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THE CORROSION SOCIETY

Downhole Corrosion Mechanisms And Mitigation Strategies

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Integrity Management Seminar

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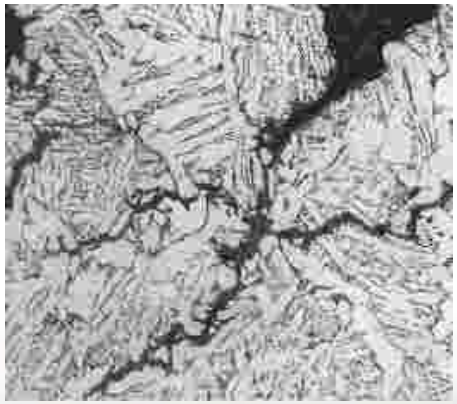
DEFINITION

CORROSION is defined as:

The deterioration of a substance (usually a metal) or its properties because of a reaction with its environment.



Corrosion Accelerators

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Corrosion - General

It is the physical condition of the metal at the anode that initiates the corrosion process. (Metal Loss occurs at the Anode.)

However, it is the:

CHEMISTRY and COMPOSITION of the electrolyte that controls the rate of the corrosion reaction and the severity of the corrosion.

CORROSION RATE Accelerators

- Dissolved Gases
  - Oxygen
  - Acid Gases = H_2S and CO_2
- pH
- Salinity / Conductivity
- Flow
- Temperature
- Solids (Iron Sulfides & Sulfur)

Oxygen Corrosion

By far the most corrosive gas in oil field waters is

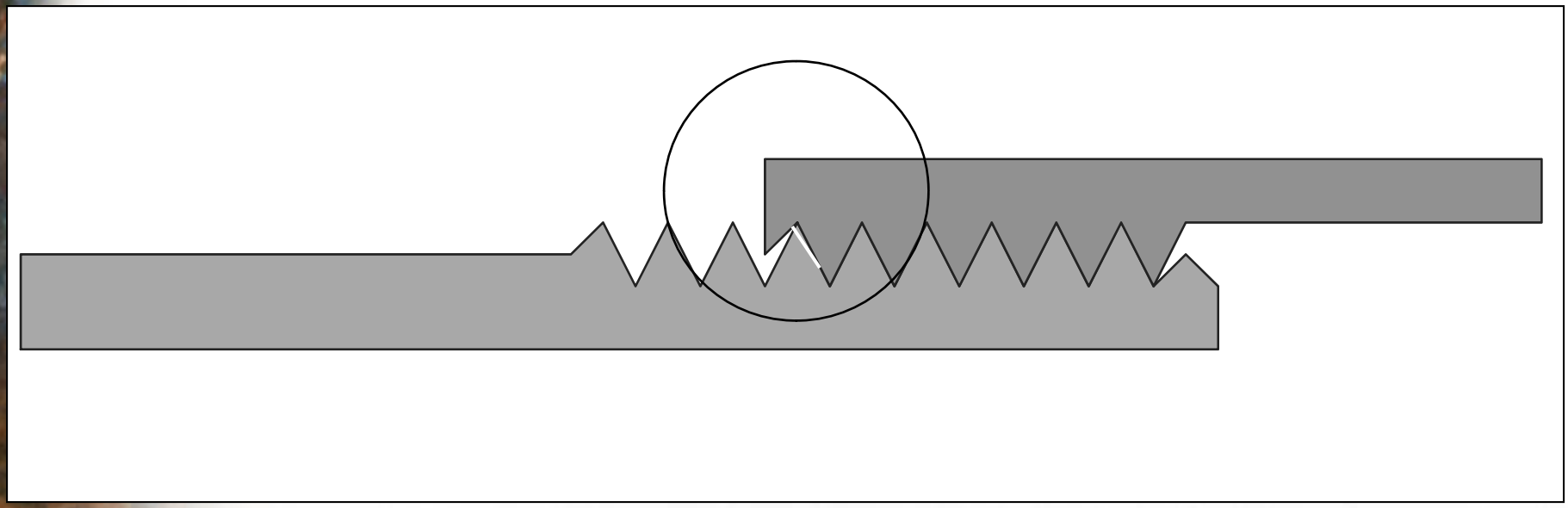
DISSOLVED OXYGEN

It does this by two mechanisms:

- **The formation of oxygen concentration cells**
- **Cathodic and Anodic depolarizer**
  - **Chemical reactions occur at both the anode and cathode**
  - **These chemical reactions speed up the corrosion process**

One of the most common locations to find evidence of OXYGEN CORROSION, is in the exposed threads near the make-up of tubing or pipe sections.

Since the "troughs" in the thread patterns are generally oxygen depleted, the thread points can exhibit loss of metal at their bases. Many times these threads will flake off on inspection of failed joints.



The most common locations for OXYGEN CORROSION

Producing Systems

- leaking stuffing boxes on rod pumps
- leaking vents on produced fluid tanks

Water Injection Systems

- leaking packings on pumps (any time a transfer pump or water injection pump is leaking water out it is leaking air in)
- leaking vents on water storage tanks

Oxygen Corrosion

In general, it is easier to repair the leak to control the corrosion that is caused when the oxygen dissolves in the water than it is to try to chemically control the corrosion.

Oxygen Corrosion

Oxygen Corrosion

- Oxygen will accelerate other corrosion effects.
- When present at concentrations as low as 50 ppb, in the presence of any of the Acid Gases, corrosion rates will be accelerated significantly.
- Because of this phenomenon, Oxygen Accelerated Corrosion is often misinterpreted in the oil field.
- Corrosion rates have been known to increase by as much as 100 times.

Oxygen Accelerated Corrosion

Stuffing Box
O_2 Leakage in Sour Brine

Corroded Stuffing Box

Acid Gases

The next most corrosive gas is carbon dioxide followed by hydrogen sulfide.

The corrosivity of both of these gases is a function

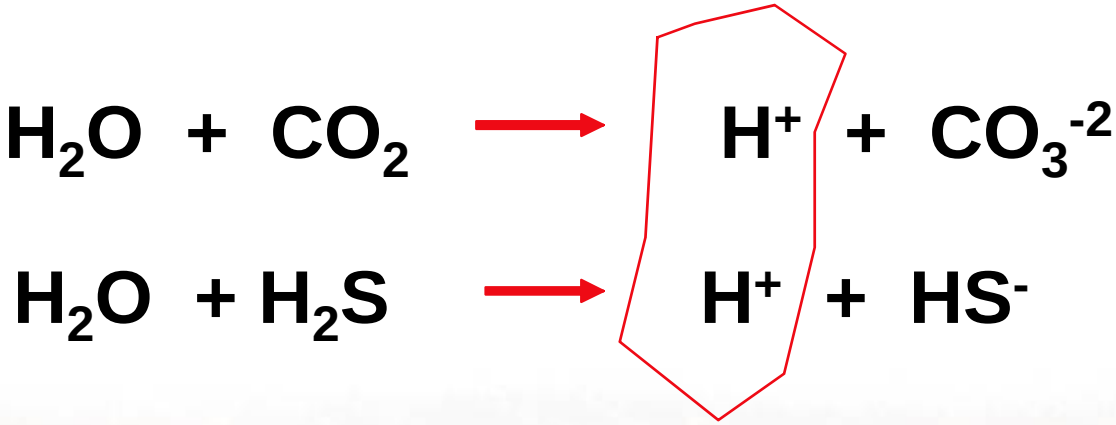
of their ABILITY TO FORM HYDROGEN IONS.

Acid Gas Corrosion

CARBON DIOXIDE

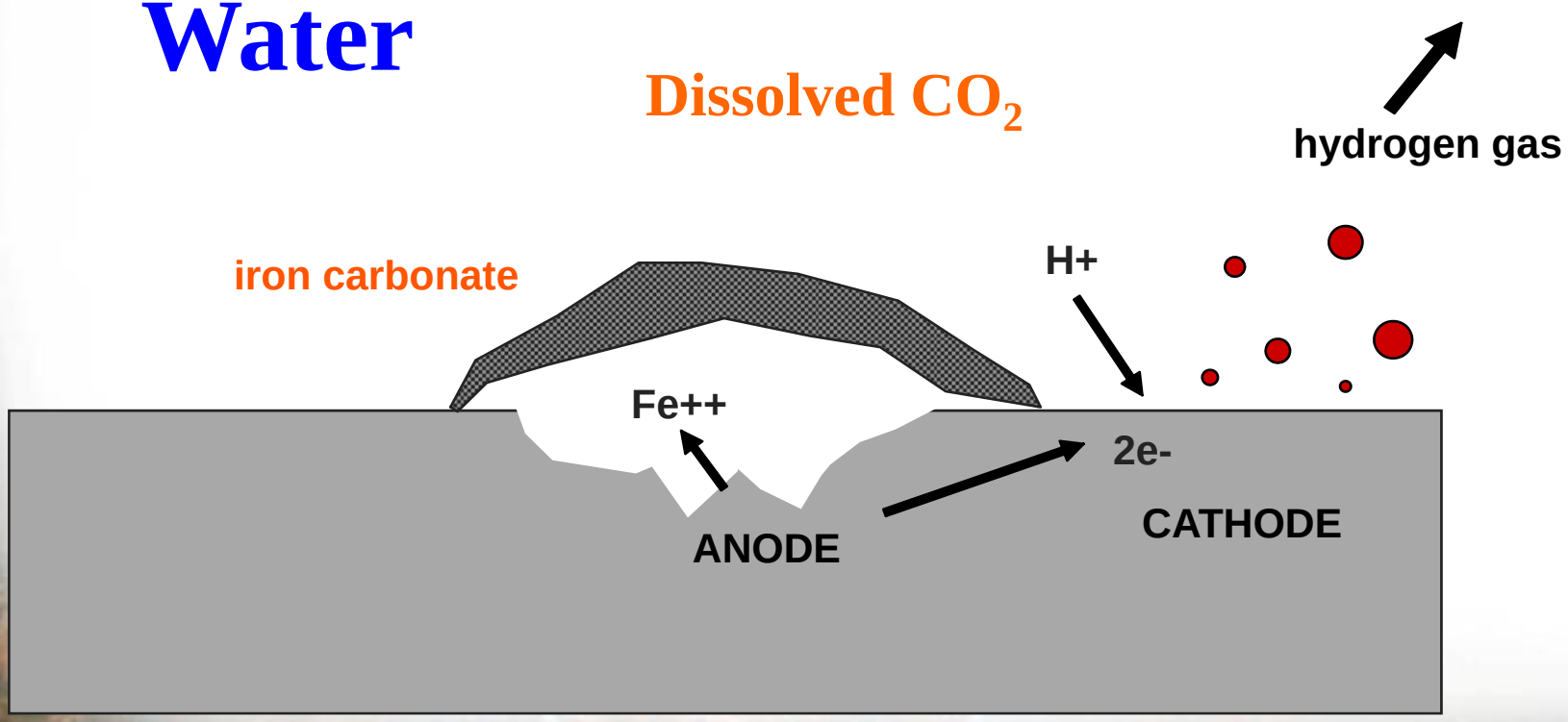
HYDROGEN SULFIDE

Both of these gases contribute to corrosion by increasing the acidity of the water when they dissolve in it.



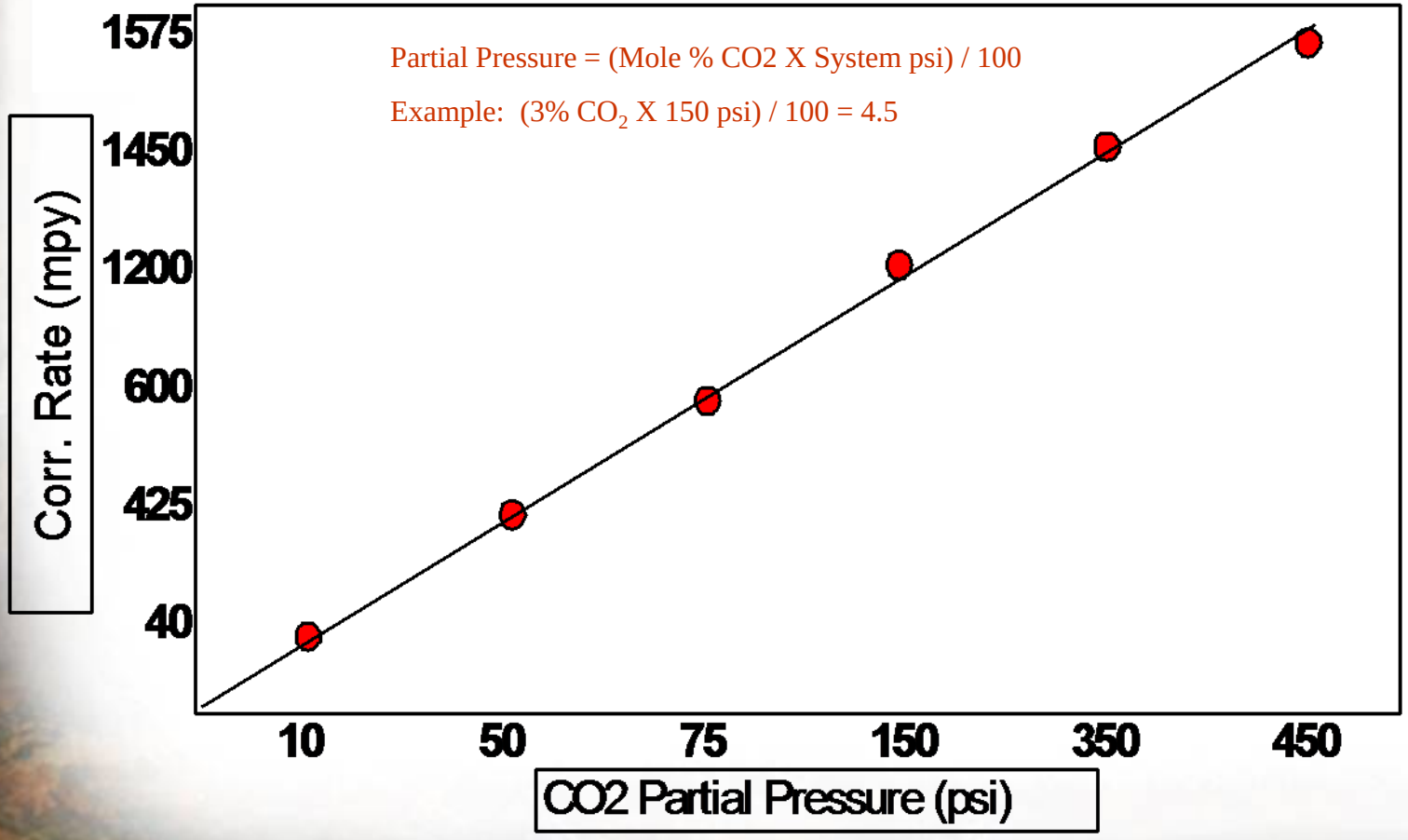
Carbon Dioxide Corrosion

The corrosion by-product is iron carbonate also known as siderite.

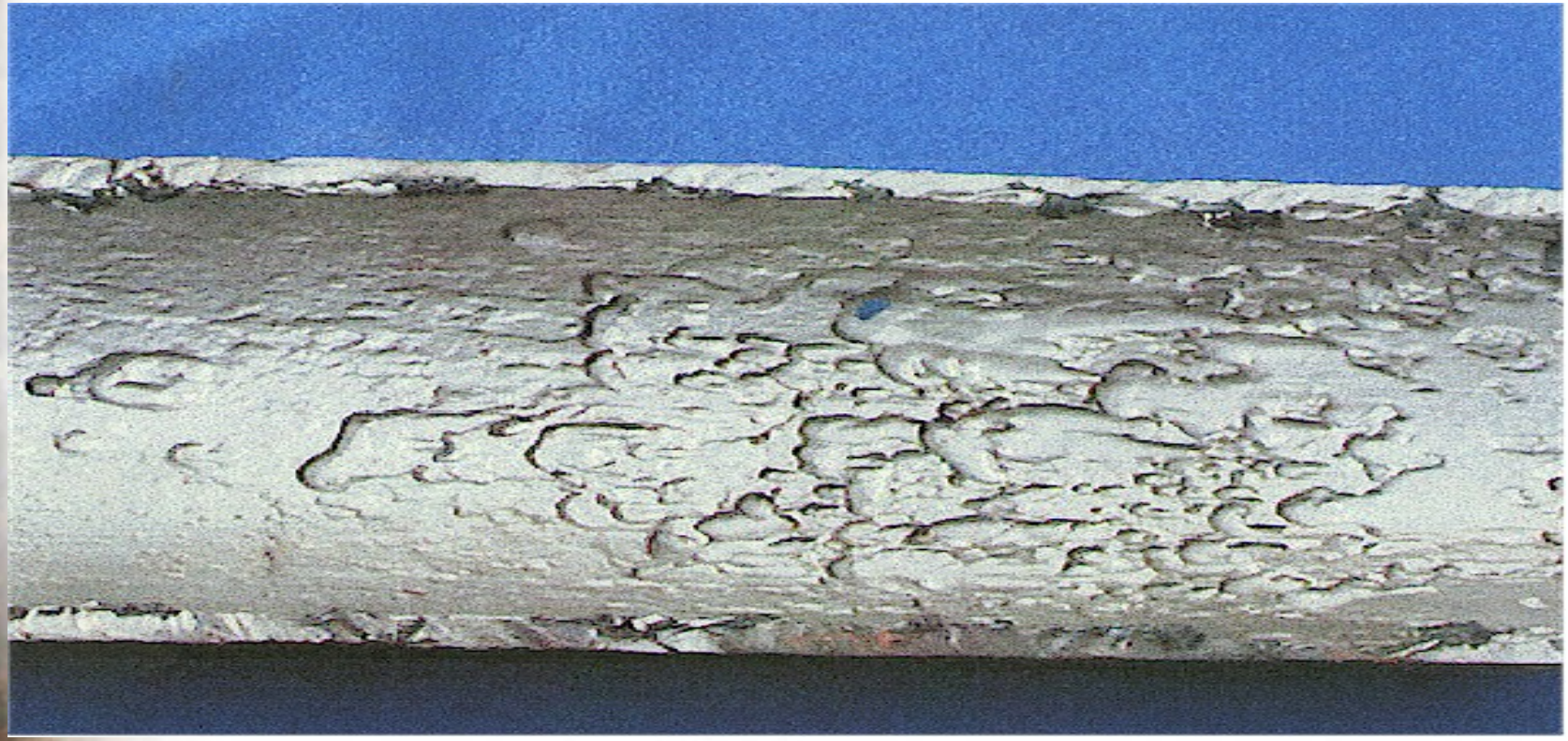


CO_2 Corrosion Rate in Distilled Water

(As Extrapolated from Chart - "OilField Water Systems" by Patton)

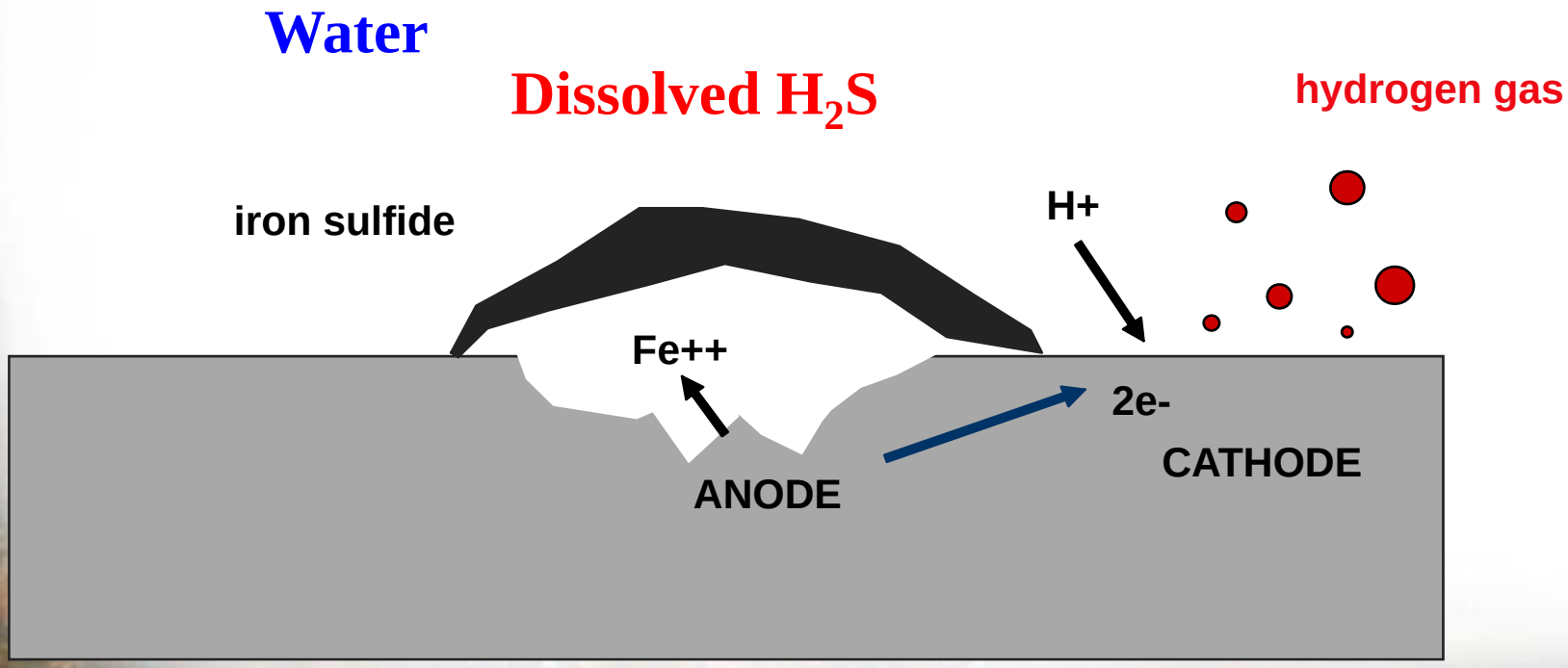


CO_2 Corrosion

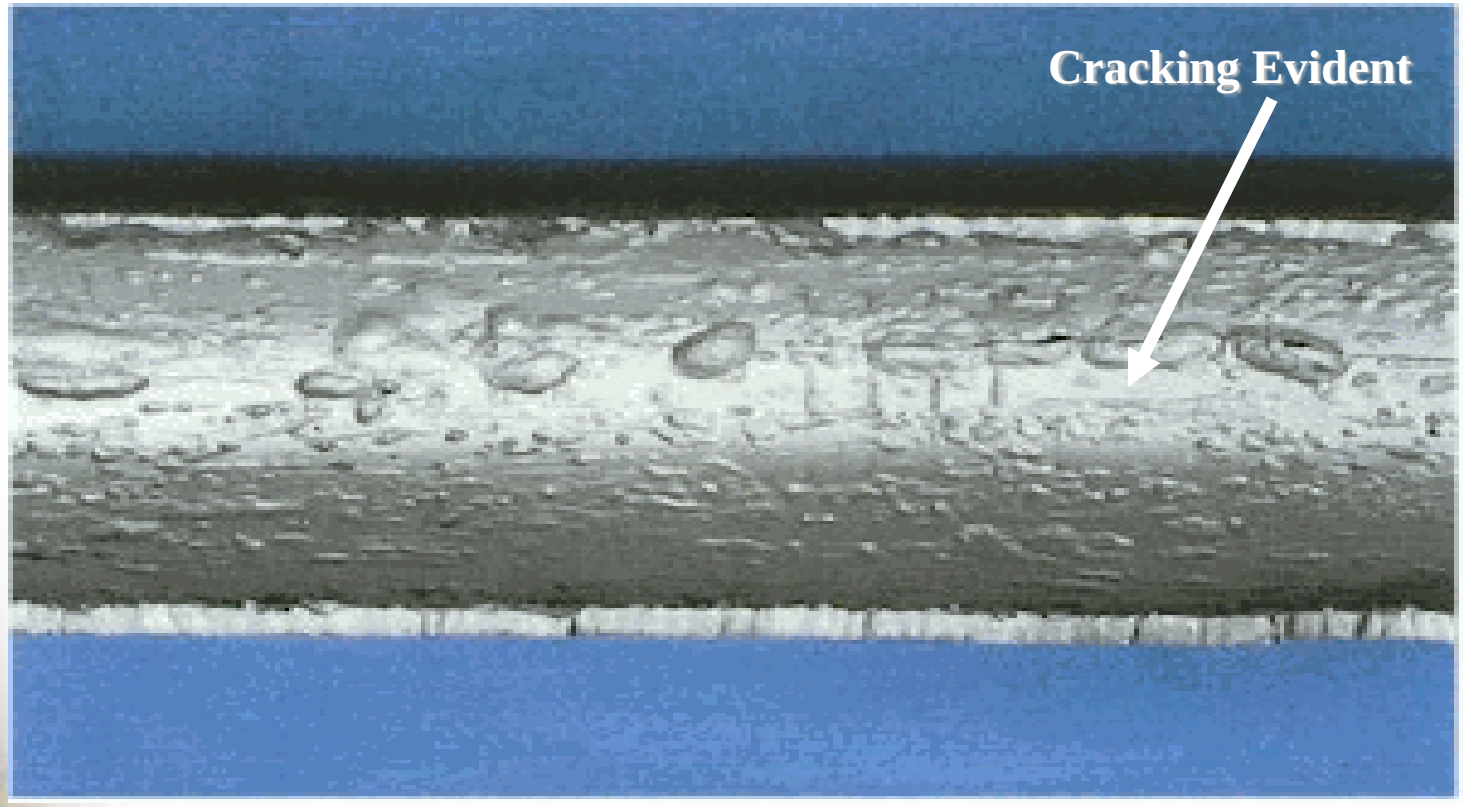


Hydrogen Sulfide Corrosion

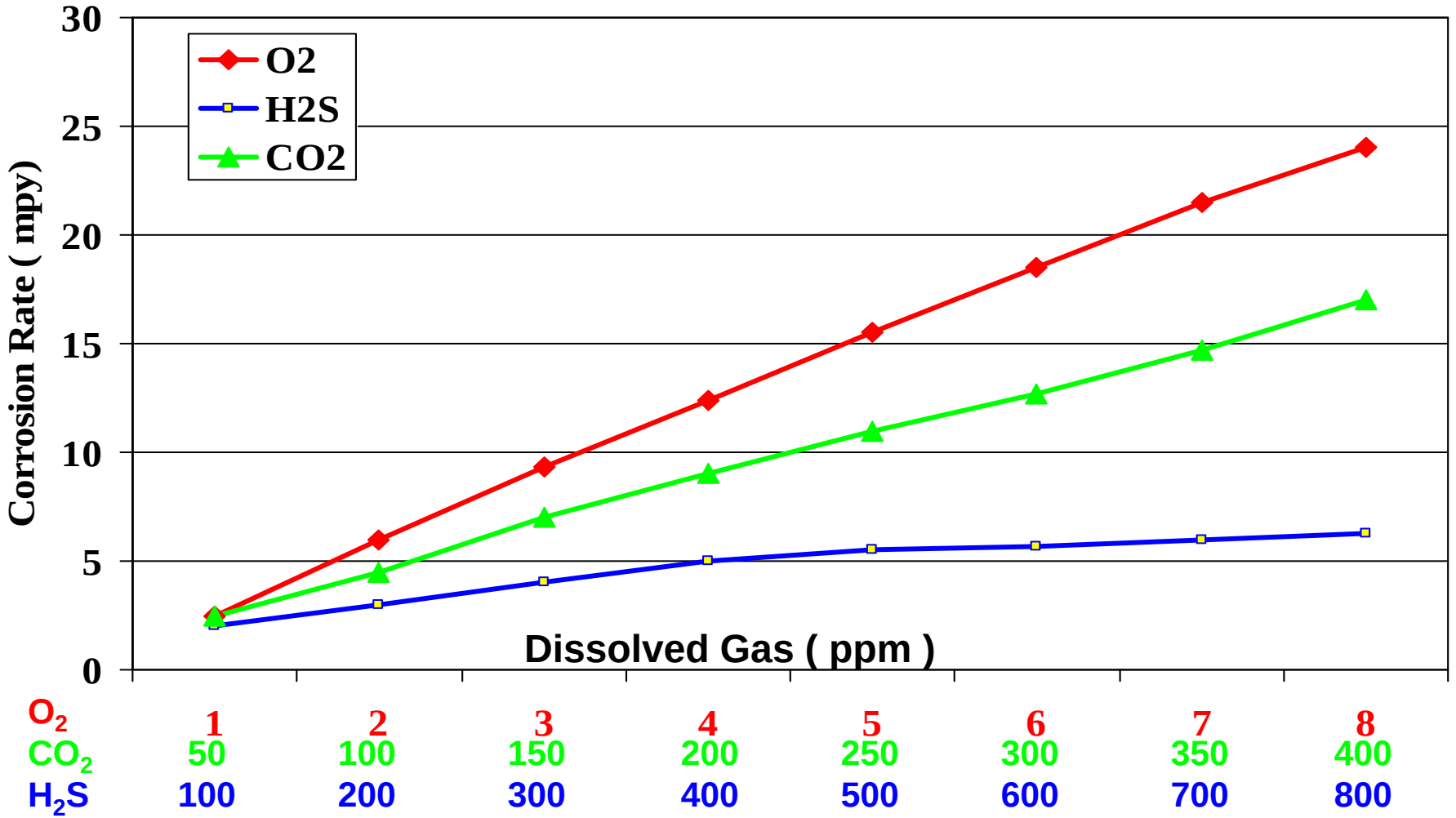
The corrosion by-product is iron sulfide. The initial crystalline form of iron sulfide is makinawite.



H_2S Corrosion



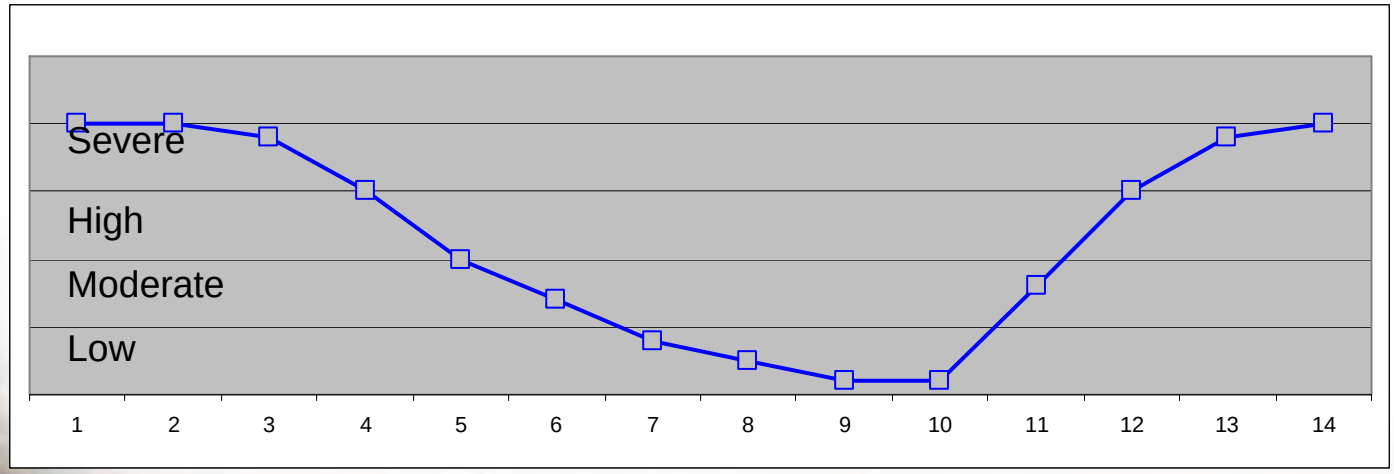
General Corrosion Rate Comparison



Excerpt taken from:
"Corrosion and Water Technology for Petroleum Producers"
Loyd W. Jones

Effects of pH

- High Corrosion rates from pH 1 to 5 and again from pH 11 to 14
- Moderate to low corrosion rates from pH 5 to 11
- Passive Zone = pH 9 - 10



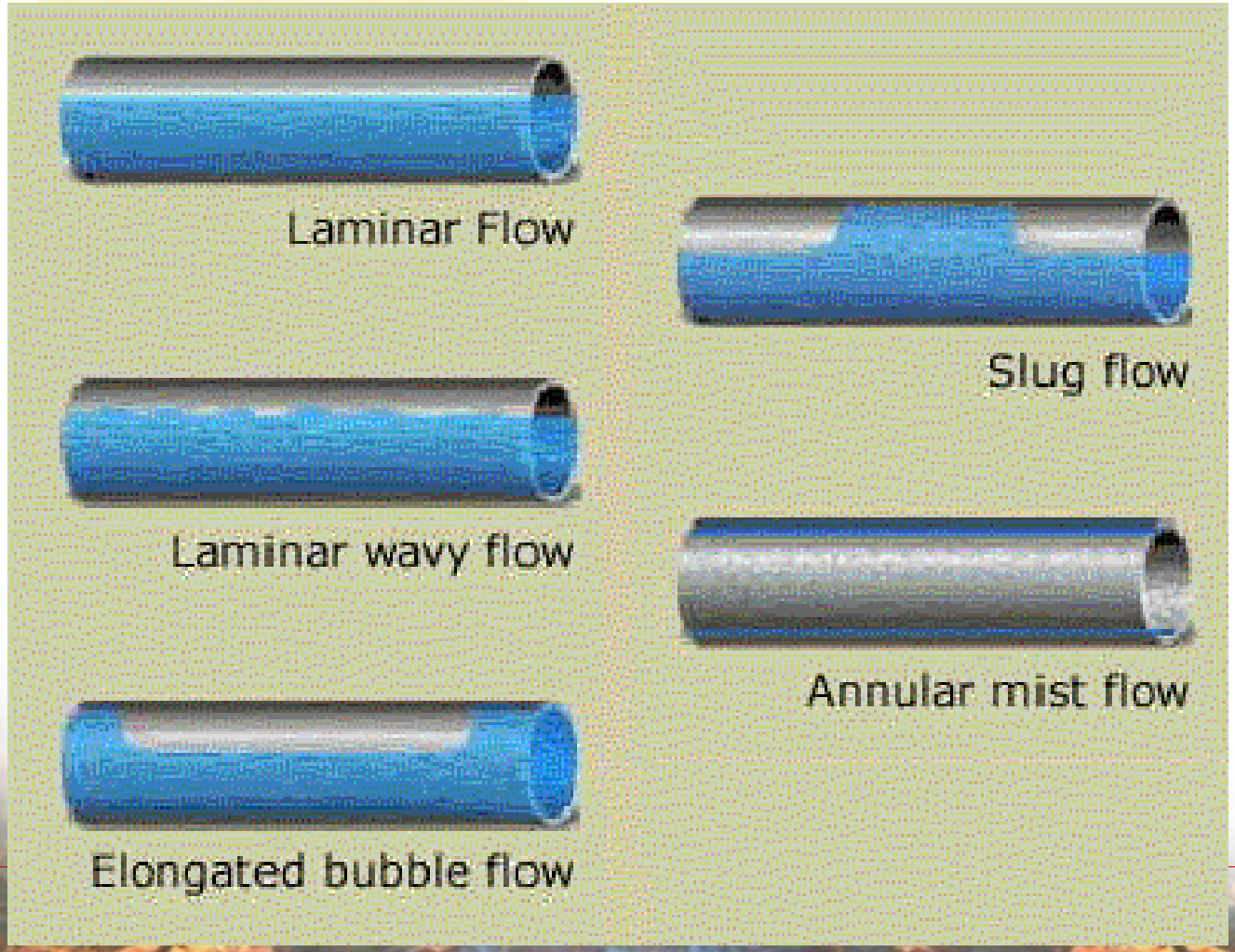
Effects of Salinity

- As a general statement
  - The higher the salinity - the higher the conductivity.
  - The higher the conductivity - the higher the corrosion rate.
  - Not really an issue unless any of H_2S, CO_2 or O_2 are present.

Effects of Flow

- **Low Flow – Stagnant to Laminar**
  - Solids have a chance to accumulate on the bottom of the line increasing the chance for Under deposit corrosion.
- **Moderate –**
  - Moderate flow is required to transport the Inhibitor through the system as well as keep the solids from accumulating on the bottom if the lines.
- **High Flow – Turbulent or Slug**
  - The high flow rates are more susceptible to corrosion. More areas for pressure differentials.
  - The Corrosion byproducts are removed from the corroding sites (anodes) exposing fresh metal to its environment.
- **Annular Flow**
  - In Gas systems where liquids exist as entrained droplets.

Types of Phase Flow



CO_2 Corrosion Accelerated by FLOW

Effects of Temperature

It should be noted that corrosion rates generally DOUBLE with every increase of 10 degrees (Centigrade) in temperature.

Effects of Solids Accumulation

- The area under a Solids Accumulation becomes Anodic to the surrounding base metal.
  - Metal loss occurs at the Anode, therefore under deposit corrosion is more likely.
- Solids accumulations can reduce corrosion inhibitor performance.
  - Surface area is increased substantially

CORROSION RATES

- Oxygen
- Acid Gases
- pH
- Salinity / Conductivity
- Flow
- Temperature
- Solids Accumulations
- EFFECTS ARE ADDITIVE

Corrosion Magnitude

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RP0775-2005 Corrosion Rates

General mpy	Pitting mpy	Corrosion Rating
< 1.0	< 5.0	Low
1.0 – 4.9	5.0 – 7.9	Moderate
5.0 – 10.0	8.0 – 15	High
> 10.0	> 15.0	Severe
1 mpy = 0.001” per year		

Downhole Corrosion SW Sask

Mitigation Strategies

- Material Design
- Coatings
- Chemical Inhibition

Material Selection

- Corrosion Resistant Metal Alloys
  - Monel, Inconel, Hastaloy
  - Pump Parts
- Fiberglass
  - Sucker Rod Material

Coatings

- There are many Epoxy type coating available
- Most often used in Water Injection wells

Chemical Additives

- Hydrogen Sulfide Scavengers
  - Remove corrosive H_2S
- Oxygen Scavengers
  - Remove corrosive Oxygen
- **Corrosion Inhibitors**
  - More to follow…

CHEMICAL CORROSION INHIBITORS

- Chemicals injected in small concentrations
  - (50 ppm to 500 ppm +)
- Physically adsorb onto the metal surface as a mobile film and reduce the cathodic reactions
- Often combine with corrosion byproducts to form a passive protective layer

Oilfield Corrosion Inhibitors

- Polar Molecules
- Typically Amine Based
- Have an attraction to surfaces, especially Iron
- Tend to “Oil Wet” the equipment to provide a barrier to the corrosive fluids.

CONTAIN:

- Inhibitor compounds (sometimes 2 or 3) blended with Surfactants, Demulsifiers, Partitioning Agents.

Oilfield Corrosion Inhibitors

- Most Oilfield Corrosion Inhibitors are capable of controlling H_2S, CO_2 and Organic Acid Corrosion
- Blended for specific applications
- Specialized chemicals are required for
  - Oxygen Accelerated Corrosion
  - Systems with Elemental Sulfur
  - Aluminum Flow-Lines
  - Atmospheric Corrosion Protection

Oilfield Corrosion Inhibitors

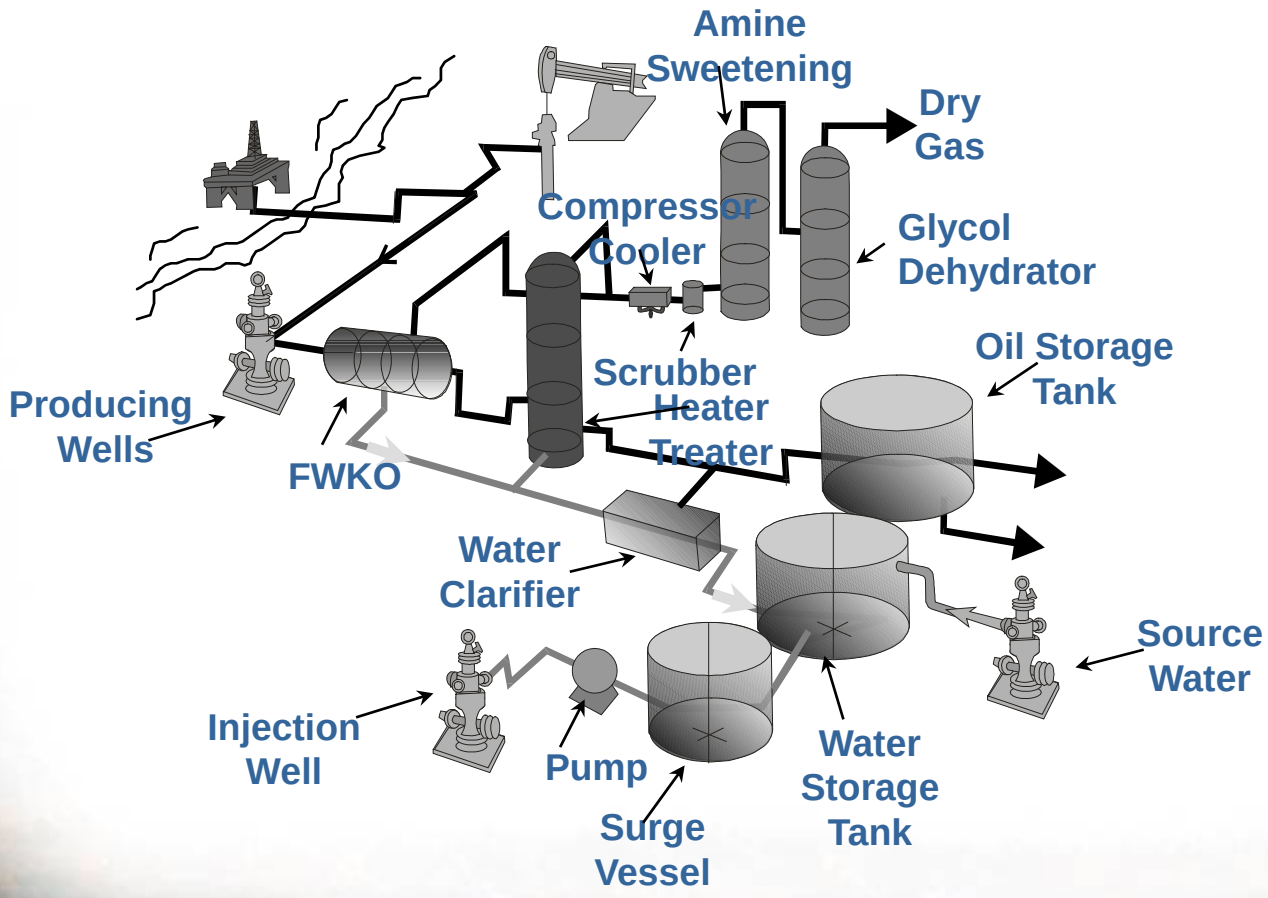
- Water Based, Oil Based
  - All are Water Dispersible to some degree
- Cleaning Capability
  - Increased by the Surfactant Additives
  - Surfactants are designed to remove loose solids accumulations

Oilfield Corrosion Inhibitors

Downhole Application Techniques

- Continuous Injection
  - Dribble down the annulus
  - Capillary Injection String
- Batch & Circulate
- Circulate and Park
- Tubing Displacement

Oilfield Corrosion Inhibitors



Oilfield Corrosion Inhibitors

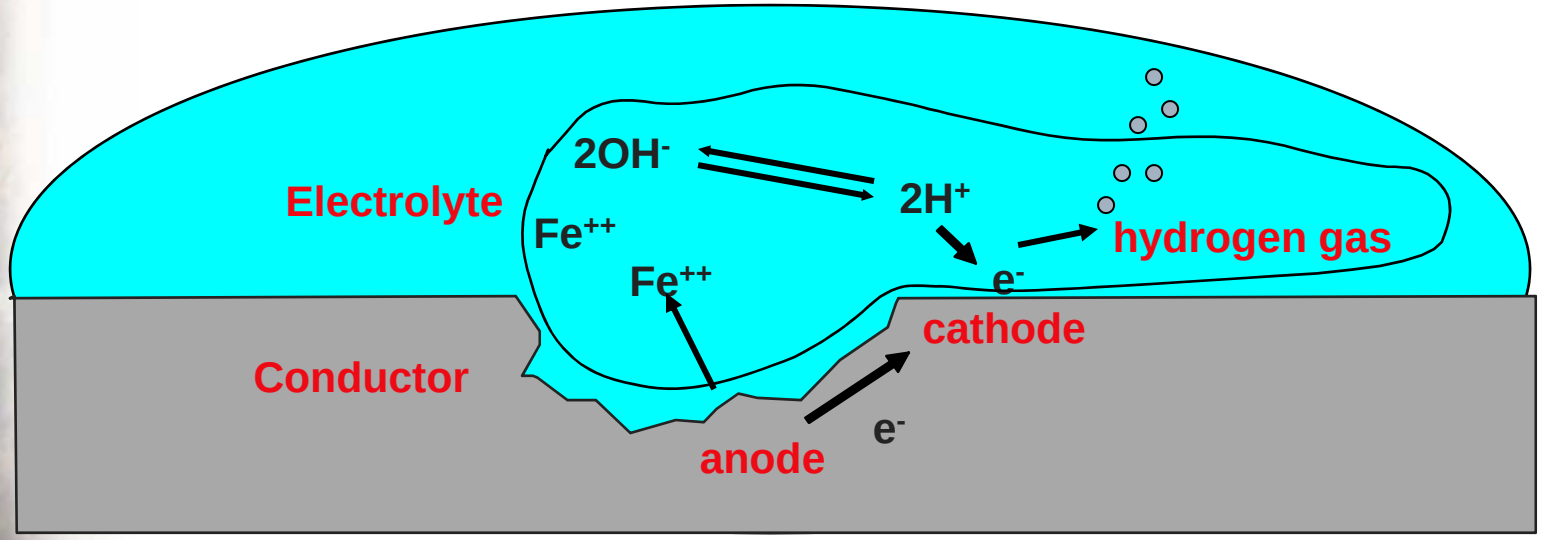
How do they work??

Corrosion Inhibitors

Large Lipophilic Tail
(Likes Oil)

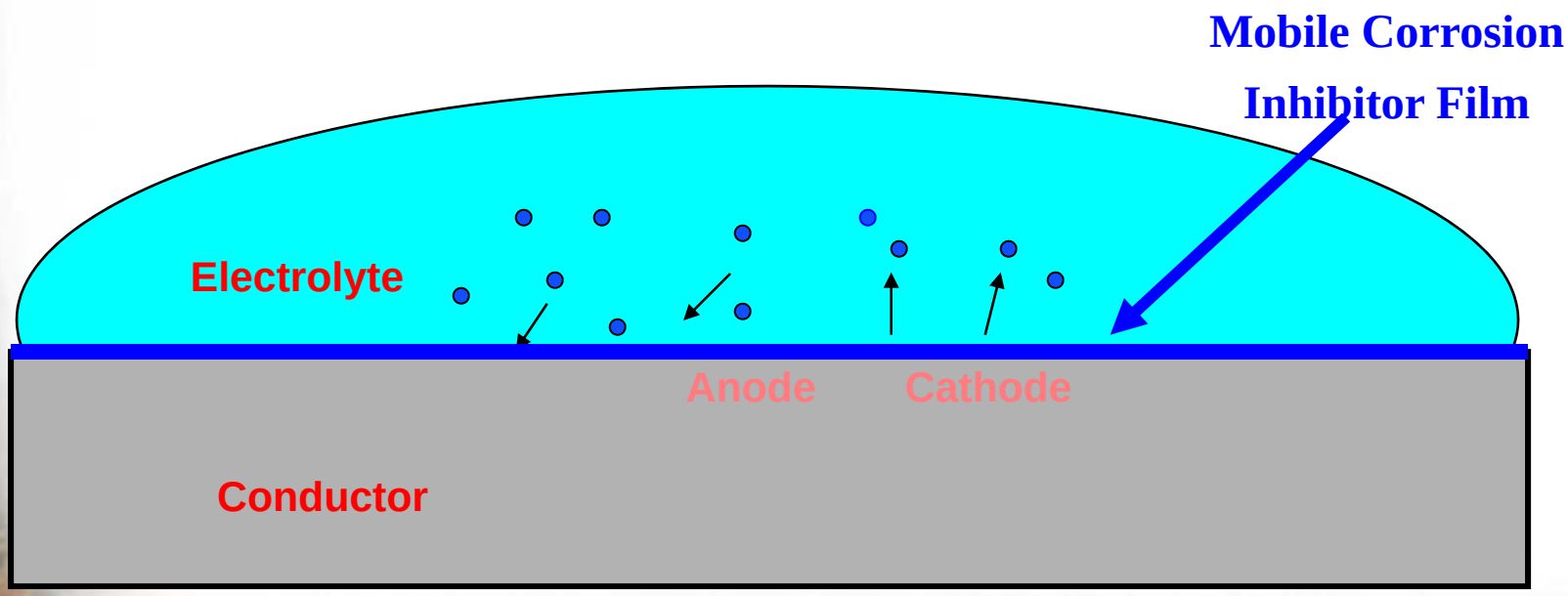
Relatively Small Lipophobic End
(Dislikes Oil)
(Strong attraction to surfaces)

Uninhibited Corrosive System



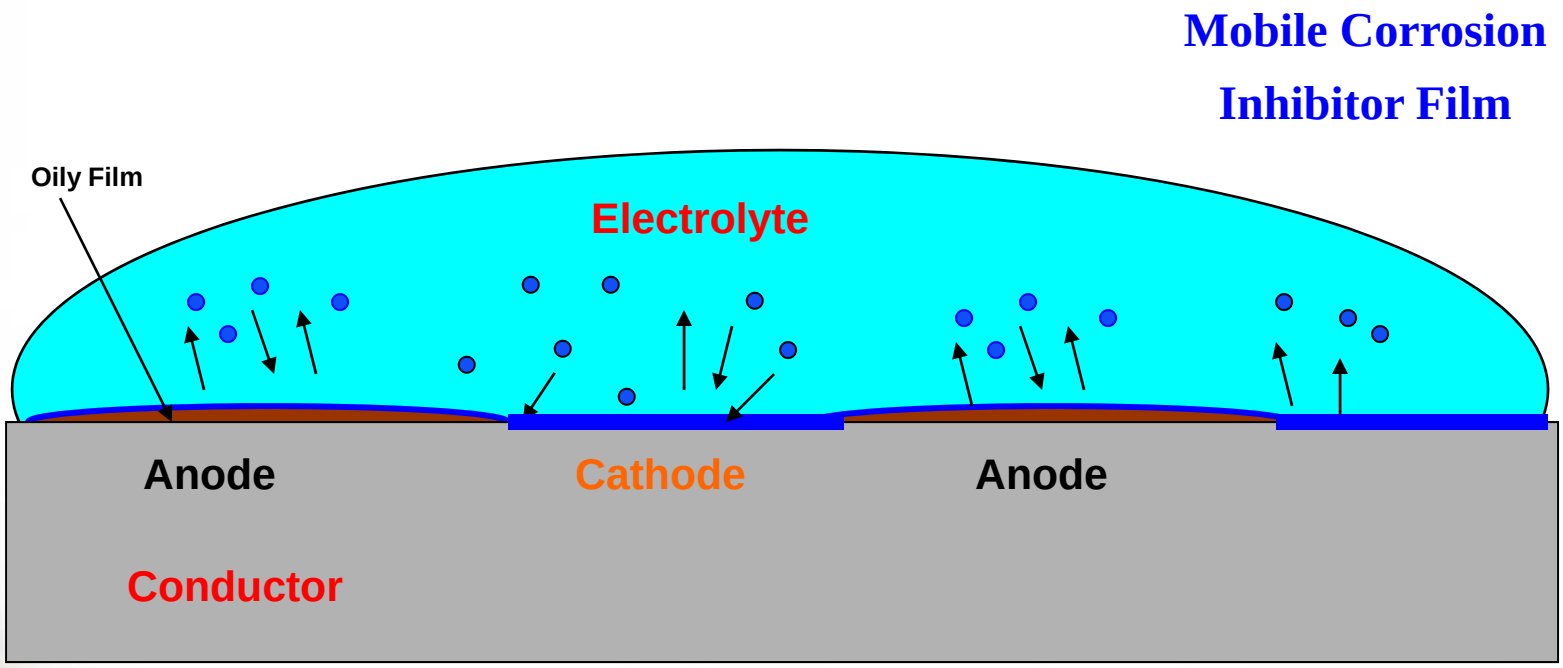
Inhibited Corrosive System

The Corrosion Inhibitor becomes a barrier between the metal surface and the electrolyte, thereby controlling corrosion.



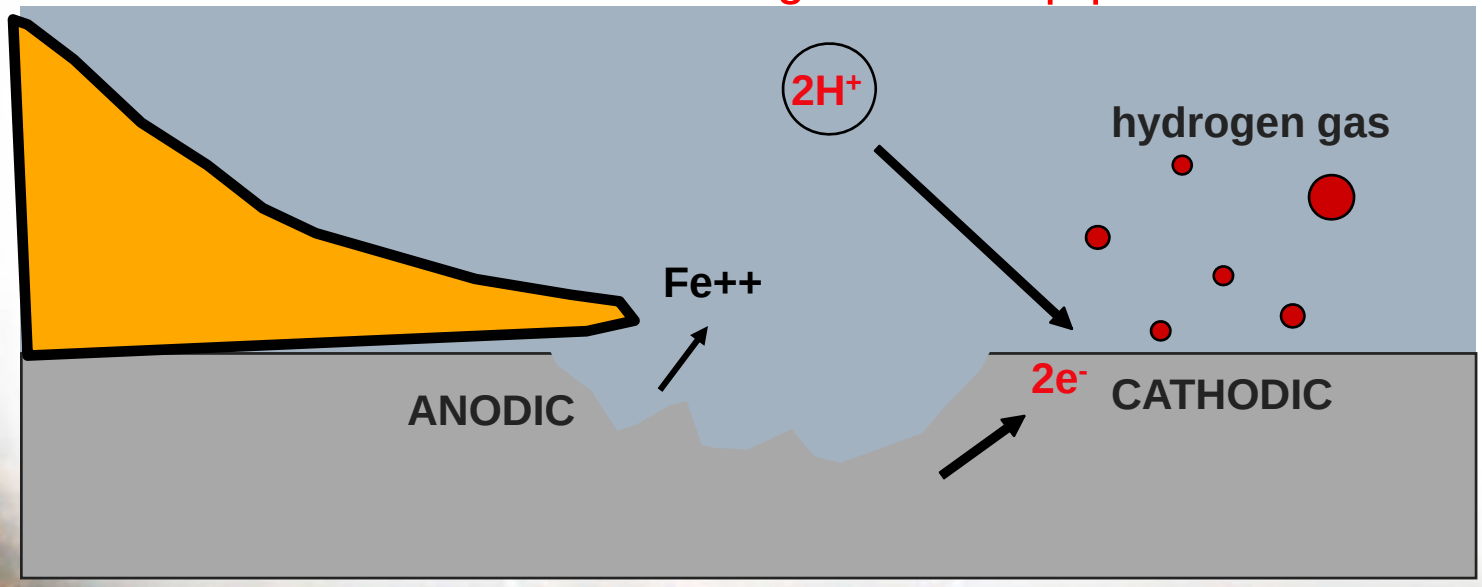
Pipe with Oily Film

(Crude Oil, Paraffins)



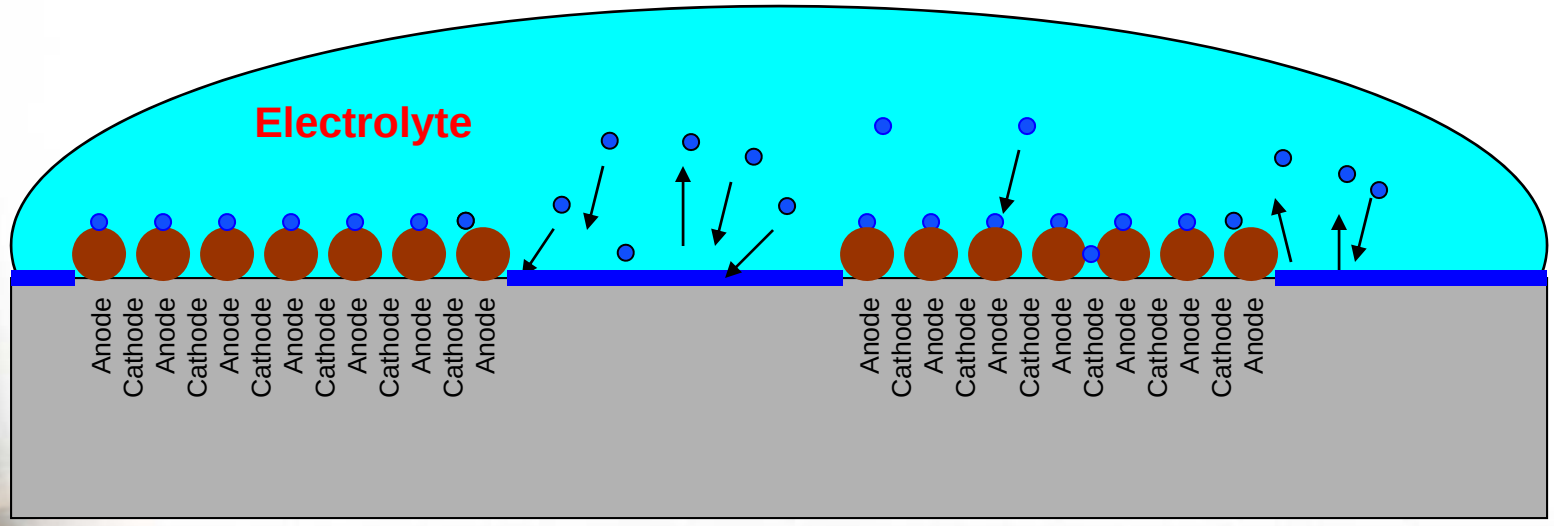
Effects of Loose Solids on the Pipe

- The area directly under a deposit becomes Anodic to the surrounding metal
  - Metal Loss occurs at the Anodic Sites
  - Corrosion Potential is increased
- Corrosion Inhibitor cannot get to the pipe!!



Pipe with Loose Solids

(Iron Sulfide Clumps, Scale, Silt, Sand)

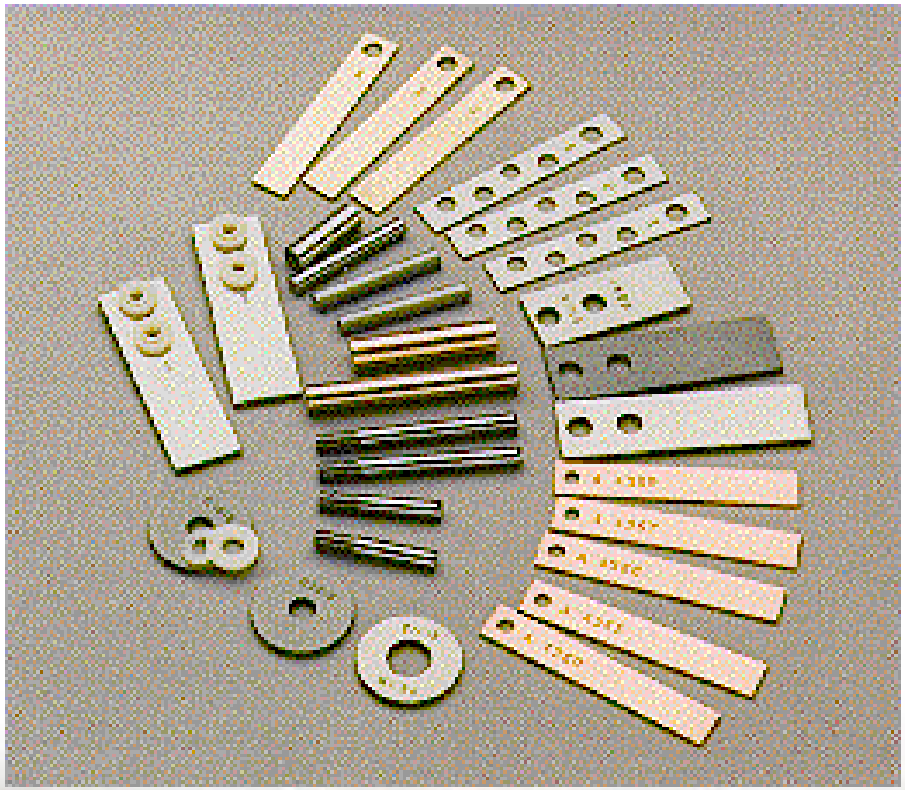


Corrosion Monitoring

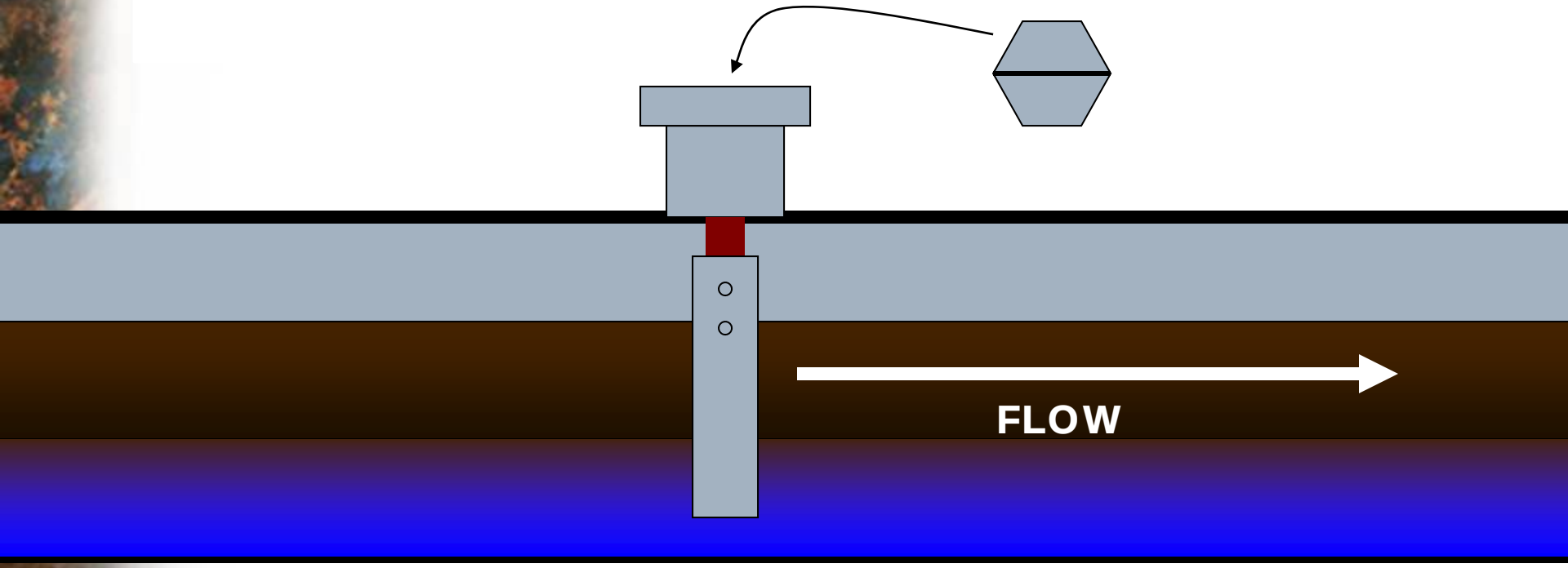
Time Averaged Techniques

Weight Loss Coupons

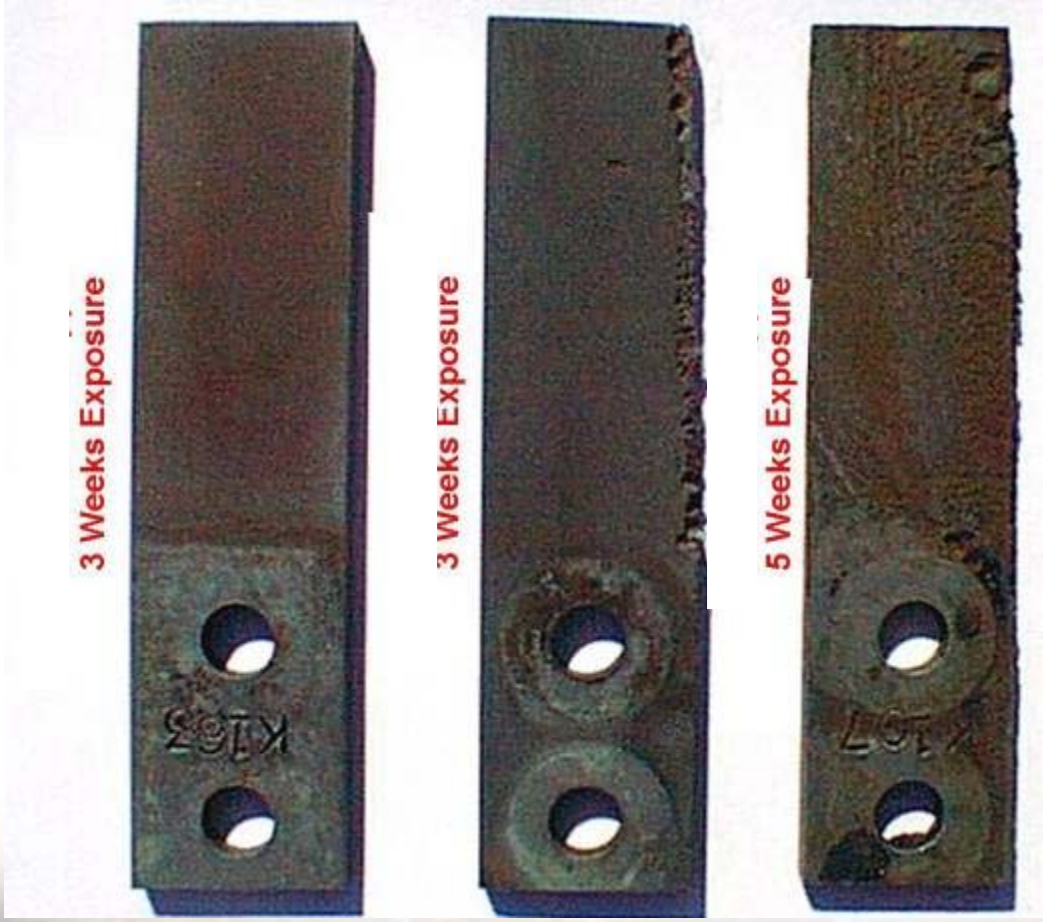
Coupons come in a variety of shapes, sizes and metallurgies …(must match the system)



Installing Corrosion Coupons



Inhibitor Comparison Using Coupons



35 ppm	35 ppm	25 ppm
Water Soluble Chemical	Oil Soluble Chemical	

Time Averaged - Cumulative Techniques

DIRECT WALL THICKNESS MEASUREMENTS:

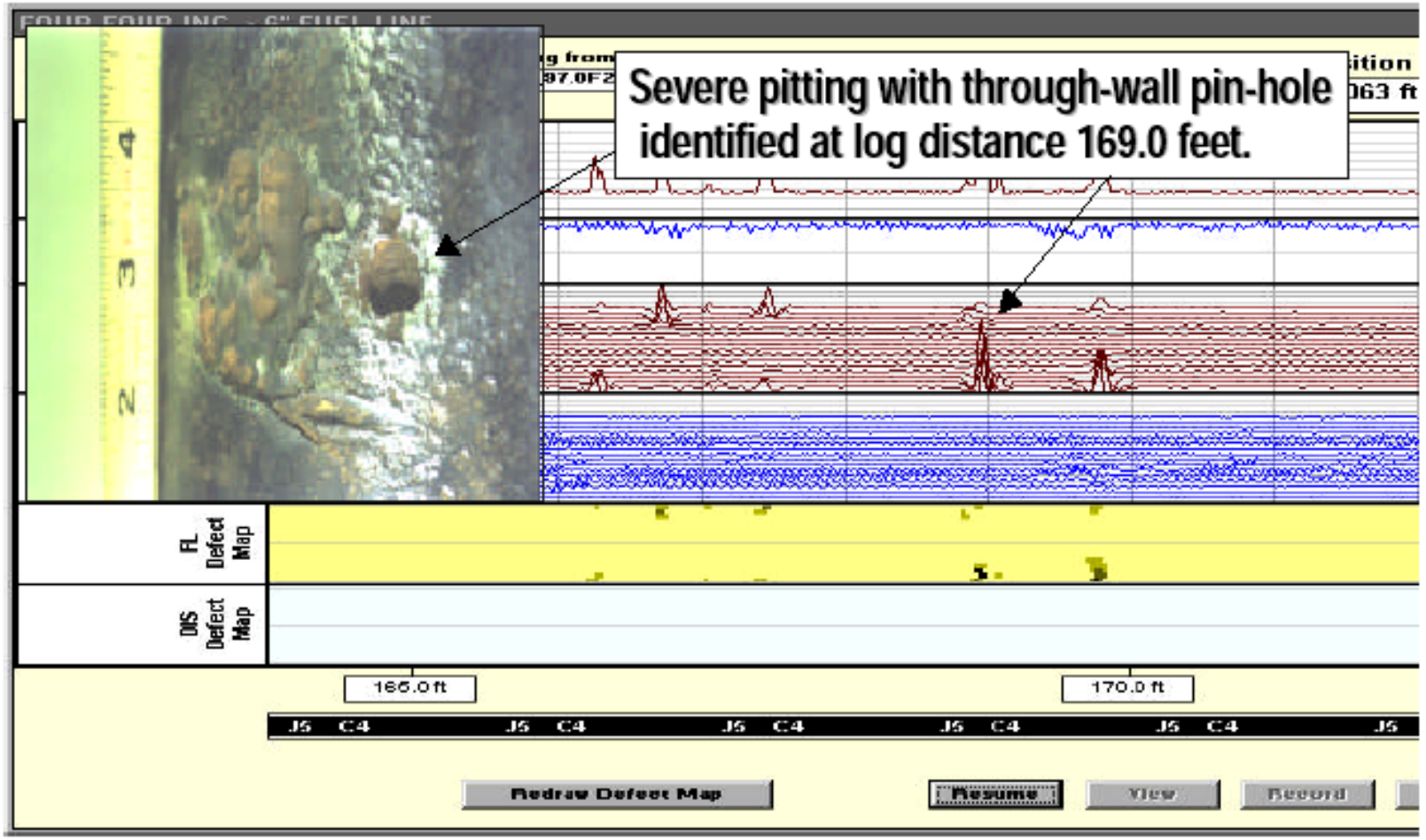
- **Ultrasonic - wall thickness measurements**

- **Wireline – Magnetic Flux Leakage Tool**

Magnetic Flux Leakage

Implementation of an Integrity Management Plan

The Vertiline MFL Inspection Provides Verification of Integrity



Time Averaged - Cumulative Techniques

- **Copper Ion Displacement Test**
  - Used to determine whether a Corrosion inhibitor film is still present on the metal surface.
  - Particularly effective in evaluating a film life on a Corrosion Inhibitor Batch program. Insert multiple coupons in a system and pull them one per week and see if the inhibitor film is still intact.

Copper Ion Displacement Test

- Dip an exposed Corrosion Coupon into a Copper Sulfate solution (~10%)
- Failure pieces can be flushed with Copper Sulfate to see if an Inhibitor film exists.
- Areas of metal exposing bare metal will film out metallic copper.

FAILURE HISTORY

This type of corrosion monitoring looks at the "Big Picture" and examines the number of corrosion related failures that have occurred over a fixed period of time.

Comparison of trends in failures provides an overview of the status of the corrosion control program.

Time Averaged - Cumulative Techniques

FAILURE HISTORY SHOULD INCLUDE:

- Number and frequency of corrosion related failures
  - Failures/Well/Year
  - Run Time per well
- Cause Analysis
- Physical Conditions- Flow rates, Water to Oil Ratios, Temperatures, Dissolved Gases, Chlorides in water etc.
- Plot on a Field Map / Plant Diagram

Instantaneous Techniques

Iron Counts --- NACE RP0192-98

- Analyze the water for changes in Iron Content
  - Total Iron (Acidized with Iron Free Acid)
- Samples from a given system must be handled the same way each time in order for the data to be meaningful.
- Data should be expressed as Kg/Day iron based on daily water production – especially useful for systems with fluctuating volumes.

Instantaneous Techniques

Iron Counts --- NACE RP0192-98

- Manganese is usually tested at the same time.
  - Carbon Steel contains 1% Mn
  - Most formations contain no Mn.

- Iron Counts from Sour systems are not as reliable as those taken from Sweet systems.
  - Iron Sulfides have a low solubility in water.
  - A few flakes of rogue Iron Sulfide can easily contaminate a water sample making the results suspect.

Failure Analysis

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Corrosion Failure

FAILURE ANALYSIS

The ability to analyze samples of failed materials lends toward a better understanding of the

“CAUSE OF THE FAILURE “

FAILURE ANALYSIS is a crucial part of designing any successful corrosion control program.