Investigation of Scale Deposition and Wellbore Corrosion in Carbonated Brine Injection: A Simulation Study

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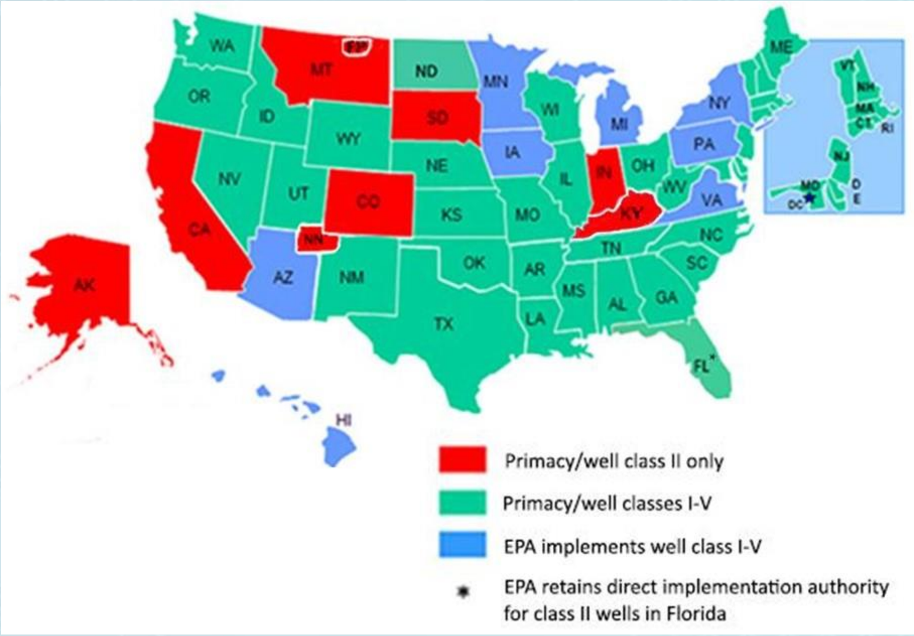
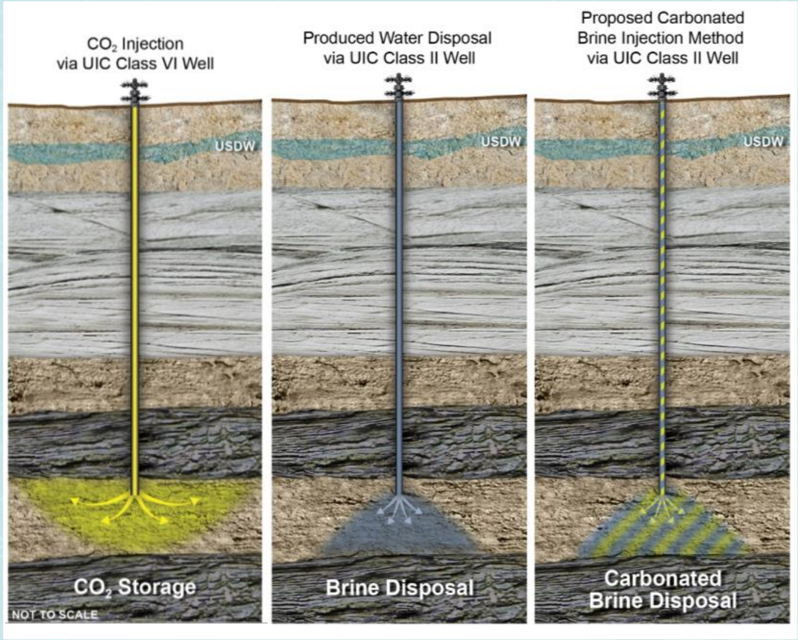
Introduction & Background

High salinity brine is a common byproduct of extracting oil and gas resources. Roughly 4 trillion liters of produced brine are managed in the U.S. each year. The most common methods for managing produced brine in the U.S. are:

- Injection for water flooding and enhanced oil recovery (EOR).
- Injection of the brine into saltwater disposal (SWD) wells.



Map of the states with full or partial underground injection control primacy.



Injection methods comparison.

Introduction & Background

Wellbore materials and corrosion issues in Class II wells:

- ***Corrosion:***
  - Tubular materials and long string made of carbon steel L80 (API 5CT). Internally coated.
  - Uncoated carbon steel L80-1 is susceptible to CO_2 corrosion.
  - Corrosion resistant alloy (CRA) casing L80 9Cr (Cr 8%-10%) & L80 13Cr (Cr 12%-14%) are susceptible to localized corrosion due to metallurgical structure, chloride concentration, temperature, pH, and the presence of other species such as scaling ions, organic acids, and CO_2 and H_2S gases.
- ***Scale deposition:***
  - $CaCO_3$ mainly is downhole: CO_2 (HCO_3^-, CO_3^{2-}), calcium content, temperature, flow, and Ph.
  - FeS, $FeCO_3$ (mainly in uphole/tank)) $CaSO_4$.

Introduction & Background

- ***Biofilm development due to the presence of scale:***
  - Microbial-induced corrosion (MIC): for example, sulfate reducing bacterium (Desulfotomaculum nigrificans) promote localized corrosion under $CaCO_3$ deposits.
  - Cement A and H (Portland-based cements): CO_2 brine solution on the cement.

- ***Cleaning procedure and corrosion control:***
  - Injection of 30% HCl into the wells to dissolve scale and remove biofilm.
  - Use coatings to mitigate corrosion.
  - Rajeev et al.* investigated corrosion behavior of L80 and L80-13 Cr steel in 15% HCl and it was found that the corrosion rate is higher for 13Cr L80 steel (44.89 mm/y) compared to L80 (22.86 mm/y).

*Rajeev P. et al,. Experimental Investigation on Corrosion Control of 13Cr L80 Steel in Hydrochloric Acid Solution using Thiophene Methanol, *J. Mater. Environ. Sci. 5 (2) (2014) 440-449.*

Objectives

The main objectives of this study are:

- Evaluate the feasibility of CO_2 storage in Class II SWD using produced water.
- Investigate the wellbore materials' compatibility with carbonated brine water during the injection process.

Reservoir Modeling

Simulation Constant Parameters (Williston Basin in North Dakota)

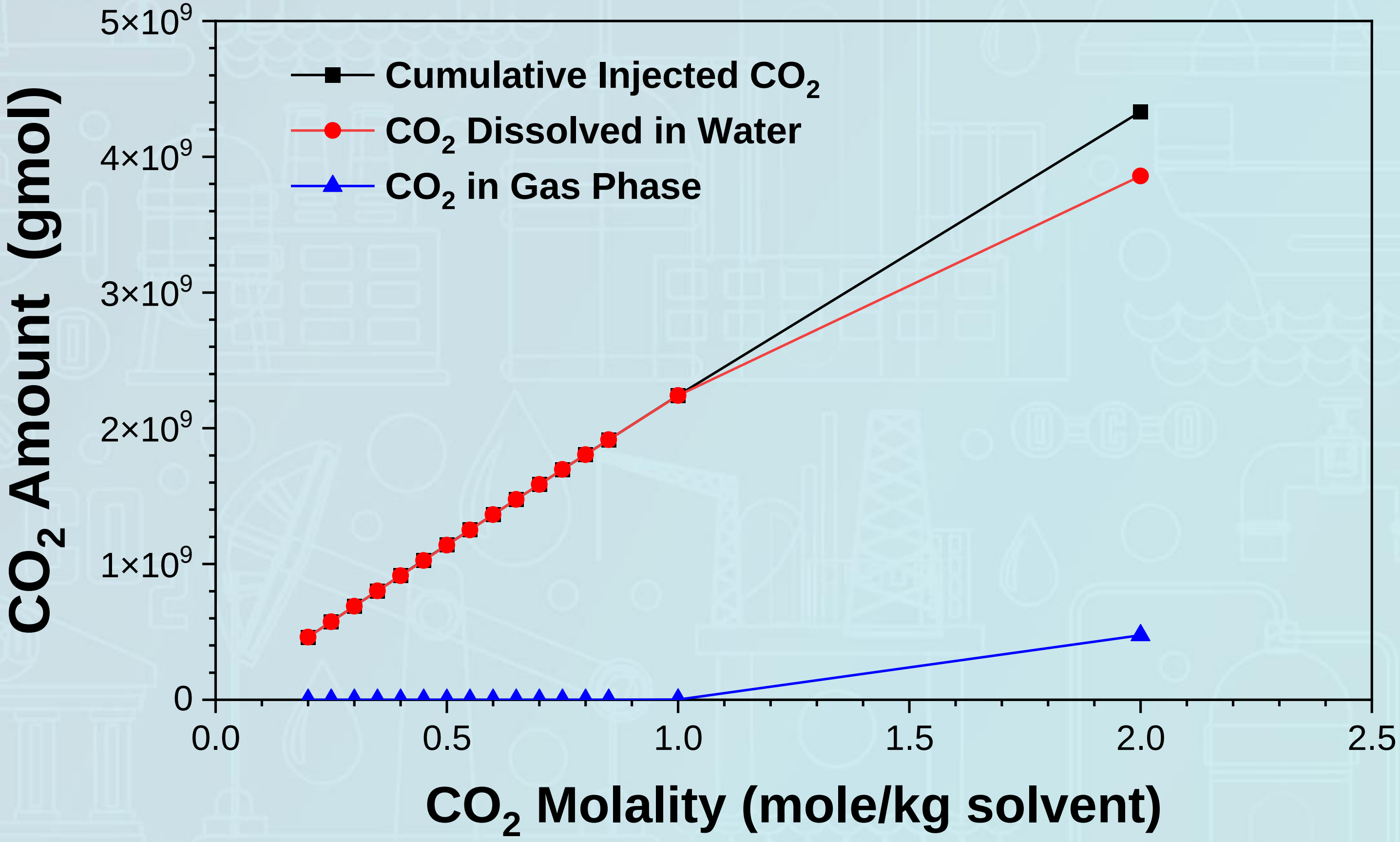
Constant Parameters	
Injection Rate, bbl/day	8,000
Years of Injection	5
Reservoir Pressure, psi	2,255
Reservoir Temperature, °C	73.89
Injection Temperature, °C	15.56
Injection Fluid Salinity, ppm	10,000
Reservoir Fluid Salinity, ppm	10,000

- The Computer Modeling Group (CMG) simulation program was utilized in this project to create a reservoir model.

Experimental Injection Simulation Scenarios

Scenario	Molarity, mol/kg solvent
1	2.00
2	1.00
3	0.85
4	0.80
5	0.75
6	0.70
7	0.65
8	0.60
9	0.55
10	0.5
11	0.45
12	0.4
13	0.35
14	0.3
15	0.25
16	0.2

CO_2 Molality in Carbonated Produced Water



Simulation results showing the amount of CO_2 dissolved in water and the CO_2 remaining in the gas phase at reservoir conditions for all scenarios.

Corrosion and Scale Tendency Modeling

- ***Carbonated Brine Chemistry*: ** USGS Produced Water Data from North Dakota-McKenzie County-Bakken. **No added CO_2**; Steam amount = 1 L; Temperature 25 °C, 1 atm.

Physical Parameters/Composition	Values
Density (g/L)	1.18
pH	5.94
K^+ (mg/L)	4,483.17
Na^+ (mg/L)	7,5341.45
Ba^{2+} (mg/L)	34.4
Ca^{2+} (mg/L)	1,6674.76
Fe^{2+} (mg/L)	124.71
Mg^{2+} (mg/L)	1,091.15
Cr^{3+} (mg/L)	0.69
Cl^- (mg/L)	152,006.21
HCO_3^- as C (mmol/L)	32.78
NO_3^- (mg/L)	151.96
SO_4^{2-} (mg/L)	613.46

- Chemical composition of produced water **with 0.6 mole/kg (= 26,400 mg/L) CO_2.** Steam amount = 1L; Temperature 25 °C; **20 atm.**
- Chemical composition of produced water **with 0.2 mole/kg (8,800 mg/L)CO_2.** Steam amount = 1L; Temperature 25 °C; **6.415 atm.**
- An aqueous chemistry software called OLI Studio was used to model corrosion and scale tendency.

https://edx.netl.doe.gov/dataset/newts-usgs-produced-waters-database

Scaling Tendency Prediction of Carbonated Produced Water

$$Scaling\ tendency = \frac{C}{C_0} = \frac{IAP}{K_{sp}} \qquad \text{(Eq. 1)}$$

Where, C: measured concentration, C_0: concentration at equilibrium, IAP: ion activity product, and K_{sp}: thermodynamic solubility product constant.

$$SI = log_{10}\left(\frac{IAP}{K_{sp}}\right) = log_{10}\,(scaling\ Tendency) \qquad \text{(Eq. 2)}$$

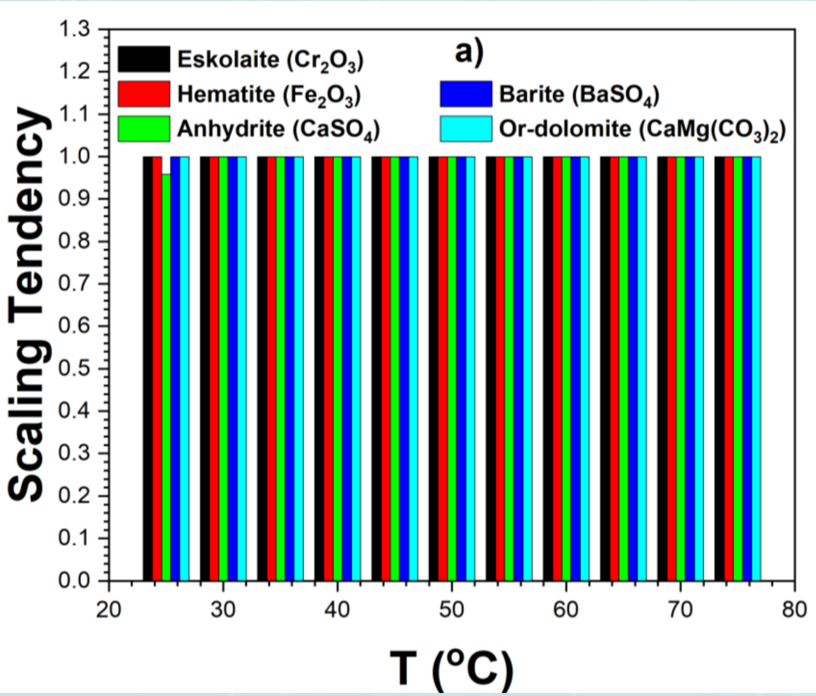
Thus,

- Scaling tendency < 1 or SI < 0: indicates sub-saturation, and the solid is not expected to form.
- Scaling tendency = 1 or SI = 0: indicates saturation, and the solid is in equilibrium with water.
- Scaling tendency > 1 or SI > 0: indicates supersaturation, and the solid is expected to form.

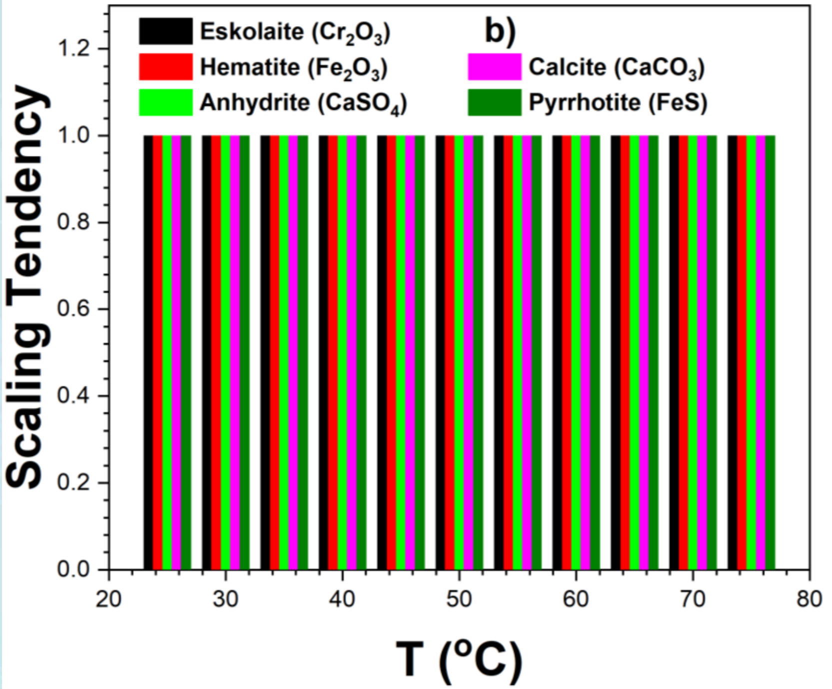
Scaling Tendency Prediction of Carbonated Produced Water

Brine solution is contact with Super 13Cr stainless-steel

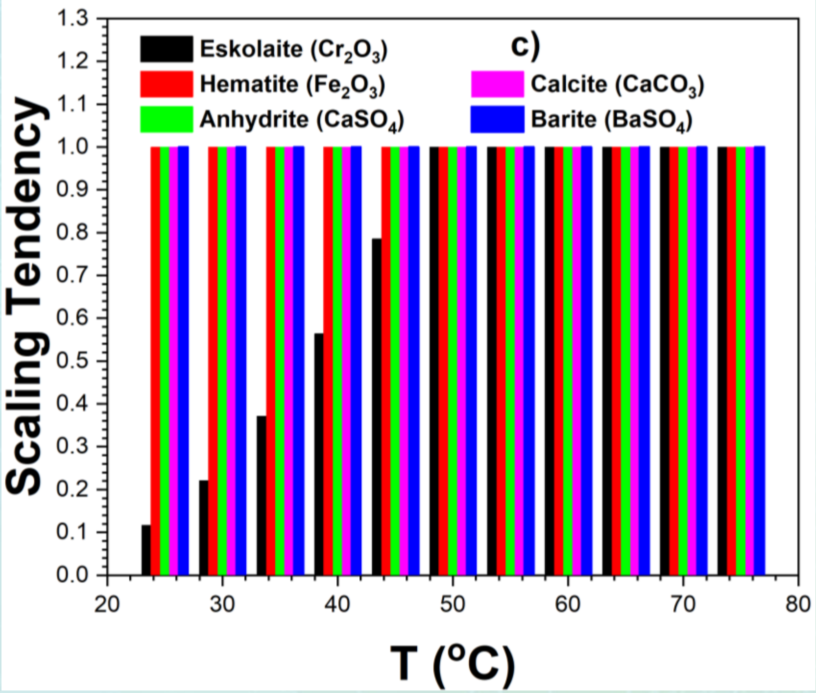
0 mole/kg CO_2



0.2 mole/kg CO_2

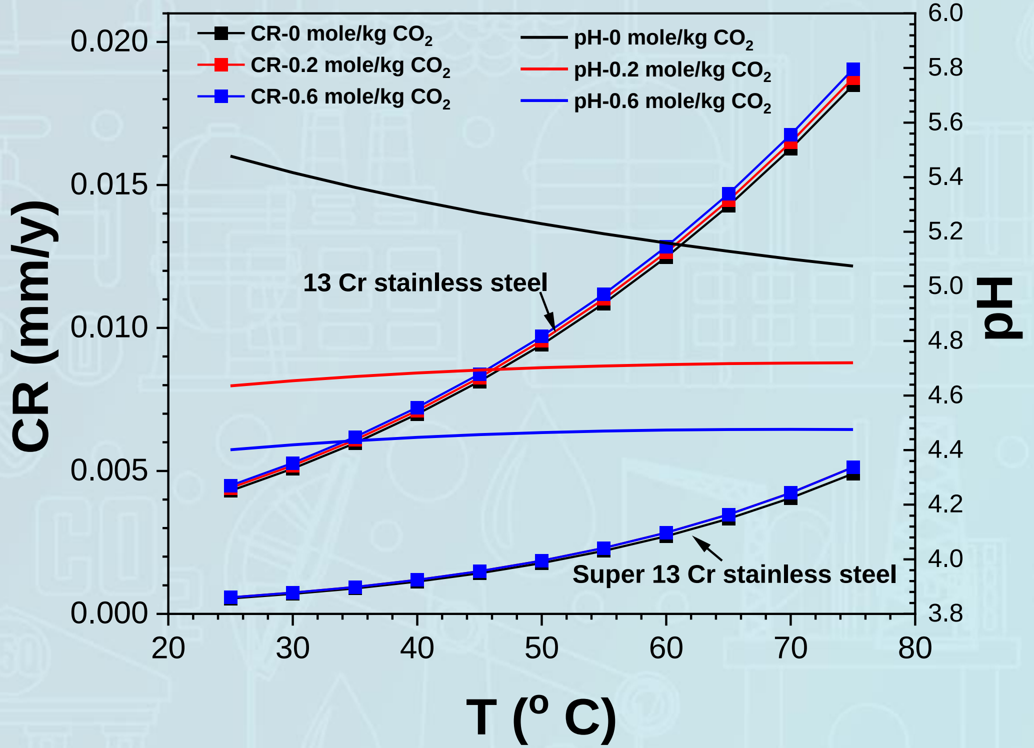


0.6 mole/kg CO_2

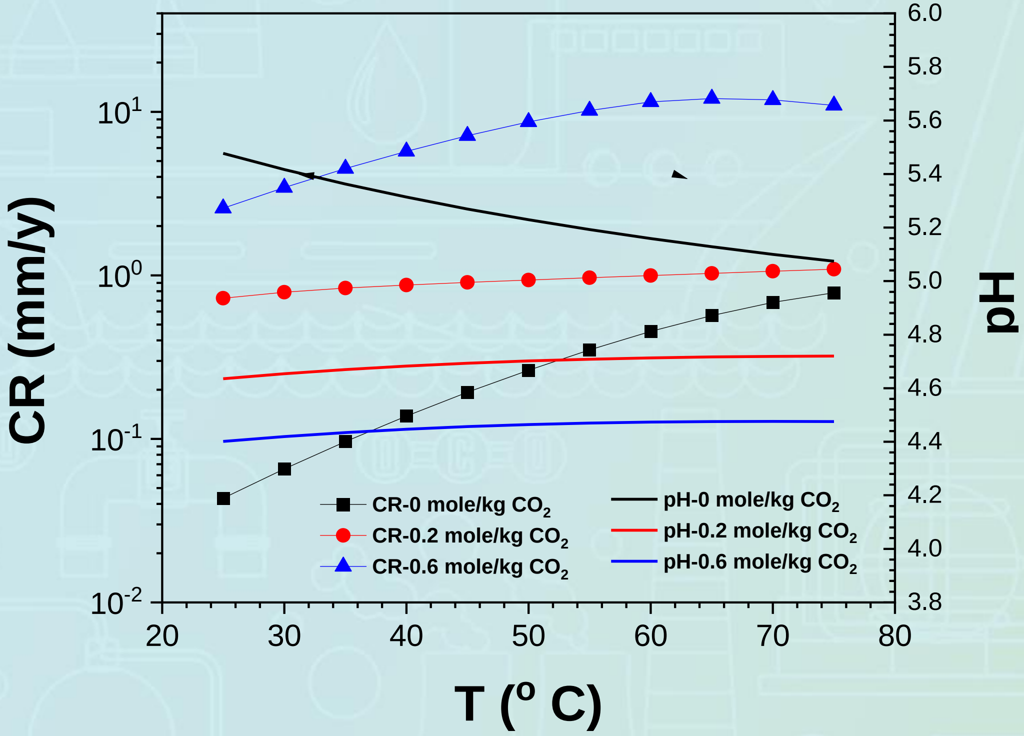


Corrosion Prediction of Steels in Carbonated Produced Water

Stainless-steel



Carbon steel UNS G10180



Wellbore corrosion model summary:

- Acceptable corrosion rates for carbonated brine injection (<0.02 mm/y).
- Scale minerals can reduce corrosion rate.

Conclusions

- Reservoir, scaling prediction, and corrosion modeling were performed to evaluate the feasibility of CO_2 storage in Class II SWD using produced water.
- Based on a simplified reservoir modeling case study, simulation findings revealed that within the molality range of 0.75 to 0.65, approximately 99.99% of CO_2 would be successfully dissolved into the reservoir fluid.
- The results showed that the amount of CO_2 injected into produced water and temperature are the main factors affecting the chemical composition and the scaling tendency of the deposits.
- Based on predicted corrosion results, carbon steel is more susceptible to CO_2 corrosion than 13 Cr stainless-steel and super 13 Cr stainless-steel.

Future Work

- For future work and pilot field demonstrations related to carbonated brine injection (CBI), additional considerations need to be addressed such as flow, geochemical reactions, and changes to the formation because of injection and formation of carbonic acid (H_2CO_3), which could lead to corrosion of the wellbore casing, tubing, packer, and surface equipment.
- In addition, significant levels of dissolved oxygen can be expected in the CBI water, and while the downhole environments may be anoxic, care should be taken to prevent the formation of differential aeration cells at the casing steel.

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