Corrosion Management Strategies for Optimal Service Life

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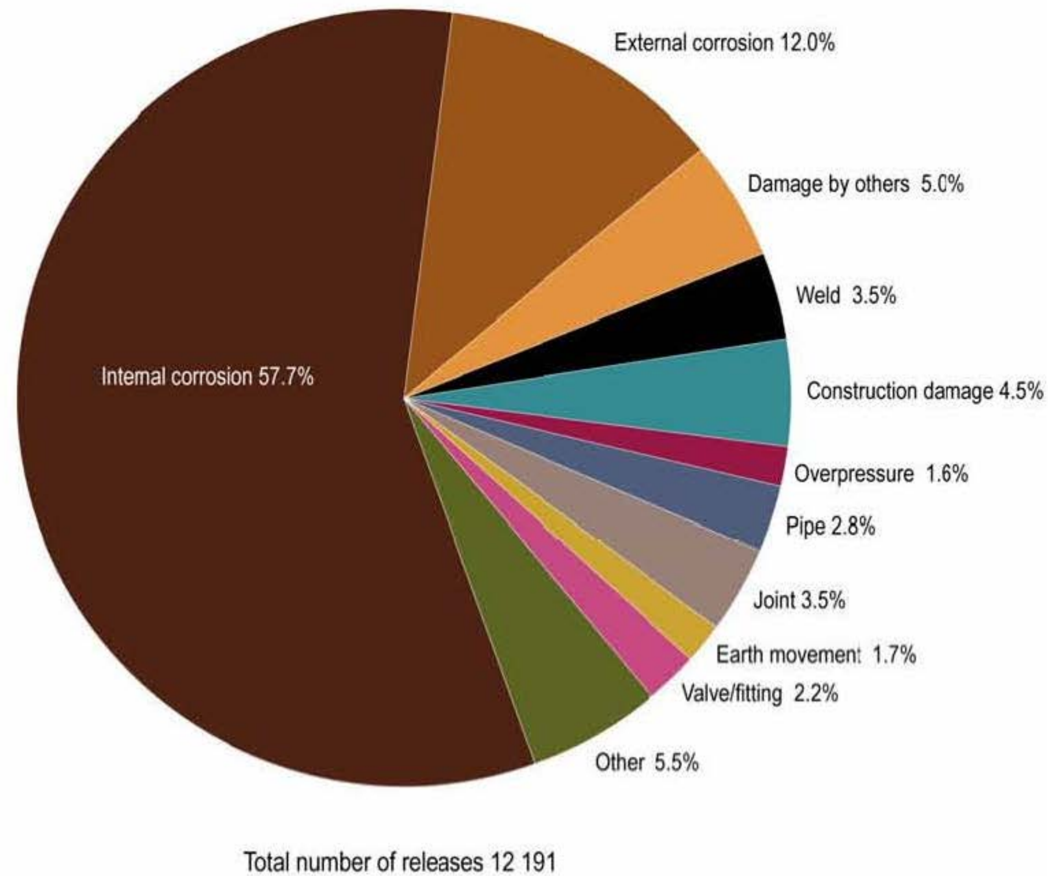
Agenda

- Failure Occurrence
- Proper System Design and Startup
- Cautionary Tale I
- Sound Management
  - Good production practices
  - Cost effective corrosion inhibition
  - Effective monitoring
- Cautionary Tale II
- Aging Systems
- Cautionary Tale III

Introduction

- Most pipeline failures caused by internal corrosion
- Improved QA in steel and pipe mills
- Improved construction practices
- Improved mitigation technologies
- Aging infrastructure
- More aggressive environments

Failures by Cause



Steady Improvement

Figure 29. Average frequency of pipeline incidents, by year

All pipelines from January 1, 1990, to December 31, 2005, all products (includes all hits, leaks and ruptures)

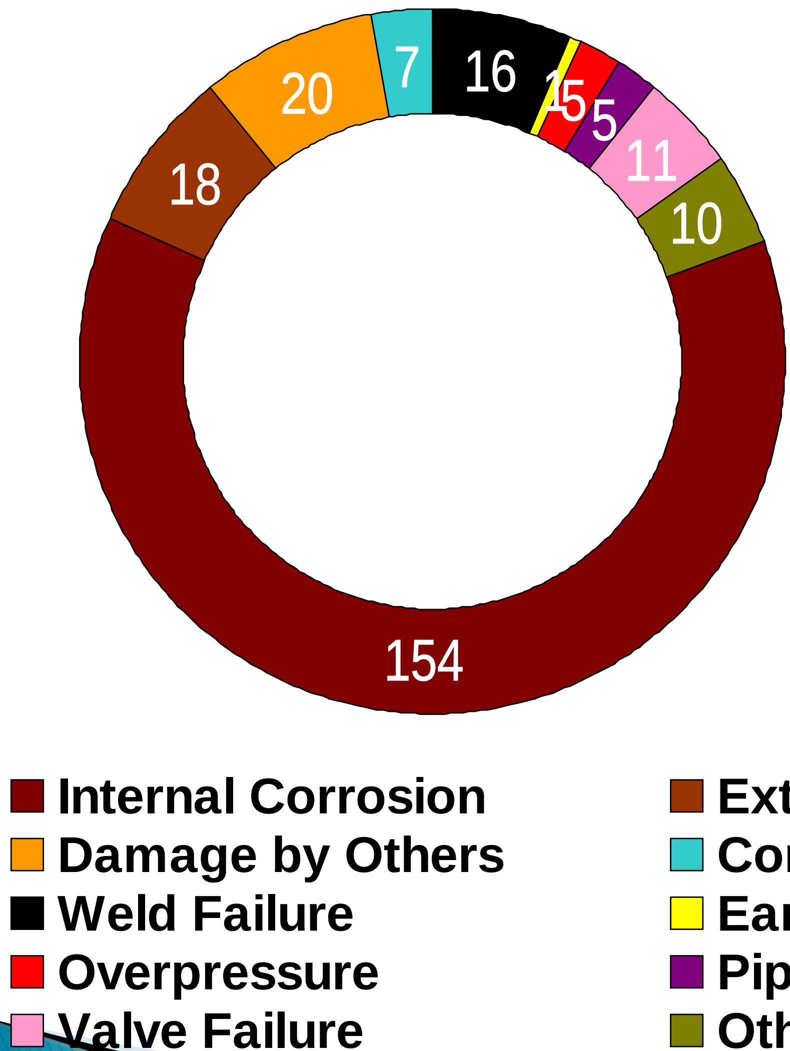
Metallurgical or Corrosion Failure ?

- Failures early in service life more likely to be materials related
- Later failures almost certainly corrosion unless service conditions change drastically
- SCC an amalgam of both

Primary Causes of Sour Gas Pipeline Failures

- Corrosion
  - Inadequate inhibition, inadequate solids removal, production of completion fluids to pipeline
- Inadequate Design
  - Failure to address mechanical and/or thermal stresses, improper anchoring, improper backfilling specification
- Faulty Construction and Inspection
  - Welding faults, high installed stresses, inadequate pipe support, backfilling, and inspection
- Improper Operation
  - Operating outside of design, no consideration for operational changes, inadequate records

Failures of Sour Gas Pipelines

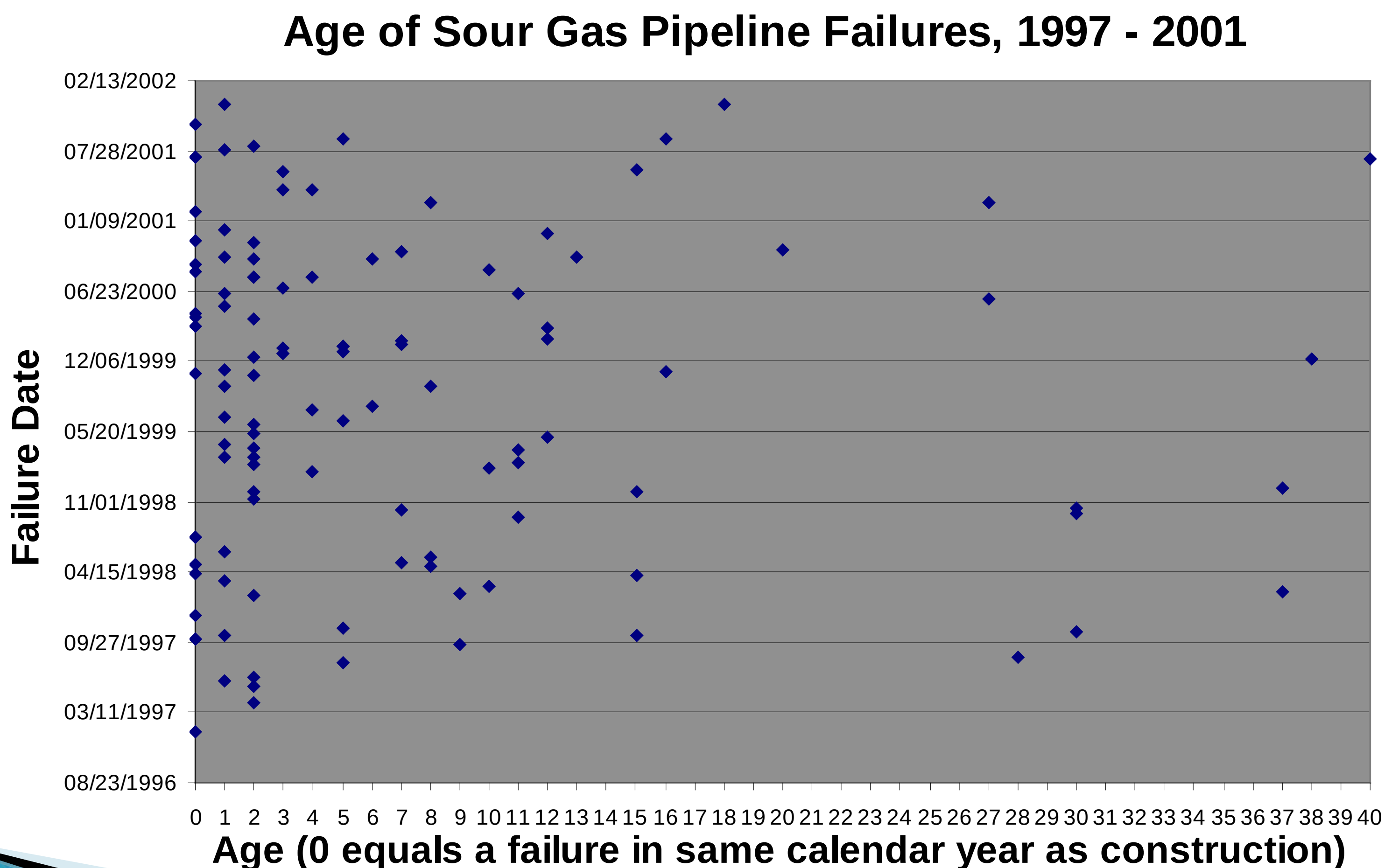


All sour gas pipeline incidents, 1991-2001 inclusive

247 failures total, of which:

214 were leaks,
21 were ruptures,
12 were hits.

Failures in Sour Gas Pipelines

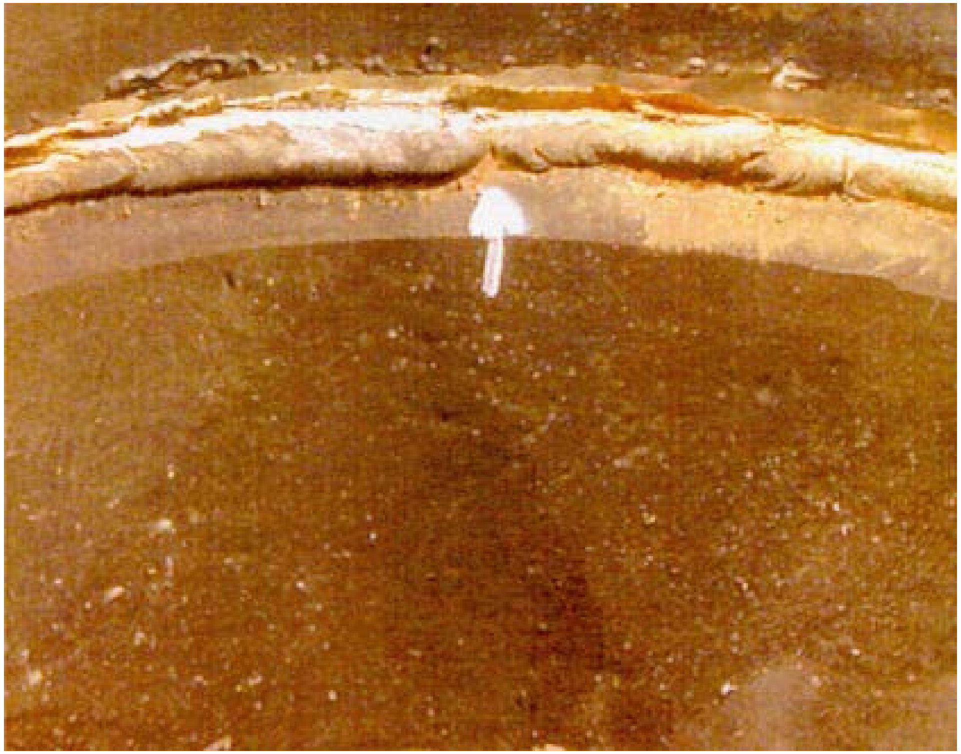


Failures of Sour Gas Pipelines

323.9 x 9.4 mm pipe
323.9 x 17.1 mm riser
30% H_2S, dehyd.
10 days service
SSC on pipe side
Small root bead flaw

EUB

Failures of Sour Gas Pipelines



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Startup protocols

- Avoid Spent acid
- Methanol batching
- System Gas and Fluid Analysis
- Flow modelling and Risk Assessment
- Corrosion inhibitor selection
- Commissioning batch inhibition
- Corrosion monitoring system

Failure in 8! days

Factor		
Temperature		59
Pressure		2528 kPa
H2S		17%
CO2		2.85%
Failure corrosion rate		175 mm per year

Factors Involved in Failure

- Acid used in wellbore cleanup entered flowline
- Solids
- Concern over flaring/rush to production
- Inadequate commissioning batch
- Indiscriminate use of methanol
- Insufficient continuous corrosion inhibitor

Good Production Practices

- Pipeline Operating Manual
- Pipeline Integrity Manual
- Chemical application procedure
- Pigging procedures
- Hydrate control (Methanol, Line heat)
- Well fluids control after workovers
- Management of Change

Chemical Application – Corrosion Inhibitors

- Product effective and compatible with system
- Clean system
- Management of change
- Continuous added at effective concentration
- No interruptions
- Batch protocols adhered to
- Pitting damage is forever

Hydrate control with Methanol

- Extremely damaging to inhibitor films
- Introduces oxygen
- Damages protective sulfide films
- Condenses with water
- Retains acid gases
- Methanol – use only inhibited product

Self Excavated Failure

Self Excavated Failure

- sour gas stream from a compressor
- rich in hydrocarbons and has a CO_2 of 4.8 % and 1.4% H_2S.
- discharge 5200 kPa
- exit temperature of about 35 ^oC.
- laminar flow with long water transit times
- water and condensate volume of about 0.6 m^3 per day.
- methanol is injected at the compressor discharge for hydrate control.

Before Cleaning

After Cleaning

What Happened?

- Failure caused by CO_2 attack
- Wet gas cooled rapidly after compressor discharge
- Water drops condense in the top quadrant of the pipe
- Water pH well below 4
- Corrosion rate of 100 mpy based on deWaard Milliams model.
- Hydrocarbon condensing from gas stream and creating a layer in the bottom.
- Once the water droplets reach the condensate layer, they will fall to the bottom of the line without creating any further corrosion to the walls which are now hydrocarbon wetted.

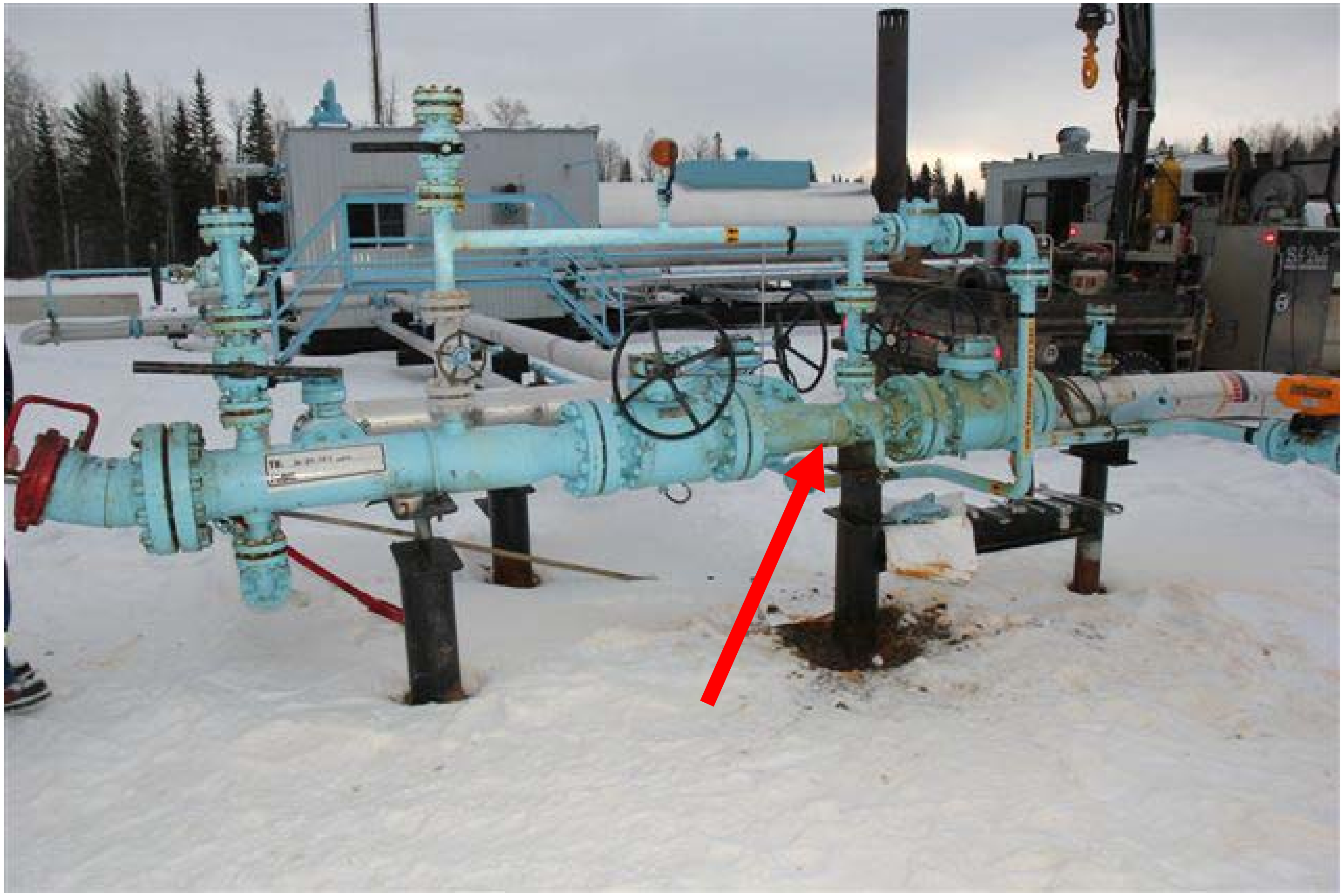
Aging Comparison

People	Pipelines
Reliability Issues	√
Chemicals needed for continued function	√
More frequent Inspections required	√
Unexpected Failures	√
Paying for Past Sins	√

Ghosts from the Past

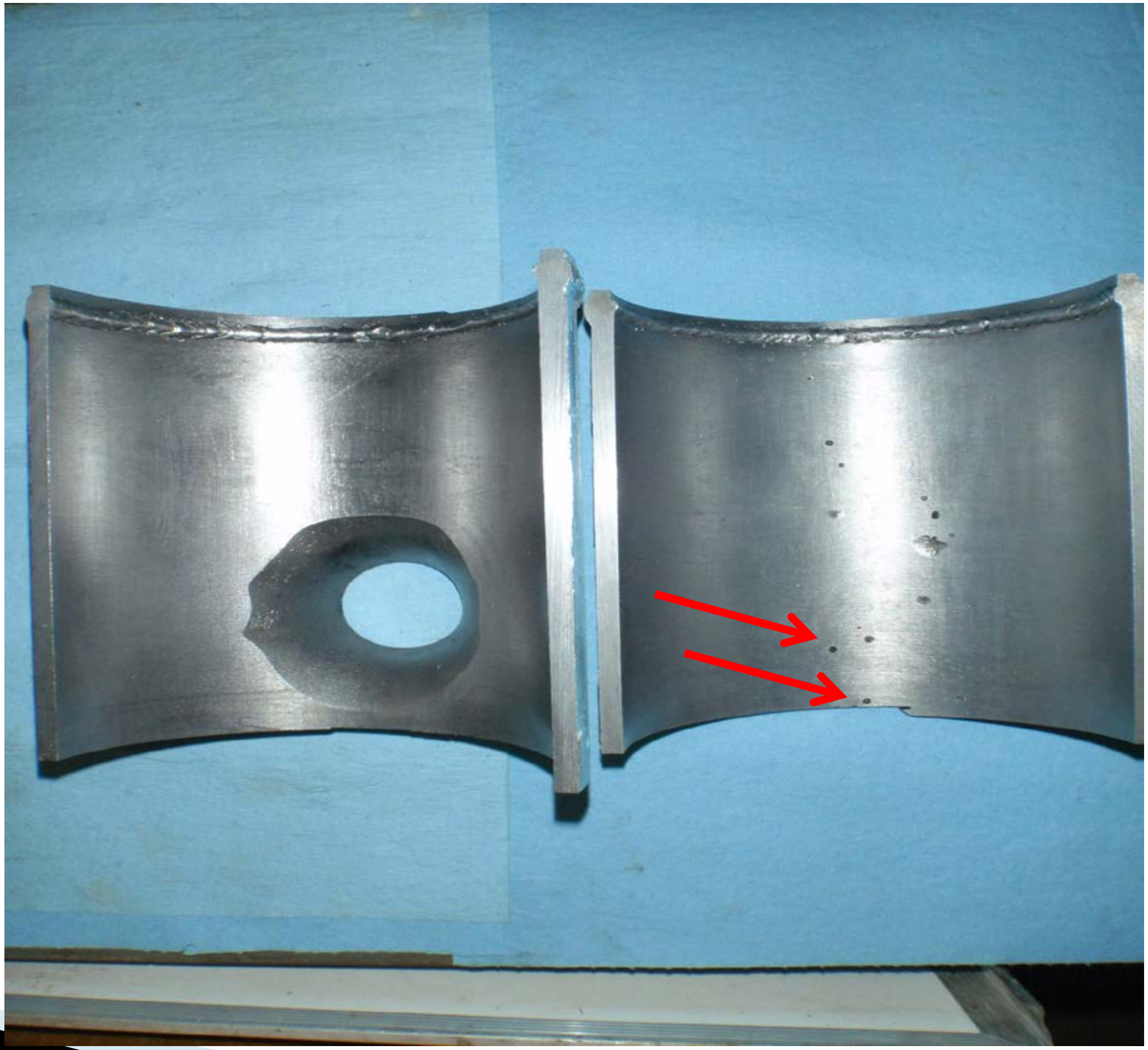
- 40 e^3m^3 per day of gas (21% H_2S, 2% CO_2)
- 50 m^3 of condensate
- 20 m^3 per day of produced water (50K TDS)
- Pressure 1400 kPa
- Temperature 27 ^oC.
- Laminar flow
- Batch corrosion inhibitor
- 5 L/d continuous corrosion inhibitor

Spool Failure



Spool Failure

Spool Failure

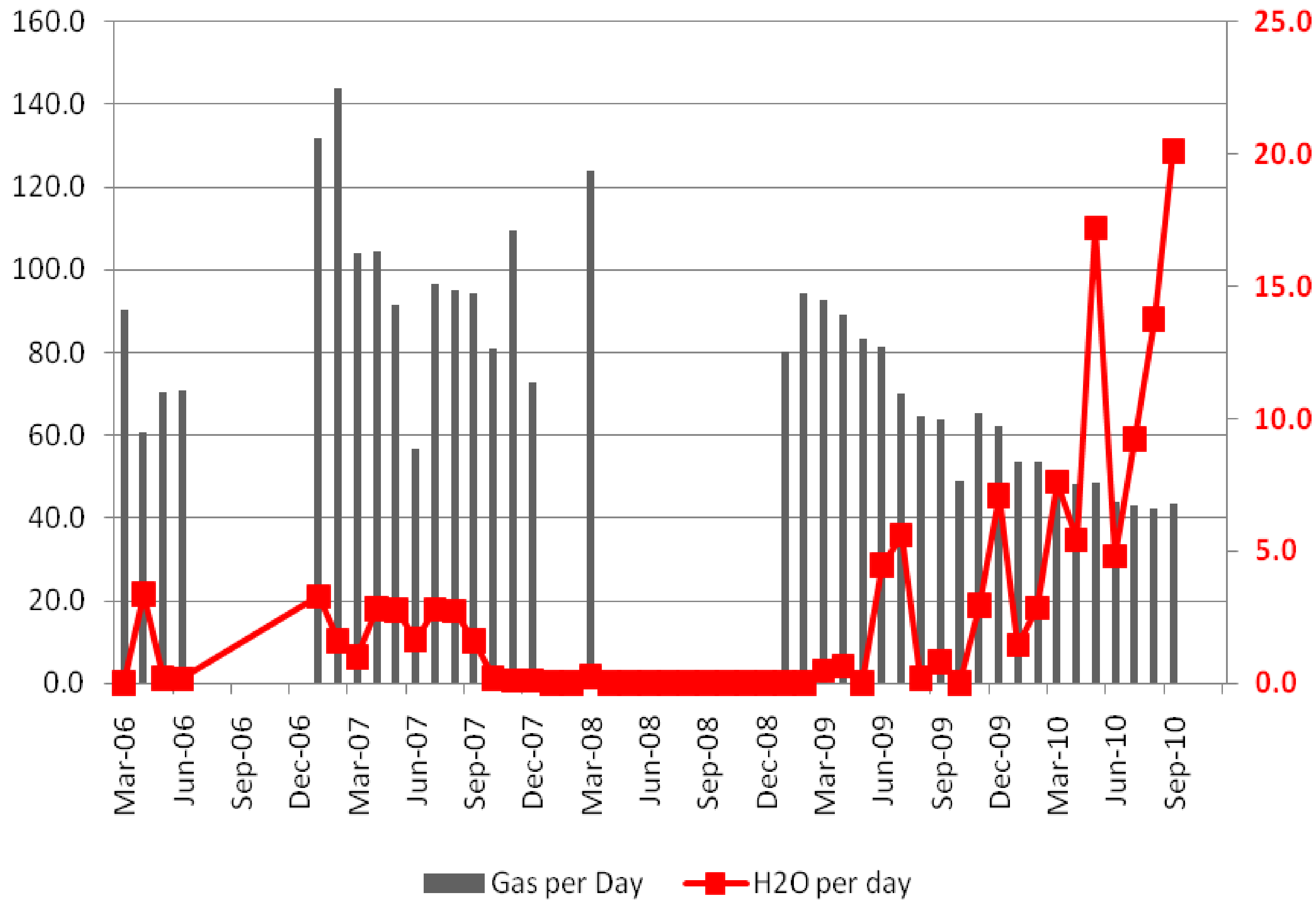


Failure Pits

Spool Failure

Spool Failure

Shut in /Water Volume Increases



Conclusions

- Poor shut in protocols, brine remained in the system
- Batch protocols–poor inhibitor coverage at onset due to pig launch procedures
- Poor management of change -increases in water production not matched by inhibitor adjustments

Aging Systems

- Pay attention to changes in production
- Limit or mitigate shut in time
- Review corrosion inhibitor programs
- Monitor changes in water chemistry and microbiology
- Monitor corrosion and inspect critical lines

Review

- Early nurturing important–avoid work over fluids, well–designed inhibition and commissioning batches
- Management of changes in production volumes and system chemistry
- Use of inhibited methanol
- Corrosion monitoring
- Effective corrosion inhibition

- Thank you
- Questions?