Sunoco Marcus Hook Refinery Ethylene Unit Fire - May 17, 2009 Lessons Learned

API Subcommittee on Inspection

Dallas, TX, November 11, 2009

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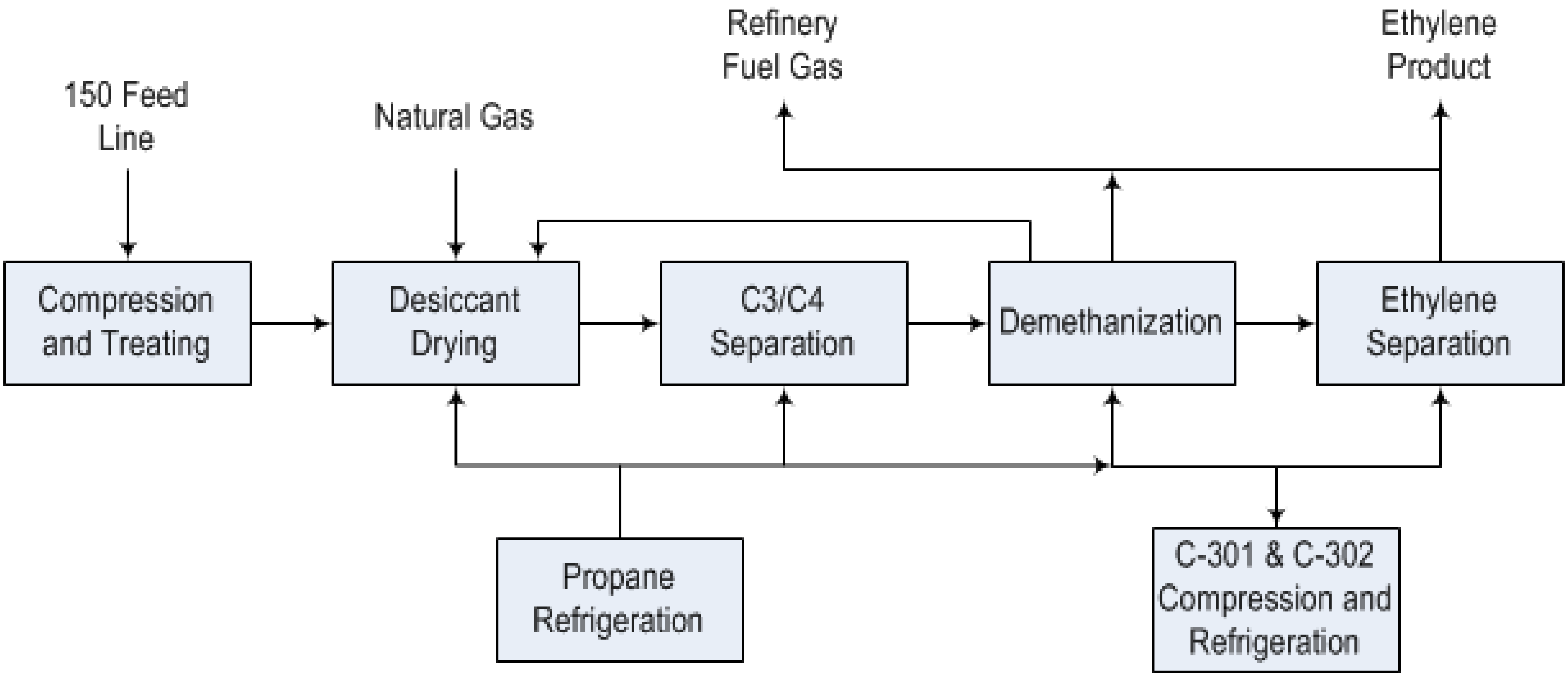
OFFICIAL FUEL OF NASCAR

Ethylene Unit Simplified Block Flow Diagram



What Happened

- 10:15 p.m. 5/17/09 - large hydrocarbon release and fire. Large and intense initial fire.
- Numerous secondary releases within 10 minutes.
- Operators isolating fuel sources and emergency responders applied water to the fire area with 10 minutes of initial release.
- Fire burned under control as systems depressured.
- Fire was extinguished at 4:42 p.m. on 5/18.
- There were no reported injuries from the fire or emergency response activities.
- An investigation was started on Monday morning, 5/18, while the fire continued to burn.

Basic Timeline of Events

10” x 7” rupture hole on the 10”” process outlet line of the gas dryers

Instant

Ethylene feed gas is released at approx 60F and 480#.

0.5 sec

The vapor cloud rapidly travels SE toward heater H-202.

0.5 sec

Ignition source at top of H-202 fire box ignites the vapor cloud.

0.5 sec

The blaze flashes back, toward the original fuel source, creating a large and sustained fire.

3 to 10 min

Multiple secondary pipe failures from short term overheat add fuel to the blaze.

People Evidence: Interviews

- Many eye/ear witnesses heard an initial loud release noise “like a high pressure boiler safety”.
- While looking toward the source of the noise the loud ignition and fire was observed “within a couple of seconds”.
- The initial fire was very large and very intense: “over 300 ft high and 300 ft wide”.
- Several secondary releases within a couple minutes and “for around 10 to 15 minutes”.
- Operators and fire fighters on scene reported several ruptured pipes feeding the fire.

Fire Photo

EC boiler stack ~300 ft high

Photo on left was taken from an eyewitness camera phone within one minute of the initial release and fire. Distance is approximately ½ mile from the ethylene unit.

Physical Evidence: Initial Failure

- Pipe failure on the 210A/B/C process drier common outlet line.
- This is the <u>**only**</u> failure found which is <u>**not**</u> a secondary failure from short term overheat.

Initial Failure

- Reduced amount of heat damage in the area around the failure indicates "too rich".
- suggests a very large fuel source.

Initial Failure

- The location of the failure was at the bottom of the line at pipe rack support.
- Failure mode is pipe wall thinning and rupture due to localized contact area external pipe corrosion.

Multiple “Fish-Mouth” Failures

Inspection and operations identified all of the other pipe failures within the fire zone – all of which were due to short term overheat:

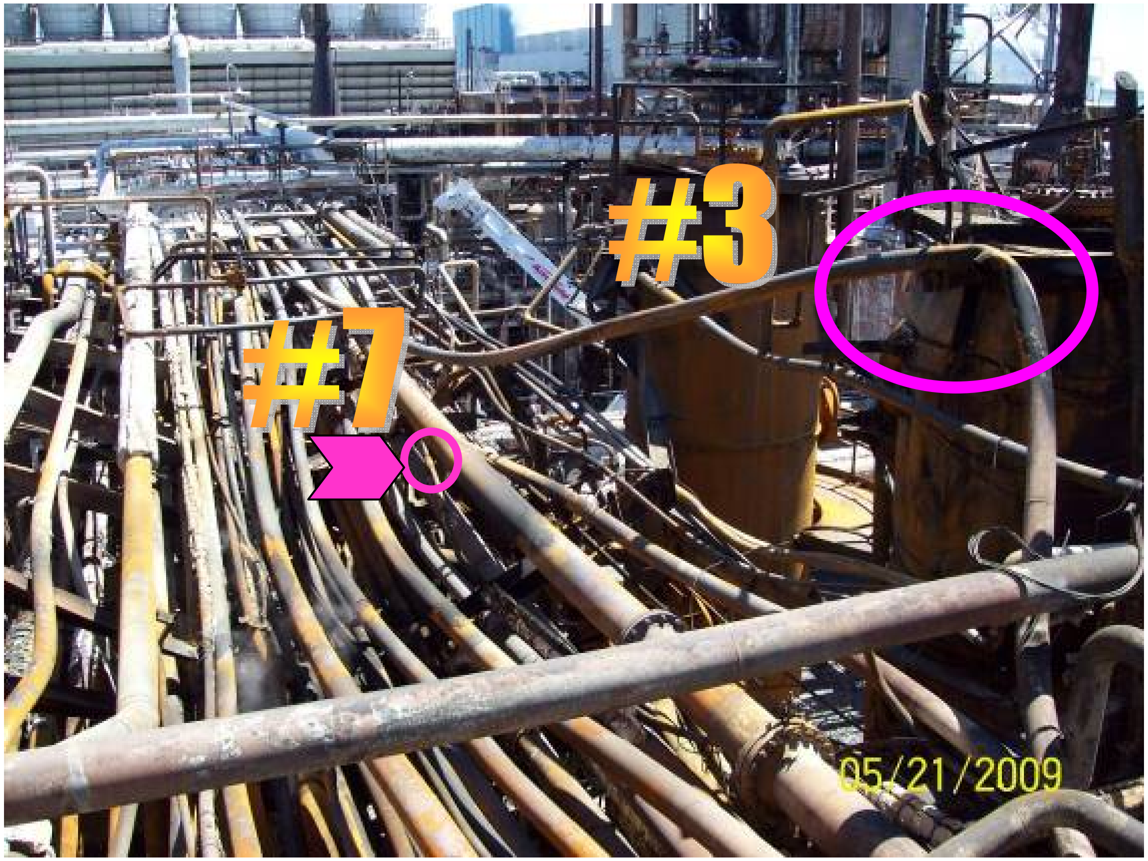
1. 4” Propane line to V104
2. 8” Hydrogen Users line
3. 6” High pressure ethylene
4. 850# steam
5. 190# steam
6. OOS BP/Tosco Feed Line
7. 2” Spent Caustic Line (Found 6/09/09)

Secondary Pipe Failures

- #1 - 4” 100 psig propane liquid line from 15-2 gas plant.
- Process data indicates this line failed ~3 minutes after the initial failure.

6” High Pressure Ethylene Line Fish Mouth

- #3 - 6” 450 psig ethylene gas product line.
- This line failed ~6 minutes after the initial line leak.
- The line itself is deformed due to reaction forces from the leak.
- #7- Failed 2” Spent Caustic Line.



850# Steam Fish Mouth

- #4 - 12” 850 psig steam line failure.
- This line failed ~8 minutes after the initial leak.

Ignition Source

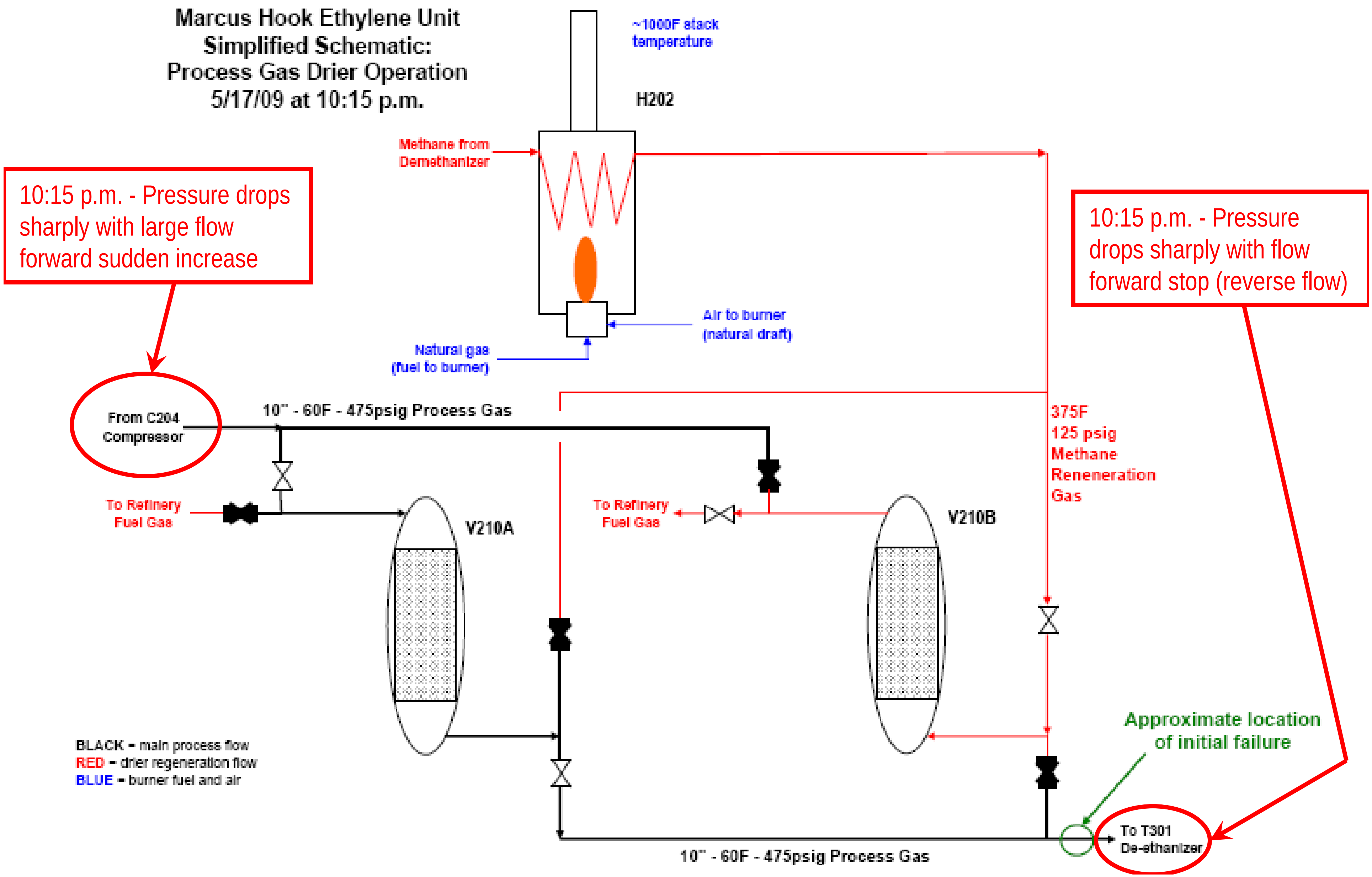
- Top of fire box would be slight negative pressure.
- Stack flue gas temperature was ~1000F at the time of the fire.

Gaps at coil inlet and outlet

- Heater shell leaks could pull vapor cloud into the ignition source – and then flash back out.

Gaps around access door

Process Drier Simplified Schematic



Physical Cause Summary

- Initial failure was the 10” ethylene feed gas line.
- The ignition source was at top of H-202 fire box.
- Dispersion model used to correlate findings.
- The cause of the initial failure was external contact area (crevice) corrosion.
  - External corrosion typically causes small leaks.
  - Why was contact corrosion area so large?
  - Where else could there be risk of a similar failure?
  - How to prioritize inspections to avoid another rupture?
- Investigation continues to identify root causes.

Loose sleeve under pipe at failure location

- Sleeve is 9-1/2 inches long and provided extended area of contact corrosion.
- Large corrosion area explains large initial “blowout” failure.

The loose sleeve was found under the failure (resting on top of the pipe support) the morning after the fire.

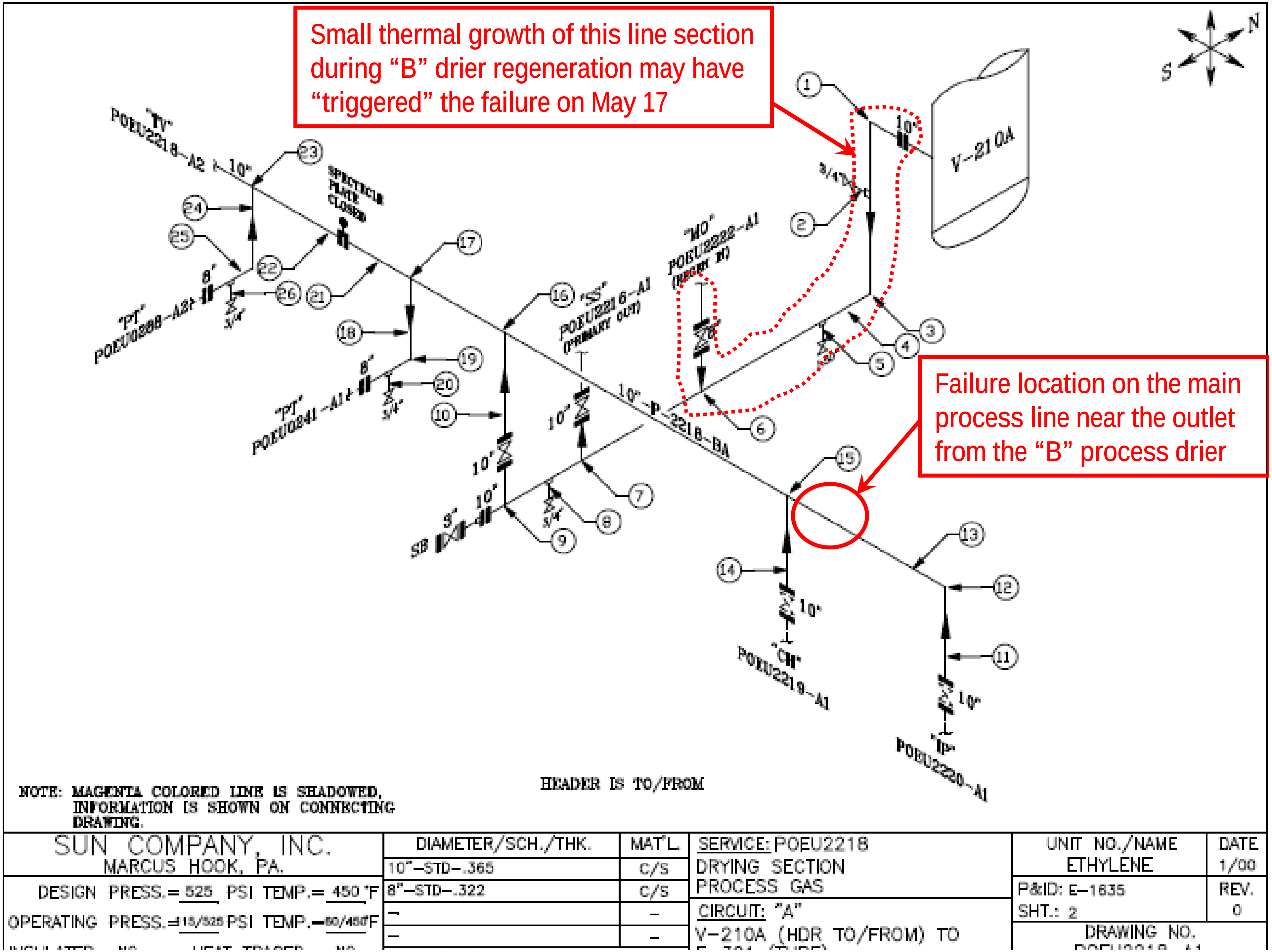
- This 10” diameter line was found at another location in the plant with similar large area of contact corrosion (this location had not yet failed).
- Believe similar loose sleeve was under this line, but the sleeve could not be found after the fire event.

8” methane gas line with external patch repair at pipe support location (repair patch was pre-1990).

Inside of line shows ~1” hole under the repair sleeve.

After the repair patch is removed from the 8" line there is evidence of a similar large contact area corrosion where a loose sleeve previously existed. This location progressed to a small consequence leak at some time prior to 1990.

Note how this lower pressure (~80 psig) line has higher probability of a smaller failure, where high pressure (~480 psig) line has greater potential for a large blowout rupture.



Small thermal growth of this line section during “B” drier regeneration may have “triggered” the failure on May 17
Failure location on the main process line near the outlet from the “B” process drier
"TV" POEU2218-A2
"PT" POEU0288-A2
"PT" POEU0241-A1
SPECTACLE PLATE CLOSED
"SS" POEU2216-A1 (PRIMARY OUT)
"MO" POEU2222-A1
10"-P-2218-BA
"CH" POEU2219-A1
"IP" POEU2220-A1
SB
N
S
NOTE: MAGENTA COLORED LINE IS SHADOWED, INFORMATION IS SHOWN ON CONNECTING DRAWING.
HEADER IS TO/FROM
SUN COMPANY, INC.
MARCUS HOOK, PA.
DESIGN PRESS.= 525 PSI TEMP.= 450 °F
OPERATING PRESS.= 15/525 PSI TEMP.= 60/450 °F
DIAMETER/SCH./THK.
MAT'L
10"-STD-.365
C/S
8"-STD-.322
C/S
SERVICE: POEU2218
DRYING SECTION
PROCESS GAS
CIRCUIT: "A"
V-210A (HDR TO/FROM) TO
UNIT NO./NAME
ETHYLENE
DATE
1/00
P&ID: E-1635
SHT.: 2
REV.
0
DRAWING NO.

Inspection Thickness Monitoring

Sunoco Marcus Hook

PCMS TML Report for Unit ID ETHYLENE PLANT

Equipment ID	Circuit ID	TML ID	Sketch	Description	Pipe Size (in)	Retire Limit (in)	Specific Material	Pipe Schedule	Repl. Freq. No. / Years	Readings (in) Thick	Date	M	Q	Loc	Code
PIP		10	2218-A1	PIPE	10.00	0.190	SA53 Grade A	STD	0 /						
										0.365	08/1961	N		NA	
										0.380	08/1989	U	G	NA	+L
										0.360	08/2002	U		E	L
		11	2218-A1	PIPE	10.00	0.190	SA53 Grade A	STD	0 /						
										0.365	08/1961	N		NA	
										0.420	08/1989	U	G	NA	+
										0.461	04/2000	R	V	NA	+L
										0.362	03/2009	U	L	S	L
		14	2218-A1	PIPE	10.00	0.190	SA53 Grade A	STD	0 /						
										0.365	08/1961	N		NA	
										0.411	04/2000	R	G	NA	+L
										0.363	03/2009	U	L	N	L

- Minimal wall loss over ~48 years; service is non-corrosive.
- Pipe would need to be <0.050” thick before it would burst.
- Data from March 2009 shows >0.350” remaining thickness (original nominal thickness of 0.365”).
- Thickness data detects general thinning, and is not effective for localized problems such as contact corrosion.
- External visual inspections are also made per API-570.

API-570 Visual Inspection Report

Sunoco, Inc. NERC
External Piping Inspection Checklist

Date: 4/ 2 / /05

Unit: ETHYLENE   Circuit: ____________   Sketch #: POEU 2218-19 /

Inspected By [redacted]   Company [redacted]   API 570 #: [redacted]

Item	Condition Present Yes	Condition Present No	Comments	Accept	Reject
1. Leaks					
a. Process (Flanges, welds, etc.) b. Steam tracing c. Existing clamps		X		X	
2. Alignment of Pipe					
a. Piping misalignment / restricted movement b. Expansion joint misalignment		X		X	
3. Loss of Integrity					
a. Vibration b. Excessive overhung weight c. Inadequate support d. Fasteners		X		X	
4. Supports					
a. Deformation b. Improper clearances c. Evidence of binding d. Physical displacement e. Support corrosion / erosion / wear f. Debris g. Bottomed out springs		X		X	
5. Piping Component Condition					
a. Corrosion b. Erosion c. Galling d. Scaling e. Biological growth f. Soil-to-Air interface g. Coating / Painting deterioration h. Cracking	X		5·A 5·G	X	
6. Insulation					
a. Damage b. Missing (jacketing / insulation) c. Sealing deterioration d. Bulging e. C.U.I. f. Inspection plugs		X		X	
7. Other					
a. Small Bore Piping issues b. Dead-leg issues c. Safety Valves (Properly tagged) D.Pitting		X		X	

8 Summary

5·A   Surf Rust   Aprox 40 FT

5·G   P. Failure   Apox 40 FT

*******Rejected items will be further reviewed by Area Inspector*******

Area Inspector : ____________________   Reviewed Date: ________________

Use back of form if needed

- External inspection in 2005 indicated only surface rust and deteriorated paint.
- These are normal and expected conditions for a pipe that is 48 years old.
- There were no identified contact corrosion concerns.
- In retrospect, we recognize that conventional API-570 visual practices are not sufficient to have detected this localized corrosion which was obscured by the concrete support and loose sleeve.

Learning #1: General Awareness

- Awareness for refinery personnel of this potential problem (internal publication and facility presentations).
- Vigilance and observations to identify locations of concern.
- Report findings to site inspection authority – ***do not attempt to disturb the area of concern***.
- The more people who are aware and making observations for this type of corrosion the better!
- Share findings throughout industry with presentations and publications (API, NPRA, IPEIA, EEMUA, EPC/AIChE, ACC, OSHA, EPA, etc.).

Learning #2: Design & Engineering

- The loose sleeve was installed during initial construction in 1961 or within first few years of service.
- Unit built by SunOlin using Lummus specifications; purchased by Sunoco ~1990.
- Original SunOlin/Lummus specs did not include the use of this loose sleeve.
- Were the specs not followed? Or deviation from specs during construction or subsequent maintenance?
- Current Sunoco Standard 0701 (2006 revision) does not allow the use of this type of loose sleeve.
- Ensure conformance with Sunoco Standards for new construction or repairs/replacements to ensure future installations are not susceptible to this type of failure.

Sunoco Standard 0701

(s) **1.2 Scope**

This Practice provides the governing criteria of the design and selection of pipe supports for aboveground piping systems. Project requirements shall identify the extent of design, selections, and shop and field fabrication of pipe supports by the engineering contractor. Repairs, modifications to and replacements of existing pipe support/pipe support elements shall conform to the requirements of this Engineering Standard.

shall be governed by the pipe class, design temperature and the environmental conditions expected to be encountered in the respective operating unit or plant. All pipe support element contact areas shall be designed to prevent local electrolysis or galvanic action.

(Δ) **4.6** Structural Steel for support design shall conform to the requirements of Sunoco Standard 0301 Design, Fabrication and Erection of Structural Steel

(Δ) **4.7** Requirements for welding of structural connections shall be in accordance with AWS D1.1. Sufficient surface shall be provided on structural connections to accommodate the weld sizes detailed on the pipe support drawings. To the extent practical, structural connections shall be welded all around to minimize the effects of corrosion.

Sunoco Standard 0701

(a) **5.16 Corrosion / Wear Protection for Uninsulated Pipe Directly Supported by Structural Steel or Concrete**

5.16.1 For new construction, there shall be no direct contact between steel pipe, (sizes 2" up to and including 24" NPS), and supporting structural steel, (racks or individual supports such as concrete pillars). Instead, either teflon or graphite slide assemblies attached to the structural steel or FRP saddle/cradle wear pads that utilizes a two part epoxy compound attached to the pipe shall be used at the point of bearing to support the load and protect against abrasion and subsequent corrosion. The use of pipe shoes is an acceptable alternative.

Note:

1. The intent of this requirement is to eliminate abrasion between pipe and steel which could compromise the protective coatings of each. This in time could lead to an undesirable condition where accelerated corrosion results in local metal loss which in turn can affect the integrity of the pipe or supporting steel. The method of support to be used, i.e. FRP wear pads, slide assemblies or shoes shall be determined at the beginning of the project.
2. Caution is to be exercised when specifying FRP wear pads or teflon slide assemblies on lines that may be subjected to periodic steam out. Wear pads and the adhesive used must be able to withstand the steam out temperature without disbondment. Advanced Piping Products, Inc. in Houston, Texas. has supplied vinyl ester FRP reinforced wear pads with a two part epoxy sealing system in hydrocarbon services where steam out temperatures can be as high as 400°F.

Learning #2: Design & Engineering Additional Improvements to Standards

The use of non-metallic half-round pipe support will minimize contact area, avoid protective coating abrasion, and avoid the potential creation of a galvanic corrosion cell.

Source: http://www.stoprust.com/6pipesupports.htm

Learning #3: Inspection Procedures

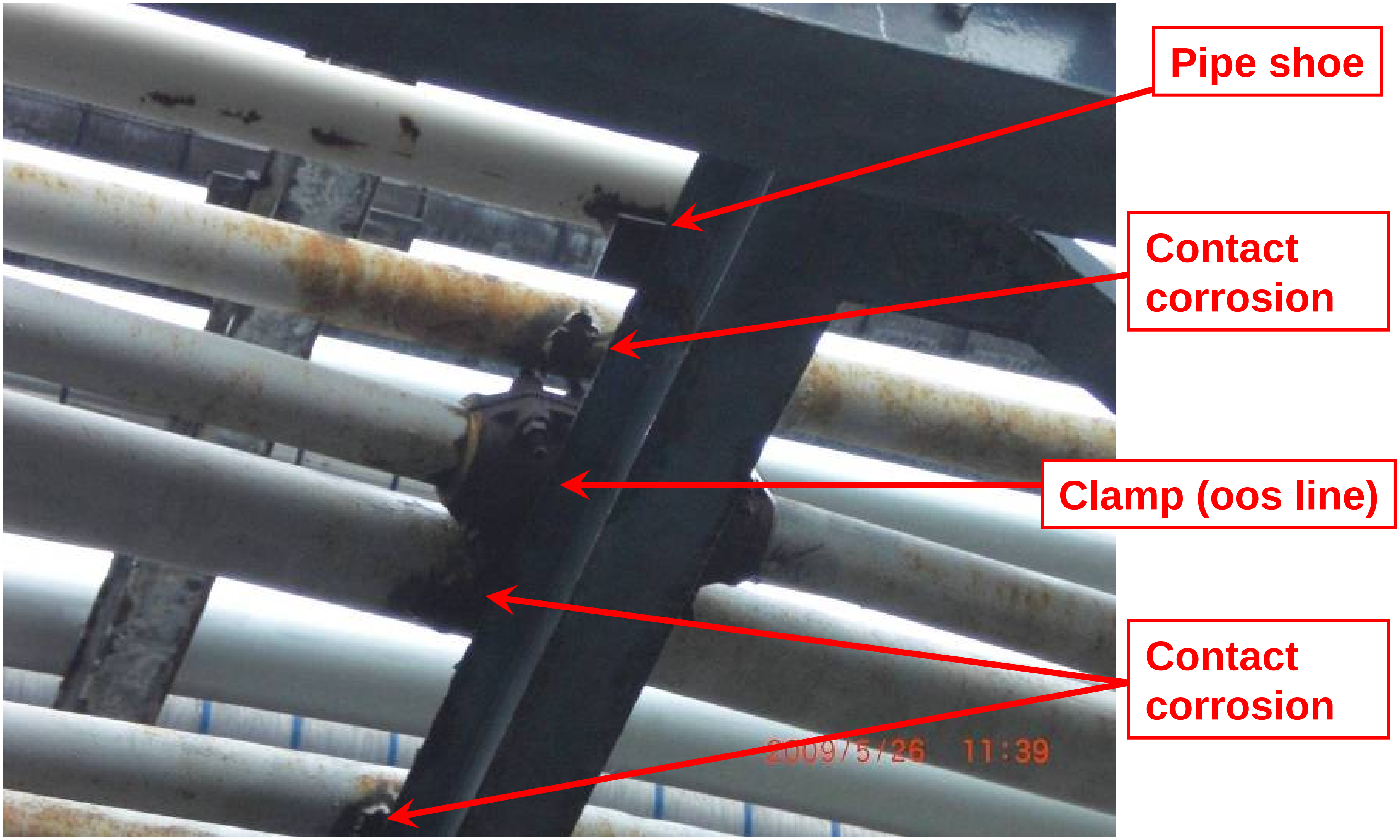
- Sunoco R&S and site-specific inspection practices are being upgraded.
- More rigor and detail to be required at pipe support and similar contact areas.
- If sleeve or similar installations are present they must be examined to be sure they are intact or to look for evidence of **obscured** corrosion.
- Similar conditions will not be missed during ongoing and future inspections.
- Findings and recommendations are being shared with industry mechanical integrity groups.

Retroactive Inspections for selected high-priority systems

<u>Focus</u>: Find any similar areas of “large rupture” vulnerability that may have been missed with previous inspections.

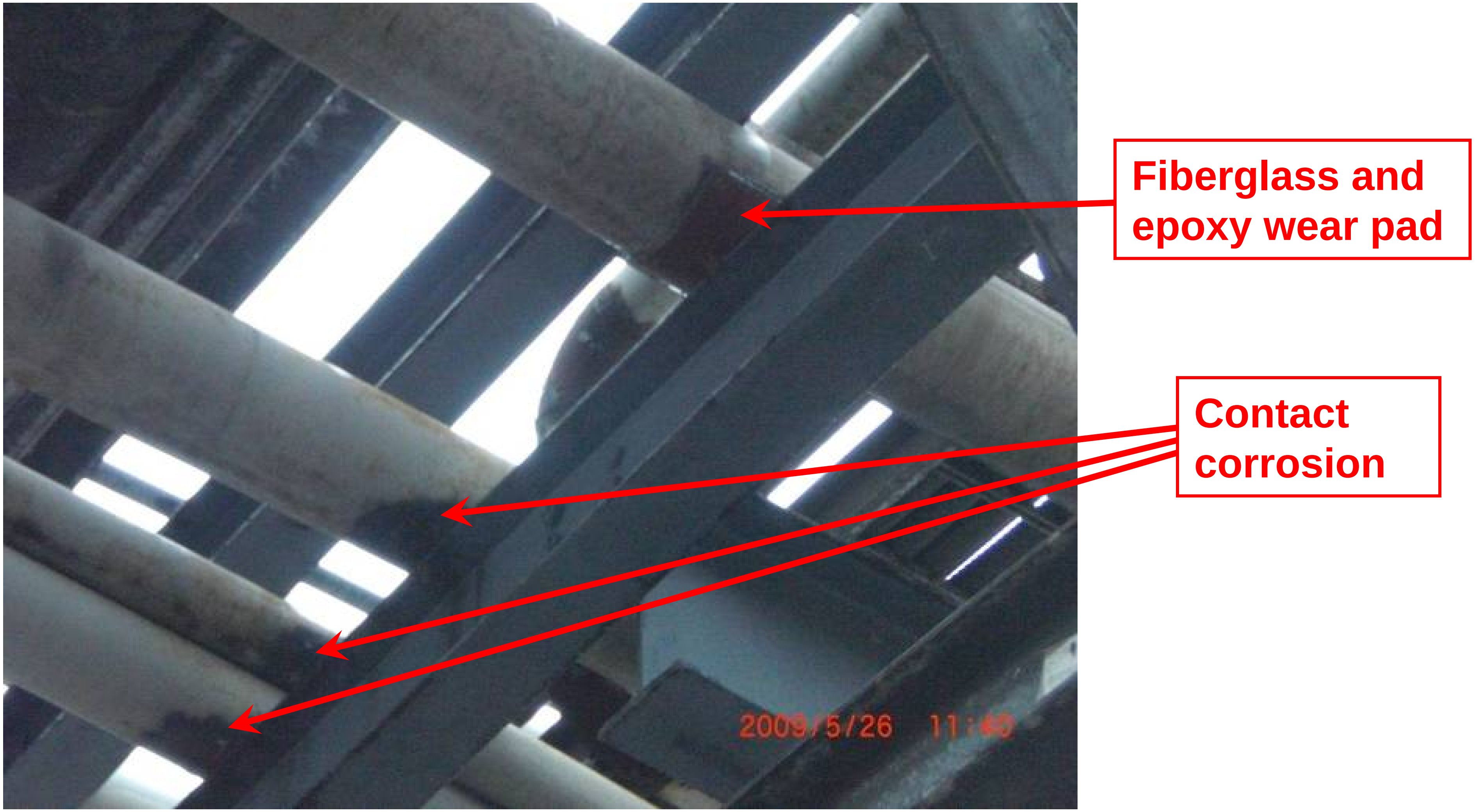
- What to inspect
- How to inspect
- How to prioritize
- How to assess conditions found
- How to make repairs or mitigation

Contact Point Corrosion – Crevice Corrosion



- Other examples of contact corrosion common in refineries.

Contact Point Corrosion – Crevice Corrosion



- More examples of contact point corrosion.

Contact Point Corrosion – Crevice Corrosion

Inspection of Pipe Supports

- Need inspection strategy to find high risk items before failure.
- Visual guideline to screen and prioritize areas for further detailed inspection and assessment.
- Simple system to combine with other risk-based drivers (likelihood and consequence of failure) to allow rapid screening of large numbers of support points.
- Crevice corrosion to be graded in three levels of severity: light, moderate, and heavy.

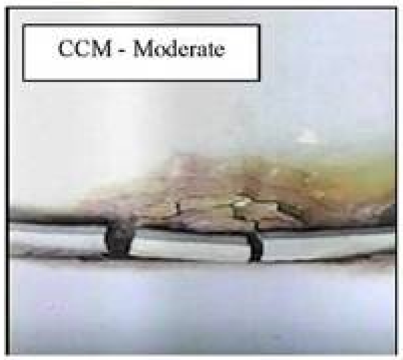
Contact Point Corrosion – Crevice Corrosion

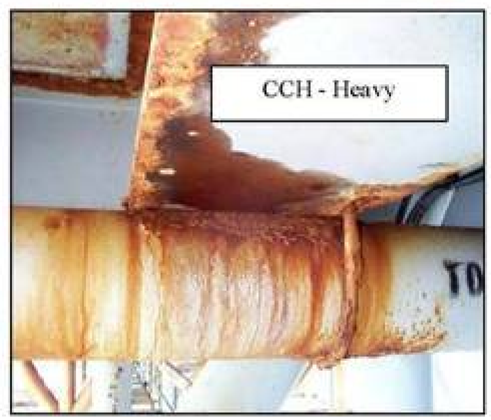
Definitions used to define these are as follows:

- **CC-L (Light Crevice Corrosion)** - Corrosion products visible but no evidence of layered scaling.
- **CC-M (Moderate Crevice Corrosion)** - A single layer of corrosion scale is visible at the edge of the crevice.
- **CC-H (Heavy Crevice Corrosion)** - corrosion product leaching and visible multi-layer corrosion scale is visible.
- When investigated more closely, the **CC-M** and **CC-H** situations would be expected to show a wall loss at the deepest pit of >40%.
- A visual guide is provided to assist in making the correct assessment.

Source: http://www.stoprust.com/6pipesupports.htm

Contact Point Corrosion – Crevice Corrosion





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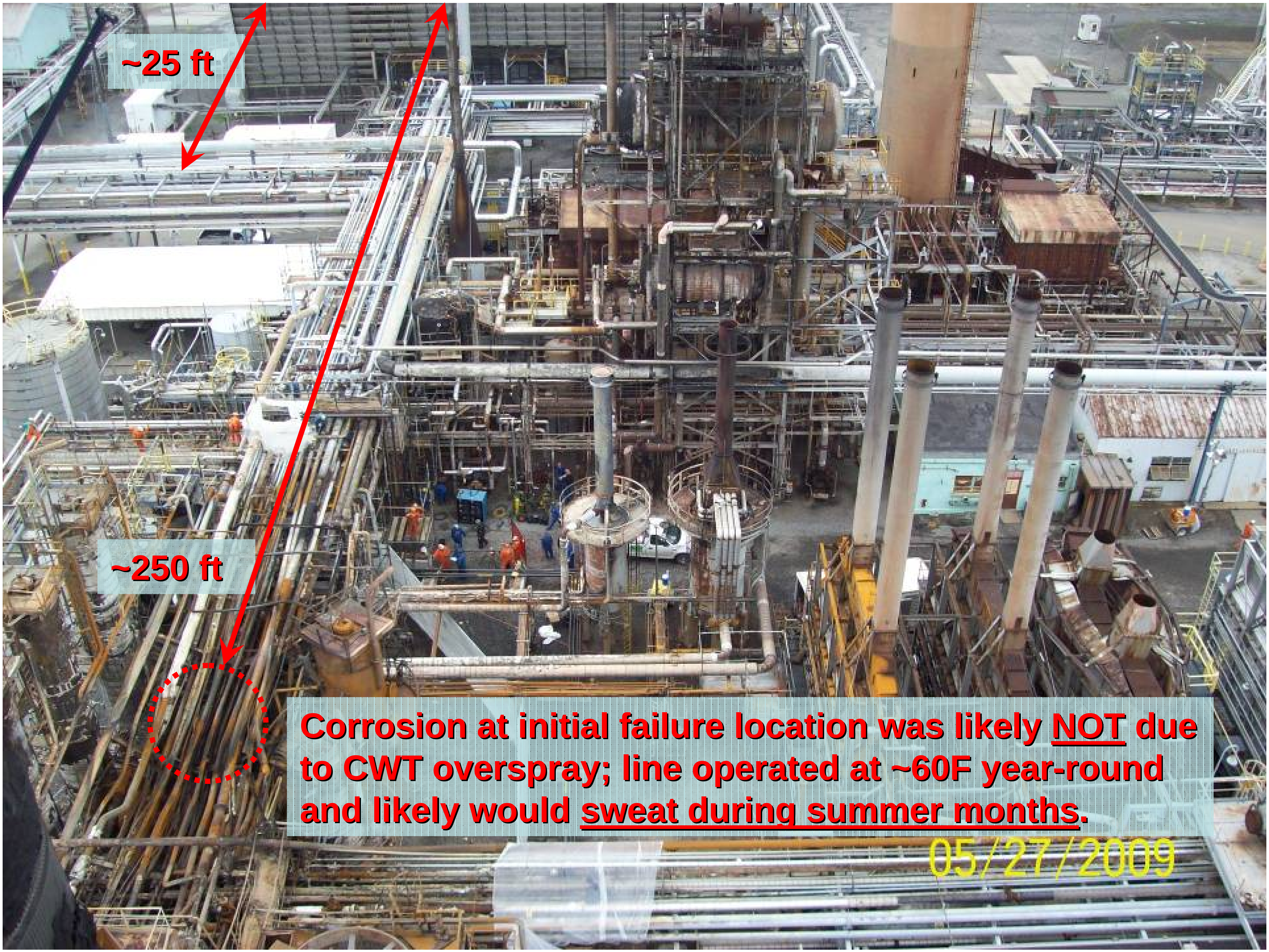
~25 ft
~250 ft
Corrosion at initial failure location was likely NOT due to CWT overspray; line operated at ~60F year-round and likely would sweat during summer months.
05/27/2009

Retroactive Inspections – Criteria to Identify "High Risk" Systems

- Urgent priority inspections for process systems :
  1. Operating pressure above 150 psig; and
  2. Gas, LPG, or other vaporizing liquid services; and
  3. Piping larger than 2" diameter; and
  4. Piping with a service life of 20 years or longer; and
  5. Carbon or low-alloy steel (12% chrome or less); and
  6. Operating temperature of 32^{o}F to 80^{o}F, or operating between 80^{o}F and 250^{o}F **and** proximity to an ambient moisture source (such as a cooling tower).
- If all 6 criteria are met, then the system has potential risk of large rupture failure from undetected contact area corrosion.

Retroactive Inspections – Implementation

- Site inspection authority to take the lead role on these high-risk systems identified.
- Review past inspection records.
- Additional field walk-down inspections as needed.
- Areas of concern to be further evaluated with NDE and/or close visual examination, to permit fitness for service assessment.
- Where heavy corrosion is found the lines will be depressured before repairs or mitigation is attempted.

Learning #4: Cold-Eye Mechanical Integrity Program Review

- Inspection practices and work quality conform with industry requirements and top performers – but is this good enough?
- If we missed this condition it suggests we have areas for continued improvement.
- What other gaps may exist?
- How can we identify these gaps proactively?
- External consultant with broad industry expertise to review mechanical integrity practices.
- Comparison with industry pacesetter practices to benefit from industry-wide learning.

Learning #5: Mitigation Devices

- Initial fire location was ~75 feet from boundary limit block valves and fixed fire monitors.
- ~150 ft radius initial hot zone restricted ability to shut valves or apply cooling water within first 3 minutes.
- 50 ft distance from plausible fire sources is the standard to determine when remote actuation is needed.
- Mitigation is targeted to keep small or moderate initial events from becoming larger events; this initial event was too large, but **was contained effectively**.

Learning #5: Mitigation Devices

- Some problems with access and operation of unit isolation valves (at Ethylene and other refinery units) while trying to isolate fuel sources.
- Emphasize the need to identify refinery-wide **emergency isolation valves**:
  - To perform design and operability reviews;
  - For rapid access in an emergency;
  - Impose operational controls (such as not used for throttling service which could erode seats);
  - Periodic operability checks (exercised); and
  - Preventive maintenance schedule.
- **Assure high reliability when they are needed.**

QUESTIONS?

Thank you!

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