PSM - Refining Damage Mechanisms “101”

Jim Riley

DMR Requirements

1. Complete a DMR for all existing and new process where DMR exists.
2. Timeline: 50% DMR’s within 3 years, complete all DMR’s within 5 years
3. Revalidation: At least once every five years
4. DMR’s reviewed as part of major process change prior to the change.
5. Where a DMR is a factor in an incident investigation, review most recent DMR’s; if no DMR then recommend a DMR be conducted.
6. DMR’s must be available to team performing a PHA for that process
7. DMR’s performed by team with expertise in engineering, equipment and pipe inspection, damage and failure mechanisms, and operations.

DMR Requirements (continued)

8. A DMR for each process shall include:
   - A. Assessment of process flow diagrams;
   - B. Identification of all potential damage mechanisms;
   - C. Determination that the materials of construction are appropriate for their application and are resistant to potential damage mechanisms;
   - D. Methods to prevent or mitigate damage; and,
   - E. Review of operating parameters to identify operating conditions that could accelerate or otherwise worsen damage, or that could minimize or eliminate damage.

DMR Requirements (continued)

9. Damage Mechanisms include:
   - A. Mechanical loading failures, such as ductile fracture, brittle fracture, mechanical fracture an buckling;
   - B. Erosion, such as abrasive wear, adhesive wear and fretting,
   - C. Corrosion, such as uniform corrosion, localized corrosion and pitting;
   - D. Thermal-related failures, such as creep, metallurgical transformation and thermal fatigue;
   - E. Cracking, such as stress-corrosion cracking; and,
   - F. Embrittlement, such as high-temperature hydrogen attack.

DMR Requirements (continued)

10. DMRs shall include an assessment of previous experience with the process, including the inspection history and all damage mechanism data; a review of industry-wide experience with the process; and all applicable standards, codes, and practices.
11. At the conclusion of the analysis, the team shall prepare a written DMR report, which shall include the following:
    A. The process unit and damage mechanisms analysed;
    B. Results of all analyses conducted, pursuant to subsection (k)(8)
    C. Recommendations for temporarily mitigating damage; and,
    D. Recommendations for preventing damage.

DMR Requirements (continued)

12. The report shall be provided to and, upon request, reviewed with employees whose work assignments are within the process unit described in the DMR.
13. The employer shall implement all recommendations in accordance with subsection (x).
14. DMR reports shall be retained for the life of the process unit.

Industry Aids Available

- API 571 – Damage Mechanisms Affecting Fixed Equipment in the Refining Industry (2nd Edition 2011)
- NBIC Part 2 Section 3 Corrosion and Failure Mechanisms (2017 Edition)
- API 580/581 Risk Based Inspection/RBI Technology BRD
- API 584 Integrity Operating Window (1st Edition 2014)
- API 970 Corrosion Control Documents (Draft)

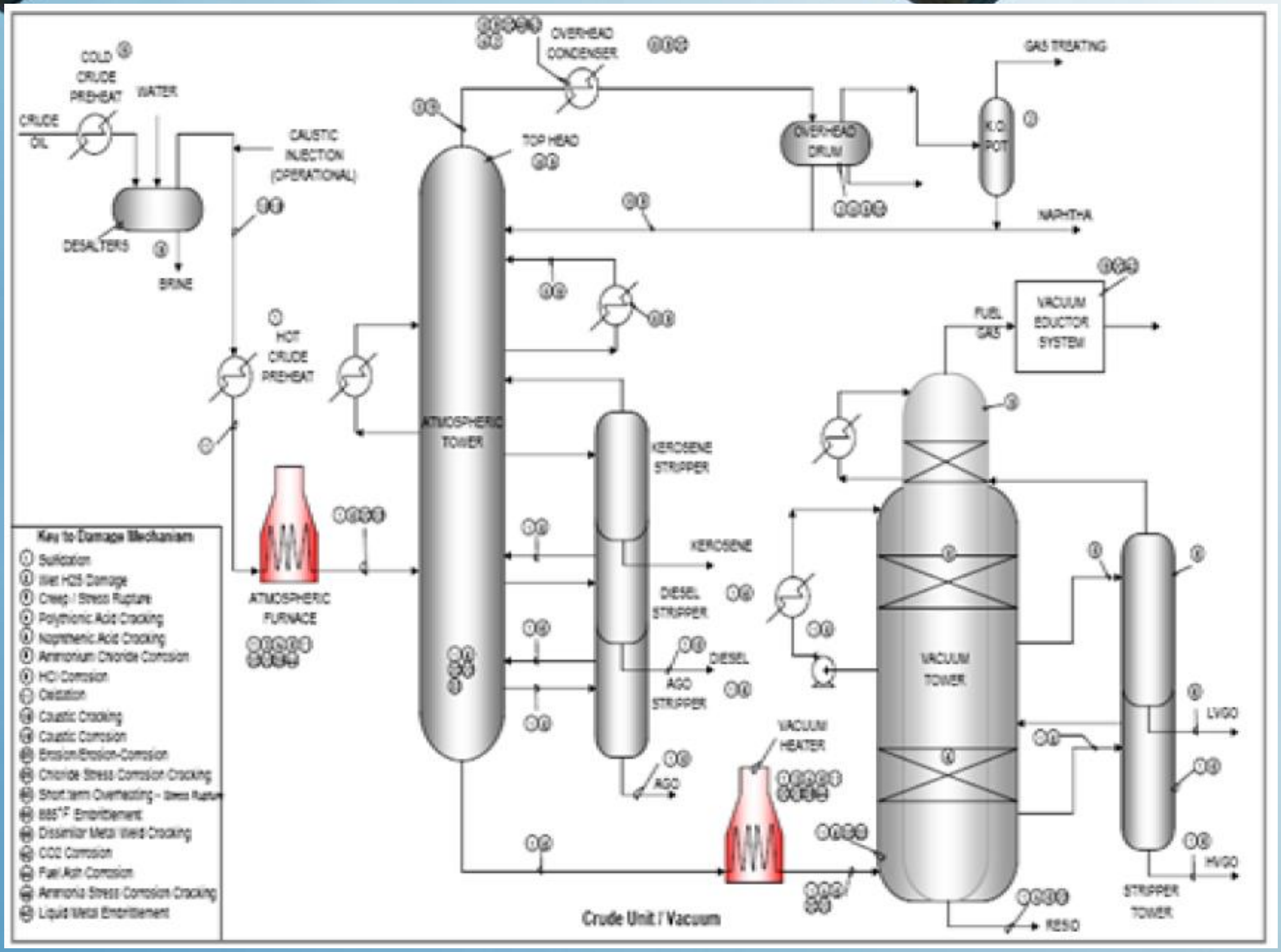
Damage Mechanisms

Based on API 571

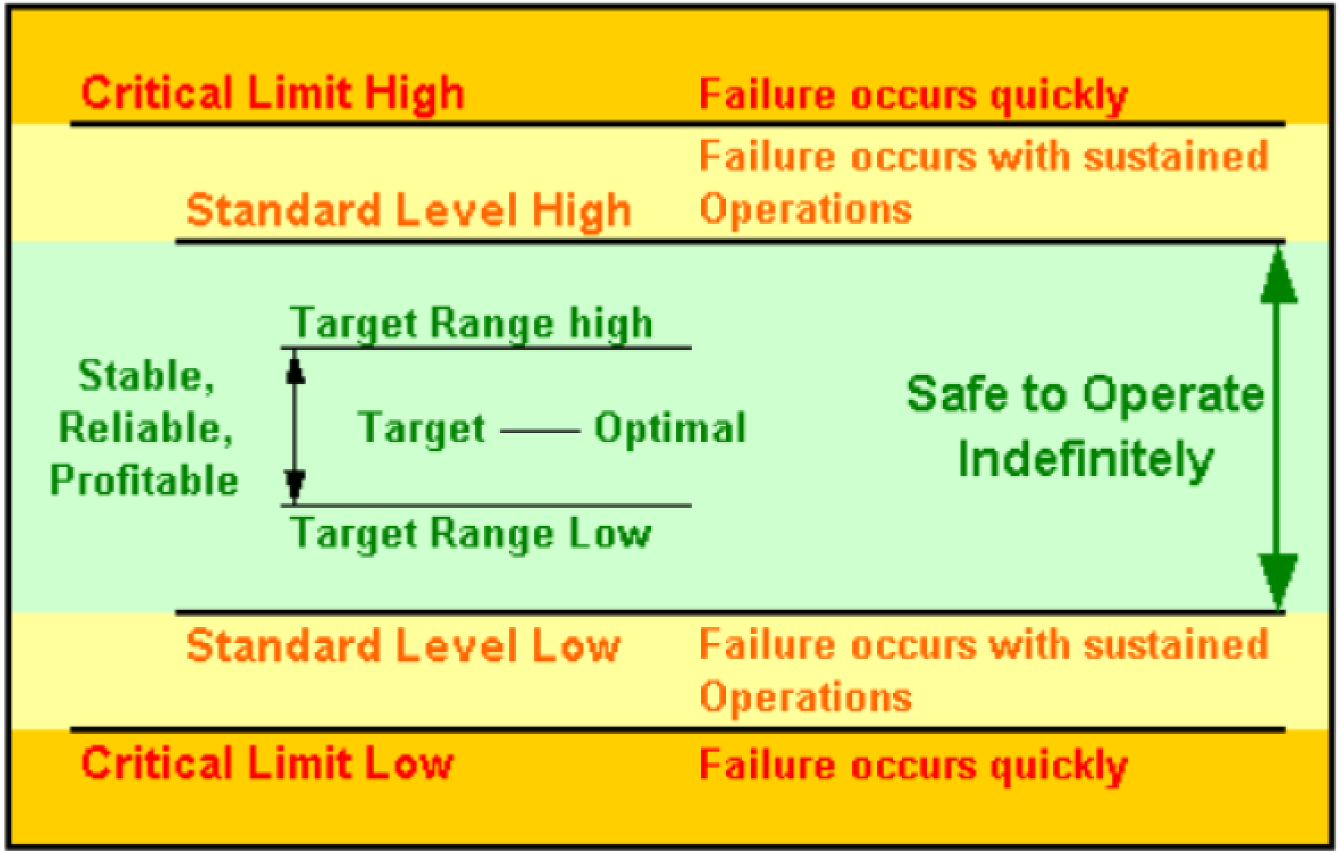
Damage Mechanism No.	Description
1	Sulfidation
2	Wet H2S Damage (Blistering/HIC/SOHIC/SSC)
3	Creep / Stress Rupture
4	High temp H2/H2S Corrosion
5	Polythionic Acid Cracking
6	Naphthenic Acid Corrosion
7	Ammonium Bisulfide Corrosion
8	Ammonium Chloride Corrosion
9	HCl Corrosion
10	High Temperature Hydrogen Attack
11	Oxidation
12	Thermal Fatigue
13	Sour Water Corrosion (acidic)
14	Refractory Damage
15	Graphitization
16	Temper Embrittlement
17	Decarburization
18	Caustic Cracking
19	Caustic Corrosion
20	Erosion / Erosion-Corrosion
21	Carbonate SCC
22	Amine Cracking
23	Chloride Stress Corrosion Cracking
24	Carburization
25	Hydrogen Embrittlement
27	Thermal Shock
28	Cavitation
29	Graphitic Corrosion (see Dealloying)
30	Short term Overheating - Stress Rupture
31	Brittle Fracture
32	Sigma Phase/ Chi Embrittlement
33	885oF (475oC) Embrittlement
34	Softening (Spheroidization)
35	Reheat Cracking
36	Sulfuric Acid Corrosion
37	Hydrofluoric Acid Corrosion
38	Flue Gas Dew Point Corrosion
39	Dissimilar Metal Weld (DMW) Cracking
40	Hydrogen Stress Cracking in HF
41	Dealloying (Dezincification/ Denickelification)
42	CO2 Corrosion
43	Corrosion Fatigue
44	Fuel Ash Corrosion
45	Amine Corrosion
46	Corrosion Under Insulation (CUI)
47	Atmospheric Corrosion
48	Ammonia Stress Corrosion Cracking
49	Cooling Water Corrosion
50	Boiler Water / Condensate Corrosion
51	Microbiologically Induced Corrosion (MIC)
52	Liquid Metal Embrittlement
53	Galvanic Corrosion
54	Mechanical Fatigue
55	Nitriding
56	Vibration-Induced Fatigue
57	Titanium Hydriding
58	Soil Corrosion
59	Metal Dusting
60	Strain Aging
61	Steam Blanketing
62	Phosphoric Acid Corrosion
63	Phenol (carbolic acid) Corrosion
64	Uniform Corrosion
65	Pitting
66	Underdeposit Corrosion
67	None
68	Intergranular Corrosion
69	Acetic Acid/Anhydride Corrosion

NBIC Part 2

Damage Mechanisms of Equipment based on API 571



Integrity Operating Window API 584



Courtesy of Shell Global Solutions – Establishing Integrity Operating Windows, Inspector Summit . January 27, 2006 Galveston, TX/

Corrosion Control Documents

- A document that summarizes:
  - Unit process description
  - Rationale for materials of construction
  - Discusses damage mechanisms
  - Defines corrosion circuits
  - Defines damage mechanisms in each circuit:
    - Includes critical locations
    - Start up and shut down influences
    - Includes predicted (or actual) corrosion rates and environmental cracking tendencies

Courtesy of The Hendrix Group – Corrosion Control Documents Revisited – 2011 API Inspection Summit - David Hendrix presentation

Corrosion Control Documents

CCD

- Process descriptions
- Hazops
- PFD's
- P&ID's
- Material and Heat Balance (H&MB)
- Equipment design
- Piping specifications
- Inspection and maintenance history

Courtesy of The Hendrix Group – Corrosion Control Documents Revisited – 2011 API Inspection Summit - David Hendrix presentation

DMR Review Flow

Define Process Limits
- Description of process and oper. modes
- Heat/Material Balance
- PFDs, P&IDs, MSDs
- SME Books

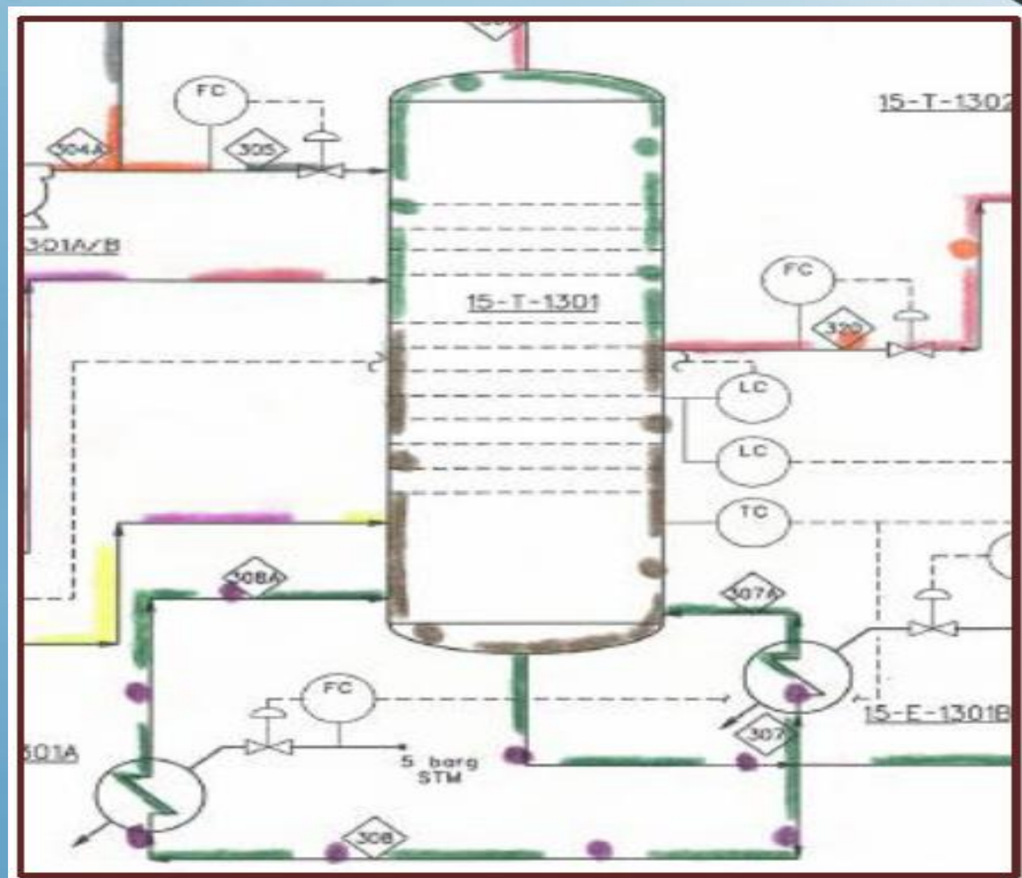
ID Corrosion Circuits
- Equipment and Piping Design, and Operating Conditions
- CVs, Inj./Mix Pts., IOWs, Bypasses
- Corrosion Circuits

ID Damage Mechanisms
- API 571 and Industry Experience
- Corr. & Mat'l Engineer
- Inspection History and Corrosion Rates
- Operating Parameters

Team Review
- Materials resistance
- Methods to prevent or mitigate DM
- Conditions that would accelerate, worsen, minimize or eliminate DM

Written Report
- Rationale for DMs susceptibility in each circuit
- Recommendations to mitigate or prevent damage
- Recommendations to adjust inspection or PM plans

Corrosion Circuit Diagrams



Courtesy of The Hendrix Group – Corrosion Control Documents Revisited – 2011 API Inspection Summit - David Hendrix presentation

Corrosion Circuit Diagrams

- Fixed equipment and piping in a process with:
  - Same stream composition
  - Similar operating pressure and temperature

    < 25F (~13C) difference

    <50 (~4 Barg) psig difference
  - Same materials of construction
  - Same phase, (liquid, vapor, etc.)

Courtesy of The Hendrix Group – Corrosion Control Documents Revisited – 2011 API Inspection Summit - David Hendrix presentation

Corrosion Circuit Attributes

- Circuit numbering system (legend)
- Circuit description
- Materials of construction
- Stream composition
- OP/OT/Phase information
- Corrosion precursors
- Operational upsets influencing corrosion

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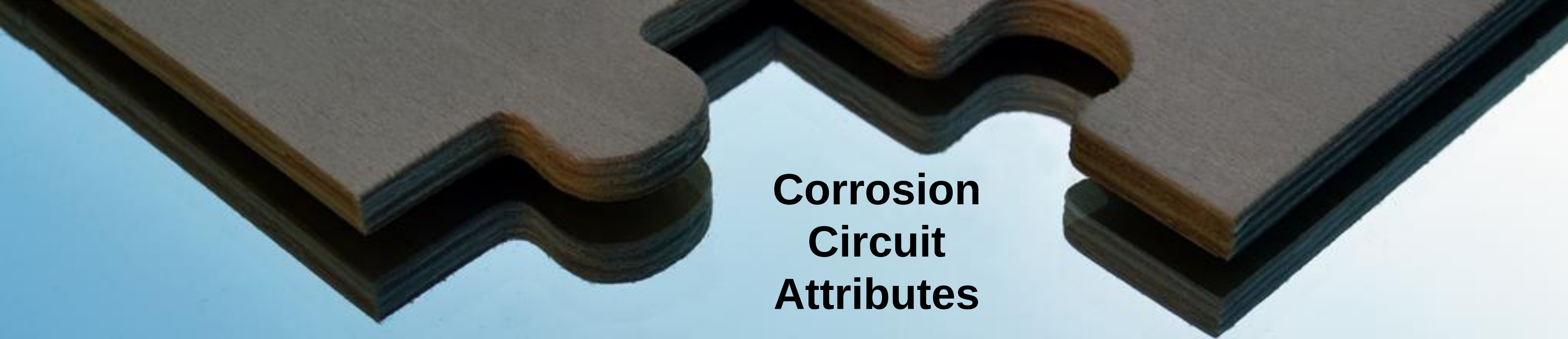

Corrosion Circuit Attributes

- Damage mechanisms
- Corrosion rates (predicted or actual)
- Critical areas
- Operating envelopes
- Startup and shutdown considerations

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Process Stream Composition

- Typically obtained from H&MB
- Difficult to obtain in refining units
- Small amounts of corrosives might not be listed:
  - Chlorides
  - Injected chemicals
  - Process contaminants or upset OP
- Should review with owner process eng.

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Process Stream Composition

- Examples of stream constituents that can influence or accelerate corrosion:
  - CO_2
  - H_2S
  - Chlorides
  - Acids
  - Oxygen
  - cyanides

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Critical Locations

- Location depends on damage mechanism
  - CO_2 – High velocity lines, elbows, etc.
  - Chlorides – Condensing, wet-dry, stagnant area, dead legs, etc.
  - Amine SCC – weld HAZ’s
- Up to unit inspector to locate specific areas in circuit on P&ID

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Report Formatting – Process Description

1. *Process Description*

The Crude Unit separates diluted crude feed into the following products:

- diluent naphtha
- combined distillate (mixture of light distillate, heavy distillate, light vacuum gas oil (LVGO), and purge naphtha).
- medium vacuum gas oil (MVGO)
- heavy vacuum gas oil (HVGO)
- vacuum residue

FEED PREHEAT

The feed is preheated by heat exchange with the following streams:

- diluent naphtha
- overhead vapor from the Atmospheric Tower
- light distillate pumparound and product
- heavy distillate pumparound and product
- medium vacuum gas oil pumparound and product
- heavy vacuum gas oil pumparound and product
- vacuum residue

Report Formatting – Circuit Assets

2. Corrosion Assessment of Specific Equipment Categories

2.1. Crude Preheat Exchangers to the Desalter Inlet

This includes the crude oil downstream of the storage tanks on the feed side of the preheat exchangers up to the Desalter inlet and the associated piping:

Equipment	Material	Description	Temp (°F)	Insulation (N - Ih - Is)	Anticipated Corrosion Rate (mpy)
Piping	CS+0.063"	Crude feed piping from battery limit to 10-E-001A/B/C Crude feed piping to 10-E-002A through J Crude feed piping to 10-E-004A/B/C Crude feed piping to 10-E-005 Crude feed piping to 10-E-006A/B/C/D Crude feed piping to 10-E-007A/B/C/D Heated feed piping to 10-E-008 Heated feed piping to 10-E-009 Heated feed piping to 10-E-010 Heated feed piping to Desalter Inlets Demulsifier chemical piping from 10-ME-003-TK-1 to injection points	101 101 101 210 215 215 264 273 285 307 98	N N N Ih Ih Ih Ih Ih Ih Ih N	<5 <5 <5 <5 <5 <5 <5 <5 <5 <5 <5
10-ME-003-TK-1	Vendor Package	Demulsifier Tank 10-ME-003-TK-1	98	N	<5
10-ME-003-P1A/B	Vendor Package	Demulsifier Injection Pumps	98	N	<5
Injection Point	CS+0.063"	Demulsifier chemical injection at HC-10-1003-J31D-20"-N	101	N	<10
Injection Point	CS+0.063"	Demulsifier chemical injection at HC-10-1014-J31D-14"-Ih	307	Ih	<10
Injection Point	CS+0.188"	Desalter water wash at HC-10-1050-J35A-14"-Ih	307	Ih	<10
Injection Point	CS+0.125"	Stripped sour water at HC-10-1050-J35A-14"-Ih	307	Ih	<10
Injection Point	CS+0.188"	Desalter water wash at HC-10-1060-J35A-14"-Ih	307	Ih	<10
Injection Point	CS+0.125"	Stripped sour water at HC-10-1060-J35A-14"-Ih	307	Ih	<10
10-E-001A/B/C	CS+0.125" shell CS tubes	Feed/Diluent Naphtha Exchangers (shell side)	101-210	Ih	<5
10-E-002A through J	CS+0.125" shell CS tubes	Feed/Atmospheric Tower Overhead Exchangers (shell side)	101-210	Ih	<5
10-E-004A/B/C	CS+0.125" shell CS tubes	Feed/MVGO Product Exchangers (shell side)	101-210	Ih	<5
10-E-005	CS+0.125" shell CS tubes	Feed/Diluent Naphtha Exchanger (shell side)	210-215	Ih	<5
10-E-006A/B/C/D	CS+0.125" shell CS tubes	Feed/Light Distillate PA Exchangers (shell side)	215-264	Ih	<5
10-E-007A/B/C/D	CS+0.125" shell CS tubes	Feed/MVGO PA and Product Exchangers (shell side)	215-264	Ih	<5
10-E-008	CS+0.125" shell CS tubes	Feed/Combined Distillate Exchanger (shell side)	264-273	Ih	<5
10-E-009	CS+0.125" shell CS tubes	Feed/HVGO Product Exchanger (shell side)	273-285	Ih	<5

Report Formatting – Specific Circuit DM Concerns

Specific Corrosion Concerns:

- Possible accelerated corrosion at the injection points where demulsifier chemical, desalter water and stripped sour water are injected into the crude oil feed. Consider the development of an injection point inspection program, using ultrasonic scanning and radiographic techniques, as discussed in API 570 and Inspection Strategy #20.
- Possible corrosion under insulation, for insulated piping and exchanger vessels with a process temperature less than 300°F. Consider a program for CUI inspection, as described in API 570 and Inspection Strategy #19.
- Possible wet H_2S cracking of heat exchanger shells and carbon steel piping. In general, none of the equipment has been PWHT. Exchanger and piping components are at low risk for sulfide stress cracking; however, other forms of long term cracking such as HIC and SOHIC would still apply. Consider prioritization and ultrasonic inspection strategies, as described in Inspection Strategy #17.

Report Formatting – IOWs and Operating Parameters

3. *Process Control Monitoring and the development of Key Critical Operating Parameters*

Process Control Monitoring is important to pressure equipment integrity, as well as product quality and production rates. The Key Critical Operating Parameters are those process operating limits that will significantly influence corrosion and other material degradation mechanisms in the Unit. They are listed in this Risk Assessment for guidance only. These operating limits should be established after the Unit is in operation as a joint exercise between the Corrosion Engineer, Unit Operations and the Unit Process Engineer. Where limits apply to the injection of chemicals, (i.e. neutralizing amine or corrosion inhibitor), then the chemical treating specialist should also be included in determining these parameters. Where appropriate, typical limits used in industry have been provided, for reference.

3.1. Crude Preheat Exchangers to the Desalter Inlet

Monitor for:

Salt content of crude oil (measured by double extraction)
Sulfur content of crude oil
Acid content of crude oil

Damage Mechanism Reviews

The Damage Mechanism Review will become an important part of a mechanical integrity program.

Results can be incorporated into validation of Integrity Operating Window programs, Ciruitization of equipment and piping for corrosion monitoring and locations for CMLs.

DMRs may be useful with RBI programs and special emphasis inspections.

There are many ways that DMRs can be formatted to accomplish the end goal of defining damage mechanisms and presenting the rational for active DMs, capturing the review by the DMR Team, and the final improvement plans for inspection and PMs.