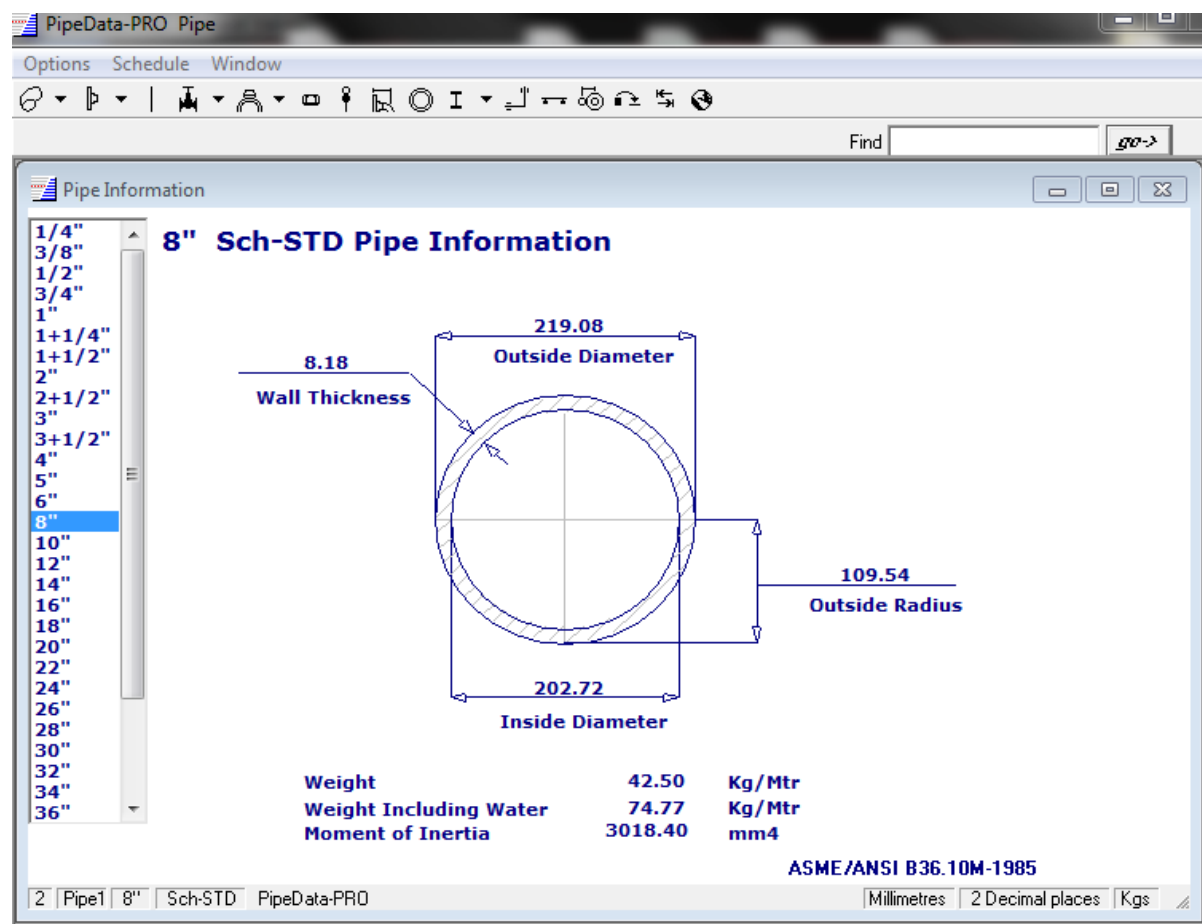


Figure 33 Pipe-Data pro showing pipe spec for 01-WP-3017-8"

Appendix I (Original Team-Furmanite clamp measure and design drawings)

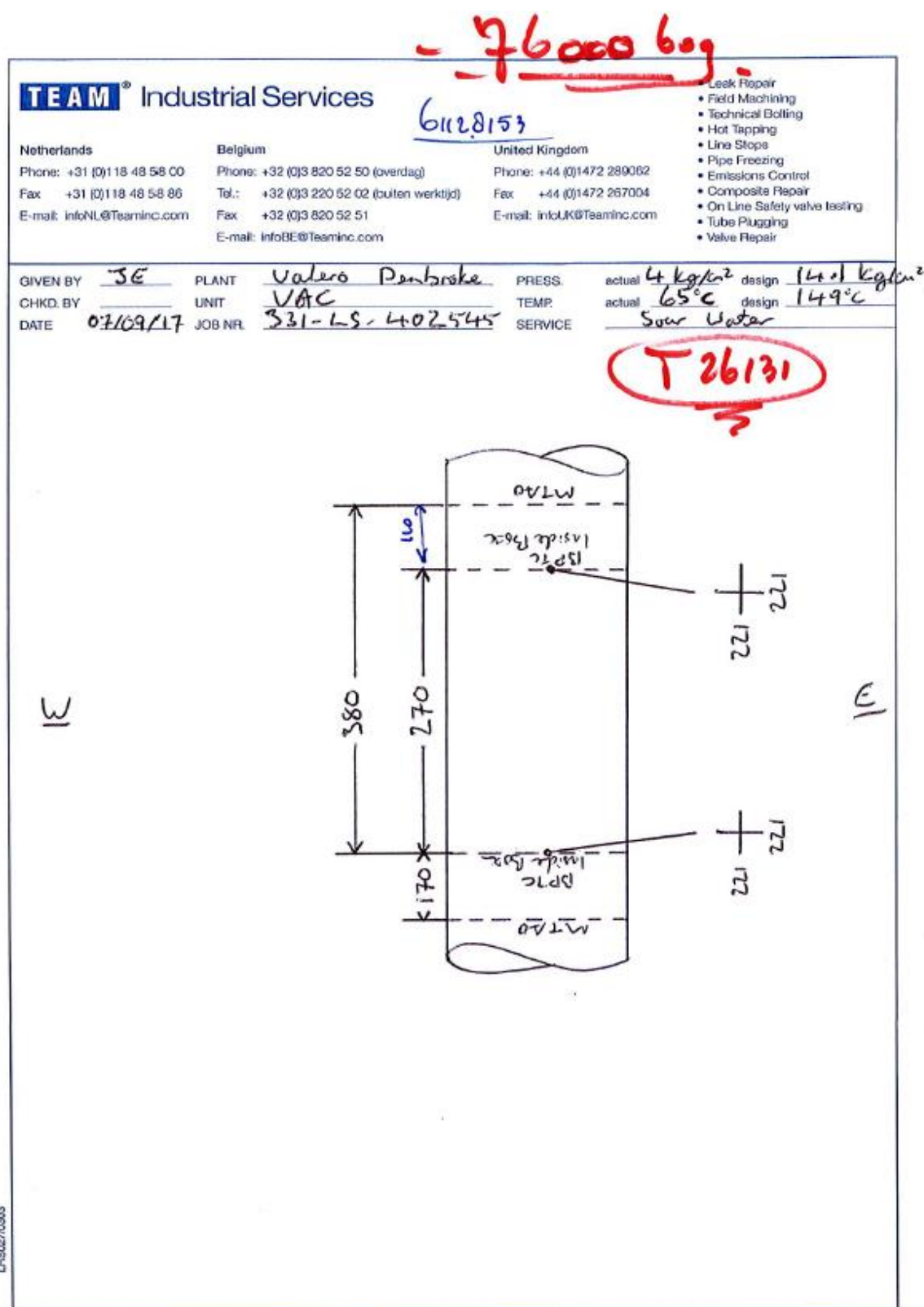


Figure 34 Team-Furmanite details of field measurements

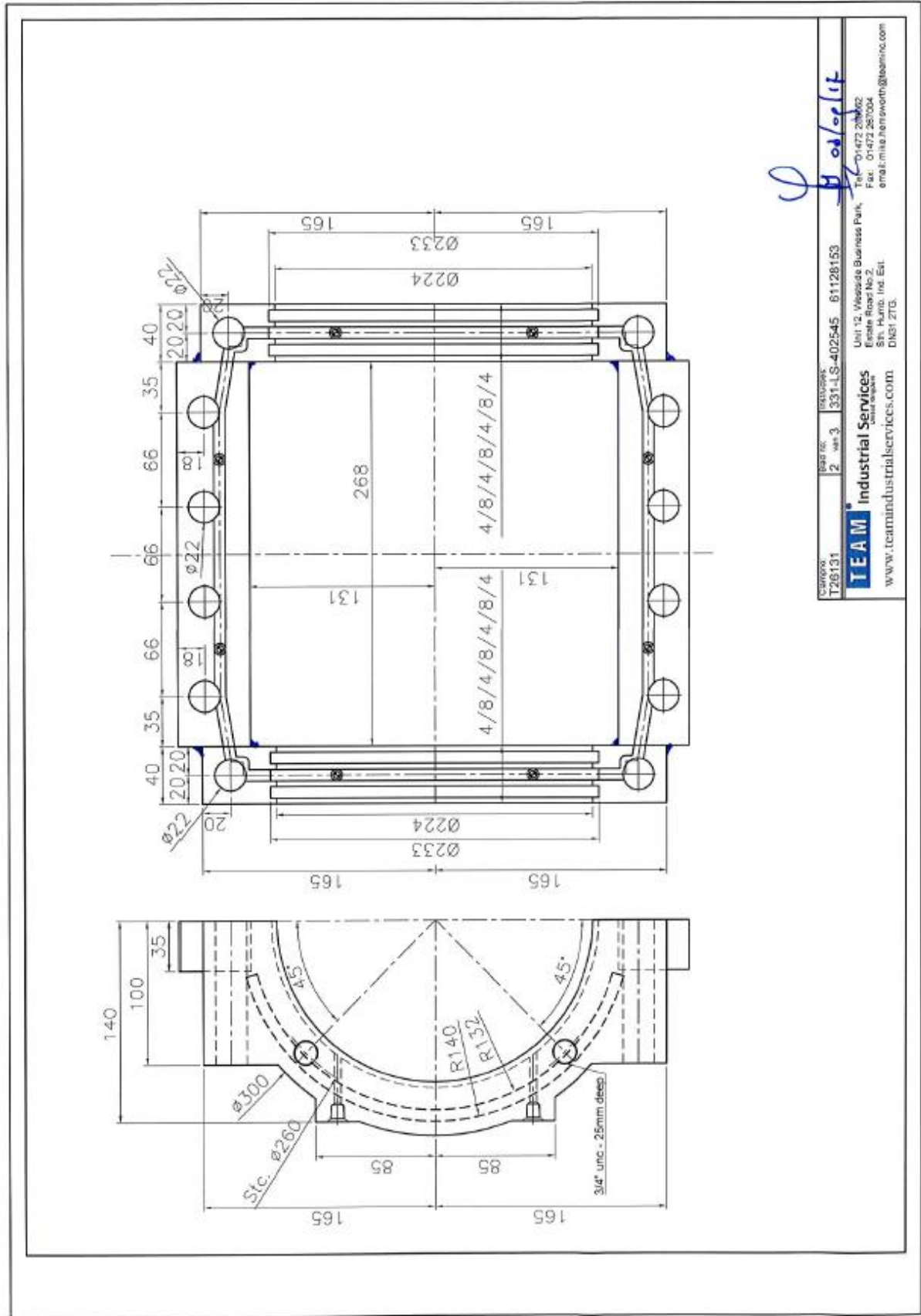


Figure 35 CAD drawing supplied for review

CONTROL SHEET Clamp/Enclosure**T26131**

rev. 0

TEAM FURMANITE : UNITED KINGDOM

Date: 08-09-17

Branch:	Team UK	Customer:	Valero Pembroke	TEAM ordeno:	311-LS-402545
TIS NL:	61128153	WON:		Pipe no.	
Product:	Sour water				
P-design:	14,1 bar	P- actual:	4,0 bar		
T-design:	149°C	T-actual:	65°C		
Description:	8" Line-enclosure			Type no.	EN 108
Strongback:	Yes				
Reasoning:	Line condition / product				
Comments TEAM:					
Comments customer:					

Applied materials and permissible calculation values:

bolts	A193 B7M/2HM	acc.	ASME-II part D table 3 (2010)
allowable stress (f)			137.9 N/mm ²
Enclosure material:	A516Gr70	acc.	ASME II part D table 1A (2010)
allowable stress (f)			137.9 N/mm ²
Endplate material:	A516Gr70	acc.	ASME II part D table 1A (2010)
allowable stress (f)			137.9 N/mm ²
strongbackbolt:	A193 B7M/2HM	acc.	ASME-II part D table 3 (2010)
allowable stress (f)			137.9 N/mm ²
strongback material:	A516Gr70	acc.	ASME II part D table 1A (2010)
allowable stress (f)			137.9 N/mm ²

Completed by: SvdH

Checked by:

page 1 of 6

Figure 36 Team-Furmanite control sheet

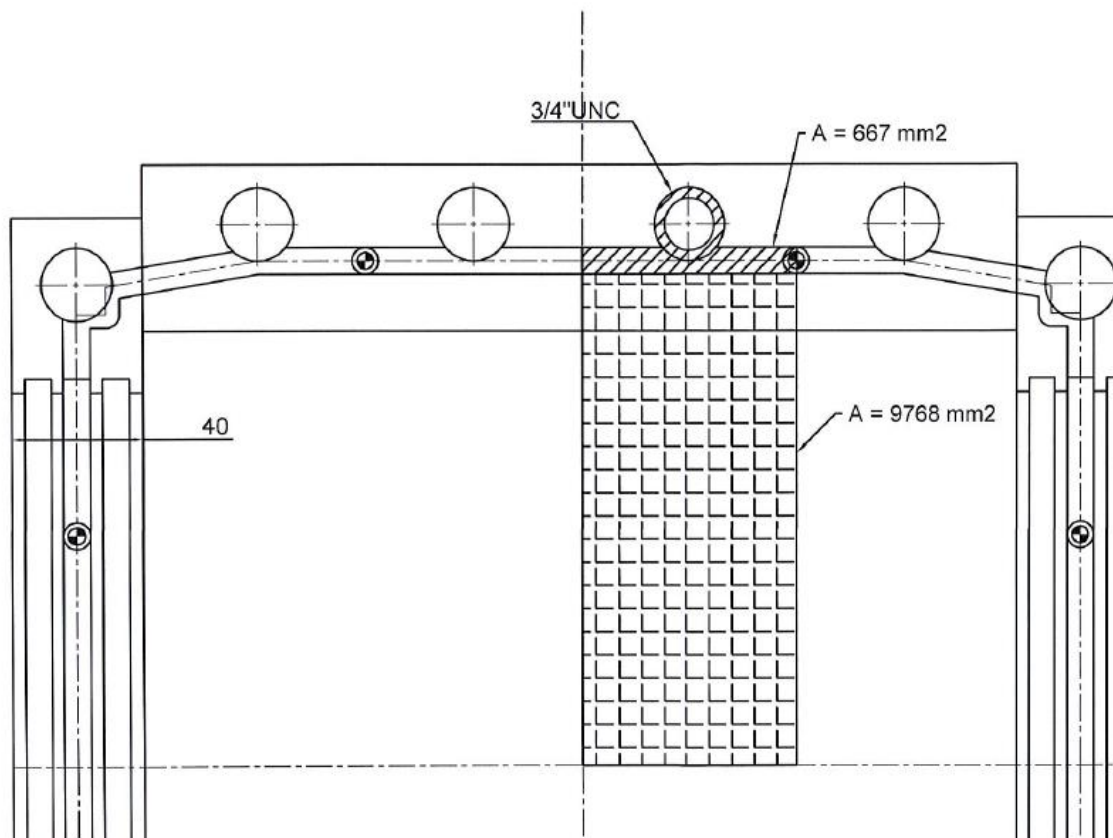
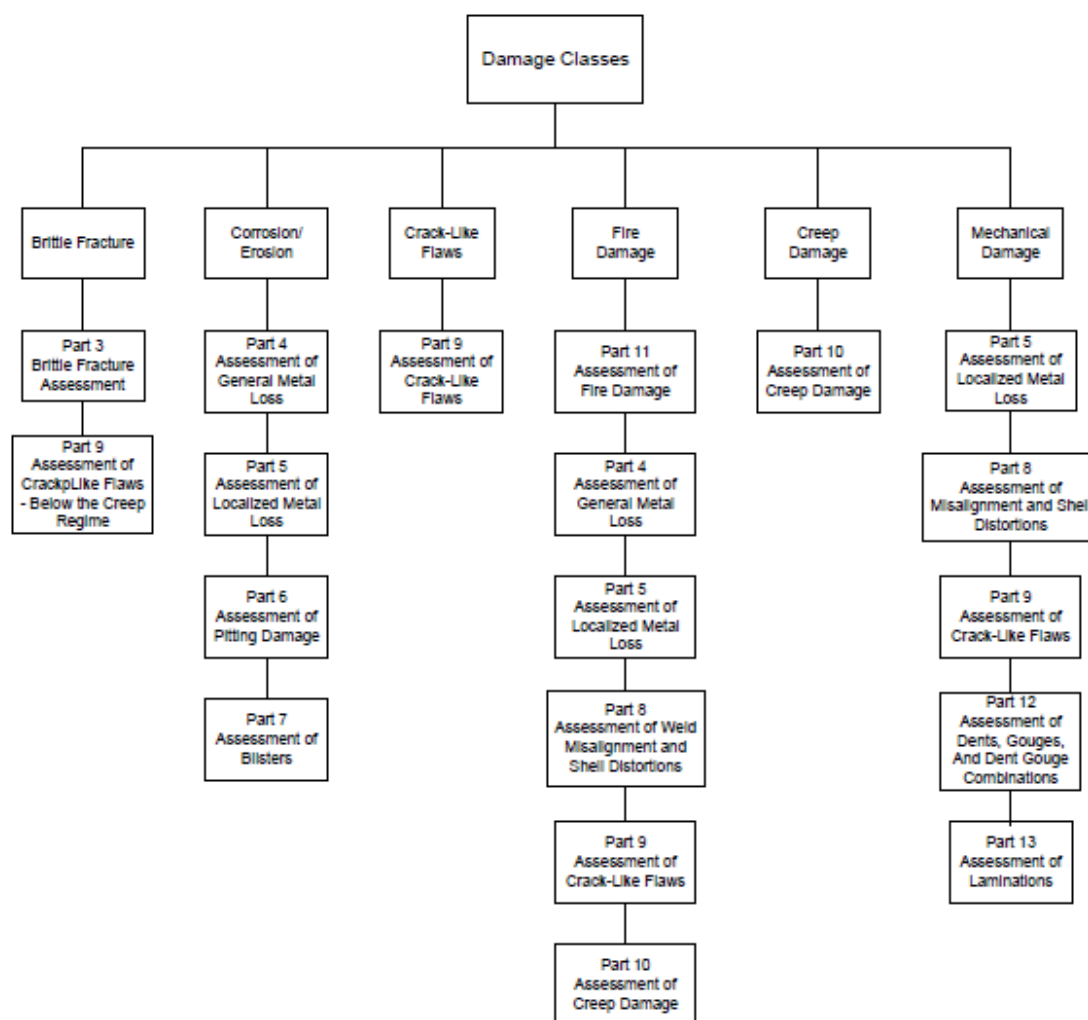


Figure 37 Team-Furmanite 3/4" UNC bolt load calculations

Appendix J (API 579 FFSA damage mechanisms)

Table 16 API 579 FFSA Damage mechanism flow chart



API 579-1, 2010, 1st Edition, 10.1.1.1, 10.1.1.2, 10.1.1.3, 10.1.1.4, 10.1.1.5, 10.1.1.6, 10.1.1.7, 10.1.1.8, 10.1.1.9, 10.1.1.10, 10.1.1.11, 10.1.1.12, 10.1.1.13, 10.1.1.14, 10.1.1.15, 10.1.1.16, 10.1.1.17, 10.1.1.18, 10.1.1.19, 10.1.1.20, 10.1.1.21, 10.1.1.22, 10.1.1.23, 10.1.1.24, 10.1.1.25, 10.1.1.26, 10.1.1.27, 10.1.1.28, 10.1.1.29, 10.1.1.30, 10.1.1.31, 10.1.1.32, 10.1.1.33, 10.1.1.34, 10.1.1.35, 10.1.1.36, 10.1.1.37, 10.1.1.38, 10.1.1.39, 10.1.1.40, 10.1.1.41, 10.1.1.42, 10.1.1.43, 10.1.1.44, 10.1.1.45, 10.1.1.46, 10.1.1.47, 10.1.1.48, 10.1.1.49, 10.1.1.50, 10.1.1.51, 10.1.1.52, 10.1.1.53, 10.1.1.54, 10.1.1.55, 10.1.1.56, 10.1.1.57, 10.1.1.58, 10.1.1.59, 10.1.1.60, 10.1.1.61, 10.1.1.62, 10.1.1.63, 10.1.1.64, 10.1.1.65, 10.1.1.66, 10.1.1.67, 10.1.1.68, 10.1.1.69, 10.1.1.70, 10.1.1.71, 10.1.1.72, 10.1.1.73, 10.1.1.74, 10.1.1.75, 10.1.1.76, 10.1.1.77, 10.1.1.78, 10.1.1.79, 10.1.1.80, 10.1.1.81, 10.1.1.82, 10.1.1.83, 10.1.1.84, 10.1.1.85, 10.1.1.86, 10.1.1.87, 10.1.1.88, 10.1.1.89, 10.1.1.90, 10.1.1.91, 10.1.1.92, 10.1.1.93, 10.1.1.94, 10.1.1.95, 10.1.1.96, 10.1.1.97, 10.1.1.98, 10.1.1.99, 10.1.1.100

Appendix K (a) (SAP work order raised to install repair clamp)

Change Urgent 5055707: Cost Overview

Order: PM02 5055707 01-WP-3017-J163-8-NONE, 01-WP-3017 insta

01-WP-3017-J163-8-NONE, 01-WP-3017 insta
 01-WP-3017-J163-8-NONE, 01-WP-3017 install clamp to thinned line
 Created by : GBWK - George Bagley
 Reported by : GBWK - George Bagley
 Approved by : ALSMITH - Andy Smith
 Problem description : IAN OX6976 has been issued highlighting several locations below PMPT. Location 12 of the IAN has highlighted a section below T-Min. This request is to install a temporary repair to this

Sys.Status: TECO GMPS MANC NMAT PRC SETC FC

HeaderData Operations Components **Costs** Partner Objects Additional Data

Estimated costs: 279.72 GBP

Val.in Object Curr. GBP
 Val.in CoAreaCurr. USD

Rep. Plan/Act. Rep. Budget/Commit.

Overview Costs Quantities Key figures

Group/Dscrptn	Est. costs	Plan costs	Act. costs	C.
Costs	0.00	372.96	11,740.39 G...	
External Services	0.00	0.00	11,740.39 G...	
Internal Labor	0.00	372.96	0.00 G...	

Figure 38 SAP work order raised to install temp repair clamp to location 12 of IAN

Appendix k (b) (SAP work order raised to remove clamp at next opportunity)

Change Turnaround 4713562: Central Header

Order: PM04 4713562 01-WP-3017-J163-8-NONE, 01-WP-3017 Repla

Problem description : 3X TEAM clamps fitted (Work order 4700463/4936117/5055707)
 IAN OX5861, (Temp repairs OX5904/OX6640/OX7030)
 Replace complete line at next IA 01-F-302 rconcern. Trunnion support has also been altered to allow for fitting of temp repair OX5904 this must be put back original after clamp is removed.

Sys.Status: CRID MANC NMAT NTUP PRC RP

HeaderData Operations Components Costs Partner Objects Additional Data

Person responsible
 PlannerGrp: T/A PL25 TURNAROUND
 Mn.wk.ctr: T/A-WE / PL25 TURNAROUND W...

Notifctn: 13663575
 Costs: GBP
 PMActType: 016 Turnaround ma...
 SystCond.:
 Address:

Dates

Bas. start	06.07.2016	09:07	Priority	TURNAROUND
Basic fin.	06.07.2016	09:07	Revision	
SchedStart		00:00	Act. start	00:00
Sched.Fin.		00:00	Actual end	00:00
SchedType	Forwards in time		RefDate	06.07.2016
Rel. view	Predecessor		Start in past	365
Version			Adjust dates	
Cal. Selection	From Wor...		Factory Cal. ID	

Reference object

Func. Loc.	PL25-01-0010-16-0...	01LN015455, 01-WP-3017-J163-8-NONE
Equipment		
Assembly		

First operation

Operation	01-WP-3017-J163-8-NONE, 01-WP-3017 Repla	CcKey	Calculate work
WkCtr/Plnt	T/A-WE / PL25	Ctrl key	PM01
Work durtn	HR	Acty Type	PMILBR
Person. no		Opnrtn dur.	HR

Person. no: []

Figure 39 SAP Turnaround work order raised to remove temporary repair clamp at location 12 at next outage

Appendix L (API 579 Nomenclature)

D	inside diameter of the cylinder, cone (at the location of the flaw), sphere, or formed head; for the center section of an elliptical head an equivalent inside diameter of $K_e D_e$ is used where D_e is inside diameter of the head straight flange and K_e is a factor defined in Annex A , paragraph A.3.6; for the center section of a torispherical head two times the crown radius of the spherical section is used. D shall be corrected for <i>LOSS</i> and <i>FCA</i> as applicable.
L_{msd}	distance to the nearest major structural discontinuity.
t_c	corroded wall thickness away from the region of local metal loss.
t_{mm}	minimum remaining thickness determined at the time of the assessment
t_{rd}	uniform thickness away from the local metal loss location established by thickness measurements at the time of the assessment.

Figure 40 API 579 Nomenclature

Appendix M (Updated data from inspection report)

Table 17 Updated IAN information showing status of FFSA pass/fail

Location (CML) ▾	Nominal Wall ▾	Corrosion Loss ▾	Remaining Wall Thickness ▾	Level 1 FFSA ▾	Level 2 FFSA ▾
Location 1: Level 16	5.6mm	4.0mm	1.6mm	FAIL	FAIL
Location 2: Level 16	5.6mm	3.5mm	2.1mm	FAIL	FAIL
Location 6: Level 16	6.0mm	4.0mm	2.0mm	FAIL	FAIL
Location 7: Level 16	5.7mm	3.5mm	2.2mm	FAIL	FAIL
Location 8: Level 16	5.7mm	3.5mm	2.2mm	FAIL	FAIL
Location 9: Level 16	5.7mm	4.0mm	1.7mm	FAIL	FAIL
Location 11; Level 14	6.0mm	4.5mm	1.5mm	FAIL	FAIL
Location 12: Level 14	6.0mm	5.5mm	0.5mm	FAIL	FAIL
Location 13: Level 14	6.0mm	3.5mm	2.5mm	FAIL	FAIL
Location 14: Level 14	6.3mm	3.5mm	2.8mm	PASS	N/A
Location 18: Level 12	6.2mm	3.5mm	2.7mm	PASS	N/A
Location 20: Level 11	6.5mm	3.5mm	3.0mm	PASS	N/A
Location 23: Level 10	6.0mm	4.5mm	1.5mm	FAIL	FAIL
Location 27:	6.2mm	4mm	2.6mm	PASS	N/A
Location 31: Level 9	6.2mm	3.5mm	2.7mm	PASS	N/A
Location 32: Level 9	6.2mm	3.5mm	2.7mm	PASS	N/A
Location 33: Level 8	6.2mm	3.7mm	2.5mm	FAIL	FAIL

Appendix N (Example of a smart action plan)

Table 18 Example of SMART action plan template

SMART Action Plan							
S- Be Specific about what you want to achieve, do not be ambiguous, communicate clearly. M- Ensure your result is Measurable. Have a clearly defined outcome and ensure this is measurable (KPIs). A- Make sure it is Appropriate. Is it an Achievable outcome? R- Check that its Realistic, it must be possible taking account of time, ability and finances. T- Make sure it is Time restricted. Set yourself an achievable time frame, set deadlines and milestones to check your progress.							
Action	Specific	Measurable	Appropriate	Realistic	Time	Staff Responsible	Status
1.							
2.							
3.							
4.							
5.							
6.							
7.							
8.							

Appendix O (RMC live line welding request form and risk assessment)

RISK MANAGEMENT COMMITTEE REQUEST/RESOLUTION MEMORANDUM		VALERO PEMBROKE	DATE SUBMITTED: No.:
REQUESTER(S):	George Bagley		
COMPLEX:	Refining	☐ Problem statement includes whether safety, mechanical integrity, or an environmental procedure is involved.	
UNIT:	01- Vacuum Unit	☐ Background information includes references to regulations, codes, specifications, policies, standards, etc.	
PROCESS:	Sour water	☐ Simplified flow diagrams, process flow diagrams, plot plans, or equipment drawings and details are attached.	
EQUIPMENT:	01-WP-3017	☐ List of options with an evaluation and risk assessment is attached. (Risk Matrix should be attached)	
ESTIMATED DATE TO START WORK:	June 2018	☐ Requester's recommendation is included.	
PROBLEM STATEMENT (Including a statement of the deviation)			
Line no. 01-WP-3017 has several location below PMPT. A mechanical enclosures are an option but due to the amount of defects the line the cost would be high. It is proposed to install patches as per ASME PCC2 using live line welding as a method. A repair of this nature is required as it is impractical to take the line out of service. (Cape0052 work pack) Live line welding is a recognised repair method and has been successfully carried out a number of times here at Valero Pembroke. The welder chosen to complete the task will be familiar with live line welding. Patches is to be installed which does not exceed 1/2 of the original pipe diameter and is in compliance with API 570 and ASME PCC2 repair codes			
BACKGROUND INFORMATION			
- Patch material to be correct as per Pembroke GEMS (PJ164) - Line 01-WP-3017 is found on P&ID 01-AA-523 - Valero engineering department to provide details of patch required to enable structural strength to be achieved in compliance with ASME PCC2/API 570 codes of repair			
OPTIONS EVALUATED			
Options of repair - Do nothing line then fails - Carry out live line over plate welding In compliance with industry code API 570 - Carry out temporary repair to the integrity repair standard by fitting a mechanical enclosure Risk with repair - Leave in service – Leak worsens and isolation will cause unit shutdowns - Carry out repair and leave line in service (minimal risk of blow through and pinhole leak) - Cost of TEAM enclosures would be in excess of £60k			

Figure 41 RMC live line welding request page-1

REQUEST/RESOLUTION MEMORANDUM		
REQUESTER'S RECOMMENDATION (Including any safeguards proposed)		
To carry out approved live line welding of patch repairs as per CAPE pack 0052 Work pack will be approved by all levels of authority in compliance with TR457 and TR686		
COMMITTEE DECISION		
FOLLOW-UP ACTION		
RESPONSIBLE PARTY:	G Bagley	TARGET DATE: June 2018
RMC MEMBERS PRESENT		OTHER EMPLOYEES PRESENT
COMMITTEE APPROVAL Approved		DATE: 12/06/2017
All decisions that have an identified risk level of 1-5 following mitigation will require approval to operate with risk. The Valero Approval to Operate with Risk Policy shall be followed before the work is implemented.		RISK LEVEL: BA APPROVER:

APPENDIX A - Risk Management Review Worksheet					Date:	Page 1 of 1
Change or Task:					Unit:	01-VDU
Project Title: 01-WP-3017					Team Leader	George Bagley
Team Member: George Bagley						
Tasks	Identify Hazards	Initial Risk Level	Develop Controls/Mitigation Methods	Residual Risk Level	Implement Controls	Who and How
Live line Welding	Safety Possible pinhole burn through line	II X D = TR	- CAPE weld procedures checked and approved by inspection - Inspection to carry out PMI, thickness and hardness checks to make sure welding is suitable at these locations	II X A = BA	- Review contractor method statement and RAMS and appropriate control measures will be put in place to cover the Hazards identified. - Operations procedure contingency/ Emergency CAPE welding procedure and inspection reports. Radio contact to be maintained throughout the job	
	Contractor injury from burns from hot surfaces	II X C = TR	Correct PPE for task as per RAP Permit RAMS	II X B = BA	Kevlar gloves and wrist protection to be provided to craftsmen	

Figure 42 RMC live line welding request page-2

Appendix P Partial details of Chevron LPO 241101/6

Crude Tanks in crude service		Tank	Volume (mbbls)						
		1	181						
		2	183						
		3	181						
		4	182						
		5	182						
		6	180						
		7	169						
		8	169						
		9	168						
		10	493						
		11	485						
				tonnes					
				177	23385.4				
				Average	234	30865.6			
				Total Ullage	2573	339521.5			
				Assumed Ullage	2395	315983.9			
Economics calculated assuming 1 200mbbl tank is taken out of service.									
Issues Likely to be seen	Consequence (\$)					Net Impact Per Year (\$/kyear)		Comments	
Total						2,321,729		We currently set aside around 800mbbls of tankage for majority crude. For every extra bit of incremental tankage we try to store minority crude in it. Therefore as we can decrease tankage the percentage minority crude in the slate decreases. Minority crude is worth around \$0.5/bbl over majority. It is assumed we can take advantage of minority crude capacity about 50% of the time.	
Reduced Minority Crude Processing	2,129,667					2,129,667		Decreased storage will cause higher demurrage costs. Currently, around 40 cargoes per year incur demurrage. If a tank is taken out of service this will increase. If the reduction in volume is 178mbbl and we assume a crude rate of 210mbbl/day, then it will be 178/210 (84.8%) of a day earlier that demurrage will be incurred. Buying patterns however can be adjusted to off set this so that the demurrage can be reduced by 50% of the crude storage reduction. Demurrage rates are approximately \$350/day.	
Demurrage	590,741					590,741		We must maintain a stock of material in our system etc be able to market in the country. If we don't have this we buy tickets. If we have extra we sell. This is applied to crude in fixed percentages (which I can't remember at the moment)	
								Category 1 (Gasoline stocks – assume 50%) \$3/tonne/month – we buy these Category 2 (Distillate stocks – assume 30%) \$4.50/tonne/month – we sell these Category 3 (Fuel Oil – assume 20%) \$0.80/tonne/month – we sell these Crude density = 0.830/m3 CSO value for crude = \$3.00/tonne/month Tickets are traded so costs vary.	
CSO	841,878					841,878		10% of the value of the material stored in the tank per year (to reflect the cost of locking away this money and not making it available for other investment)	
Cost of Capital	-1,240,555					-1,240,555		Assumed cost of crude \$70/bbl	

Figure 43 LPO of a crude tank outage shown in US Dollars (\$)