Environmental and Corrosion Analysis of a CO_2 Injection Well

Revised Final Report

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June 4, 2021

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Project Objective

- Hackberry Carbon Sequestration, LLC (herein, HCS) is planning a CO_2 injection well in support of carbon capture and storage (CCS) activities at a coal-fired power plant, and Lonquist Sequestration, LLC (herein, Lonquist) was contracted to provide injection well design recommendations.

- Lonquist in-turn contracted Honeywell Corrosion COE (herein, Honeywell) to evaluate the corrosivity of the downhole injection well environment during CO_2 injection, to support optimization of material selections for the:
    - Wetted sections of the wellhead
    - Tubing
    - Packer

- The Honeywell performed a corrosion severity assessment of the environments anticipated in the CO_2 injection wells to support reliable material selection recommendations.

Background

- Dry CO_2 injection gas is not corrosive to carbon steel. However, if the CO_2 pipeline source gas contains significant water vapor, liquid water condensation is possible under downhole conditions:
  - Some of the gaseous CO_2 will dissolve into the essentially unbuffered aqueous condensate.
  - This dissolved CO_2 is a major parameter that influences the *in situ* pH, and the corrosion rate of carbon and alloy steels.

- **To optimize material selection for selected well components, Honeywell:**
  - Reviewed the proposed well design
  - Assessed the likely downwell environments of the injection well, and
  - Modelled corrosion rate and cracking data for candidate materials.

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INJECTION GAS REVIEW

HCS CO_2 Injection Specification

Pipeline Transport and Sequestration

Constituent	Description
CO2	> 95% mol
H20	No liquid, < 30 lb vapor per MMscf
H2S	< 20 ppm by vol
Total Sulphur	< 35 ppm by weight
Temperature	< 120 degF (to protect coating, maintain supercritical phase)
Oxygen	< 10 ppm by weight
Hydrocarbons	< 5% mol
Glycol	No liquid, < 0.3 gal per MMscf

- No water alternating gas (WAG) operations are envisioned.

On the temperature line, "to protect coating" refers to what coating?
Are the topside flowlines internally coated?

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HCCS Specifications

From: Tomaski, Richard
To: Steve Pattee
Cc: Gilbert, Maurice
Subject: HCCS Spec
Date: Wednesday, December 23, 2020 2:16:45 PM

Steve –

Here is the information on the CO2 composition and volumes that you requested. Please let me know if need something else for your initial analysis. We are planning to run a dehy system to take the H2O content below 500ppmv (pipeline spec) and, of course, pressure will be based off what you tell us the required pressure needs to be at the wellhead

We will likely want to ensure that our CO2 sequestration well could accommodate our proposed Train 4 at CLNG, but at this time our project scope doesn't include the CO2 from the turbine emissions or other potential sources. My assumption is that T4 will take the total flow to somewhere around 30 mmscfd. Our engineer estimated our design basis this to be about 350,000 tonne\yr of C02 based on known T1-3 volumes, but potentially we would need a well capable of up to 500,000 tonne\yr.

A dehydration unit has been under consideration.

HCCS Specifications

Table 4: Design Basis – Feed Stream Summary to the CO_2 Compression Unit

Stream ID		107/107A	111	111 w/ Design Margin
Description		Acid Gas to Acid Gas KO Drum D0 1407 (from Single LNG Train)	Acid Gas to Thermal Oxidizer S0-1405 (Three LNG trains combined)	Rated Flow (includes 25% Design Margin)
Total Mole Flow	lbmol/hr	690	2,071	2,589
Total Mass Flow	lb/hr	29,623	88,869	111,086
Std. Vap Flow	MMSCFD	6.29	18.87	23.59
Temperature	F	94	94	94
Pressure	psig	15	5	5
Mass Density	lb/ft3	0.21	0.19	0.19
MW		42.9	42.9	42.9
Composition				
Nitrogen	mol%	0.001	0.001	0.001
CO_2	mol%	95.73	95.73	95.73
Methane	mol%	1.568	1.568	1.568
Ethane	mol%	0.0531	0.0531	0.0531
Propane	mol%	0.0122	0.0122	0.0122
i-Butane	mol%	0.0043	0.0043	0.0043
n-Butane	mol%	0.005	0.005	0.005
i-Pentane	mol%	0.0011	0.0011	0.0011
n-Pentane	mol%	0.0008	0.0008	0.0008
n-Hexane	mol%	0.0011	0.0011	0.0011
n-Heptane	mol%	0.002	0.002	0.002
n-Octane	mol%	0.002	0.002	0.002
n-Nonane	mol%	0.0003	0.0003	0.0003
Benzene	mol%	0.0335	0.0335	0.0335
Water	mol%	2.588	2.588	2.588
H_2S	mol%	0.0011	0.0011	0.0011
Total Sulfur	mol%	0	0	0
Oxygen	mol%	0	0	0

According to the HCCS specification, water content in the injection gas could be as high as 2.588 mol%.

In the absence of a dehydration unit, condensed water within the wellbore is a real possibility, and a corrosion threat.

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HCS CO_2 Pre-FEED Composition

AGRU conditions

Design Flow Rate	1,000,000	tonnes/year
Initial Pressure	5	psig
Temperature	94	degF

Gas Composition Constituent	mol %
Nitrogen	0.0103
CO2	94.4432
Methane	4.8279
Ethane	0.0910
Propane	0.0155
i-Butane	0.0038
n-Butane	0.0045
i-Pentane	0.0012
n-Pentane	0.0008
n-Hexane	0.0008
n-Heptane	0.0010
n-Octane	0.0000
n-Nonane	0.0000
Benzene	0.0065
H2O	0.5932
H2S	0.0003

- At 94 °F and 5 psig, no liquid water exists.
- Therefore, liquid water is likely not a concern during transportation.
- However, during injection into the wellbore, the CO_2 injection gas will need to be pressurized to overcome the formation pressure.
- 0.5932 mol% H_2O in the gas phase translates to 284 lb H_2O per 1 MMscft of gas. This is a higher vapor content then specified by HCS's carbon dioxide specifications.

Design flow rate is between 1 to 2 million tonnes per year

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H_2S Cracking Assessment

AGRU conditions

Design Flow Rate	1,000,000	tonnes/year
Initial Pressure	5	psig
Temperature	94	degF

Gas Composition Constituent	mol %
Nitrogen	0.0103
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n-Hexane	0.0008
n-Heptane	0.0010
n-Octane	0.0000
n-Nonane	0.0000
Benzene	0.0065
H2O	0.5932
H2S	0.0003

- 3 mol ppm H_2S is expected in the gas.
- The estimated hydrostatic pressure of the injection well is 4,885 psia at 11,250 ft
- $P_{H2S} = y_{H2S} \times P_T$ = 3 mol-ppm H_2S x 4885 psia injection zone pressure = 0.015 psia H_2S
- 0.015 psia H_2S (field) is well below the NACE 0.05 psia H_2S threshold of concern for SSC of carbon steel.
- **System is not considered sour based on NACE MR0175/ISO 15156-2:2015 criteria.**

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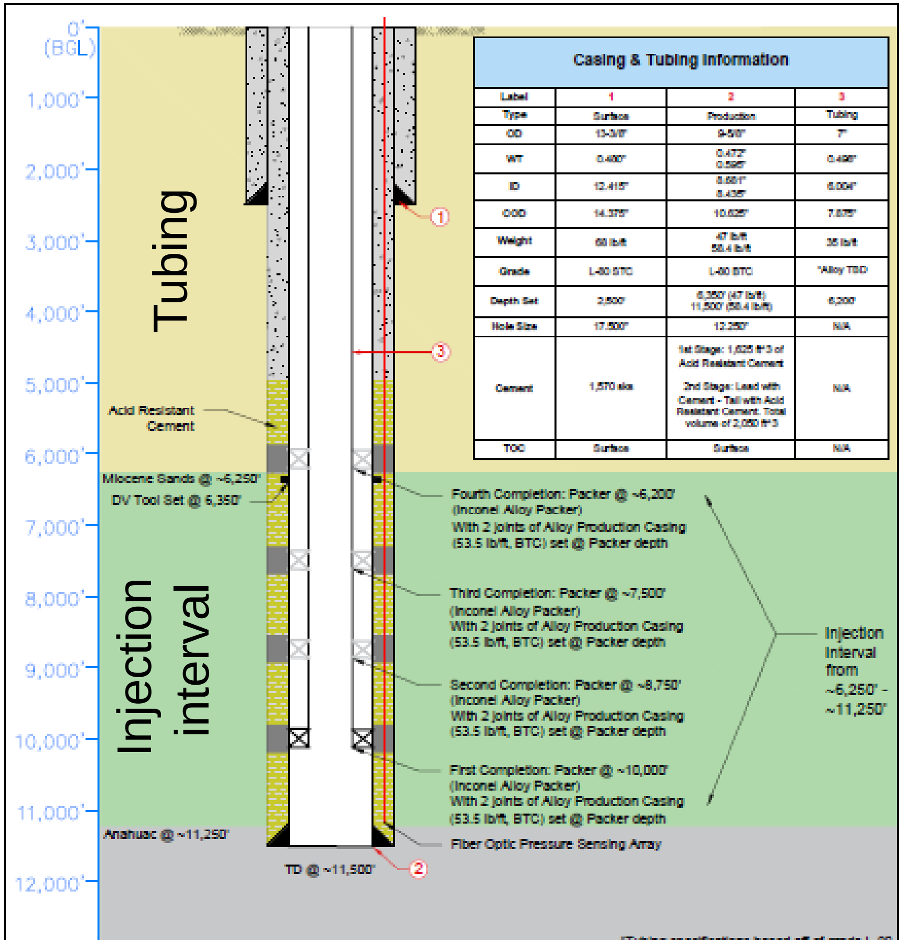
WELL DESIGN REVIEW

CO_2 Injection Well Design



Casing & Tubing Information

Label	1	2	3
Type	Surface	Production	Tubing
OD	13-3/8"	9-5/8"	7"
WT	0.480"	0.472" 0.595"	0.498"
ID	12.415"	8.681" 8.435"	6.004"
COD	14.375"	10.625"	7.875"
Weight	68 lb/ft	47 lb/ft 58.4 lb/ft	35 lb/ft
Grade	L-80 STC	L-80 BTC	*Alloy TBD
Depth Set	2,500'	6,350' (47 lb/ft) 11,500' (58.4 lb/ft)	6,200'
Hole Size	17.500"	12.250"	N/A
Cement	1,570 sks	1st Stage: 1,625 ft^3 of Acid Resistant Cement 2nd Stage: Lead with Cement - Tail with Acid Resistant Cement. Total volume of 2,050 ft^3	N/A
TOC	Surface	Surface	N/A

LONQUIST FIELD SERVICE AUSTIN WICHITA HOUSTON CALGARY	Sempra Carbon Storage - Louisiana	Hackberry CCS Tract 21 Well #1	
	Country: USA	State/Province:	County/Parish:
	Location:	Site:	Status:
	Survey/STR:	Field:	Serial No:
	Well API No:	Project No:	Date: 4/15/2021
3345 Bee Cave Road, Suite 201 Austin, Texas 78746 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: NJP	Reviewed:	Approved: SLP
	Rev No:	Notes:	

Expected to operate the field for XX years.

Well String	Production Casing	Wall thickness (in)
Tubing	7" 35# ?	0.498
Production casing	9-5/8" 47# L80 BTC 58.4# L80 BTC	0.472 0.595

Injection interval is from 6,250 to 11,250 ft

Estimated hydrostatic pressure range: ~2,710 to 4,870 psig

Daily injection rate: 6 to 23 MMSFD

Well design loads were not distributed.

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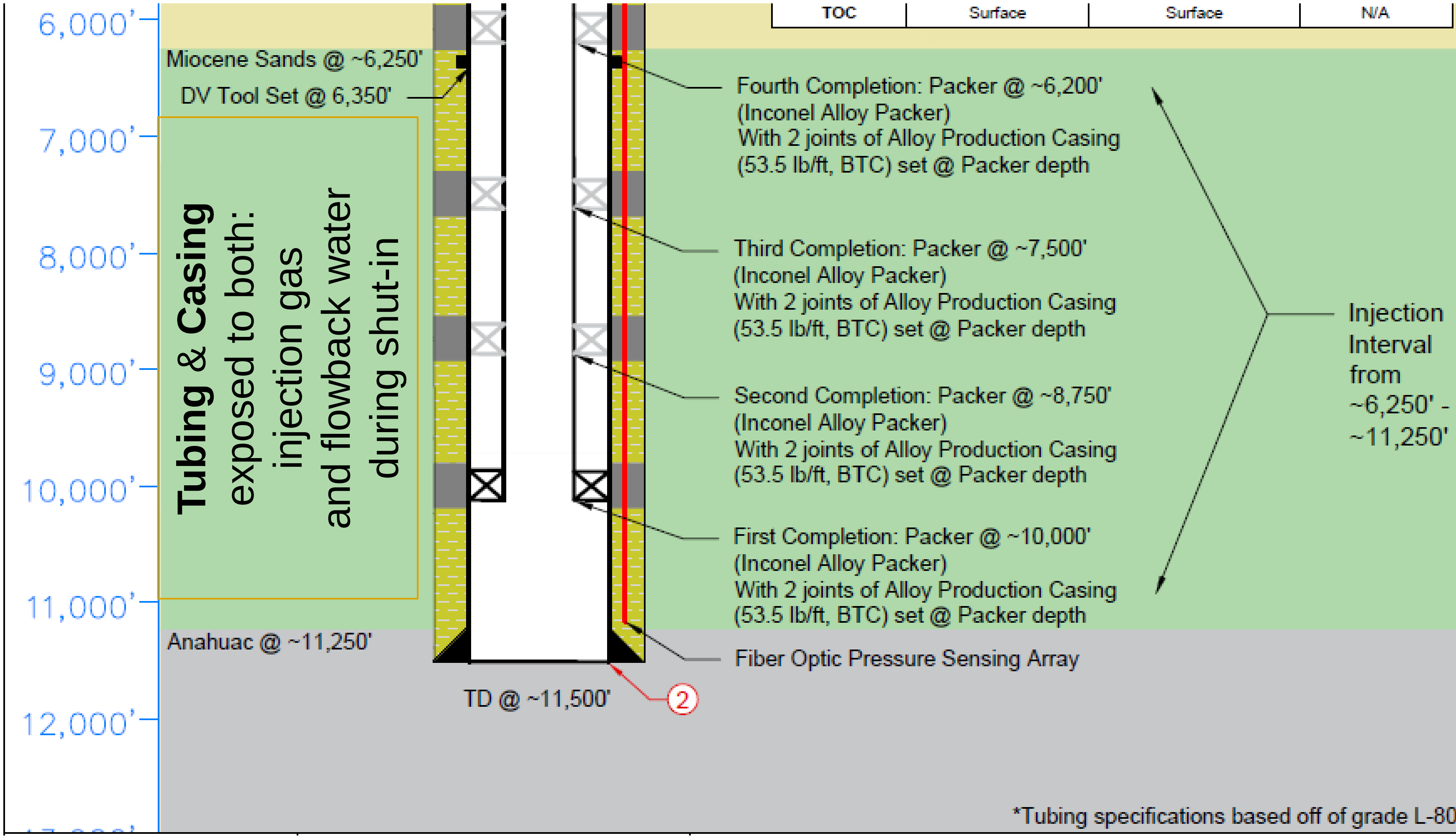
Injection Interval



Depending upon tubing hydraulics, the entire injection interval may be exposed to acidic (corrosive) formation water during a well shut-in.

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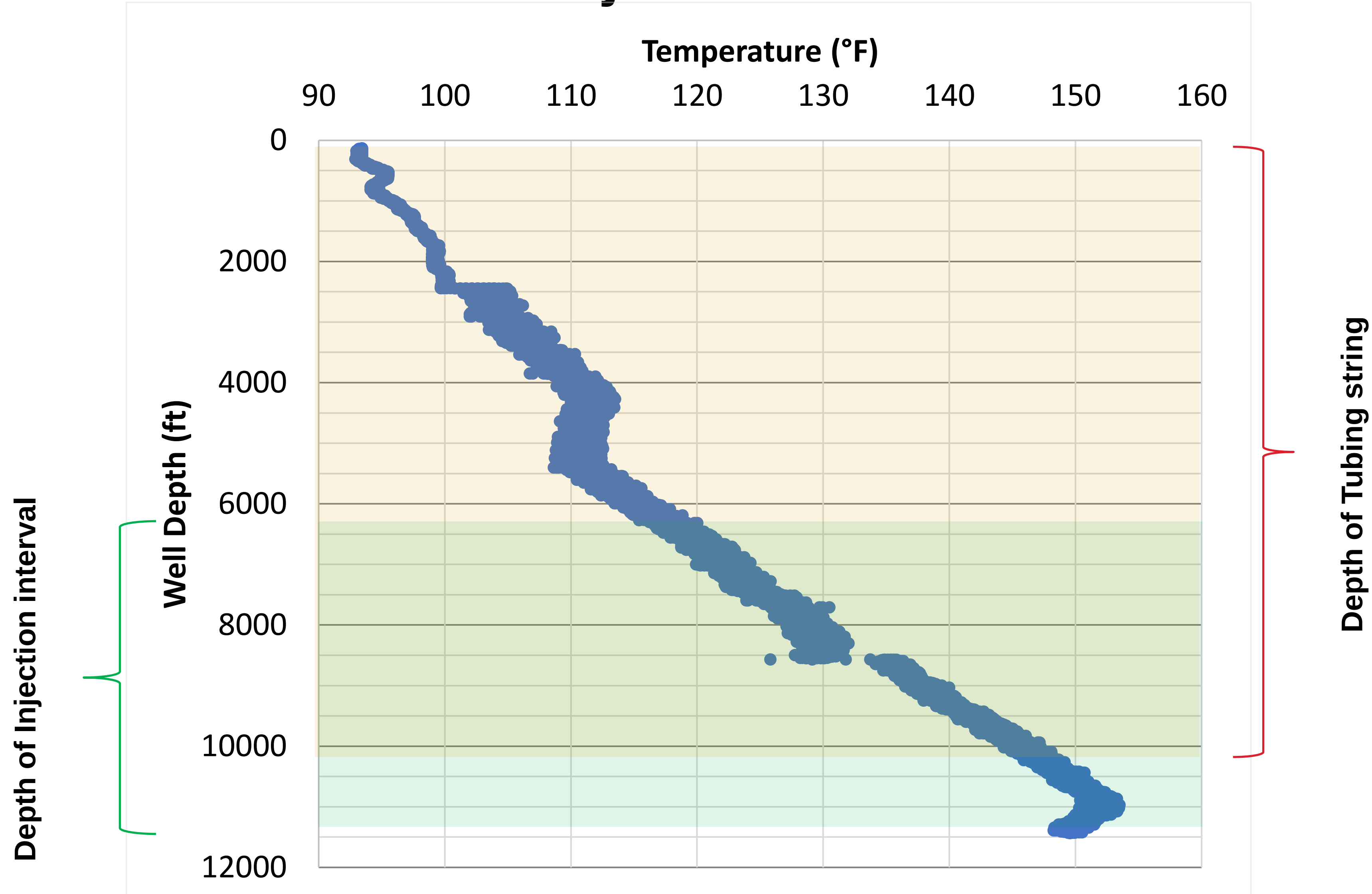
Thermal Profile of Injection Well



The expected temperature range within the injection internal is 115 to 150 °F

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ENVIRONMENTAL & CORROSION MODELING

Consequence of CO_2 Injection

- In order to optimize the material selection for the injector well, Honeywell evaluated whether the injection gas would condense water. In the presence of a high CO_2 partial pressure, the water would be acidic.

- Approach: Use specialized chemical/thermodynamic and corrosion prediction software (OLI Analyzer and Honeywell Predict) to model the corrosion impact of CO_2 injection along the length of the production tubing.

- The corrosivity analysis was impeded because a chemical analysis of the native formation water was not available.

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Environmental Modeling

1. Evaluate PVT behavior within the wellbore:
   - Vary wellbore temperature from 94 to 150 °F at four hypothetical total pressure intervals: 4,870, 3,100, 2,000, and 900 psig.

2. Identify condensed water dropout along tubing:
   - Set maximum amount of water vapor available as 284 lb H_2O per MMscft (assuming 0.6 mol% H_2O vapor from injection gas)
   - Model the maximum amount of the liquid water dropout possible as a function of PVT
   - Model the *in situ* pH of condensed water.

3. Predict the carbon steel corrosion rate as a function of:
   - Temperature (70 to 150 °F)
   - Bicarbonate concentration [HCO_3^-]: 0, 100, 250, and 500 mg/L

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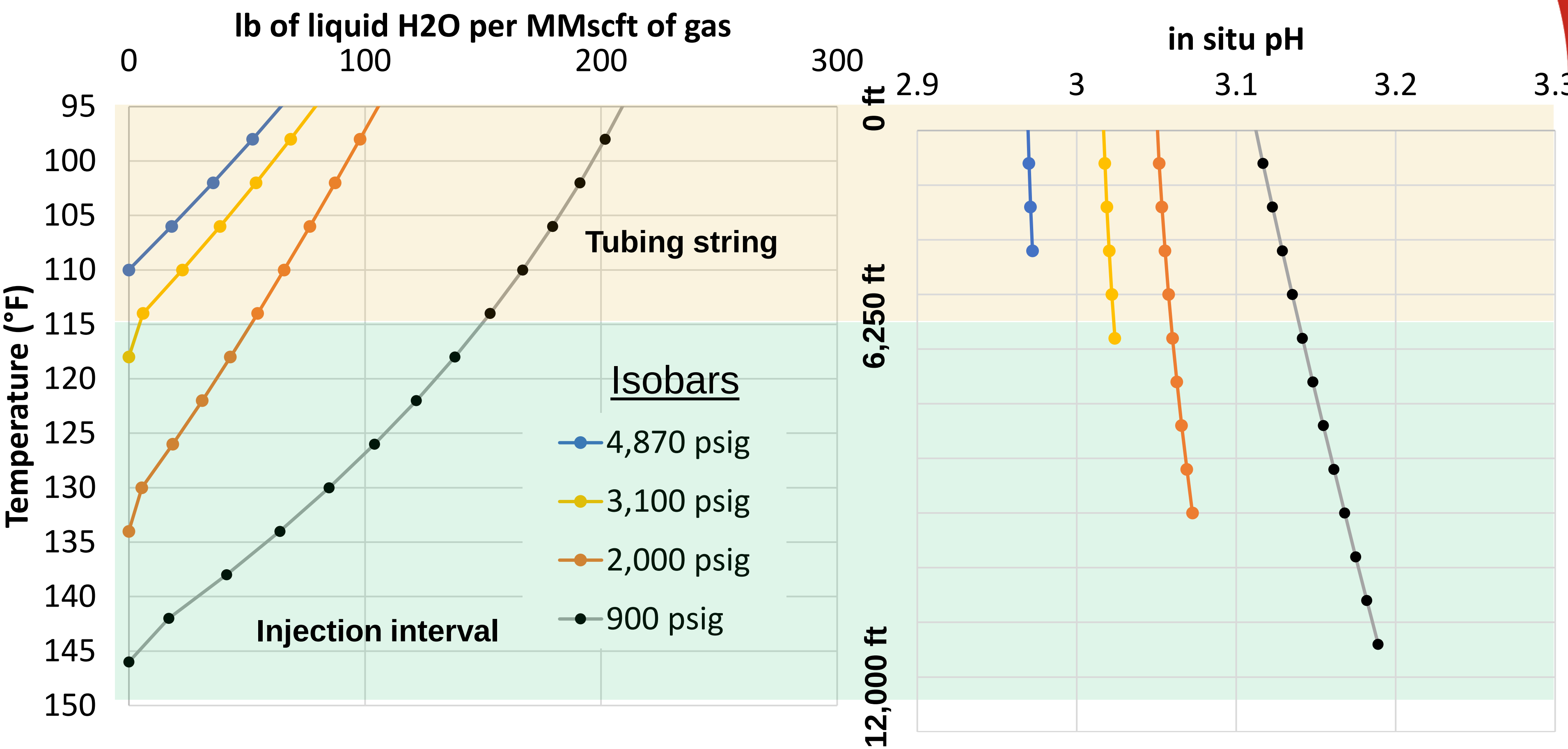
Environmental Modeling: Temperature and in-situ pH Sensitivity Along Tubing String During Injection



Based on the CO_2 composition provided, liquid water dropout is likely in the wellbore. The pH of the resulting aqueous phase will likely approach 3.

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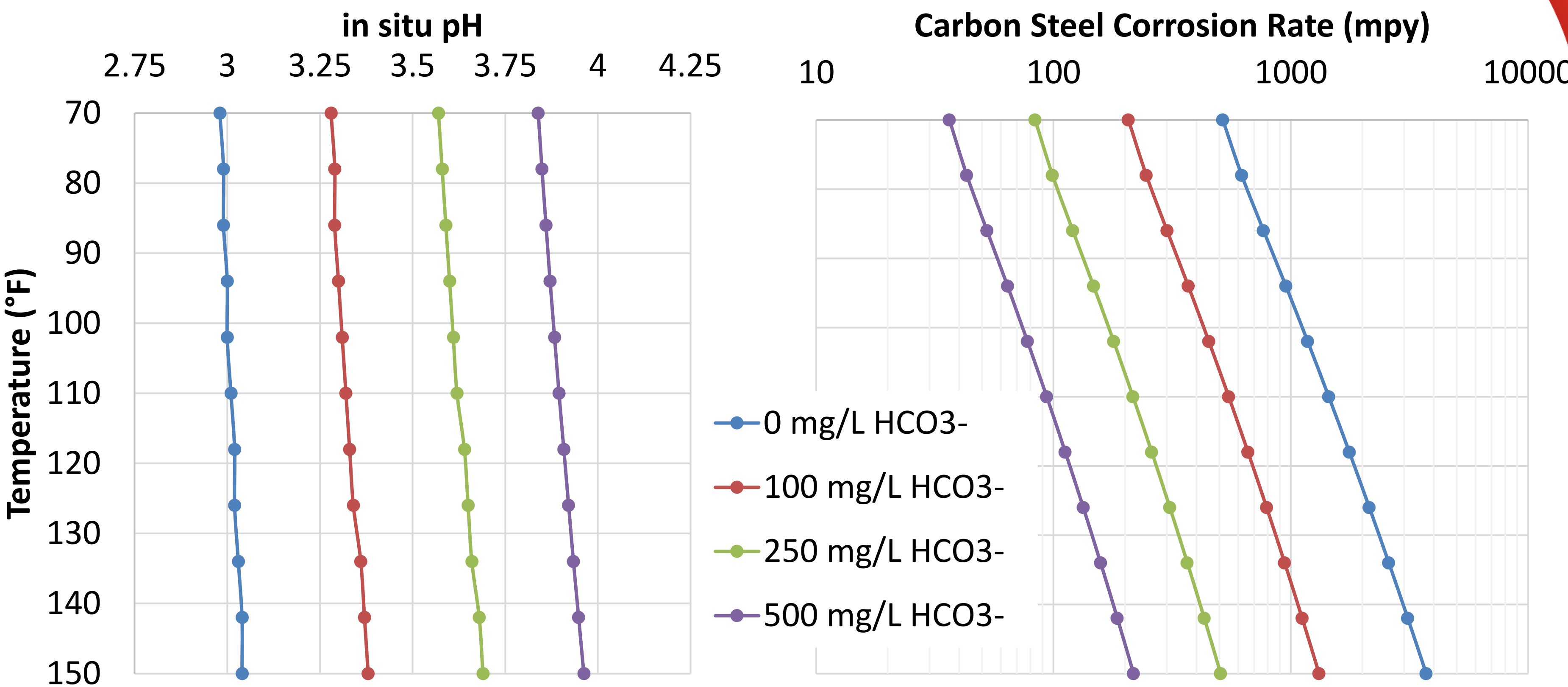
Carbon steel Corrosion Rate Modeling at 2,000 psig CO_2



- For condensed water, the initial pH will be ~3 (0 mg/L HCO_3^-) with predicted carbon steel corrosion rates ranging between 500 mpy and 3700 mpy.
- CO_2 corrosion will eventually produce Fe^{2+} and HCO_3^-, which raises the *in-situ* pH. At 500 mg/L HCO_3^-, however, predicted, long-term uninhibited carbon steel corrosion rates are still > 35 mpy.

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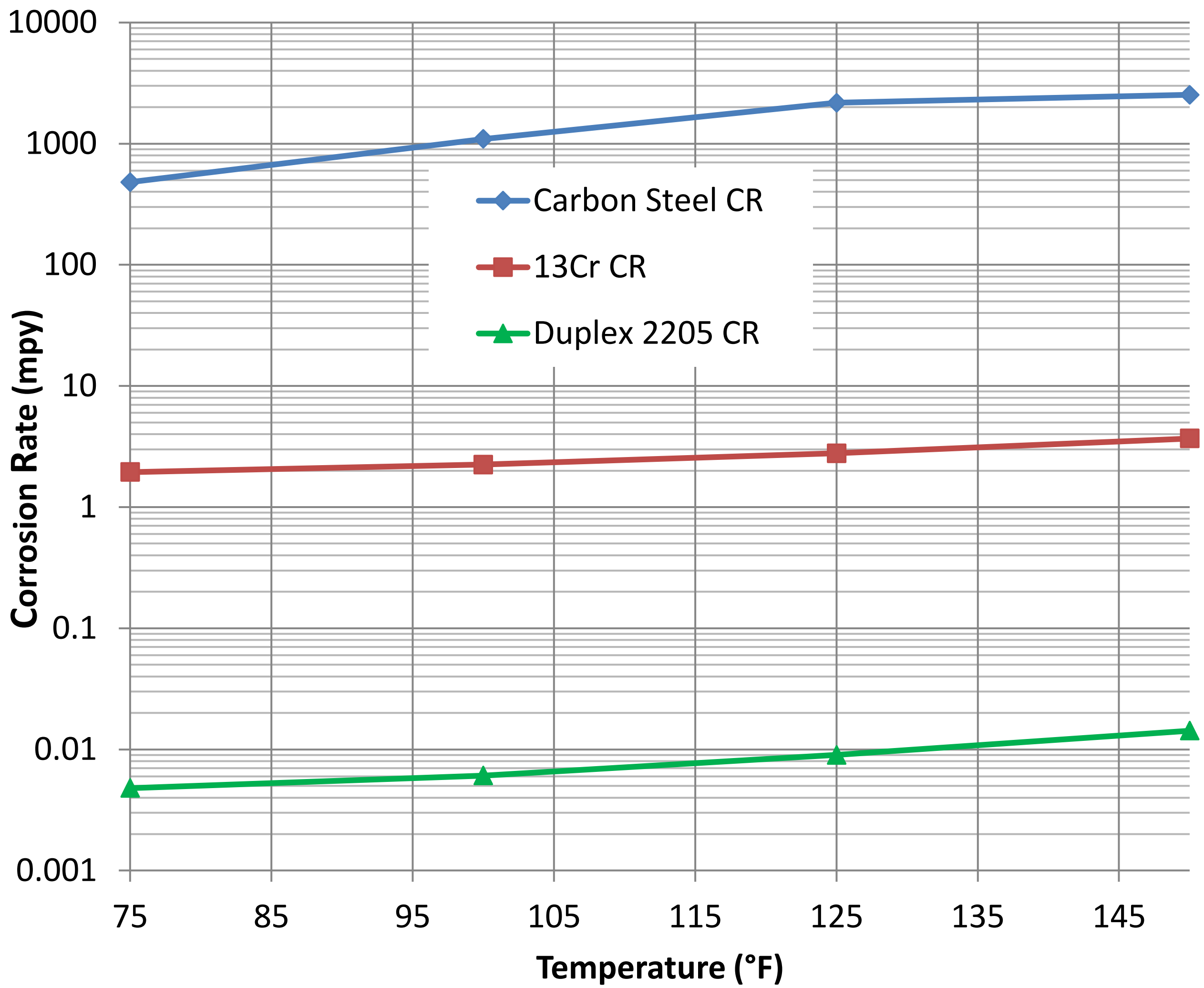
PREDICTED CORROSION RATES FOR VARIOUS METALLURGIES AT 3,100 PSIG



Calculations assume no oxygen contamination.

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PREDICTED IN SITU PH CALCULATIONS FOR WELL KILL BRINE OPERATIONS

Well Kill Brine Density	Brine Composition		pH of Neat Brine		in situ pH of brine exposed to CO2 injection gas		
	[Na+] (mg/L)	[Cl-] (mg/L)	at 77 °F and 14,7 psia	at 150 °F and 4,870 psig	1 bbl/0.001 MMscft	1 bbl/1 MMscft	1 bbl/10 MMscft
8.5 ppg	13,000	20,000	6.9	6.3	2.9	2.7	4.1
9.0 ppg	50,000	77,000	6.7	6.2	2.8	2.6	3.8

- In the event of a recompletion, the injection well will be killed with brine weighted with unbuffered NaCl. During the well kill process, there is a possibility that the brine pill will be in contact with the CO_2 injection gas, rendering the brine acidic.
- In the absence of H_2S, an *in situ* pH range from 2.5 to 4 is not expected to compromise the integrity of duplex stainless steel.
- It is advised, however, to use a nitrogen spacer when transitioning from CO_2 injection to killing the well with brine.

ENVIRONMENTAL & CORROSION MODELING

CO_2 Injection Scenarios and Material Options

Component	Dehydrated Injection Gas Scenario	O_2-free Injection Gas Scenario	Injection Gas (as reported composition)
Requirements	Must maintain dehydration unit and/or use corrosion inhibitors	Must mechanically and chemically exclude O_2 to < 10 ppb (extremely difficult)	No requirements
Wetted sections of the wellhead	Carbon steel	Regular or super 13Cr	22Cr/25Cr
Tubing	Carbon steel	Regular or super 13Cr	22Cr/25Cr
Packer*	22Cr/25Cr	22Cr/25Cr	22Cr/25Cr

*Casing below the packer will be exposed to acidic flowback (of unknown composition).

Conclusions: Use-Limiting Environmental Conditions

Corrosion-Controlling Environmental Conclusions

- Oxygen ingress into the captured CO_2 stream is inevitable in an industrial application such as carbon capture.
- In the absence of a dehydration unit, liquid water formation within the wellbore is predicted forming acidic condensates with pH values near 3.
- However, the modelled P_{H2S} is far below the NACE 0.05 psia threshold of concern for sulfide stress cracking (SSC).
- To our knowledge, there are currently no plans to apply either corrosion inhibitors or biocides.

Conclusions – Materials Selection Recommendations

Carbon and Low-Alloy Steels

- While SSC of carbon and low-alloy steels, even at hardnesses above HRC 22 are not anticipated because the predicted H_2S partial pressures < 0.05 psia, the anticipated metal-loss corrosion rates of steel in contact with the acidic aqueous condensates, from 35 mils/yr to 3,000 mils/yr. **Therefore, Honeywell DOES NOT RECOMMEND the selection of carbon and low-alloy steels in any downwell application that has the potential for moisture condensation**

All grades of 13Cr and Modified 13Cr Martensitic Stainless Steels

- All grades of 13Cr martensitic stainless steel (MSS) are notoriously susceptible to Stress Corrosion Cracking (SCC) even at room temperature in the presence of CO_2-containing brines with even mol-ppb levels of dissolved oxygen (DO). Thus, the potential of SCC of this class of alloys under mechanical stress**.** **Honeywell believes that this sensitivity precludes safe use of regular and super/modified 13Cr MSS under downwell CO_2-injection conditions and DOES NOT RECOMMEMD selection of any grade of 13Cr MSS.**

Conclusions – Materials Selection Recommendations (Cont.)

Duplex Stainless Steels

- Duplex Stainless Steels, the limited nickel content of which assures a mixed martensite/austenite microstructure, are widely recognized as highly resistant to both SSC at near-ambient temperatures and SCC at elevated temperatures, are not sensitive to dissolved oxygen. They typically have negligible corrosion rates, typically <0.05 mil/yr, under CO_2-injection service, as well as good resistance to pitting and crevice corrosion, but require meticulous heat-treatment in the mill and rigid adherence to qualified welding procedures.

- **Honeywell RECOMMENDS that duplex stainless steels including Grades 2205 and 2507, be considered for the potentially wetted portions of the Carbon-Capture CO_2 Injection wells.**

Summary

- Injection gas is expected to be hydrated.
- Since carbon steel corrosion rates are too high, an alternative corrosion resistant alloy (CRA) is necessary.
- As this is an injection well, martensitic stainless steels (i.e., regular 13Cr and super 13Cr grades) are not recommended as these materials are sensitive to trace levels (i.e., parts per billion) of O_2 and may the material may crack.
- Therefore, Honeywell's recommendation is to utilize either 22Cr and/or 25Cr duplex stainless steel (DSS) for all components as recommended in NORSOK M-001 *Materials Selection* Standard (2004).

M. A. Abu Bakar, et al. , Material Selection and Corrosion Rate Analysis for **CO2** Injection Well: A Case Study of K1 Field CO_2 Sequestration Project, IPTC-21818-MS (2021).

L. Smith et al., CO_2 Sequestration Wells - The Lifetime Integrity Challenge, SPE-136160-MS, 2010

Contact Info

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