Corrosion

• Corrosion Basics
  – General corrosion theory
  – Corrosion examples

• Specialty Problems
  – CO$_2$ and H$_2$S
  – O$_2$ in sea water injection
  – Acid Treatment
  – Packer Fluids
Corrosion Control

• Recognition of Corrosion
• Causes of Corrosion
• Corrosion Prevention
Major Causes of Corrosion

- Salt water (excellent electrolyte, chloride source)
- H₂S (acid gas with iron sulfide the by-product)
- CO₂ (Major cause of produced gas corrosion)
- O₂ (key corrosion element, eliminate if possible)
- Bacteria (by products, acid produced)
- Acids
Other Factors

• pH
• Chlorides (influences corrosion inhibitor solubility)
• Temperature (Increase usually increases corrosion)
• Pressures (CO$_2$ and H$_2$S more soluble in H$_2$O)
• Velocity - important in stripping films, even for sweet systems
• Wear/Abrasion (accelerates corrosion)
• Solids – strips film and erodes metal
Chemical Corrosion

• H2S  
  – weak acid, source of H+  
  – very corrosive, especially at low pressure  
  – different regions of corrosion w/ temp.

• CO2  
  – weak acid, (must hydrate to become acid)  
  – leads to pitting damage

• Strong acids - HCl, HCl/HF, acetic, formic

• Brines - chlorides and zinc are worst
Corrosion Recognition

• Failures have many causes and appearances
  – abrasion (rod wear on tubing, etc.)
  – erosion (solids, droplets, mists) wear
  – chemical (oxidizing, acids, acid gases, chlorides, etc)
  – galvanic coupling (electromotive series)
  – metal alteration
    • chemical
    • physical
1970’s Industry Study of Failures

<table>
<thead>
<tr>
<th>Method</th>
<th>% of Failures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrosion (all types)</td>
<td>33%</td>
</tr>
<tr>
<td>Fatigue</td>
<td>18%</td>
</tr>
<tr>
<td>Brittle Fracture</td>
<td>9%</td>
</tr>
<tr>
<td>Mechanical Damage</td>
<td>14%</td>
</tr>
<tr>
<td>Fab./Welding Defects</td>
<td>16%</td>
</tr>
<tr>
<td>Other</td>
<td>10%</td>
</tr>
</tbody>
</table>
# Causes of Petroleum Related Failures (1970’s study)

<table>
<thead>
<tr>
<th>Cause</th>
<th>% of Failures</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO$_2$ Corrosion</td>
<td>28%</td>
</tr>
<tr>
<td>H$_2$S Corrosion</td>
<td>18%</td>
</tr>
<tr>
<td>Corrosion at the weld</td>
<td>18%</td>
</tr>
<tr>
<td>Pitting</td>
<td>12%</td>
</tr>
<tr>
<td>Erosion Corrosion</td>
<td>9%</td>
</tr>
<tr>
<td>Galvanic</td>
<td>6%</td>
</tr>
<tr>
<td>Crevice</td>
<td>3%</td>
</tr>
<tr>
<td>Impingement</td>
<td>3%</td>
</tr>
<tr>
<td>Stress Corrosion</td>
<td>3%</td>
</tr>
</tbody>
</table>
Corrosion can be considered a natural result of energy stored in the metal when it was refined and fabricated.
Corrosion cell. The basic corrosion cell is formed by two dissimilar metals immersed in an electrolyte joined by a conductor. One electrode will tend to corrode more readily than the other and is called the anode. The anode loses positive metal ions to the electrolyte leaving free electrons and a net negative charge. At the other electrode, called the cathode, free electrons are taken up by ions in the electrolyte leaving a net positive charge. Free electrons can travel from anode to cathode along the conductor. The electrolyte then completes the circuit.
Steel loss at the Anode – weight loss and pitting are simply illustrations of iron going into solution.
Anodes can form on a single piece of metal that has small crystals of slightly different composition.

The size and number of the crystals present in metals are a function of the cooling process (quenching).
Corrosion Types

• **Galvanic** – a potential difference between dissimilar metals in contact creates a current flow. This may also occur in some metals at the grain boundaries.

• **Crevice Corrosion** – Intensive localized electrochemical corrosion occurs within crevices when in contact with a corrosive fluid. Will accelerate after start.

• **Pitting** – Extremely localized attack that results in holes in the metal. Will accelerate after start.

• **Stress Corrosion** – Occurs in metal that is subject to both stress and a corrosive environment. May start at a “stress riser” like a wrench mark or packer slip mark.
Corrosion Types

• **Erosion Corrosion** – Passage of fluid at high velocity may remove the thin, protective oxide film that protects exposed metal surface.

• **Hydrogen Sulfide Corrosion** – $\text{H}_2\text{S}$ gas a water creates an acid gas environment resulting in $\text{FeS}_x$ and hydrogen.

• **Hydrogen Embrittlement** – Atomic hydrogen diffuses into the grain boundary of the metal, generating trapped larger molecules of hydrogen molecules, resulting in metal embrittlement.

• **Hydrogen Corrosion** – Hydrogen blistering, hydrogen embrittlement, decarburization and hydrogen attack.
CO2 Partial Pressure

• Severity is a function of the partial pressure
  – 0-3 psi - very low – non chrome use possible
  – 3-7 psi – marginal for chrome use
  – 7-10 psi – medium to serious problem
  – >10 psi – severe problem

Partial pressure is the mole fraction of the specific gas times the total pressure.
CO$_2$ localized corrosion or pitting
The corrosion rate of CO2 is a function of partial pressure, temperature, chloride presence of water and the type of material.

Corrosion rate in MPY – mills per year is a standard method of expression, but not a good way to express corrosion where pitting is the major failure.
Note the effect of the temperature on the corrosion rate.

Cost factors between the tubulars is about 2x to 4x for Chrome-13 over low alloy steel and about 8x to 10x for duplex (nickel replacing the iron).
CO$_2$ CORROSION ISOPLOT

pH 5

Corrosion Rate, mm/y

Temperature, degC

Log(Pco2)

- 0.9 - 1.0 mm/y
- 0.8 - 0.9 mm/y
- 0.7 - 0.8 mm/y
- 0.6 - 0.7 mm/y
- 0.5 - 0.6 mm/y
- 0.4 - 0.5 mm/y
- 0.3 - 0.4 mm/y
- 0.2 - 0.3 mm/y
- 0.1 - 0.2 mm/y
- 0.0 - 0.1 mm/y
Chloride Stress Cracking

- Starts at a pit, scratch or notch. Crack proceeds primarily along grain boundaries. The cracking process is accelerated by chloride ions and lower pH.
Stress Sulfide Corrosion

• Occurs when metal is in tension and exposed to H$_2$S and water.
• Generates atomic hydrogen. Hydrogen moves between grains of the metal. Reduces metal ductility.
## API/SPEC 5A, 5AC, 5AX Tubing and Casing

<table>
<thead>
<tr>
<th>Grade</th>
<th>Yield Min.</th>
<th>Yield Max.</th>
<th>Tensile Min.</th>
<th>H₂S</th>
<th>Spec.</th>
</tr>
</thead>
<tbody>
<tr>
<td>H-40</td>
<td>40,000</td>
<td>--</td>
<td>60,000</td>
<td>Yes</td>
<td>5A</td>
</tr>
<tr>
<td>J-55</td>
<td>55,000</td>
<td>80,000</td>
<td>75,000</td>
<td>Yes</td>
<td>5A</td>
</tr>
<tr>
<td>K-55</td>
<td>55,000</td>
<td>80,000</td>
<td>95,000</td>
<td>Yes</td>
<td>5A</td>
</tr>
<tr>
<td>N-80</td>
<td>80,000</td>
<td>110,000</td>
<td>100,000</td>
<td>?</td>
<td>5A</td>
</tr>
<tr>
<td>C-75</td>
<td>75,000</td>
<td>90,000</td>
<td>95,000</td>
<td>Yes</td>
<td>5AC</td>
</tr>
<tr>
<td>L-80</td>
<td>80,000</td>
<td>95,000</td>
<td>95,000</td>
<td>Yes</td>
<td>5AC</td>
</tr>
<tr>
<td>C-95</td>
<td>95,000</td>
<td>110,000</td>
<td>105,000</td>
<td>?</td>
<td>5AC</td>
</tr>
<tr>
<td>P-105</td>
<td>105,000</td>
<td>135,000</td>
<td>120,000</td>
<td>No</td>
<td>5AX</td>
</tr>
<tr>
<td>P-110</td>
<td>110,000</td>
<td>140,000</td>
<td>125,000</td>
<td>No</td>
<td>5AX</td>
</tr>
</tbody>
</table>
Domain Diagram for C110

Sulphide Stress Cracking Performance Domain of "Sour Resistant" Grade 110ksi Steel

- **Acceptable**
- **Unacceptable**

Solution pH

pH₂S (bara)
Hydrogen Sulfide Corrosion

- Fe + H₂S + H₂O $\rightleftharpoons$ FeSₓ + H₂ + H₂O
- FeS - cathode to steel: accelerates corrosion
- FeS is a plugging solid
- Damage Results
  - Sulfide Stress Cracking
  - Blistering
  - Hydrogen induced cracking
  - Hydrogen embrittlement
H2S corrosion

- Several forms
- Results in some form of iron sulfide
- Most FeS$_x$ only very slowly acid soluble in thicker deposits
H₂S corrosion is minimized by sweetening the gas (knocking the H₂S out or raising pH.)
Note the effect of increasing pH on the lowering of corrosion potential.
Approximate Domain Diagram for Super 13Cr

Domain Diagram For The Sulphide Stress Cracking Limits Of 95ksi Super 13Cr Alloys In High Chloride (120,000 ppm Cl⁻) Waters
SSC Failure of Downhole Tubular String in Louisiana

3/14/2009

George E. King, Engineering GEKEngineering.com
SSC Failure of Downhole Tubular String in Louisiana

- HP/HT Gas Producer – 45mmscf/d, 50ppm H₂S and 8.7mol%CO₂ (0.5psia H₂S, pH 3.5).
- Completed with a mixture of L80-13Cr & CR13 95ksi 13/4/1 tubing.
- Packerless completion allowed produced fluid to contact tubing OD.
- Tubing failed via SSC at localised sites of cold work on the OD (slip and tong marks).
- Gas, water and sand flowed from the tubing bore to the annulus, resulting in significant erosion of both the tubing and casing.
- Tubing replaced with CR13 95ksi 13/5/2, casing repaired with an expandable solid casing patch.
Crevice Corrosion

- The physical nature of the crevice formed by the tubing to coupling metal-to-metal seal may produce a low pH aggressive environment that is different from the bulk solution chemistry – hence a material that looks fine when tested as a flat strip of metal can fail when the test sample (or actual tubing) includes a tight crevice.

- This damage can be very rapid in water injection wells, wells that produce some brine or in wells where there is water alternating gas (WAG) sequencing – causing failure at the metal-to-metal seals in a matter of months.
Crevice Corrosion

Note the seal crevice corrosion – this caused a leak to the annulus.
Crevice Corrosion

- There have been three notable instances of this occurring in 13Cr seawater injection systems in the North Sea
  - a Statoil well after 9 months,
  - Gyda where they claimed O$_2$ levels were kept to <20 ppb,
  - at Machar (part of ETAP) where O$_2$ levels were controlled to 50 ppb or lower (Super 13Cr).
Crevice Corrosion

Note the pit that started the washout – seal crevice corrosion.

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O$_2$ Corrosion

There is no corrosion mechanism more damaging on a concentration basis than oxygen – small amounts of oxygen, water and chlorides can ruin a chrome tubing completion in a few months. Injection wells are the most severely affected – minimise oxygen and don’t use chrome pipe in injectors.

20 ppb O$_2$ limit for seawater in carbon steel injection tubulars. 13Cr is CO$_2$ resistant but very susceptible to pitting corrosion in aerated brines. 5 ppb O$_2$ is suggested as a limit, but even these levels have not been confirmed.
Oxygen in Surface Waters

- 32°F - 10 ppm (saturation)
- 212°F - 0 ppm

\[
\text{ppm O}_2 = 10 - 0.055 \ (T - 30^\circ) \\
T = \text{water system temperature, } \degree F
\]
A split in the side of 5-1/2” casing. Cause was unknown – mechanical damage (thinning by drill string abrasion) was suspected.
Abrasion by solids, gas bubbles or liquid droplets may significantly increase corrosion by continuously removing the protective oxide or other films that cover the surface following the initial chemical reaction.
Choke “Bean” Erosion – by produced formation sand
EXAMPLE OF SCREEN EROSION BY SAND OPPOSITE PERFORATION
(COURTESY OF WORLD OIL MAGAZINE & GEORGE SUMAN)
Most graphs do not show the effect of too low a velocity on the corrosion rate. When the surface is not swept clean, biofilms can develop or the surface liquid layer may saturate with CO2 or other gas, increasing corrosion.
Corrosion and Velocity

- Corrosion increases steadily for all liquid systems with velocity.
- Corrosion jumps sharply for solids or liquid drops in a fluid stream.
## Maximum Velocities

<table>
<thead>
<tr>
<th>Conditions</th>
<th>Tubing Pressure</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1000 psi</td>
</tr>
<tr>
<td></td>
<td>5000 psi</td>
</tr>
<tr>
<td>Wet, non corrosive gas</td>
<td>85 fps</td>
</tr>
<tr>
<td>Wet, corrosive gas</td>
<td>50 fps</td>
</tr>
<tr>
<td>Wet, corrosive &amp; abrasive</td>
<td>30 fps</td>
</tr>
</tbody>
</table>

There may be minimum velocities needed to prevent biofilms or other static fluid problems.
Note the effect of increasing flowing fluid density on corrosion rate.

Also — presence of solids in the flowing fluids very significantly lowers the maximum permissible flow rate.
Critical or maximum velocities for flow using the API RP 14E equation. The variable is the C factor – for short lived projects, this factor may be 200 or more. It may also rise when CRA pipe is used.
Corrosion increases after water cut reaches 10 to 20%. The cause is removal of the protective oil film. In the third phase, the pipe is completely water coated and corrosion rate becomes more constant.
Corrosion: water in sweet gas

<table>
<thead>
<tr>
<th>Water (bbl/mcf)</th>
<th>Chlorides (ppm)</th>
<th>Iron (ppm)</th>
<th>Corrosion Possibility</th>
</tr>
</thead>
<tbody>
<tr>
<td>+- 2</td>
<td>0-250</td>
<td>50</td>
<td>No</td>
</tr>
<tr>
<td>+- 2</td>
<td>0-250</td>
<td>50-100</td>
<td>possible</td>
</tr>
<tr>
<td>+- 2</td>
<td>0-250</td>
<td>&gt;150</td>
<td>possible</td>
</tr>
<tr>
<td>2-5</td>
<td>250-500</td>
<td>50</td>
<td>possible</td>
</tr>
<tr>
<td>2-5</td>
<td>250-500</td>
<td>50-150</td>
<td>probable</td>
</tr>
<tr>
<td>2-5</td>
<td>250-500</td>
<td>&gt;150</td>
<td>Yes</td>
</tr>
<tr>
<td>&gt;5</td>
<td>&gt;500</td>
<td>&gt;150</td>
<td>Yes</td>
</tr>
</tbody>
</table>

A rise in chlorides is usually accompanied by a drop in pH. Iron content often reflects corrosion in the system, but is also a reflection of low pH.
Effect of pitting on penetration rate – Low mpy (mils per year) readings can mask pit development that leads to leaks.
Acid Corrosion Rates on Alloys

Graphs showing the corrosion rate in mpy (millimeters per year) for N-80 and 410-Stainless alloys as a function of temperature in °F. The graphs compare the corrosion rates at different HCl concentrations (5%, 10%, 15%, 15% HCl inhibited).
Increasing Rate of Penetration with Pit Development

Large anodic area, rate of metal loss and pit penetration is slow.

Anodic area decreases, cathodic area extends down side of pit. Rate of penetration increases.

Anodic area confined to bottom of pit. Rapid rate of metal loss and wall penetration.

NOTE: Corrosion product normally coating or filling pits not shown.
Welds

The heating that occurs during the welding process will cause the weld metal and the heat affected zone around the weld to be physically different from the surrounding, original metal.

An anode is created by this difference.
Pitting in the heat affected zone around a weld. May be an example of galvanic corrosion.
CO2 Injection Materials

1. Aluminum Bronze for all wetted wellhead parts - common piping for CO2 and water (West Texas practice).
2. Rice Duoline for tubing.
3. 13Cr or higher for the packer. Note: current recommendations for WAG wells limits the O2 content for 25%Cr Duplex to 50 ppb nominal with excursions to 200 ppb.
4. The area below the perfs and above the packer will be exposed to trapped water which will be in equilibrium with the injection gas. This can produce significant corrosion and damage. A Duoline liner can be inserted (puddle cement job).

CO2 injection wells have special metallurgy requirements. Designs should minimize un-swept or static areas. Corrosion may occur preferentially downstream of the coupling.
Biological Corrosion

• Anaerobic
  – SRB’s - sours the well/reservoir
  – Iron Fixers - slime and sludge
  – Slime Formers - formation damage
Bacterial deposits on injection tubing. Pitting under the bacterial colony can be severe.
Sulfate Reducing Bacteria

• SRB’s anaerobic bacteria
  – colony growth most numerous
  – low pH below colony

• Generates high H$_2$S concentration in small area

• worst where velocity < 3-1/2 fps
## Corrosion Resistant Alloys

<table>
<thead>
<tr>
<th>Steel</th>
<th>Location</th>
<th>Relative Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Steel</td>
<td>Wytch Farm, UK</td>
<td>1</td>
</tr>
<tr>
<td>13%Cr</td>
<td>S.N.Sea, Trinidad</td>
<td>3</td>
</tr>
<tr>
<td>Super 13%Cr</td>
<td>Rhum, Tuscaloosa</td>
<td>5</td>
</tr>
<tr>
<td>Duplex SS</td>
<td>Miller, T. Horse</td>
<td>8-10</td>
</tr>
<tr>
<td>Austenitic SS</td>
<td>Miller, Congo - Liners</td>
<td>12-15</td>
</tr>
<tr>
<td>Nickel Alloys</td>
<td>Middle East (825)</td>
<td>20</td>
</tr>
<tr>
<td>Hastelloy</td>
<td>Gulf Of Mexico (G3)</td>
<td>&gt;20</td>
</tr>
</tbody>
</table>
### TABLE 4. TYPICAL DUPLEX ALLOY (22/25% CR) ENVIRONMENTS.

<table>
<thead>
<tr>
<th>Location</th>
<th>Depth, ft</th>
<th>Bottomhole temperature, °F</th>
<th>Bottomhole pressure, psi</th>
<th>CO₂, %</th>
<th>Cl⁻, ppm</th>
<th>H₂S, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mississippi</td>
<td>15,000</td>
<td>325</td>
<td>10,500</td>
<td>5</td>
<td>110,000</td>
<td>&lt; 1</td>
</tr>
<tr>
<td>Louisiana</td>
<td>18,700</td>
<td>330</td>
<td>14,700</td>
<td>7</td>
<td>High</td>
<td>&lt; 1</td>
</tr>
<tr>
<td>Louisiana</td>
<td>15,800</td>
<td>325</td>
<td>10,500</td>
<td>3</td>
<td>100,000</td>
<td>&lt; 1</td>
</tr>
</tbody>
</table>

### TABLE 5. NICKEL-BASE ALLOY USAGE.

<table>
<thead>
<tr>
<th>Location</th>
<th>Depth, ft</th>
<th>Bottomhole temperature, °F</th>
<th>Bottomhole pressure, psi</th>
<th>CO₂, %</th>
<th>Cl⁻, ppm</th>
<th>H₂S</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oklahoma (Huntoon)</td>
<td>22,800</td>
<td>285</td>
<td>15,000</td>
<td>3</td>
<td>&lt; 2,000</td>
<td>225 psi</td>
</tr>
<tr>
<td>Big Escambia Creek</td>
<td>15,500</td>
<td>280</td>
<td>3,500</td>
<td>40</td>
<td>&lt; 190,000</td>
<td>21%</td>
</tr>
<tr>
<td>La Barge, Wyo.</td>
<td>15,000</td>
<td>285</td>
<td>4,000</td>
<td>65</td>
<td>150-200,000</td>
<td>220 psi</td>
</tr>
<tr>
<td>Big Horn, Wyo.</td>
<td>24,500</td>
<td>425</td>
<td>9,500</td>
<td>19</td>
<td>6,870</td>
<td>11%</td>
</tr>
</tbody>
</table>

### TABLE 6. MOBILE BAY ENVIRONMENTS.

<table>
<thead>
<tr>
<th>Location</th>
<th>Depth, ft</th>
<th>Bottomhole temperature, °F</th>
<th>Bottomhole pressure, psi</th>
<th>CO₂, %</th>
<th>Cl⁻, ppm</th>
<th>H₂S</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mary Ann field, Mobil</td>
<td>21,700</td>
<td>400</td>
<td>10,350</td>
<td>3-5</td>
<td>180,000</td>
<td>11.5%</td>
</tr>
<tr>
<td>Block 904, UNOCAL</td>
<td>22,400</td>
<td>400</td>
<td>20,000</td>
<td>5</td>
<td>–</td>
<td>120 ppm</td>
</tr>
<tr>
<td>Block 916, UNOCAL</td>
<td>23,000</td>
<td>400</td>
<td>12,000</td>
<td>4</td>
<td>–</td>
<td>50 ppm</td>
</tr>
</tbody>
</table>
Erskine – Failure of 25Cr Duplex SS

Source – BP Corrosion – John Alkire and John JW Martin
Bacterial Corrosion
Trench corrosion common from CO2 attack.
Severe CO₂ corrosion – probably along a low side/trapped volume of water that is saturated with CO₂.
Cracking initiated at a stress riser – impact or wrench mark.
CO2 corrosion

Slow crack growth – note smooth surface

Fast crack growth – very rough surface

3/14/2009

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65
CO2 corrosion on pin end of tubing, above the coupling.

Solutions:
1. Use a 13 Chrome tubing
2. Eliminate the coupling - (may work for short term projects)
5" casing collar/ note corrosion
5" casing collar/
note corrosion
5" casing parted
Co2 corrosion in box, just past gap in coupling

3/14/2009
Corrosion on the housing of an ESP (electric submersible pump).
Parted coupling – CO2 corrosion – note trenches and pits.
Severe $O_2$ corrosion in a surface line, just downstream of a connection.
Galled Threads – physical damage. Galvanic corrosion would have metal loss specific to one member of the coupling.
CT Corrosion Problems

- cyclic immersion increases corrosion
- flow assisted corrosion
- abrasion assisted corrosion (fines)
- abrasion damage (> 50 micron)
- storage may be worst problem area
- salt fluids increase Cl⁻ corrosion
- stressed locations see accelerated corrosion
- marks, welds, HAZ are problem areas
Chrome pipe after acidizing with the proper inhibitor and a inhibitor intensifier. – Source Khalefa Esaklul
Chrome pipe after acidizing with marginal inhibitor. – Source Khalefa Esaklul
Chrome pipe after acidizing – no inhibitor

3/14/2009

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Well Failure Statistics

Well Life Prior to Casing Leak, Years

Wells Developing Leaks

0% 5% 10% 15% 20% 25% 30% 35% 40%

'94-2000' '90-'93 '80-'89 '70-'79 '58-'70 Vastar Putnam
Acid Inhibitor Mixing

• Set up for “rolling” the tank, not slow circulation - upper layer must be mixed in

This Won’t Work!

Unless you get the top level caught in the circulation
Acid Inhibitor Mixing

• Check the inhibitor layer is possible

This will work

Inhibitor pulled in

pump
Inhibitor Mixing

• What will work?
  – Air sparging or rolling the tank with gas
  – paddle mixing that creates a vortex
  – vigorous rolling

• Effect of oxygen in acid -
  – oxygen increases corrosion
  – oxygen saturation in acid is 7 parts per billion effect is limited
Metallic accumulation on a trench magnet.

SEA. The photograph was taken looking downward at the sea.
Corrosion in Packer Fluids

• Corrosion in general is retarded in the packer fluids by the use of oxygen scavengers and corrosion inhibitors. Using of the right corrosion inhibitor and oxygen scavenger products will ensure that all forms of corrosion are prevented.

• Some concern have risen recently with the use of Zinc bromide packer fluids with stainless steel tubing. Its use with 13 Cr is not recommended (cracking failures in HPHT wells in Louisiana, when a Zn brine was accidently blended with the designed Ca brine packer fluid)

Information source – Khalefa Esaklul and John Alkire
Electrochemical

• Galvanic - two dissimilar metals - couplings, centralizers, pumps, packers, profiles – usually severe metal loss on one metal near contact point. May see galvanic loss on a single metal with current.

• Crevice Corrosion - localized, forced penetration, oxygen and chloride major factors

• Stray Current Corrosion - extraneous AC or DC current in earth. Point of arrival is cathode - departure point is anode.
Galvanic Series in Sea Water

1. Magnesium
2. Zinc
3. soft aluminum
4. cadmium
5. hard aluminum
6. steel
7. stainless steel (300 series)
8. lead
9. brass and bronze
10. Inconel
11. Hasteloy C 276
Sacrificial anode (magnesium) from an offshore platform. This was a round bar stock anode.
Controlling Corrosion

1. Maintain high pH
2. Control gas breakout
3. Use passive metals
4. Remove Oxygen
5. Control velocities
6. Lower chlorides
7. Bacteria control
8. Acid/brine use considerations and alternatives
9. Liquid removal
10. Inhibitor injection
11. coatings
Corrosion Films

• First products of corrosion
• films may form a tight, barrier film and reduce corrosion.
Chromium

• Increasing Cr content of the alloy increases the Cr content (and film resistivity) of corrosion layer. Above 10% Cr in alloy, composition of layer is constant. Why use more???? - chemical resistance.

• For 13% and 22% Chrome tubulars, critical erosion velocities are twice carbon steels in CO₂.
Tubular Selection Criteria

• Embrittlement
  – hydrogen
  – chloride stress cracking

• Weight Loss Corrosion
  – $\text{H}_2\text{S-CO}_2\text{-H}_2\text{O-NaCl}$ systems
  – $\text{CO}_2\text{-H}_2\text{O-NaCl}$

• Localized Corrosion

• Acidizing

• Galvanic

• Strength

• Cost and availability
Crack in the casing immediately below the wellhead. Probably due to a minor defect in the tubular and perhaps compounded by wellhead stress.
This is the starting point – but what caused the break? Clues are found in the well environment, the history and the area surrounding the break.
Wear from rod string on tubing.