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PRCI Research Exchange

Case Studies in Corrosion Trends taken from Liquid Pipelines Experiencing Increased Operating Temperatures

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    - Line A Corrosion Digs and Corrosion Growth Rate (CGR)
    - Line B Regression Analysis
    - Line C Corrosion Failure
- **Conclusions**

Introduction

- Pipeline operating temperature increases due to
  - Increasing flow rate of heavy crude oil – higher frictional heating
  - Hotter product entering pipelines
  - Environmental warming
- Arrhenius Equation

$$Corrosion\ rate = Ae^{\frac{-E_a}{RT}}$$

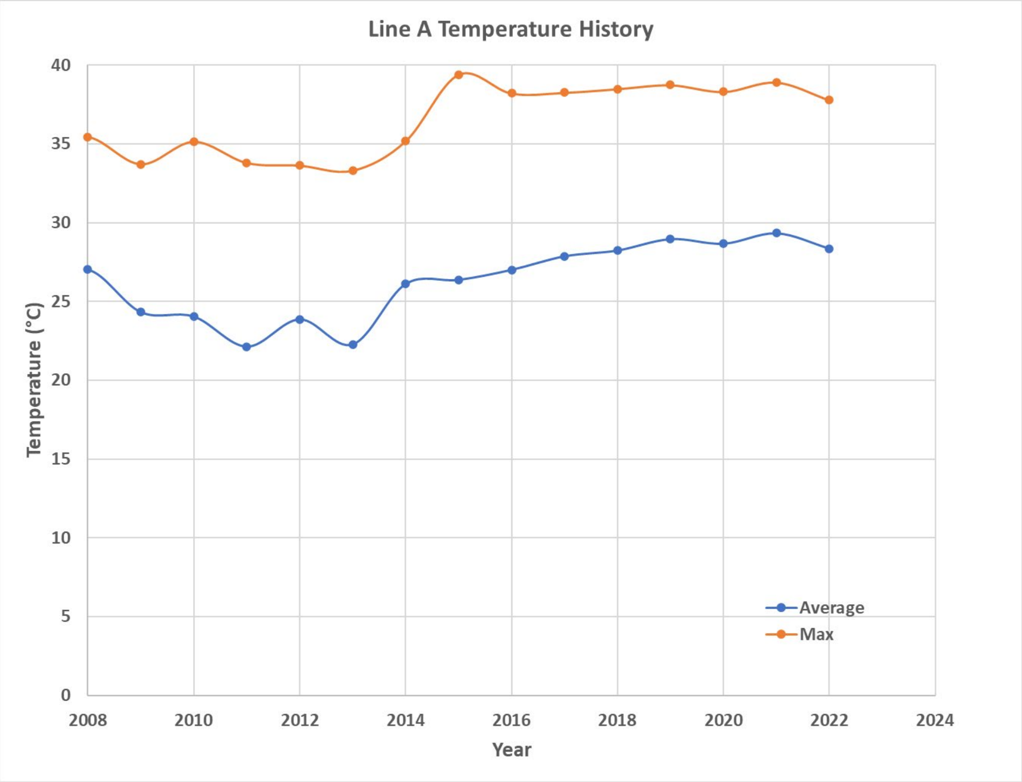
A - pre-exponential factor, E_a - activation energy, R - Universal gas constant, T – Absolute temperature

Corrosion growth rate (CGR) doubles with every 10°C temperature increase

- Does this really happen to the real-world pipelines?
  - Case study of three in-service liquids pipelines

Case study: Line A Corrosion Digs and CGR

- Pipe properties: 1960s vintage, PE tape coating
- Over 700km long: Segment 1 and Segment 2
- Maximum and average operating temperature increased by 5-10℃ after 2013



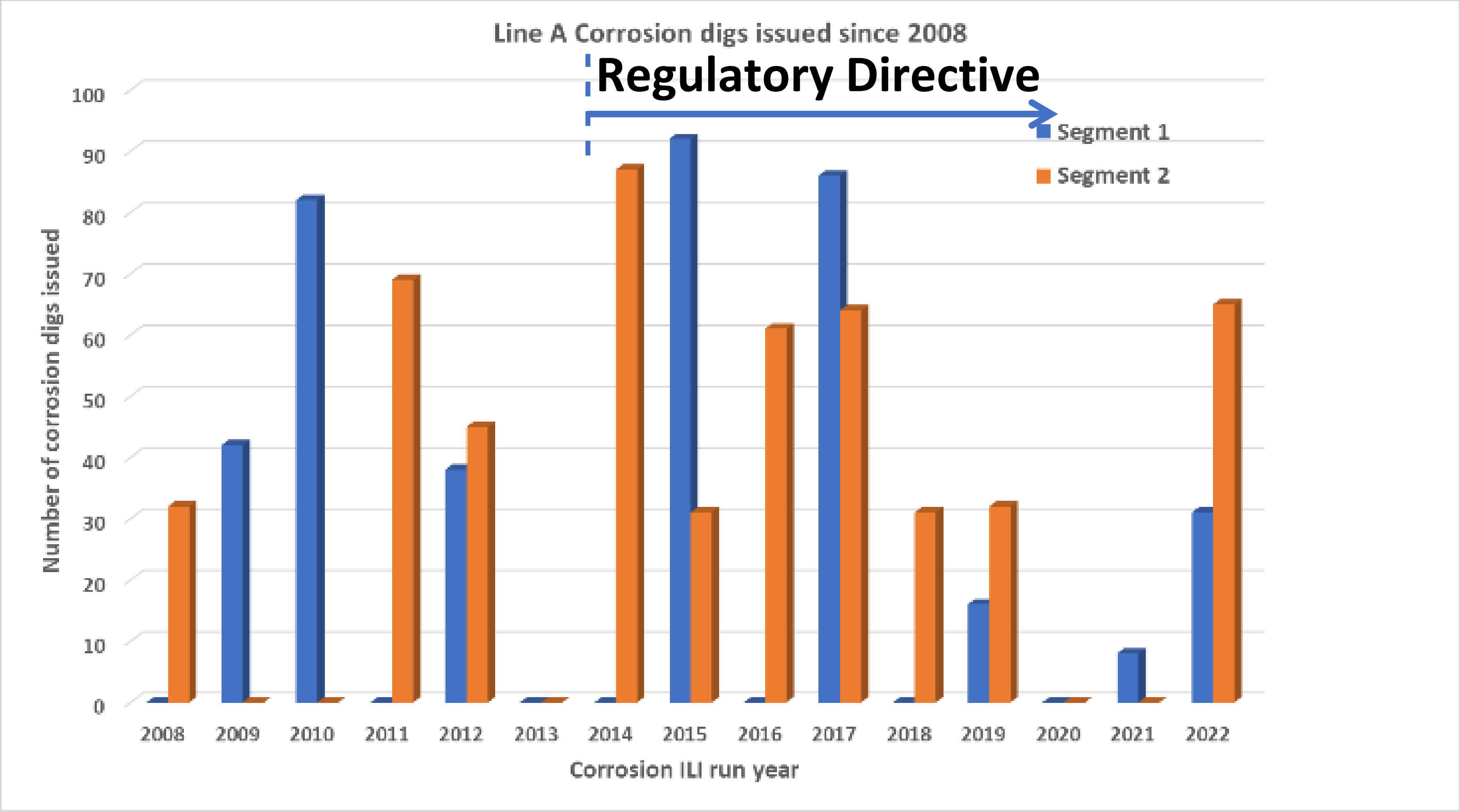
Case study: Line A Corrosion Digs

ILI history and issued corrosion digs

	Segment 1				Segment 2			
ILI year	MFL	UTWM	MFL-C	Sum	MFL	UTWM	MFL-C	Sum
2008				0	32			32
2009	33	9		42				0
2010			82	82				0
2011				0	4		65	69
2012	19	19		38		45		45
2013				0				0
2014				0	87			87
2015	10	61	21	92		31		31
2016				0	38		23	61
2017	48	38		86		64		64
2018				0	31			31
2019	8	8		16	3	29		32
2020				0				0
2021		8		8				0
2022	31			31	8	57		65
Sum	149	143	103	395	203	226	88	517

Case study: Line A Corrosion Digs

The correlation between increased corrosion digs and increased operating temperature is not seen

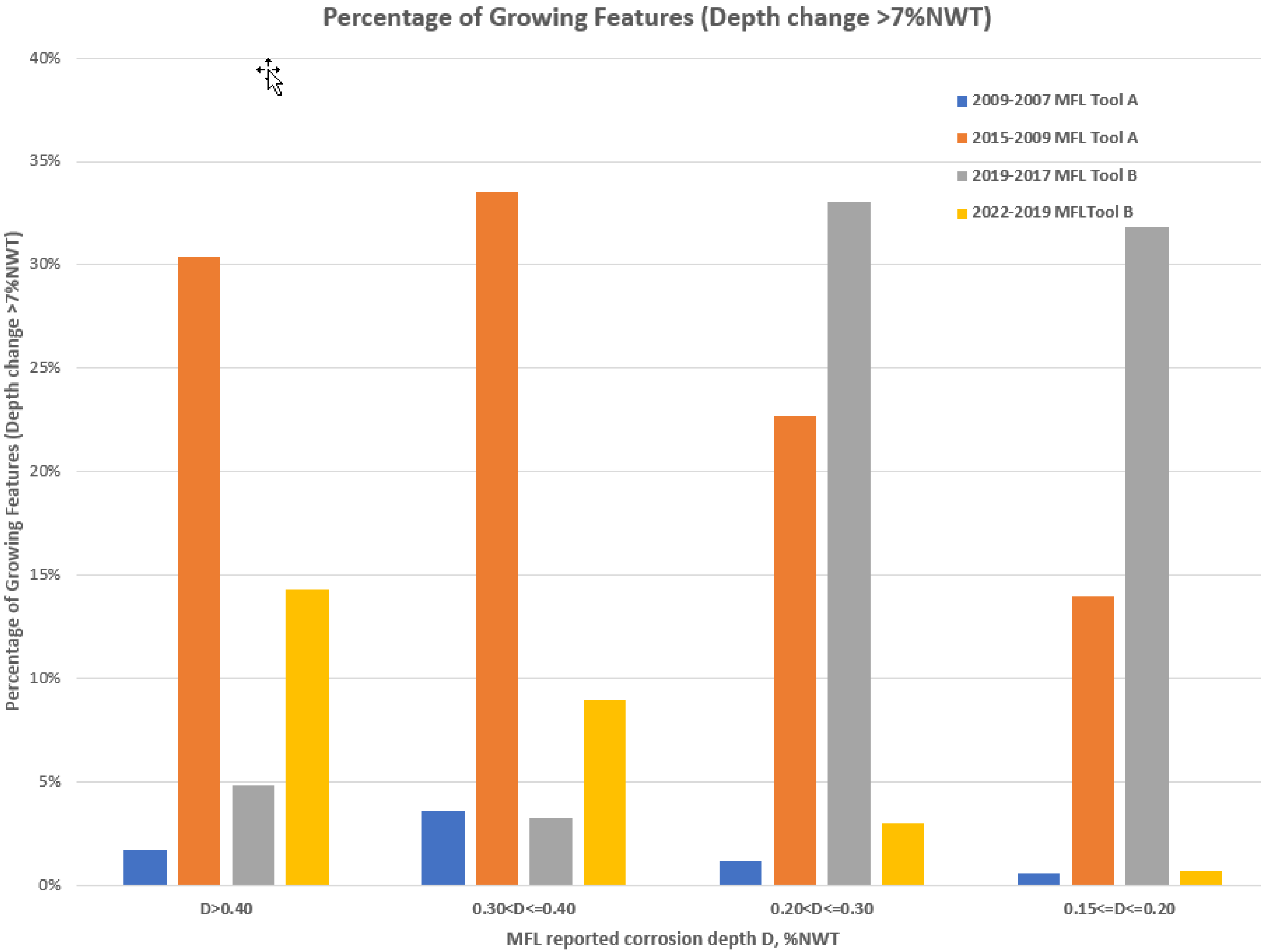


Case study: Line A CGR

RunCom CGRs by MFL

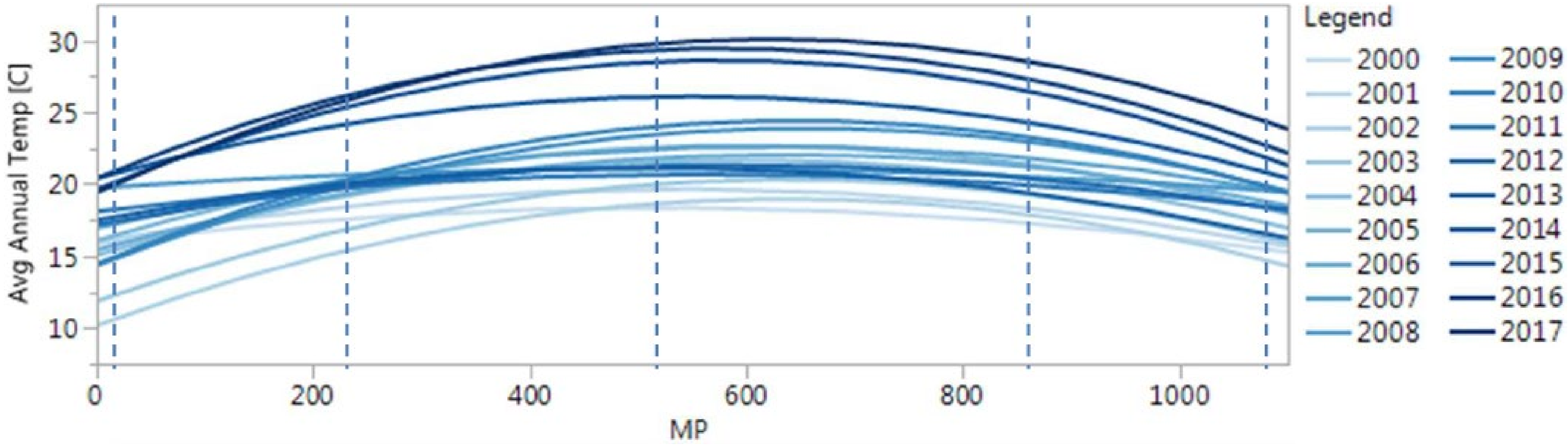
- Growing features
- Depth bins

Expected higher CGR, more growing features and thus more corrosion digs are not observed



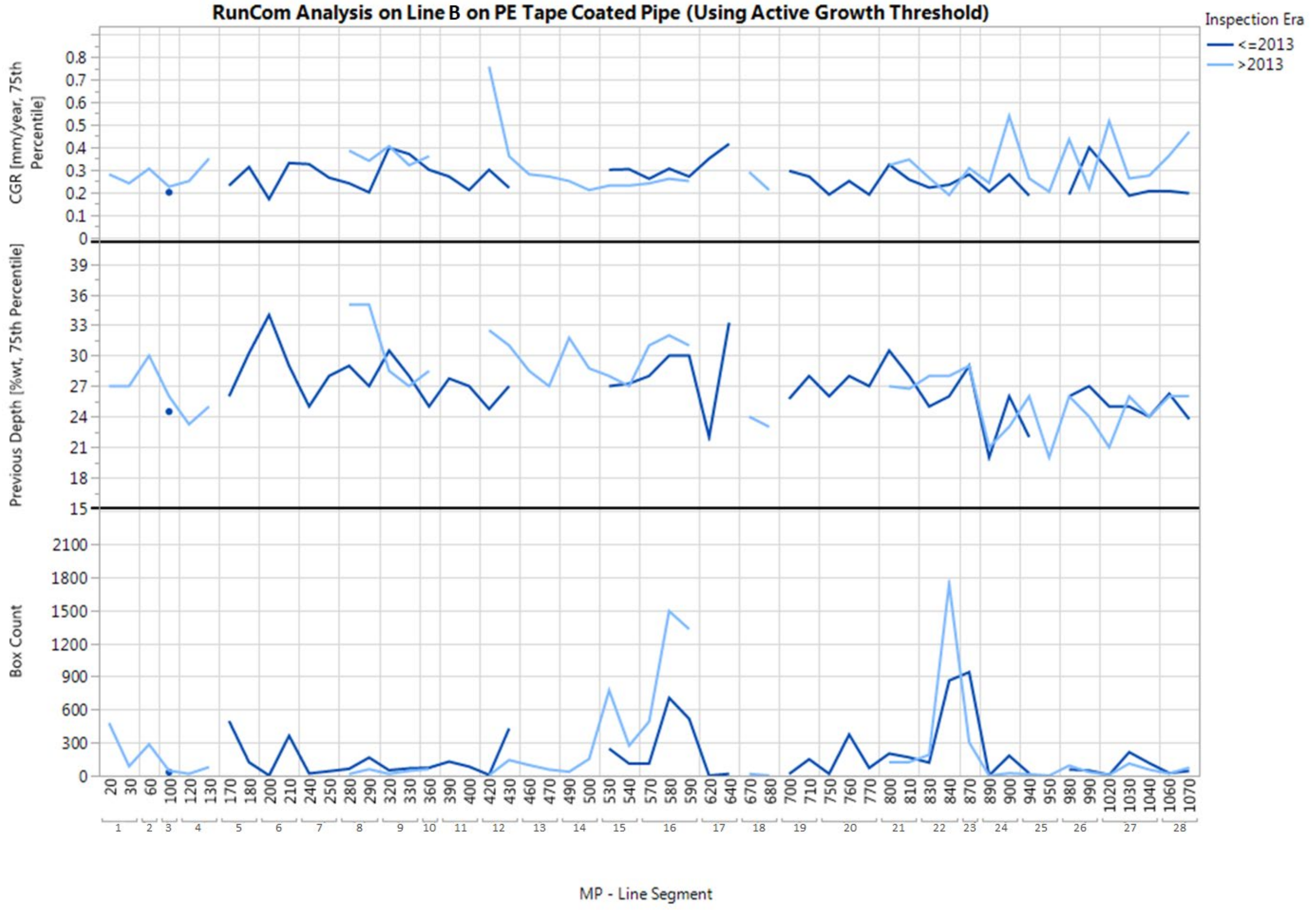
Case Study: Line B Regression Analysis

- **Line B:**
  - Over 1000 km long liquids pipeline with PE tape coated piping in each segment
  - PE tape piping constructed mainly in 1970s
  - Notable operating temperature increase starting in 2013



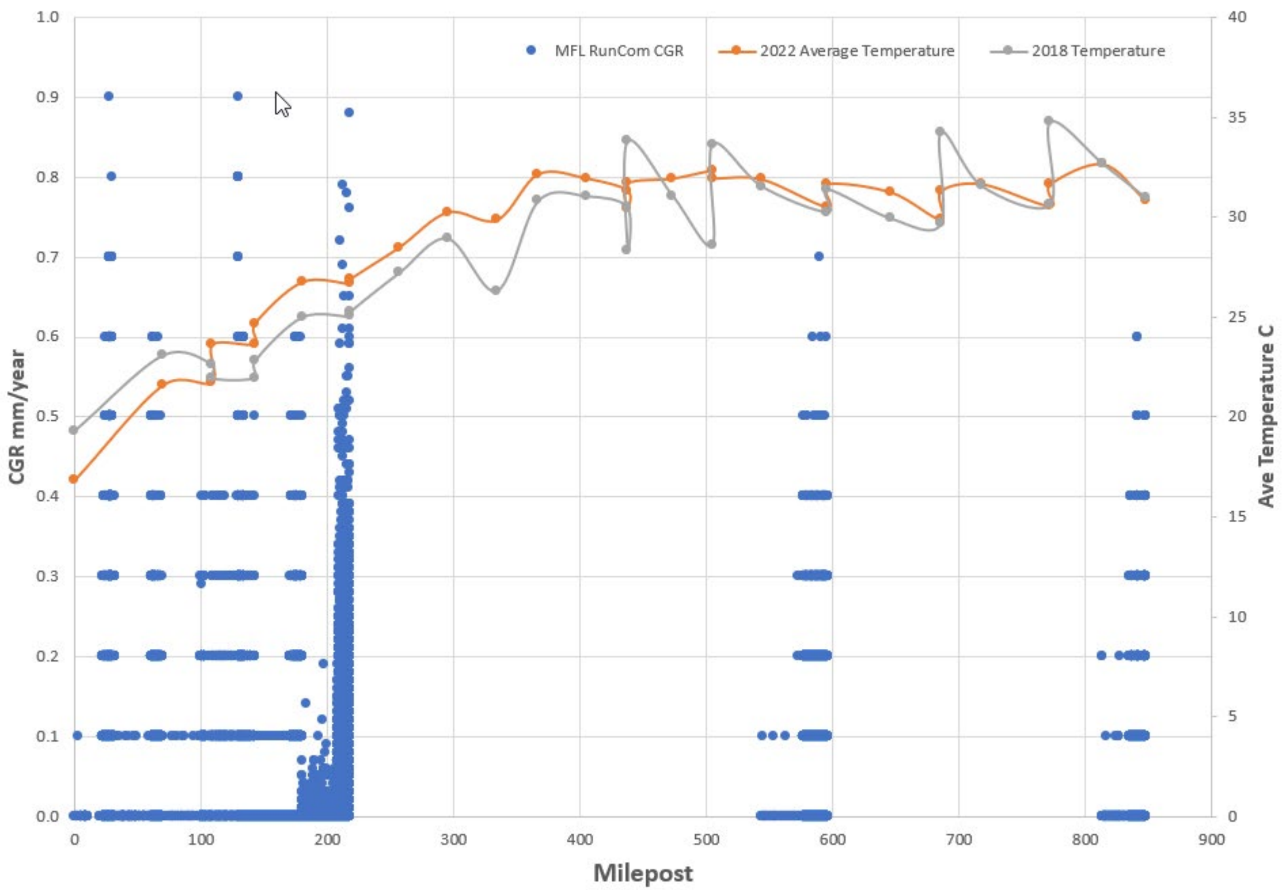
Case Study: Line B Regression Analysis

- **Investigation of RunCom CGRs for Line B found:**
  - No clear indication of increased corrosion growth rates between pre and post-2013 data
  - No clear correlation between temperature and corrosion growth
  - No clear indication of new metal loss population growth



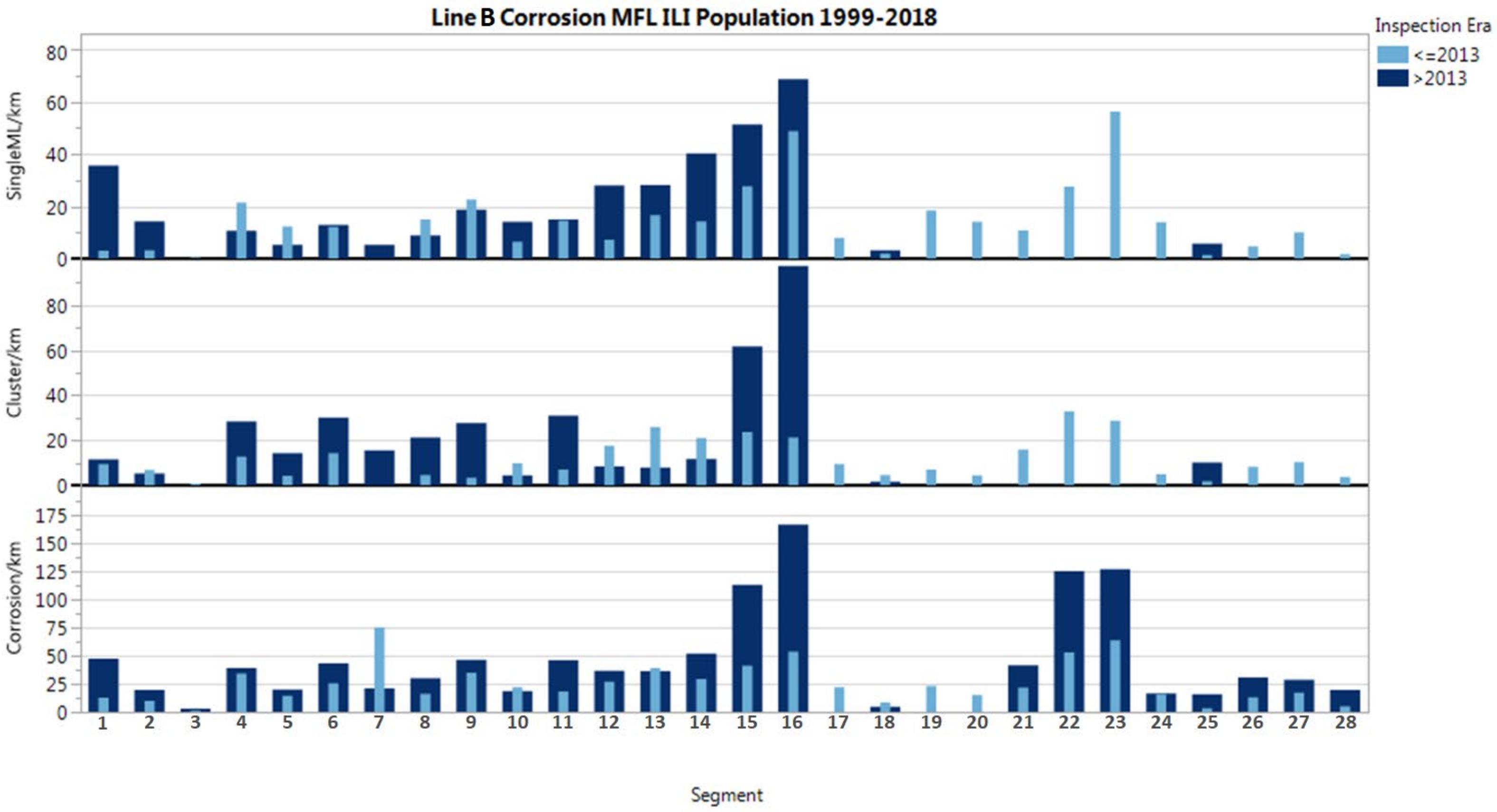
Case Study: Line B Regression Analysis

- **Findings supported by further evaluation of most recent RunCom data: no correlation between temperature and CGR found**



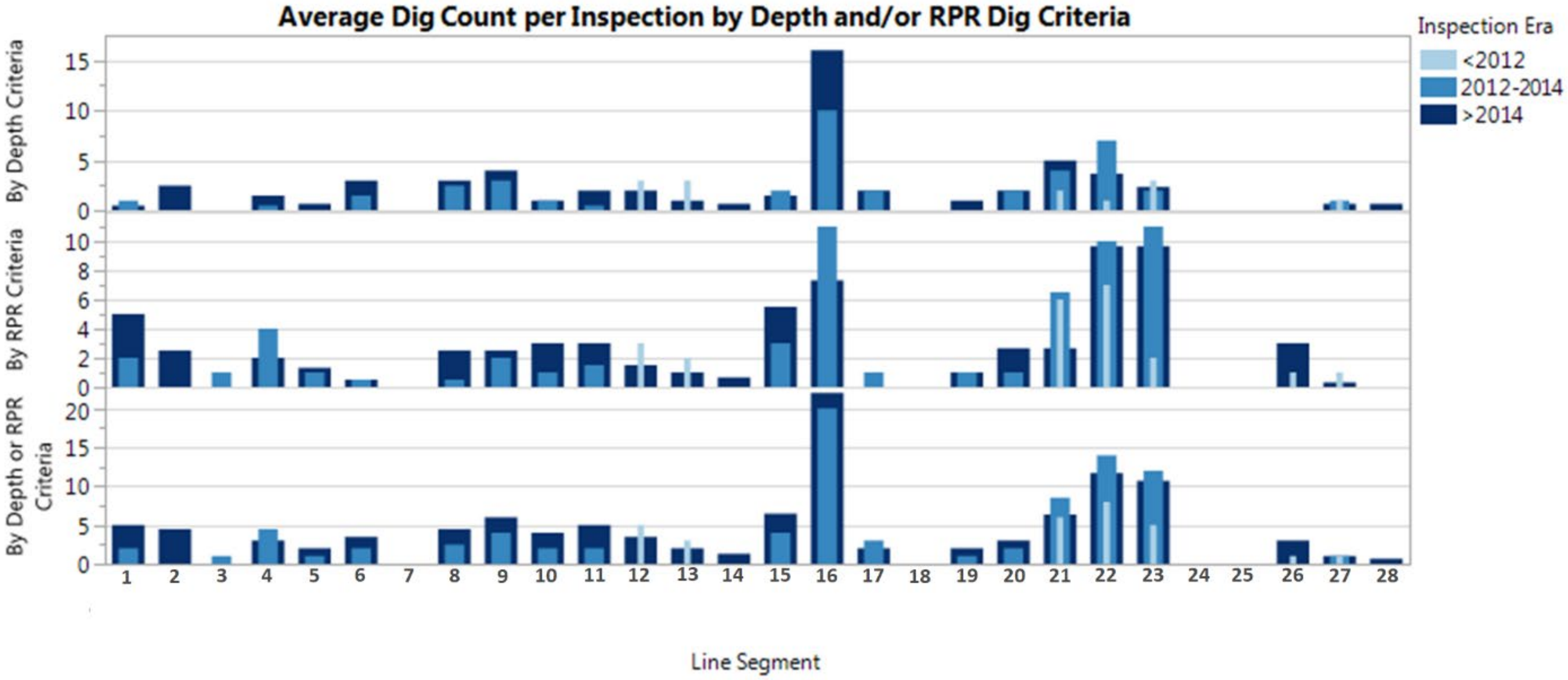
Case Study: Line B Regression Analysis

- **Line B: ILI Population Density**
  - No consistent correlation between temperature and corrosion population density



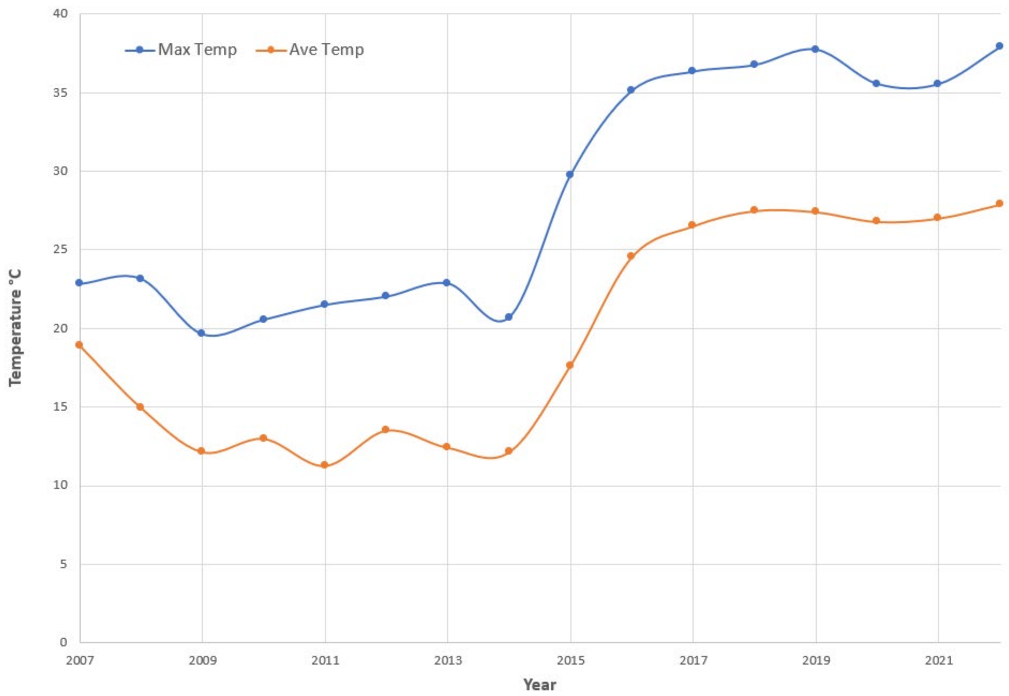
Case Study: Line B Regression Analysis

- **Line B: Dig History**
  - No clear indication that dig program has shown a direct response to the increase in temperature across the line.



Case Study: Line C Corrosion Failure

- **Line C**
  - NPS 22 diameter coal tar coated liquids pipeline constructed in the 1950s
  - Increase in average operating temperature starting in 2015
  - Two corrosion features under a casing became through wall after sandblasting
  - Features were located on top of the pipe

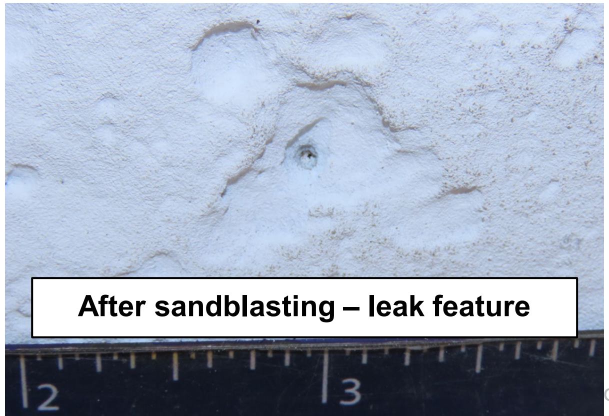


Case Study: Line C Corrosion Failure

- **Corrosion process believed to have occurred:**
  - Moisture entered the casing
  - Elevated temperatures caused the available moisture in the casing to be cycled from a liquid state to a vapor state resulting in a relative humidity within the casing to be close to saturation
  - Cold surface of the casing inside wall promoted condensation of moisture which dripped onto the carrier pipe


Coating condition observed after casing removed


Pipe surface before sandblasting



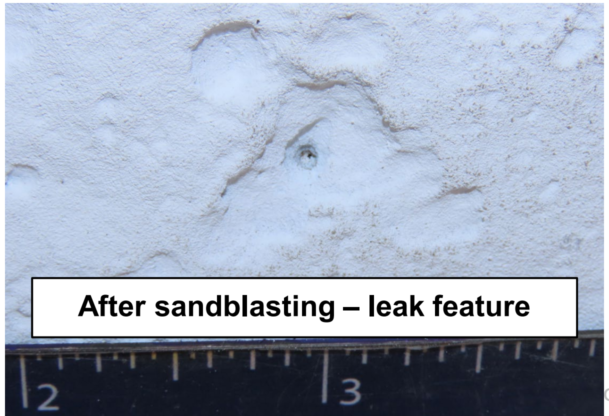
After sandblasting – leak feature

Case Study: Line C Corrosion Failure

- **Corrosion process (continued):**
  - Persistent water permeated imperfections in the coating (pores, cracks) causing corrosion
  - Buildup of corrosion product assisted coating degradation by mechanically spalling the coal tar away from the pipe and creating an area to hold moisture at the pipe wall;
  - Crevice corrosion accelerated corrosion both laterally and through wall
  - Continuous dripping of condensed water can create a new cycle of corrosion at some locations by washing away the oxide

Coating condition observed after casing removed

Pipe surface before sandblasting



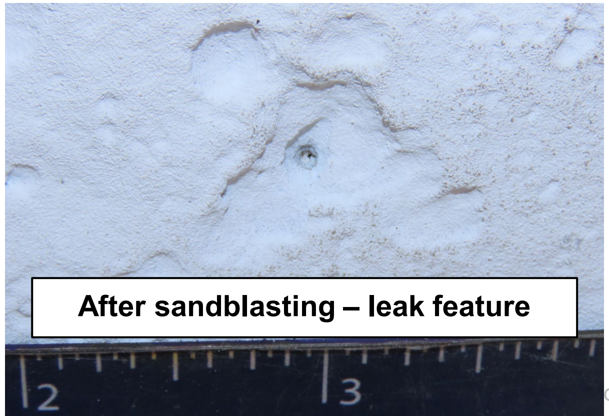
After sandblasting – leak feature

Case Study: Line C Corrosion Failure

- **This conclusion was drawn after eliminating other possible corrosion mechanisms such as:**
  - Cathodic protection deficiency
  - Stray current interference
  - AC corrosion
  - Microbiologically influenced corrosion
  - Chemical accelerants

Coating condition observed after casing removed

Pipe surface before sandblasting



After sandblasting – leak feature

Conclusions

- **Impact of temperature on individual corrosion features:**
  - There is a risk that increased temperature may drive factors that impact corrosion in certain scenarios
  - It may be prudent to increase the frequency of inspection for pipelines experiencing an increase in average operating temperature
  - These scenarios would be considered outliers compared to the full population of corrosion features on a pipeline

Conclusions (continued)

- **Impact of temperature on overall corrosion population:**
  - No strong correlation between temperature increases and CGR or corrosion digs when considering the full population of corrosion features
  - Corrosion is complex and is influenced by factors that are not temperature dependent
  - Temperature is not likely a dominant factor influencing corrosion growth for in-service buried liquids pipelines with CP shielding coatings, such as PE tape, or other scenarios where CP may be limited.
  - Further study into the correlation between CGR and temperature in practical pipeline conditions may be warranted

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