Current Status and Need for Future Research Related to Corrosion in Oil & Gas Production

Downhole Materials
It is important when considering the construction Materials for a Well that consideration is placed on ALL fluids whether produced or Injected.

This should be an ongoing process that covers the whole life-cycle of a well.

The fluids to be considered should include but not limited to are:
• Produced or Reservoir Fluids
• Injected or Pumped fluids (muds, brines, stimulation fluids, dissolvers, etc;)

Produced Reservoir Fluids
R&D Corrosion Challenges in Wells

- High Strength Production Casing for High H₂S wells
- HT Well Completion and Packer Fluids
- “Green” Inhibitors for HT Scale Dissolvers
R&D Corrosion Challenges in Wells

High Strength Production Casing for High H₂S wells
Production Casing:

No direct exposure to produced fluid, but these materials should be resistant to SSC in presence of H₂S if a tubing leaks occurs while producing!!
Improved High Strength Sour Service Casing

Current situ:

- Only ISO 11960/API 5CT grade T-95 or Proprietary Sour Service grades 95 are considered acceptable for production casing in wells with High ppH$_2$S >1bar.

- Proprietary High Strength Sour Service grades 110 and 125 are not considered suitable for ppH$_2$S above 1 bar and 0.1 bar respectively (note: depending upon pH).

- ISO 11960/API 5CT Group 3 (grade P-110) and 4 (grade Q-125) have limited H$_2$S or SSC resistance.
Improved High Strength Sour Service Casing

Example

In SPE paper paper no 97583 it was highlighted the benefits registered for the Kristin Field when using the recently developed “mild sour service SM125S” Namely:

- Casing string air weight: Reduced by 70 Tonnes or 12%.
- Drilling induced casing wear: Higher acceptance level.
- Equivalent Circulating Density: Significantly decreased.
- Overall Operation Window: Improved.
Improved High Strength Sour Service Casing

**NEED:**

1. High strength steel casing grade (140 ksi) with similar \( \text{H}_2\text{S} \) performance to the current mild sour service grade 125.

2. Improvements in the \( \text{H}_2\text{S} \) performance of both current proprietary high strength sour service grades 110 and 125.
Improved High Strength Sour Service Casing

Cautionary Note:

A recent publication (SPE Paper 97580) by B. Craig stated:

“Higher strength steel tubulars cannot be manufactured by conventional processing routes and maintain SSC resistance. Thermomechanical processing is probably the only means to achieve both increasing strength and SSC resistance”

IT’S NOT GOING TO BE EASY !!!!
R&D Corrosion Challenges in Wells

HT Well Completion and Packer Fluids
Completion/Packer Fluids

Several Area’s of Research Identified:

1. Need for a “Green” High Density Brine for HPHT SG>1.9 (16 ppg) which is compatible with the Well Construction Metallurgy.

2. Need to determine/characterise the effect of “impurities” within industrial grade brines upon the corrosion and environmental cracking of Well Construction Metallurgy.

3. Need for the identification and standardisation (where possible) corrosion and environmental cracking test methodology for evaluation of Completion/Workover Brines.
Well Completion and Packer Fluids 1

Need for a “Green” High Density Brine for HPHT SG>1.9 (16 ppg) which is compatible with the Well Construction Metallurgy

- Zn based Brines are considered not environmentally friendly and potentially corrosive.
- Formate based Brines/Muds are not unstable over long term exposure to high temperature without maintaining its buffering system. This can lead to potential hydrogen induced cracking failures in high strength CRA’s.

1. Need: Requirement is for an environmentally friendly, none corrosive, thermally stable brine system SG>1.9 (16 ppg) for application in long term (>1 month) P&A’s and Packer Fluids.
Completion/Packer Fluids 2

Need to determine/characterise the effect of “impurities” within industrial grade brines upon the corrosion and environmental cracking of Well Construction Metallurgy

- Testing of analytical grade or high purity salts in simulated corrosion and environmental cracking laboratory tests can give “false” results.
- Salts normally used in treatment brines are so-called “industrial grade” and can contain a certain quantities of “impurities”, e.g. bromate (BrO3), hypobromite (OBr–), bromine (Br2), chlorate (ClO3–). Ref. Termine et al World Oil June 2007 and Kaneta, K. et al.: “Corrosion Problems in High-density Clear Brines”, J. Japanese Assoc. Petrol. Technol., vol. 59, no. 2 (1994).

These impurities occur during the manufacturing process and/or are introduced when mixing the brine for use. These impurities can potentially influence the corrosion and/or environmental cracking behaviour of a brine.

1. Need: To the identify and characterise these impurities and determine their influence upon the corrosion and environmental cracking behaviour of CRA’s.
2. Need: To determine concentration limits for the “impurities” identified as “risk” compounds for QA/QC manufacturing controls.
Completion/Packer Fluids 3

Need for the identification and standardisation of corrosion and environmental Cracking test methodology for evaluation of Completion and packer Brines

- A variety of Methods used by Operators and Manufacturers from electrochemical, weight loss and adaptations of NACE TM0177, etc
- Difficult to compare test results
- No specifically designed screening or testing program requirements defined as a minimum before introduction of a brine for Field use. This is essentially a high risk or unsafe practice!
- Some initiatives exist within the API CRA Brine program but little progress.

Need:

1. The safe use of brines to avoid corrosion and environmental cracking i.e. testing protocol.
2. Better Operators/Brine Company inter Laboratory Data Comparisons.
3. Determine standardised testing approach (where possible) and examine more recently developed testing methodology ref. Trillo et al, NACE Paper 06136 Corrosion 2006
R&D Corrosion Challenges in Wells

“Green” Inhibitors for HT Scale Dissolvers
Scale Dissolver Treatments

Several Area’s of Research Identified:

1. Need for an Carbonate Scale Dissolver with “Green” corrosion inhibition Package suitable for high temperatures (>170°C) well applications which is compatible with the Well Construction Metallurgy.

2. Need for the identification and standardisation (where possible) of corrosion and environmental cracking test methodology for the evaluation of Oilfield Mineral Scale Dissolvers.
Scale Dissolver Treatments

Need for an Carbonate Scale Dissolver with “Green” corrosion inhibition Package Suitable for high temperatures (>170°C) well applications which is compatible with the Well Construction Metallurgy.

Current situ:
Recent work at Statoil for a number of our HPHT Fields has determined the difficulty of finding suitable “Green” Inhibitor packages at 170C. Testing results in either high general or localised corrosion of Corrosion Resistant Alloys. The situation is that the most efficient dissolvers are the most difficult to inhibit and therefore do not stop at just dissolving the scale, but severely attack the metals!

Need: To meet the demands of exiting and future HPHT and Ultra HPHT Fields Carbonate Scale Dissolver Green Inhibition Packages need to be developed to avoid severe damage to the Well Materials!
Scale Dissolver Treatment

Need for the identification and standardisation (where possible) corrosion and environmental cracking test methodology for the evaluation of Oilfield Mineral Scale Dissolvers

- A variety of Methods used by Operators and Manufacturers from electrochemical, weight loss and adaptations of NACE TM0177, etc.;
- Difficult to compare inter Lab and/or Company Test results
- No specifically screening or testing program requirements defined as a minimum before Field use. This is essentially a high risk or unsafe practice!

Need:

1. The safe use of scale dissolvers without corrosion and environmental cracking.
2. Better Operators/Brine Company inter Laboratory Comparisons.
THANKYOU !!