Internal Corrosion Monitoring for Gas Pipelines

37th Annual Corrosion Short Course

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Why Do We Need To Monitor Gas Pipelines

Upsets Occur

I have dry gas, so I don't have corrosion argument no longer works

High profile accidents recently with gas pipelines lead to:

<u>Additional Regulations</u>

How Can We Monitor Gas Pipelines?

PRODUCT QUALITY

INDIRECT MEASUREMENTS

DIRECT MEASUREMENTS

Product Quality

What is Pipeline Quality Gas?

7#/MMCF water vapor

¼ grain (4 ppm) H2S

Pressures

Temperatures

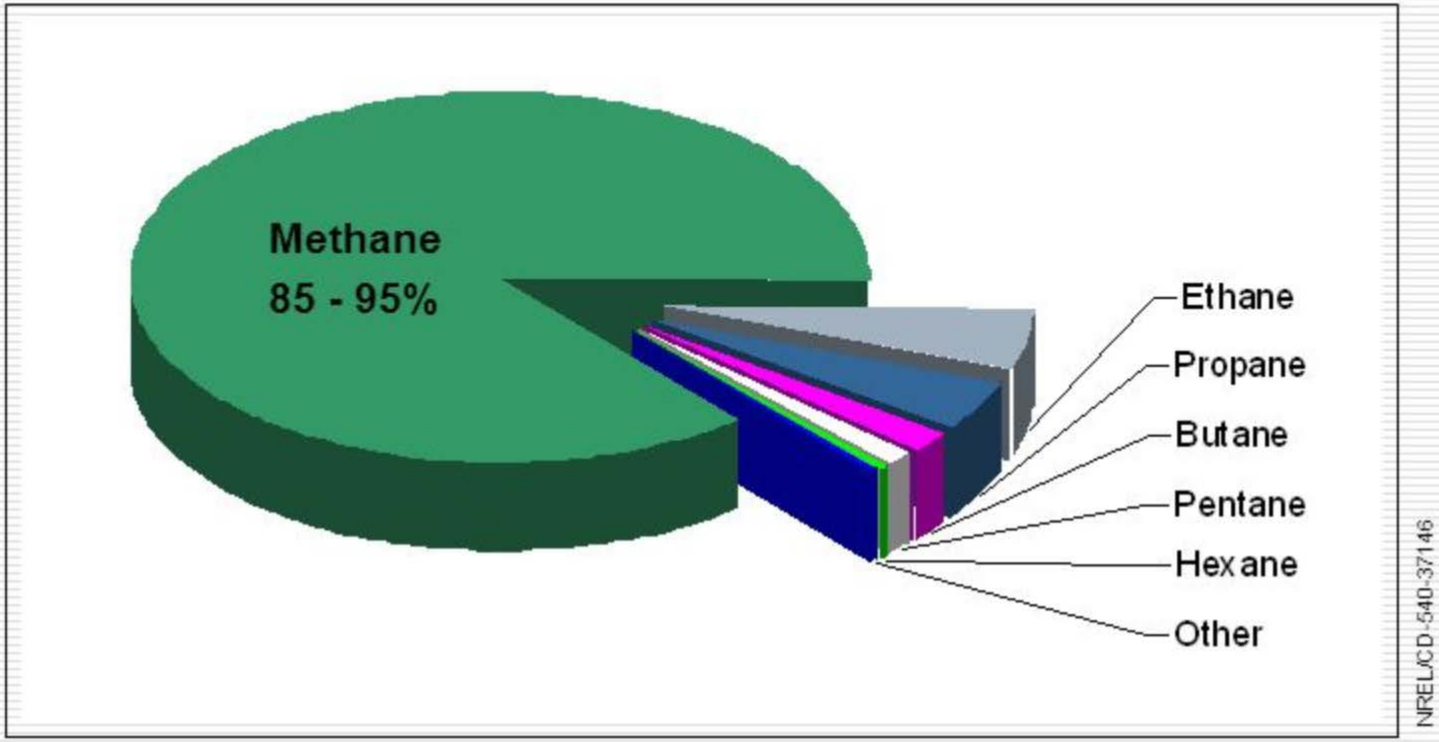
"Dust" or Rouge

Specifications for Pipeline Quality Gas

Major Components	Minimum Mol%	Maximum Mol%
Methane	75	None
Ethane	None	10
Propane	None	5
Butanes	None	2
Pentanes and heavier	None	0.5
Nitrogen and other inerts	None	3
Carbon dioxide	None	2–3
Total diluent gases	None	4–5
	Trace components	
Hydrogen sulfide	0.25–0.3 g/100 scf ($6–7\ mg/m^3$)	
Total sulfur	5–20 g/100 scf ($115–460\ mg/m^3$)	
Water vapor	4.0–7.0 lb/MM scf ($60–110\ mg/m^3$)	
Oxygen	1.0%	
	Other characteristics	
Heating value (gross, saturated)	950–1,150 Btu/scf ($35{,}400–42{,}800\ kJ/m^3$)	
Liquids	Free of liquid water and hydrocarbons at delivery temperature and pressure	
Solids	Free of particulates in amounts deleterious to transmission and utilization equipment	

Source: Engineering Data Book (2004).

Pipeline Natural Gas composition



In the ground, natural gas contains a wide range of compounds. During well-head cleaning and processing, gas quality is improved to pipeline standards. Gas in the pipeline has a range of acceptable compositions. Typical pipeline gas would be as shown.

How Much Oxygen is 1%?

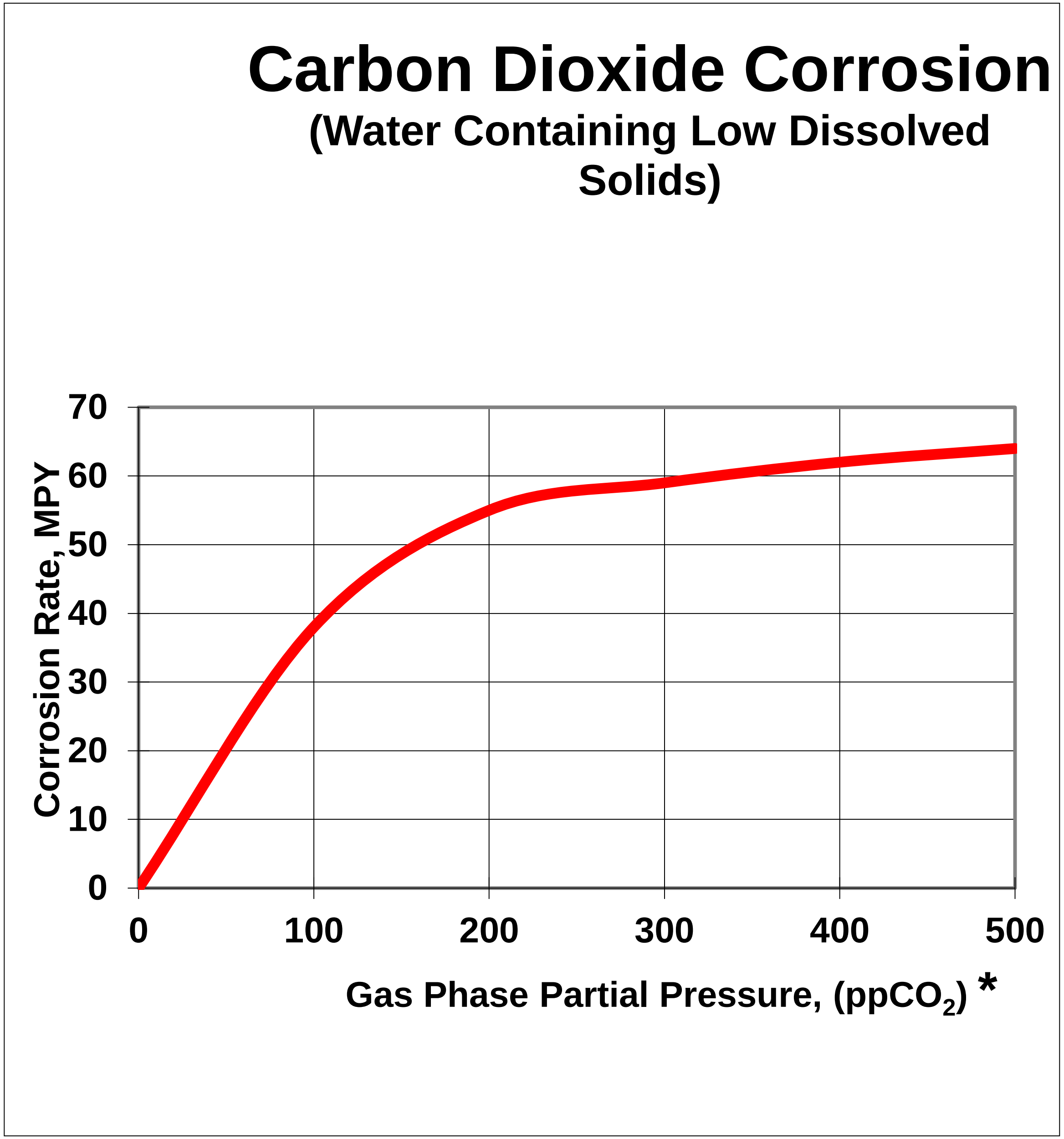
1% = 10,000 ppm

All we need for corrosion is <u>10-50 ppb</u>

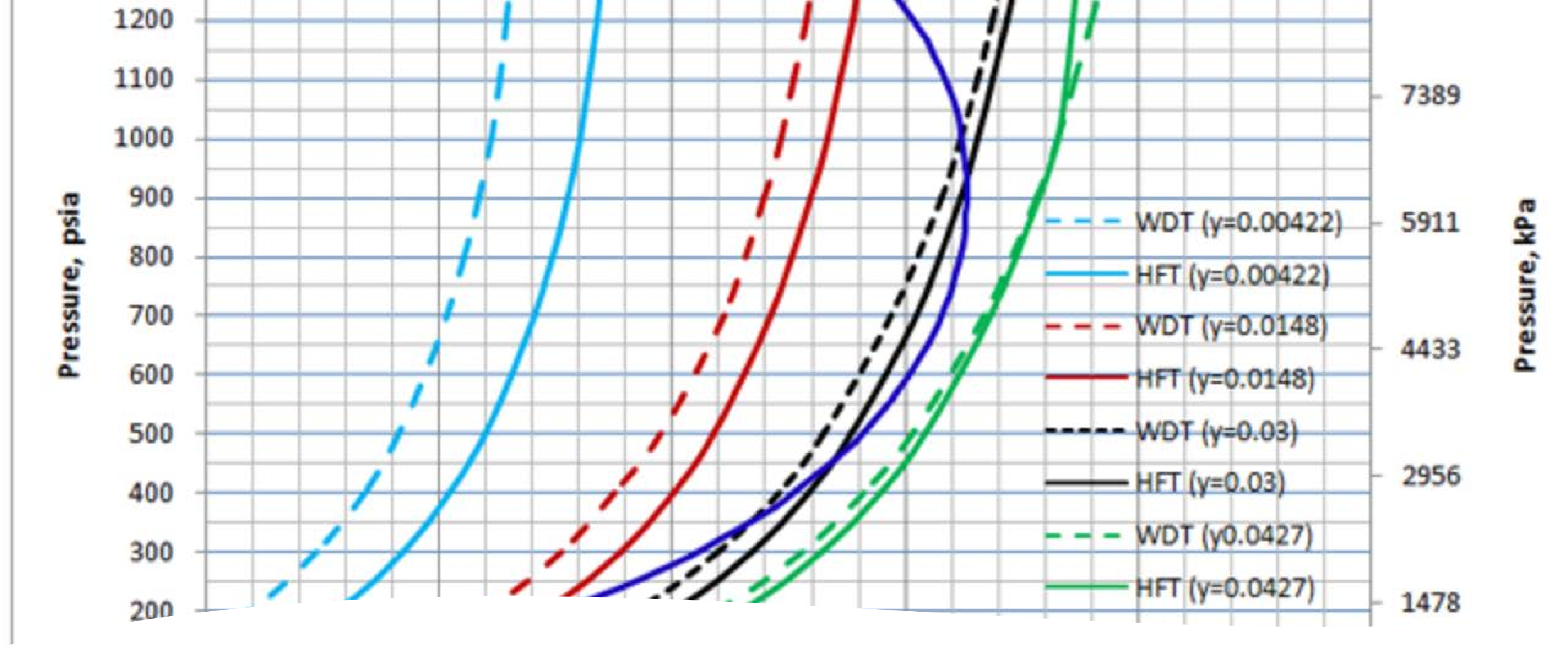
<u>10,000 ppm = 10,000,000 ppb!</u>

So any moisture is BAD

What About the Partial Pressure of Carbon Dioxide



- http://www.jmcampbell.com/tip-of-the-month/2011/01/what-is-the-impact-of-water-content-on-the-dew-point-and-hydrate-phase-behavior/



At What Point Do We Form Water?

- http://www.jmcampbell.com/tip-of-the-month/2011/01/what-is-the-impact-of-water-content-on-the-dew-point-and-hydrate-phase-behavior/

The NPRM Requirements are Covered by Three Sections for

192.478
Internal corrosion control: Onshore transmission monitoring and mitigation

192.710
Pipeline Assessments

192.935
What additional preventive and mitigative measures must an operator take?

http://www.energyindustryphotos.com/pipeline_blowout_photos_and_natu.htm

NPRM Requirements

§ 192.478 Internal corrosion control: Onshore transmission monitoring and mitigation.

- For onshore transmission pipelines, each operator must develop and implement a monitoring and mitigation program to identify potentially corrosive constituents in the gas being transported and mitigate the corrosive effects.
- Potentially corrosive constituents
  - include but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and free water, either by itself or in combination.
- Each operator must evaluate the partial pressure of each corrosive constituent by itself or in combination to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures.

192.478 The Monitoring and Mitigation Plan MUST Include

- Gas Quality Monitoring for potentially corrosive constituents (Gas Chromatograph or Samples) at each inlet
- Product sampling, inhibitor injections, in-line cleaning pigging, separators or other technology to mitigate the potentially corrosive gas stream constituents;
- Evaluation twice each calendar year, at intervals not to exceed 7-½ months, of gas stream and liquid quality samples and implementation of adjustments and mitigative measures to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

192.478 If Corrosive Gas is Being Transported

- Coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion.
- Each coupon or other means of monitoring internal corrosion must be checked at least twice each calendar year, at intervals not exceeding 7 ½ months.

192.478 Each Operator MUST Review its Program

- At least twice each calendar year, at intervals not to exceed 7 ½ months,
- based on the results of its gas stream sampling and internal corrosion monitoring in (a) and (b)
- Implement adjustments in its monitoring for and mitigation of the potential for internal corrosion due to the presence of potentially corrosive gas stream constituents.

§ 192.710 - Pipeline Assessments

Internal corrosion. To address the threat of internal corrosion on a low stress segment, an operator must—

- Conduct a gas analysis for corrosive agents at least twice each calendar year;
- Conduct periodic testing of fluids removed from the segment.
- At least once each calendar year test the fluids removed from each storage field that may affect a segment;

§ 192.710 - Pipeline Assessments

- At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (ii)(A)-(ii)(B) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records,

- And define and implement appropriate remediation actions.

§ 192.935 What additional preventive and mitigative measures must an operator take?

- Monitor for, and mitigate the presence of, deleterious gas stream constituents.
- At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and continuous gas quality monitoring equipment.
- At least once per quarter, use gas quality monitoring equipment that includes, but is not limited to, a moisture analyzer, chromatograph, carbon dioxide sampling, and hydrogen sulfide sampling.

§ 192.935 What additional preventive and mitigative measures must an operator take?

- Use cleaning pigs and sample accumulated liquids and solids, including tests for microbiologically induced corrosion
- Use inhibitors when corrosive gas or corrosive liquids are present

§ 192.935 What additional preventive and mitigative measures must an operator take?

Address potentially corrosive gas stream constituents as specified in § 192.478(a), where the volumes exceed these amounts over a 24-hour interval in the pipeline as follows:

- Limit carbon dioxide to three percent by volume
- Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and
- Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas. If the hydrogen sulfide concentration is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents,
- including follow-up sampling and quality testing of liquids at receipt points.

Indirect Measurements

CORROSION COUPONS AND PROBES

GAS SAMPLES

SOLIDS

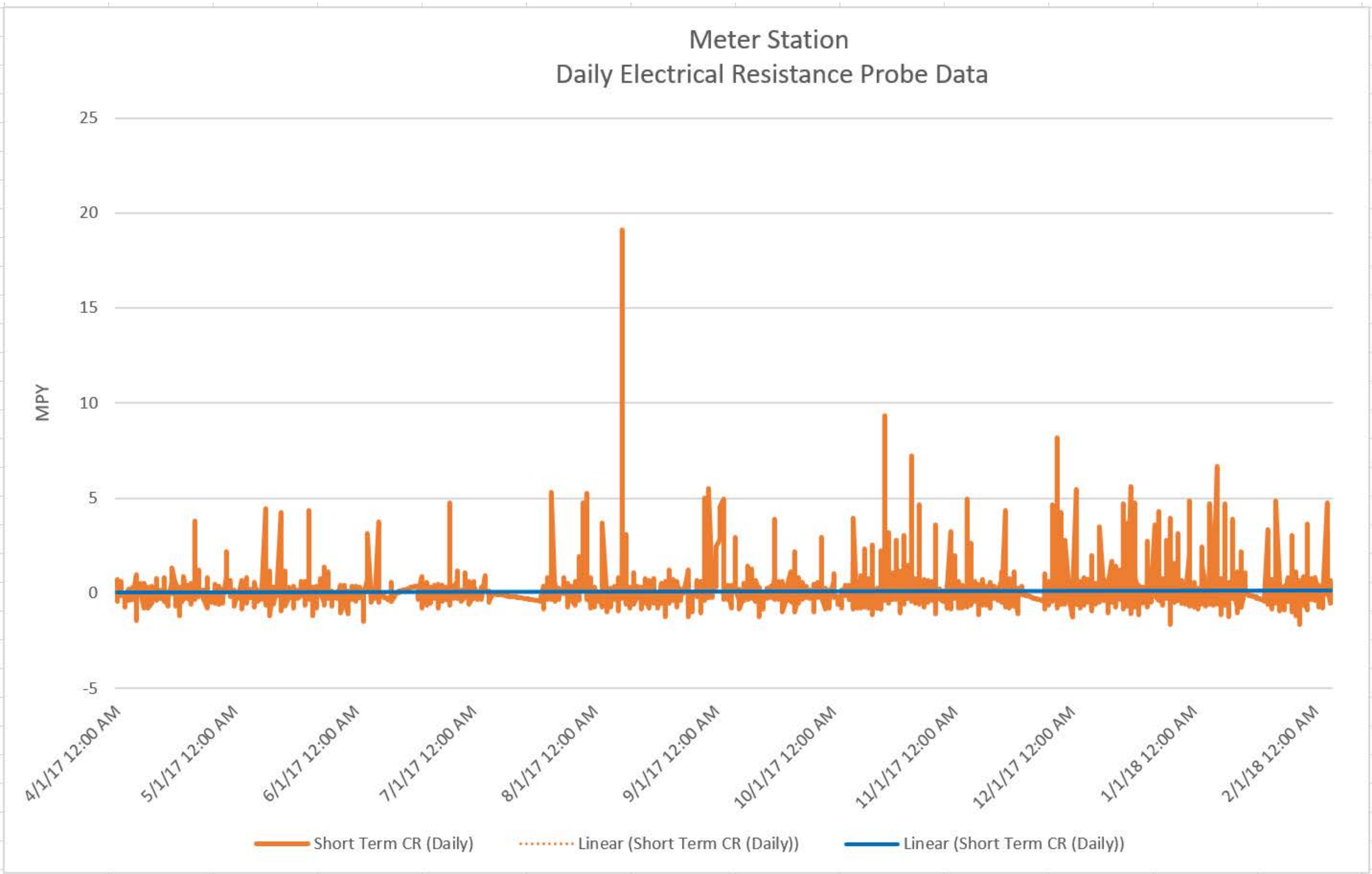
LIQUIDS (HYDROCARBON AND WATER)

MICROBIOLOGY

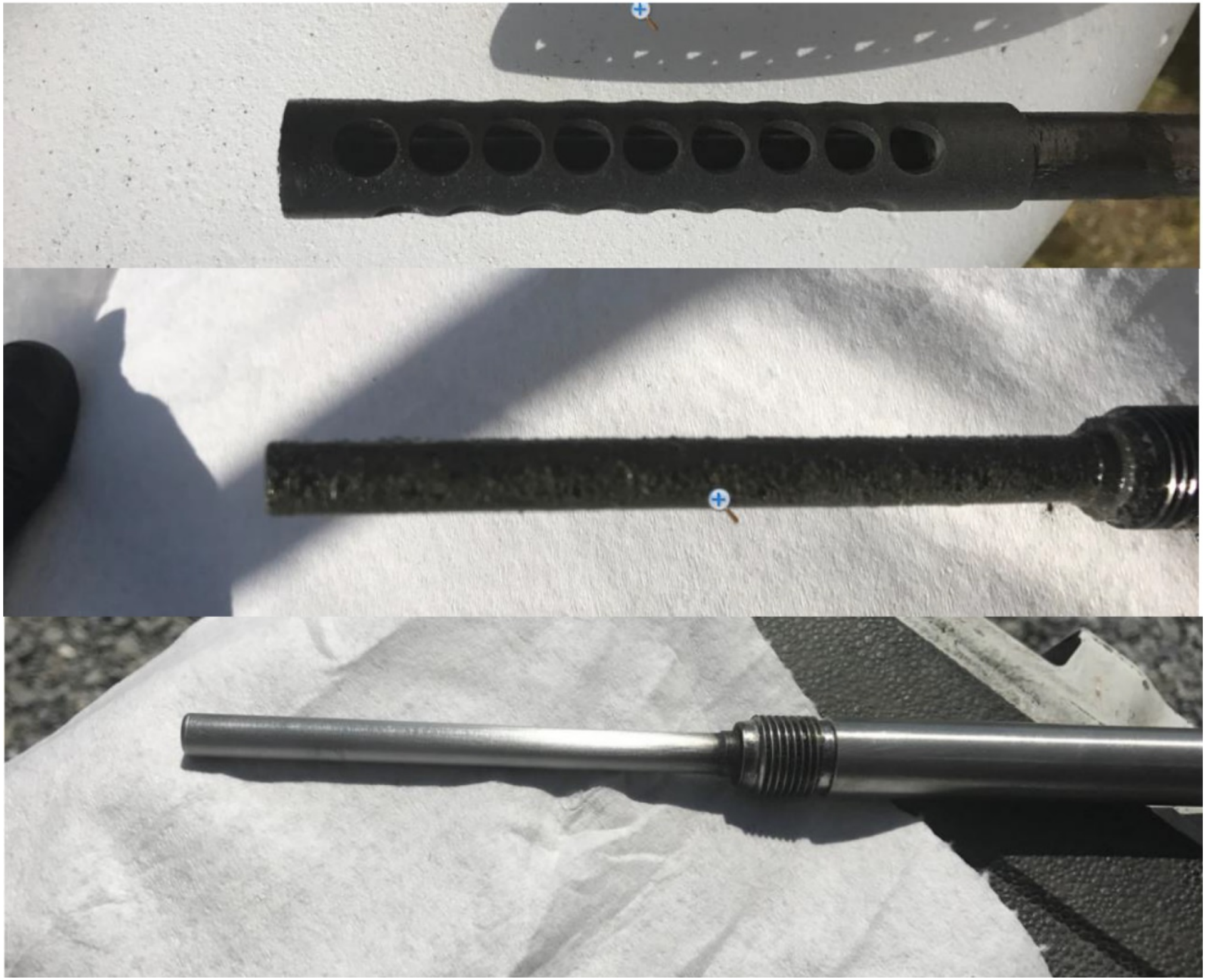
REVIEW

Electrical Resistance

On Line Corrosion Rate Readings



What We Found



Coupons and Holders

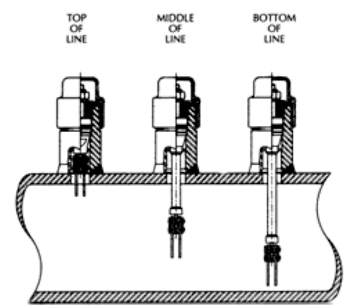
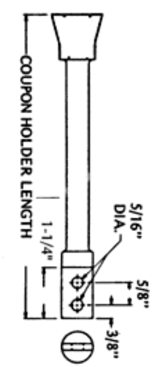
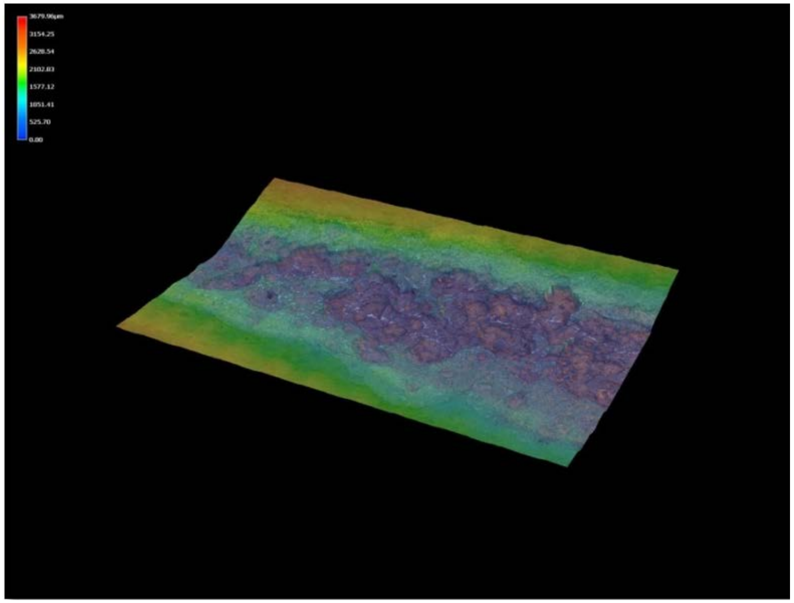
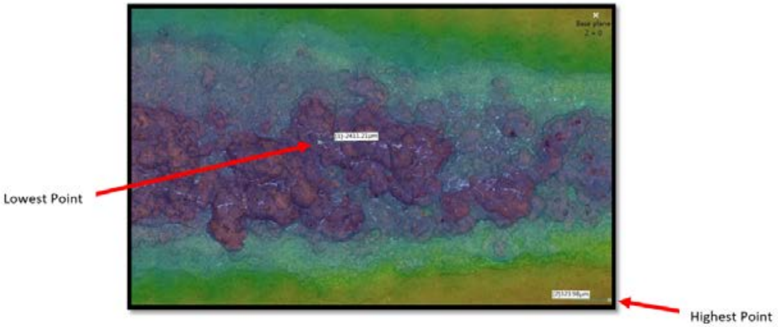


FIG. 1
Coupons shown rotated 90° from normal position.

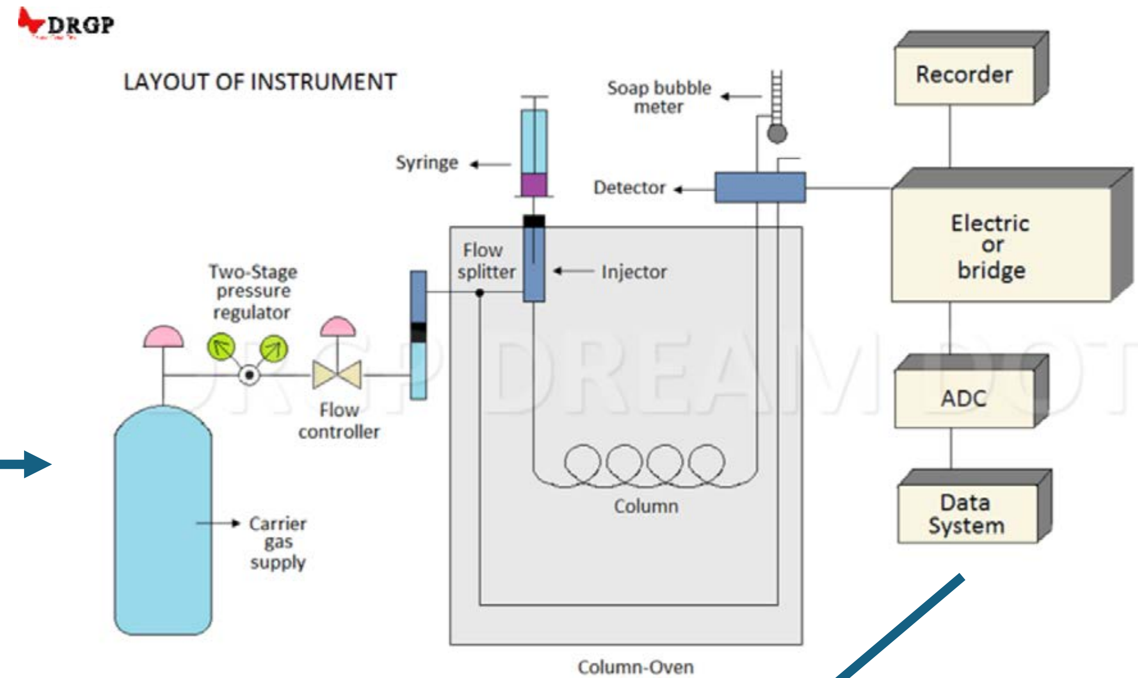






Structured Light Inspection

Gas Sampling



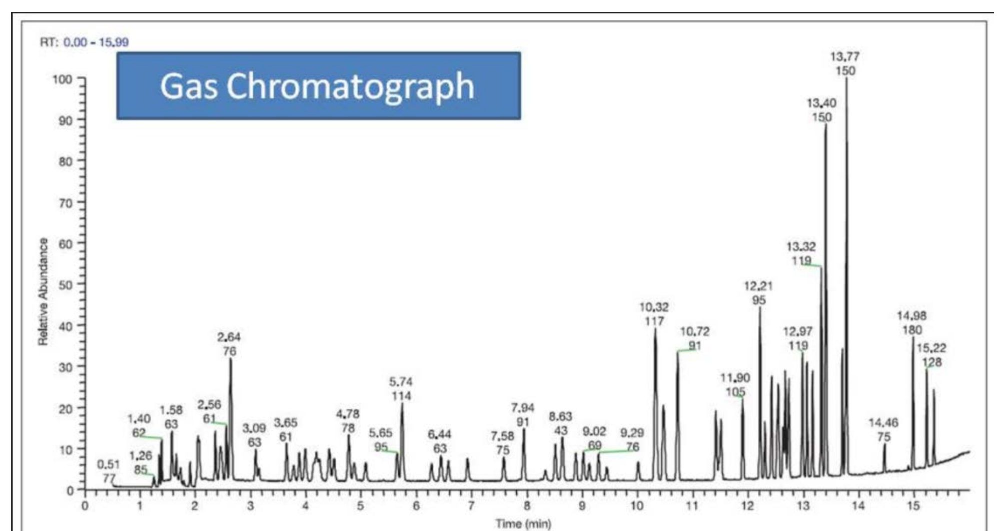


Figure 2: TIC of a 2 μg/L standard in full scan

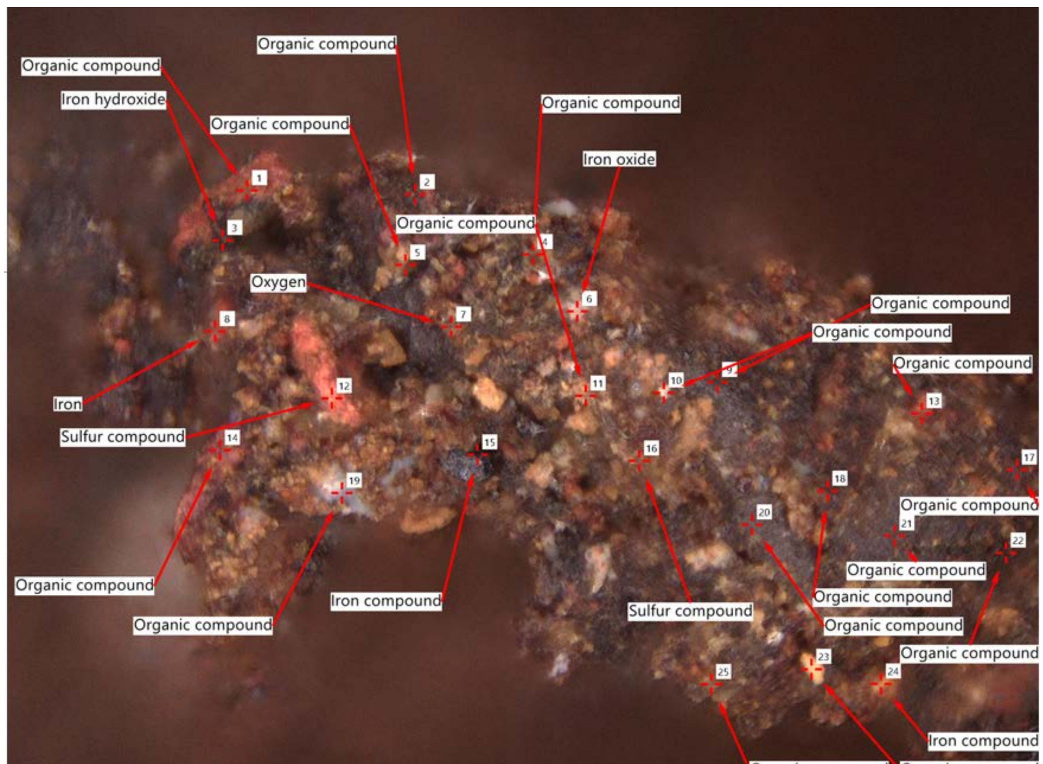
What Components of the Gas should I Sample?

- Oxygen
- Carbon Dioxide
- Hydrogen Sulfide
- Moisture

Solids Sampling

What Do I need to Know?	Where Do I Get the Sample?	Are There Any Special Precautions?
• Elements • Compounds	• Pig Returns • Meter Runs • Gas Filtration	

Solids Analysis



Multi-point analysis by [wt%]

No.	Presumed material	C	S	O	Fe	H
1	Organic compound	30.0%	23.7%	21.9%	21.3%	3.1%
2	Organic compound	44.6%	0.0%	34.0%	21.4%	
3	Iron hydroxide	0.0%	0.0%	49.0%	44.4%	6.6%
4	Organic compound	51.4%	0.0%	25.7%	19.6%	3.3%
5	Organic compound	31.5%	0.0%	34.4%	23.8%	
6	Iron oxide	0.0%	0.0%	51.0%	49.0%	
7	Oxygen	0.0%	0.0%	100.0%	0.0%	
8	Iron	0.0%	0.0%	0.0%	100.0%	
9	Organic compound	56.0%	17.3%	22.8%	0.0%	3.9%
10	Organic compound	29.9%	21.5%	23.8%	8.4%	2.9%
11	Organic compound	47.1%	0.0%	32.9%	15.5%	4.5%
12	Sulfur compound	15.9%	54.6%	0.0%	0.0%	
13	Organic compound	34.4%	32.9%	14.7%	0.0%	2.6%
14	Organic compound	44.2%	0.0%	37.7%	18.1%	
15	Iron compound	26.9%	23.9%	17.9%	29.1%	2.2%
16	Sulfur compound	22.9%	77.1%	0.0%	0.0%	
17	Organic compound	53.0%	0.0%	23.1%	20.3%	3.6%
18	Organic compound	50.5%	0.0%	26.2%	19.0%	4.3%
19	Organic compound	36.7%	0.0%	33.4%	10.4%	3.5%
20	Organic compound	38.8%	0.0%	15.6%	25.7%	2.2%
21	Organic compound	54.0%	28.3%	14.4%	0.0%	3.3%
22	Organic compound	42.3%	0.0%	35.8%	21.9%	
23	Organic compound	46.9%	0.0%	32.3%	20.8%	
24	Iron compound	0.0%	61.8%	0.0%	38.2%	

Liquids Analysis

What Do I need to Know?

- Water?
  - pH
  - Anions
  - Cations
  - Compounds
- Hydrocarbon?
  - FTIR /chemical Makeup
  - Carbon Chains

Where Do I Get the Sample?

- Pig Returns
- Drips
- Filter Separators

Are There Any Special Precautions?

Direct Measurements

IN LINE INSPECTIONS

ULTRASONIC THICKNESS INSPECTIONS

CUT OUTS AND TIE INS

In Line Inspection

Automated Phase Array Inspection

https://www.olympus-ims.com/en/resources/slideshare/phased-array-pipeline-zone-discrimination-inspection/

This is NOT how we want to remove pipe

http://www.energyindustryphotos.com/pipeline_blowout_photos_and_natu.htm

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EST. 2022

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