Attachment A.II-1

ATTACHMENT A.II-1. MATERIALS OF CONSTRUCTION JUSTIFICATION FOR CSS #1 AND MW #1

RUSSELL CO_2 CAPTURE AND SEQUESTRATION

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List of Acronyms and Abbreviations

$CaCO_3$ = calcium carbonate
$Ca(OH)_2$ = Lime
$CaSO_4$ = calcium sulfate
CO_2 = carbon dioxide
CO_2-EOR = CO_2 enhanced oil recovery
CO_3^{2-} = carbonate anion
CRA = corrosion resistant alloy
CSH = calcium silicate hydrate
EPDM = Ethylene Propylene Diene Monomer rubber
FEPM = Tetrafluoroethylene Propylene Copolymer rubber
FKM = Fluorine Kautschuk Material – a family of fluoroelastomers
GS = geologic sequestration
H^+ = hydrogen cation
H_2 = hydrogen
H_2S = hydrogen sulfide
HCO_3^- = bicarbonate anion
HDPE = High Density Polyethylene
HNBR = Hydrogenated Nitrile Butadiene Rubber
HNO_3 = nitric acid
HNO_2 = nitrous acid
HS^- = bisulfide anion
HSO_3^- = bisulfite anion

N_2 = nitrogen
NBR = Nitrile Butadiene Rubber
NO_2 = nitrogen dioxide
NO_3^- = nitrate anion
NO_2^- = nitrite anion
NO_x = nitrogen oxides
PCC = PureField Carbon Capture, LCC
p_{CO2} = partial pressure of CO_2
p_{H2S} = partial pressure of H_2S
p_{O2} = partial pressure of O_2
PISC = Post Injection Site Care
PREN = pitting resistance number
PTFE = Polytetrafluoroethylene
S^{2-} = sulfide anion
SCC = stress corrosion cracking
SO_2 = sulfur dioxide
SSC = sulfide stress cracking
SO_3^{2-} = sulfite anion
SO_x = sulfur oxides
TDS = total dissolved solids
WAG = water alternating gas
y_{H2S} = mole fraction of hydrogen sulfide

A.II-1.1. Summary

PureField Carbon Capture, LLC (PCC) submits this attachment to demonstrate compliance with the portions of 40 CFR 146.86 that require the owner or operator to ensure the casing and cement or other materials used in the construction of each Class VI well have sufficient structural strength, be designed for the life of the geologic sequestration project, and that all construction materials are compatible with fluids with which the materials may be expected to come into contact; and tubing and packer materials used in the construction of each Class VI well are compatible with fluids with which the materials may be expected to come into contact. More specifically, this attachment addresses suitability of the cements, metals, and non-metallic components used for construction of the injection and deep zone monitoring wells CSS #1 and MW #1, respectively. 40 CFR 146.86 strictly only applies to Class VI injection wells, however PCC has elected to provide a similar analysis of the materials utilized for construction of the deep zone monitoring well MW #1 to demonstrate compliance with the spirit of 40 CFR 146.86 in accordance with US EPA recommendations (EPA 2012).

The PCC geologic sequestration (GS) project conditions are mild, characterized by a high-purity injectate with limited content of potentially corrosive impurities, favorable injection zone properties (low temperature, low salinity, mild pH), and favorable injection zone rock properties (mostly carbonates that maintain pH = 4.5 – 5.5 within the CO_2 plume). Evaluation of the CSS #1 and MW #1 materials of construction determined the cement, metal, and non-metallic components should satisfy the structural strength, design life, and fluid compatibility requirements of 40 CR 146.86. Standard general-purpose cement formulations are utilized in zones outside the sequestration zone, and suitable CO_2-resistant cements are utilized in the sequestration zone. A combination of carbon steel and corrosion resistant alloys (CRAs) such as 13Cr, Alloy 925, and nickel-plated carbon steel are utilized for metallic structural components with the choice of metal dependent upon the anticipated fluid exposures. PCC utilizes a two-prong approach for construction in the sequestration zone, using a combination of CO_2 resistant cement in tandem with CRAs to avoid spalling. Non-metallic components (e.g., O-rings, valve stem packings, seals) are constructed from CO_2-compatible materials for CO_2 contact applications.

A.II-1.2. General Background

40 CFR 146.86(b)(1) and 40 CFR 146.86(c)(1) outlines several requirements for Class VI wells including a requirement that all well materials must be compatible with fluids with which the materials may be expected to come into contact. More specifically, cement, metal, and non-metallic components should have adequate resistance to degradation when exposed to the CO_2-rich injectate, formation fluids, and injectate+formation fluid mixtures.

A.II-1.2.1. Site-Specific Design Basis

Table A.II-1.2.1 summarizes the site-specific design basis PCC utilized for the CSS #1 and MW #1 wells. This table is a synthesis of information obtained during Pre-Construction testing of the raw CO_2 source with allowances for source gas variability and adjustments for expected changes from compression and dehydration of the source gas, plus information on formation fluid and rock properties obtained from CSS #1 while in stratigraphic well service, plus the design basis for the project- and well-service lives. The project conditions are relatively mild, characterized by a high purity injectate with limited corrosive impurities, and favorable injection zone fluid and rock properties.

A.II-1.2.2. Limitations of Field Studies and Laboratory Testing

The GS industry is in its infancy so there are few published long-term field studies on the corrosion performance of various materials in GS wells. Application guidelines have been created for most materials of interest using the long history of their use in the oil & gas and CO_2 Enhanced Oil Recovery (CO_2-EOR) industries; however, these guidelines must be used carefully as the conditions in oil & gas and CO_2-EOR industries are not necessarily comparable to a specific GS project (Craig and Rowe 2024). Laboratory testing can also be used to gather data, yet this approach has several pitfalls that limit its usefulness:

<u>Non-Representative Testing</u> It is difficult to design tests that: utilize representative materials (injectate, formation fluid, and formation rock) and reproduce the pH and other key conditions encountered at GS wells, reproduce the fluid flow regimes present in GS wells, and reproduce protective mechanisms in well design such as the cement sheath that protects the casing.

<u>Short-Term Testing</u> The duration of lab tests are short (typically several days to one year) compared to the service life of GS wells, thus long-term corrosion phenomena are missing.

<u>Mis-Matched Conditions</u> It is difficult to find published laboratory tests that closely match the site-specific conditions of a particular GS project.

Despite these limitations, PCC has confidence that appropriate materials of construction have been selected for CSS #1 and MW #1 based on a rigorous analysis of field- and laboratory-data, combined with use of application guidelines for material selection and experienced engineering judgement.

Table A.II-1.2.1. Design Basis for CSS #1 and MW #1

Factor		CSS #1	MW #1	Comments
Injection Zone Properties				
Temperature	Prior to Injection	110 °F	Same as CSS #1	From measurements at CSS #1 in stratigraphic well service
	Injection & PISC Periods	110 °F	Same as CSS #1	Computational model assumes isothermal injection zone
Pressure	Prior to Injection	1,259 psia	Same as CSS #1	From measurements at CSS #1 in stratigraphic well service
	Injection & PISC Periods	2,166 psia (peak)	Same as CSS #1	From 80% of fracture pressure limit
p_{CO2}	Outside Plume	Neglect	Same as CSS #1	May '23 swab sample at CSS #1 found total CO_2 = 525 mg/L, equivalent to p_{CO2} = 0.7 psia
	Inside Plume	455 to 700 psia	Same as CSS #1	From computational model
pH	Outside Plume	6.8	Same as CSS #1	From May '23 swab sample at CSS #1
	Inside Plume	Injection Period: At Perforation: Not Meaningful Elsewhere: 4.5 to 5.5	4.5 to 5.5	pH values from computational model. Insufficient water present for a meaningful pH at the CSS #1 perforations during the Injection period
		PISC Period: 4.5 to 5.5		
Other Injection Zone Formation Fluid Properties				
Chlorides		24,900 mg/L as TDS	Same as CSS #1	From May '23 swab sample at CSS #1
H_2S		Neglect	Same as CSS #1	May '23 swab sample at CSS #1 found sulfide (as H_2S) to be below detection limit (< 1.0 mg/L)
O_2, SO_x, NO_x, H_2, N_2		Neglect	Same as CSS #1	No geologic reason to anticipate presence of these impurities in the injection zone formation fluid
Alkalinity		435 mg/L Total as $CaCO_3$	Same as CSS #1	From May '23 swab sample at CSS #1
Injection Zone Formation Rock Properties				
Minerals		Predominately Carbonates	Same as CSS #1	From measurements at CSS #1 in stratigraphic well service. Provides pH buffering capacity within the CO_2 plume
Injectate Composition				
CO_2		> 99 vol%	Same as CSS #1	From Pre-Construction testing of CO_2 source
H_2O		< 400 ppmv	Same as CSS #1	From design specification for dehydration skid
H_2S		0 - 20 ppm	Same as CSS #1	Allowance; H_2S was below detection limit (< 0.01 ppmv) during Pre-Construction testing
O_2		0 - 100 ppm	Neglect	CSS #1: Allowance; Unable to definitively quantify O_2 concentration during Pre-Construction testing MW #1: Assume injectate O_2 is either preferentially adsorbed on rock or consumed by microbes as it travels to MW #1
SO_2 and Other SO_x		Neglect	Same as CSS #1	SO_2 was below detection limit (<0.05 ppmv) during Pre-Construction testing, plus no process reason to anticipate presence of SO_2 or SO_X
NO_2 and Other NO_x		Neglect	Same as CSS #1	No process reason to anticipate presence of NO_2 or NO_x
H_2		Neglect	Same as CSS #1	H_2 was below detection limit (< 0.1 vol%) during Pre-Construction testing
N_2		< 0.5 vol %	Same as CSS #1	Allowance; Unable to definitively quantify N_2 concentration during Pre-Construction testing
Elemental Sulfur		Neglect	Same as CSS #1	No process reason to anticipate presence of elemental sulfur
Service Life				
CSS #1	Injection Period	12 yr	-	From project design basis - Injection service
	PISC	50 yr	-	From project design basis - Monitoring well service
	Total	62 yr	-	
MW #1 Upper Zone	Injection Period	-	12 yr	From project design basis
	PISC	-	50 yr	From project design basis
	Total	-	62 yr	
MW #1 Lower Zone	Injection Period	-	5 yr w/o CO_2 Exposure 2 yr w/ CO_2 Exposure	Plume arrives at MW #1 in Year 5, MW #1 lower zone to be isolated (or plugged) within 2 yr of plume arrival

A.II-1.3. Selection Factors for Cements

This section discusses selection factors for the general purpose and CO_2 resistant cements used in the construction of the PCC wells. These cements serve a number of purposes including: preventing the vertical migration of fluids by sealing the annular space between the wellbore and casing; improving structural strength by anchoring the casing to the formation rock; and providing corrosion protection for the outside of the casing by ensheathing it in cement and thus limiting contact with formation fluids and injectate/formation fluid mixtures.

PCC followed standard oil and gas practices for the selection of cements and casing materials used in construction of its wells in zones not expected to be exposed to injectate+formation fluid mixtures. For zones expected to be exposed to injectate+formation fluid mixtures, PCC followed a system-level approach that utilizes CO_2 resistant cements in tandem with CRA casing to improve long-term external mechanical integrity of its wells. Cements are slightly permeable with the pores and passageways mostly filled with liquid water, thus over long durations the cement and ensheathed metal casing are subject to degradation from exposures to CO_2, chlorides, dissolved O_2, and other agents. Often, the cement is chemically stable but the ensheathed metal corrodes, swells, and mechanically cracks the ensheathing cement, which further accelerates degradation of the remaining cement and metal. As an analogy, Figure A.II-1.3-1 is a photo of concrete spalling on a highway bridge exposed to road salts during winter de-icing. The encased carbon steel rebar corroded from saltwater penetration through the concrete, leading to spalling and further corrosion of the cement and rebar. PCC's system-level approach of selecting appropriate cements and casing materials in tandem leads to extended durations for the external mechanical integrity of its wells vs. common practices in the oil and gas and CO_2-EOR industries. General purpose and CO_2 resistant cements are discussed here; carbon steels and CRAs are discussed in Section A.II-1.4.

Figure A.II-1.3-1. Highway Bridge with Spalling Concrete and Rusting Rebar

Source: Doug Madsen, Lewis River Bridge, Yellowstone National Park, WY

A.II-1.3.1. General Purpose Cements The general purpose cements utilized in the construction of the PCC wells are suitable Portland cement-based formulations compliant with either ASTM or API specifications. PCC only utilized general purpose cements at locations where no exposure to injectate+formation fluid mixtures is anticipated since general purpose cements do not provide CO_2 resistance. Portland cement is the most common form of cement, and is defined as a hydraulic cement (i.e., a cement that sets and hardens by chemical reaction with water and is capable of doing so under water) produced by pulverizing clinker, consisting essentially of crystalline hydraulic calcium silicates, and usually containing one or more of the following: water, calcium sulfate, up to 5% limestone, and processing additions (ASTM 2024). Hydration of Portland cement creates a high-strength network of interlocking calcium silicate hydrate (CSH) crystals responsible for 50-60% of the hardened cement, plus two classes of compounds that contribute little to the strength of hardened cement [lime - $Ca(OH)_2$, 20-25% of hardened cement; ettringite - hexacalcium aluminate trisulfate hydrates, 15-20% of hardened cement], and heat. The cements of interest are discussed below and summarized in Table A.II-1.3.1:

<u>ASTM Type 1</u> This is the most widely available general purpose Portland cement. ASTM C150 (ASTM 2012) defines the requirements for composition and properties for ASTM Type 1 cement, which are similar to the requirements for API Class A cement (API 2019). ASTM Type 1 is an ordinary cement intended for cementing casing from surface to depths of 6,000 ft (or more) depending upon site conditions. It contains no additives needed to impart special properties required for other ASTM/API cements. PCC utilized ASTM Type 1 cement as grout surrounding the conductor casings for both the CSS #1 and MW #1 wells.

<u>ASTM Type 1L</u> This general purpose Portland cement is made from ASTM Type I/II clinker ground with additional limestone to both reduce costs and reduce greenhouse gas emissions in cement manufacture while retaining the properties of ASTM Type 1 cement. ASTM C595/C595M (ASTM 2024) defines the requirements for ASTM Type 1L cement. PCC utilized Halliburton's Swiftcem for the MW #1 surface casing, which is a proprietary formulation that meets ASTM Type 1L specifications.

<u>API Class H</u> This general purpose cement is manufactured by inter-grinding Portland cement clinker with one or more forms of calcium sulfate ($CaSO_4$). Class H is intended for cementing casing from surface to depths of 8,000 ft (or more) depending upon site conditions and may be mixed with accelerators or retarders as needed to cover a range of well depths and temperatures. PCC utilized Class H cement for the CSS #1 surface casing.

Table A.II-1.3.1. Composition and Properties for General Purpose Cements

From: API Spec 10A (API 2019)

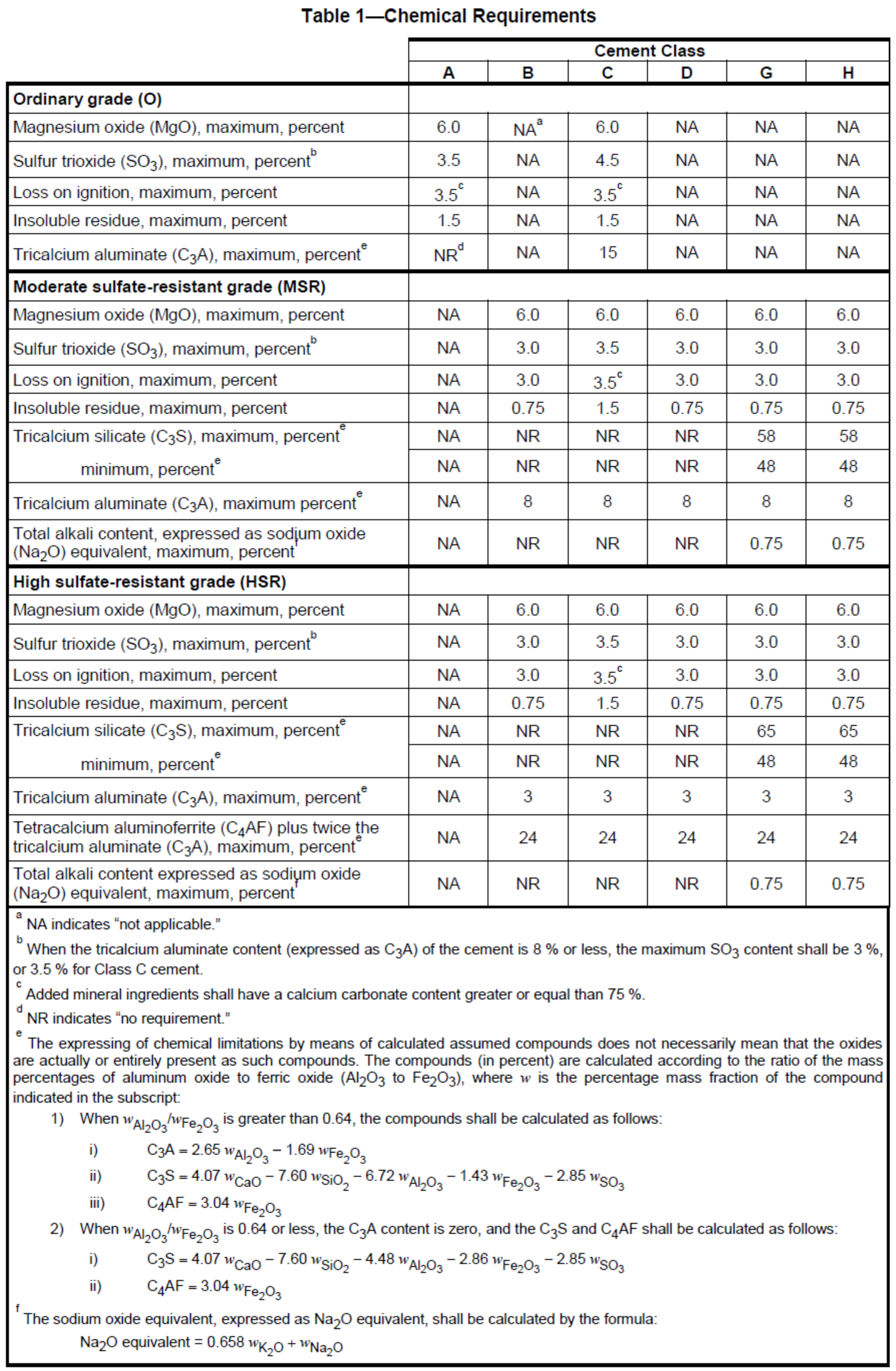


Table 1—Chemical Requirements

	Cement Class A	B	C	D	G	H
Ordinary grade (O)						
Magnesium oxide (MgO), maximum, percent	6.0	NA[a]	6.0	NA	NA	NA
Sulfur trioxide (SO_3), maximum, percent[b]	3.5	NA	4.5	NA	NA	NA
Loss on ignition, maximum, percent	3.5[c]	NA	3.5[c]	NA	NA	NA
Insoluble residue, maximum, percent	1.5	NA	1.5	NA	NA	NA
Tricalcium aluminate (C_3A), maximum, percent[e]	NR[d]	NA	15	NA	NA	NA
Moderate sulfate-resistant grade (MSR)						
Magnesium oxide (MgO), maximum, percent	NA	6.0	6.0	6.0	6.0	6.0
Sulfur trioxide (SO_3), maximum, percent[b]	NA	3.0	3.5	3.0	3.0	3.0
Loss on ignition, maximum, percent	NA	3.0	3.5[c]	3.0	3.0	3.0
Insoluble residue, maximum, percent	NA	0.75	1.5	0.75	0.75	0.75
Tricalcium silicate (C_3S), maximum, percent[e]	NA	NR	NR	NR	58	58
minimum, percent[e]	NA	NR	NR	NR	48	48
Tricalcium aluminate (C_3A), maximum percent[e]	NA	8	8	8	8	8
Total alkali content, expressed as sodium oxide (Na_2O) equivalent, maximum, percent[f]	NA	NR	NR	NR	0.75	0.75
High sulfate-resistant grade (HSR)						
Magnesium oxide (MgO), maximum, percent	NA	6.0	6.0	6.0	6.0	6.0
Sulfur trioxide (SO_3), maximum, percent[b]	NA	3.0	3.5	3.0	3.0	3.0
Loss on ignition, maximum, percent	NA	3.0	3.5[c]	3.0	3.0	3.0
Insoluble residue, maximum, percent	NA	0.75	1.5	0.75	0.75	0.75
Tricalcium silicate (C_3S), maximum, percent[e]	NA	NR	NR	NR	65	65
minimum, percent[e]	NA	NR	NR	NR	48	48
Tricalcium aluminate (C_3A), maximum, percent[e]	NA	3	3	3	3	3
Tetracalcium aluminoferrite (C_4AF) plus twice the tricalcium aluminate (C_3A), maximum, percent[e]	NA	24	24	24	24	24
Total alkali content expressed as sodium oxide (Na_2O) equivalent, maximum, percent[f]	NA	NR	NR	NR	0.75	0.75

[a] NA indicates “not applicable.”

[b] When the tricalcium aluminate content (expressed as C_3A) of the cement is 8 % or less, the maximum SO_3 content shall be 3 %, or 3.5 % for Class C cement.

[c] Added mineral ingredients shall have a calcium carbonate content greater or equal than 75 %.

[d] NR indicates “no requirement.”

[e] The expressing of chemical limitations by means of calculated assumed compounds does not necessarily mean that the oxides are actually or entirely present as such compounds. The compounds (in percent) are calculated according to the ratio of the mass percentages of aluminum oxide to ferric oxide (Al_2O_3 to Fe_2O_3), where w is the percentage mass fraction of the compound indicated in the subscript:

1) When $w_{Al_2O_3}/w_{Fe_2O_3}$ is greater than 0.64, the compounds shall be calculated as follows:
   - i) $C_3A = 2.65\, w_{Al_2O_3} - 1.69\, w_{Fe_2O_3}$
   - ii) $C_3S = 4.07\, w_{CaO} - 7.60\, w_{SiO_2} - 6.72\, w_{Al_2O_3} - 1.43\, w_{Fe_2O_3} - 2.85\, w_{SO_3}$
   - iii) $C_4AF = 3.04\, w_{Fe_2O_3}$
2) When $w_{Al_2O_3}/w_{Fe_2O_3}$ is 0.64 or less, the C_3A content is zero, and the C_3S and C_4AF shall be calculated as follows:
   - i) $C_3S = 4.07\, w_{CaO} - 7.60\, w_{SiO_2} - 4.48\, w_{Al_2O_3} - 2.86\, w_{Fe_2O_3} - 2.85\, w_{SO_3}$
   - ii) $C_4AF = 3.04\, w_{Fe_2O_3}$

[f] The sodium oxide equivalent, expressed as Na_2O equivalent, shall be calculated by the formula:

Na_2O equivalent $= 0.658\, w_{K_2O} + w_{Na_2O}$

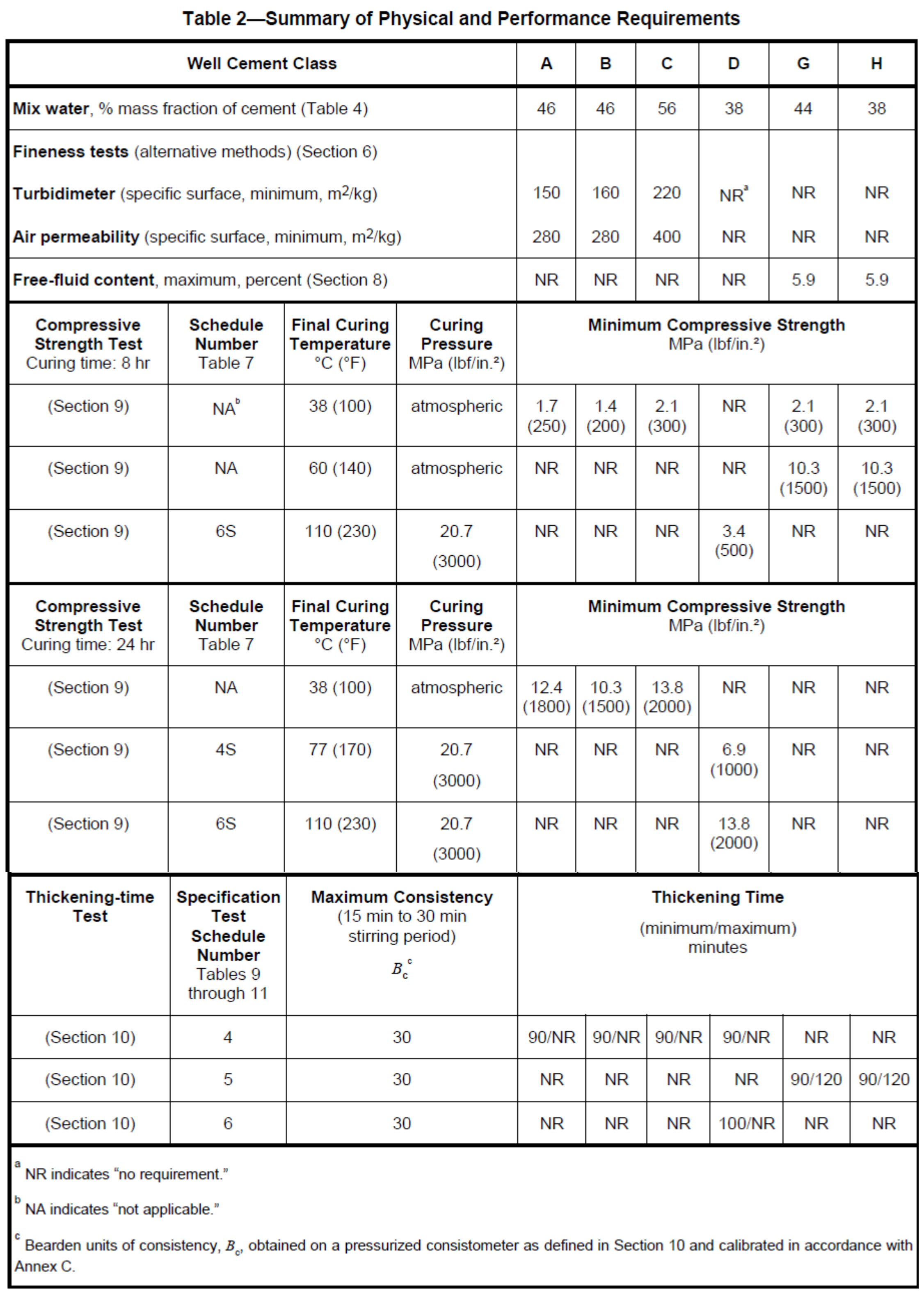


Table 2—Summary of Physical and Performance Requirements

Well Cement Class				**A**	**B**	**C**	**D**	**G**	**H**
Mix water, % mass fraction of cement (Table 4)				46	46	56	38	44	38
Fineness tests (alternative methods) (Section 6)									
Turbidimeter (specific surface, minimum, m^2/kg)				150	160	220	NR[a]	NR	NR
Air permeability (specific surface, minimum, m^2/kg)				280	280	400	NR	NR	NR
Free-fluid content, maximum, percent (Section 8)				NR	NR	NR	NR	5.9	5.9
Compressive Strength Test Curing time: 8 hr	**Schedule Number** Table 7	**Final Curing Temperature** °C (°F)	**Curing Pressure** MPa (lbf/in.²)	**Minimum Compressive Strength** MPa (lbf/in.²)					
(Section 9)	NA[b]	38 (100)	atmospheric	1.7 (250)	1.4 (200)	2.1 (300)	NR	2.1 (300)	2.1 (300)
(Section 9)	NA	60 (140)	atmospheric	NR	NR	NR	NR	10.3 (1500)	10.3 (1500)
(Section 9)	6S	110 (230)	20.7 (3000)	NR	NR	NR	3.4 (500)	NR	NR
Compressive Strength Test Curing time: 24 hr	**Schedule Number** Table 7	**Final Curing Temperature** °C (°F)	**Curing Pressure** MPa (lbf/in.²)	**Minimum Compressive Strength** MPa (lbf/in.²)					
(Section 9)	NA	38 (100)	atmospheric	12.4 (1800)	10.3 (1500)	13.8 (2000)	NR	NR	NR
(Section 9)	4S	77 (170)	20.7 (3000)	NR	NR	NR	6.9 (1000)	NR	NR
(Section 9)	6S	110 (230)	20.7 (3000)	NR	NR	NR	13.8 (2000)	NR	NR
Thickening-time Test	**Specification Test Schedule Number** Tables 9 through 11	**Maximum Consistency** (15 min to 30 min stirring period) B_c[c]		**Thickening Time** (minimum/maximum) minutes					
(Section 10)	4	30		90/NR	90/NR	90/NR	90/NR	NR	NR
(Section 10)	5	30		NR	NR	NR	NR	90/120	90/120
(Section 10)	6	30		NR	NR	NR	100/NR	NR	NR

[a] NR indicates “no requirement.”

[b] NA indicates “not applicable.”

[c] Bearden units of consistency, B_c, obtained on a pressurized consistometer as defined in Section 10 and calibrated in accordance with Annex C.

A.II-1.3.2. CO_2 Resistant Cements The calcium-silica-hydrate (C-S-H) and lime fractions of hydrated Portland cements are subject to CO_2 attack, slowly degrading by forming calcium carbonate ($CaCO_3$) via the carbonatation reactions:

Carbonatation Reactions:

$$CO_2 + H_2O + \text{C-S-H} \rightarrow amorphous\ silica\ gel + CaCO_3$$
$$CO_2 + Ca(OH)_2 \rightarrow CaCO_3 + H_2O$$

Several published field studies provide results on long-term CO_2 exposure of conventional Portland cements and carbon steel casing strings in CO_2-EOR applications. The results are inconsistent with respect to whether these materials are sufficient for long-term external mechanical integrity as discussed below:

Carey et al. 2007 The upper panel of Figure A.II-1.3-2 contains photos of a sidewall core taken from a CO_2-EOR well in West Texas with 30 years of CO_2 exposure. The well was constructed with Portland cement and carbon steel casing, with the cores taken from an upper primary confining layer just a few meters above the injection zone. The core indicates external mechanical integrity was maintained, with little evidence of casing corrosion and some evidence of cement carbonation in the white rind immediately adjacent to the casing and cement carbonation in the orange layer adjacent to the formation shale. The lower panel of Figure A.II-1.3-2 shows a plot of pH as a function of radial distance from the casing. The pore water within Portland cement layer is alkaline at pH = 12.5 – 13.5 (distance < 0.045 m) so the surface of the ensheathed casing is passivated and protected from corrosion.

Laumb et al. 2016 As a counter example, Figure A.II-1.3-3 summarizes cement bond and x-y caliper logging for a well located in the Weyburn field near Midedale, SK. The well was constructed using Portland cement and carbon steel casing and originally placed into oil production service from 1957 to 1964, followed by water injection service from 1964 to 2000, CO_2-EOR water alternating gas (WAG) service from 2000 to 2009, and finally water injector service until its abandonment in 2010. The left panel compares cement bond logs from 1987 and 2002. The 2002 logs show significant deterioration of cement bonding to the casing and cement bonding to the formation at depths from 1,133-1,175 m vs. the 1987 logs, which corresponds to the time when the well was in WAG service. The right panel containing the x-y caliper log taken in 2008 shows complete loss of the carbon steel casing below 1,368 m.

Currently there are no ASTM, API, or other standards that fully encompass CO_2 resistant cements for use in GS wells. PCC determined suitability of a particular cement formulation in close consultation with well-service companies and cement vendors. Both CO_2 resistant cements selected by PCC utilize a bulk blend of Portland cement and pozzolans. A pozzolan is a siliceous or siliceous and aluminous material, which in itself possesses little or no cementitious value but will, in finely divided form and in the presence of moisture, chemically react with calcium hydroxide at ordinary temperatures to form cementitious hydrates (ASTM 2024). Typical pozzolans include: fly ashes; ground blast-furnace slags; volcanic ashes; diatomaceous earths; and partially calcined clays, shales, and certain siliceous rocks.

Figure A.II-1.3-2. Field Study from a CO_2-EOR Well in Service for 30 Years

Upper: Sidewall Cores in Upper Confining Layer Showing Good External Mechanical Integrity;
Lower: Alkaline pH of Pore Water Within Cement Sheath (Distance <0.045 m)
From: Carey et al. 2007

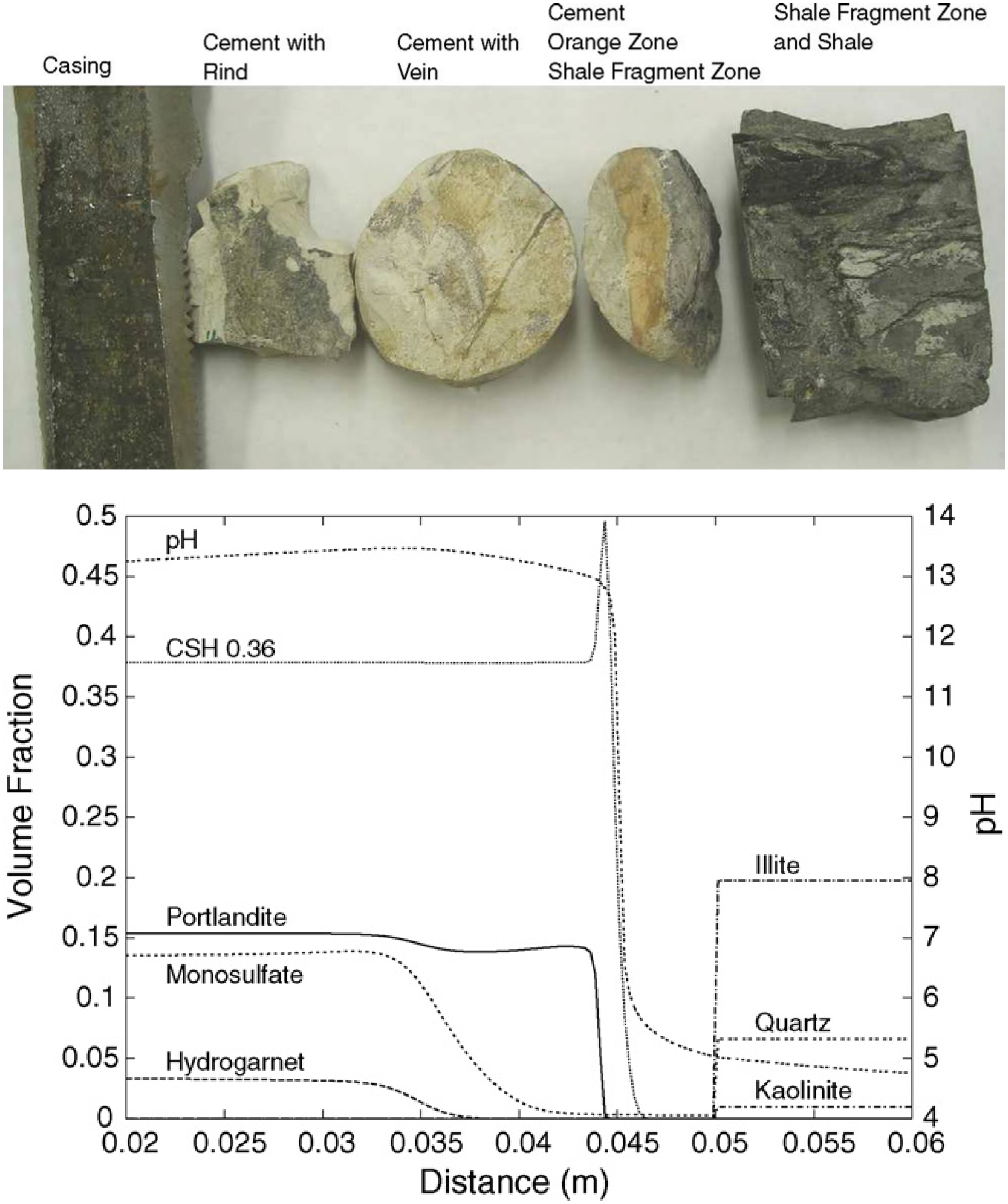
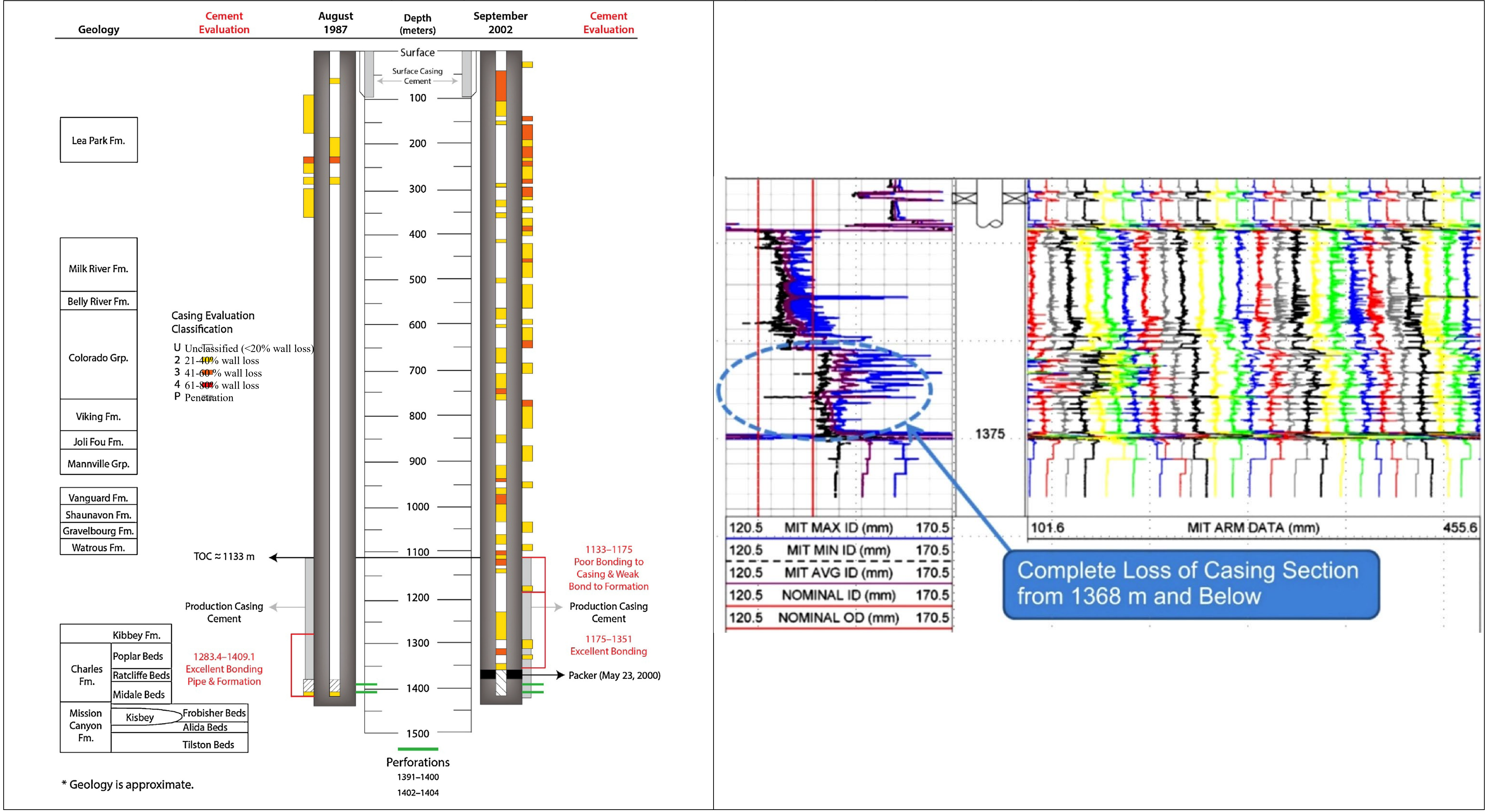


Figure A.II-1.3.3. Field Study from an Oil & Gas/CO_2-EOR Well in Service for 53 Years

Left: Cement Bond Logs Show Significant Deterioration in 2002 vs. 1987; Right: X-Y Caliper Log in 2008 Shows Missing Casing; From: Laumb et al. 2016



The outstanding longevity of pozzolanic concretes was well-known to ancient Romans, having been used in the construction of buildings, roads, and aqueducts throughout the Roman Empire, with the dome of the Pantheon in Rome being an often cited extant example of pozzolanic concrete construction (Natural Pozzolan Association 2024, Moore 1995). Unfortunately, the pozzolan knowledge held by the ancient Romans was lost with the collapse of the Empire and was not re-developed until the modern era. Several large-scale water infrastructure projects were built during the 20th century in the US West (e.g., Los Angeles Aqueduct, Hoover Dam, Glens Canyon Dam) using Portland cement/pozzolan blends to reduce cost, control heat release, and provide other properties (Thomas and Del Rey Castillo 2023).

Portland cement/pozzolan blends were introduced to the oil and gas industry in 1949 and have since achieved wide commercial use under diverse field conditions (Johnson and Garvin 1972). A typical application is for casing cement in deep wells where a lightweight slurry is needed to prevent exceeding formation fracture pressure during cementing (i.e., pozzolans have lower specific gravity than Portland cement thus creating lighter weight slurries at a given consistency). More recently, Portland cement/pozzolan blends are used in geologic sequestration applications since they exhibit good resistance to CO_2 degradation. Hydration of a Portland cement-only formulation creates 20-25% lime in the hydrated cement, which contributes little to strength, increases permeability of the cement, and increases the degradation rate of both the cement and ensheathed casing. When Portland cement is blended with pozzolan and then hydrated, the Portland cement fraction releases lime upon its hydration, and this lime is then combined with the pozzolan to form additional cementitious hydrates during hydration of the pozzolan fraction. This in-situ reduction of lime in the hydrated Portland cement/pozzolan blend improves strength, reduces permeability, and increases CO_2 resistance.

Below are the specific CO_2 resistant cements utilized by PCC for well construction:

50/50 Poz-Mix w/ Liquid Latex This cement is a bulk 50/50 blend of API Class H cement and pozzolan with 2% bentonite (reduces free water) and latex. Latex is a colloidal suspension of various co-polymers in water that effectively coats the walls of the capillary pores within the cement and thus protects the cement from CO_2 attack. PCC selected this cement for the CSS #1 long string casing.

Halliburton CorrosaCem™[1] CorrosaCem is a proprietary Portland cement/pozzolan blend with latex and fibers developed by Halliburton as a CO_2-resistant cement for geologic sequestration wells. Figure A.II-1.3.4 provides a technical data sheet with more details on this cement. PCC selected this cement for the MW #1 long string casing.

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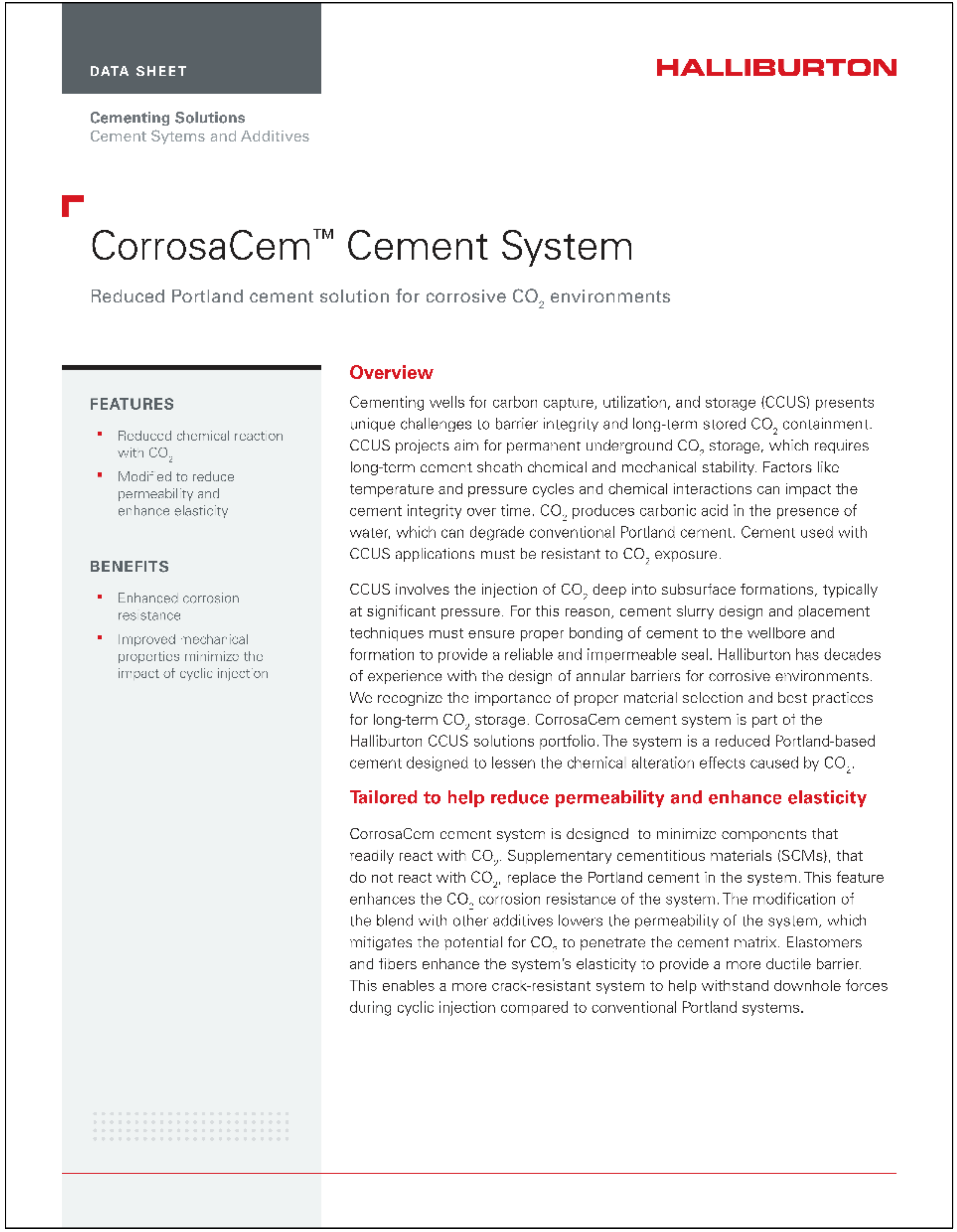
[1] CorrosaCem is a trademark owned by the Halliburton Company, Houston, TX, USA

Figure A.II-1.3-4. Technical Data Sheet for CorrosaCem Cement

From: https://www.halliburton.com/en/products/corrosacem-cement-system



DATA SHEET

HALLIBURTON

Cementing Solutions
Cement Sytems and Additives

CorrosaCem™ Cement System

Reduced Portland cement solution for corrosive CO_2 environments

FEATURES

- Reduced chemical reaction with CO_2
- Modified to reduce permeability and enhance elasticity

BENEFITS

- Enhanced corrosion resistance
- Improved mechanical properties minimize the impact of cyclic injection

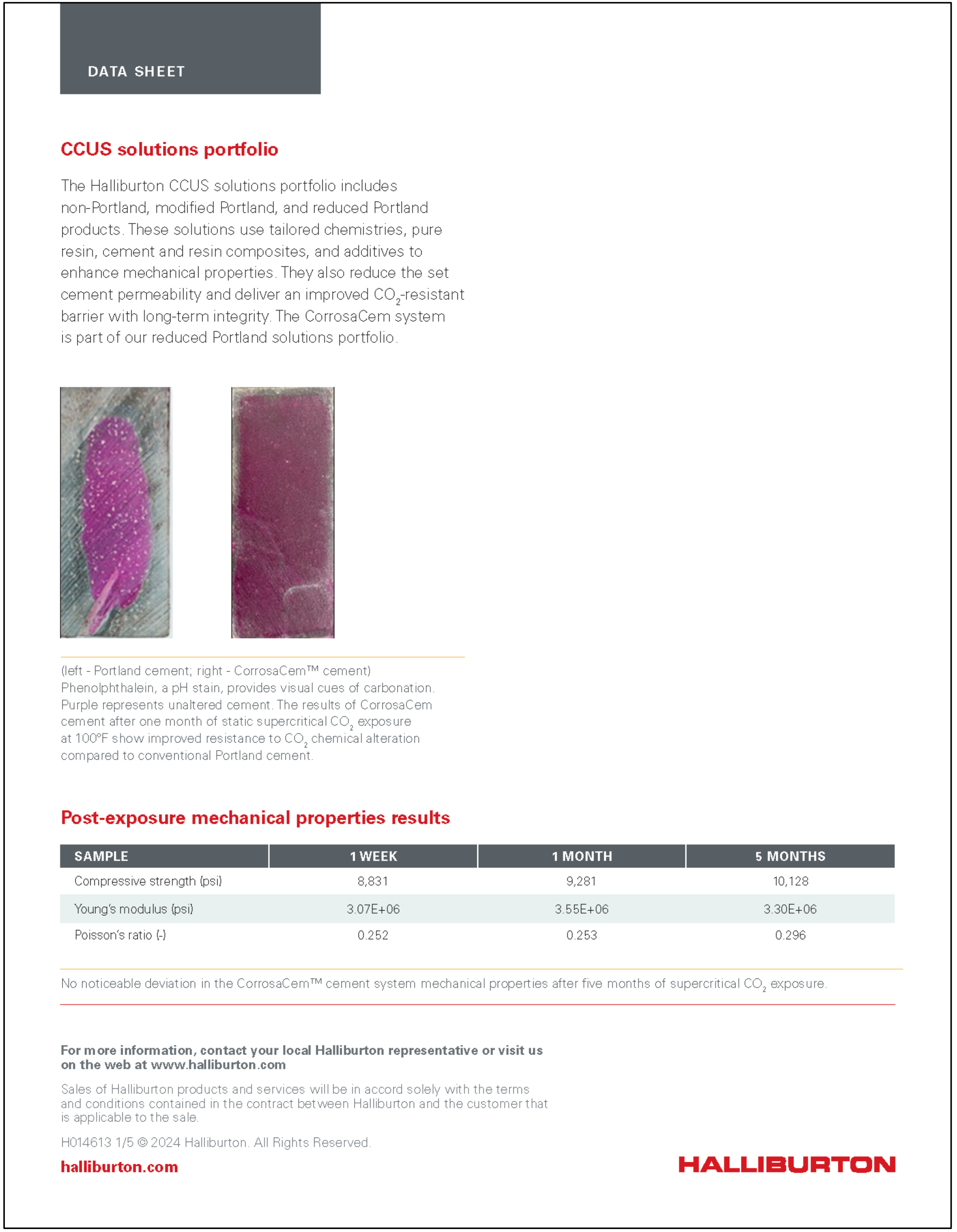
Overview

Cementing wells for carbon capture, utilization, and storage (CCUS) presents unique challenges to barrier integrity and long-term stored CO_2 containment. CCUS projects aim for permanent underground CO_2 storage, which requires long-term cement sheath chemical and mechanical stability. Factors like temperature and pressure cycles and chemical interactions can impact the cement integrity over time. CO_2 produces carbonic acid in the presence of water, which can degrade conventional Portland cement. Cement used with CCUS applications must be resistant to CO_2 exposure.

CCUS involves the injection of CO_2 deep into subsurface formations, typically at significant pressure. For this reason, cement slurry design and placement techniques must ensure proper bonding of cement to the wellbore and formation to provide a reliable and impermeable seal. Halliburton has decades of experience with the design of annular barriers for corrosive environments. We recognize the importance of proper material selection and best practices for long-term CO_2 storage. CorrosaCem cement system is part of the Halliburton CCUS solutions portfolio. The system is a reduced Portland-based cement designed to lessen the chemical alteration effects caused by CO_2.

Tailored to help reduce permeability and enhance elasticity

CorrosaCem cement system is designed to minimize components that readily react with CO_2. Supplementary cementitious materials (SCMs), that do not react with CO_2, replace the Portland cement in the system. This feature enhances the CO_2 corrosion resistance of the system. The modification of the blend with other additives lowers the permeability of the system, which mitigates the potential for CO_2 to penetrate the cement matrix. Elastomers and fibers enhance the system's elasticity to provide a more ductile barrier. This enables a more crack-resistant system to help withstand downhole forces during cyclic injection compared to conventional Portland systems.



DATA SHEET

CCUS solutions portfolio

The Halliburton CCUS solutions portfolio includes non-Portland, modified Portland, and reduced Portland products. These solutions use tailored chemistries, pure resin, cement and resin composites, and additives to enhance mechanical properties. They also reduce the set cement permeability and deliver an improved CO_2-resistant barrier with long-term integrity. The CorrosaCem system is part of our reduced Portland solutions portfolio.

(left - Portland cement; right - CorrosaCem™ cement)
Phenolphthalein, a pH stain, provides visual cues of carbonation. Purple represents unaltered cement. The results of CorrosaCem cement after one month of static supercritical CO_2 exposure at 100°F show improved resistance to CO_2 chemical alteration compared to conventional Portland cement.

Post-exposure mechanical properties results

SAMPLE	1 WEEK	1 MONTH	5 MONTHS
Compressive strength (psi)	8,831	9,281	10,128
Young's modulus (psi)	3.07E+06	3.55E+06	3.30E+06
Poisson's ratio (-)	0.252	0.253	0.296

No noticeable deviation in the CorrosaCem™ cement system mechanical properties after five months of supercritical CO_2 exposure.

For more information, contact your local Halliburton representative or visit us on the web at www.halliburton.com

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A.II-1.4. Selection Factors for Metals

Metals are used for construction of casing, tubing, packers, wellhead, instruments, and other components of the wells. This section defines the relevant metals for the PCC wells, explains relevant corrosion mechanism for those metals, explains the main factors driving corrosion rates in GS applications along with presentations of material selection guidelines and summaries of published laboratory data at conditions similar to the site-specific conditions for the PCC wells.

A.II-1.4.1. Compositions of Relevant Metals

Table A.II-1.4-1 provides composition information for the metals used in the construction of the PCC wells.

Carbon steel is a general name for an iron-carbon alloy with a mass carbon percentage content ≤ 2.0% plus lesser amounts of other elements, with specific limits on carbon and other others set according to the specific grade. PCC utilized carbon steels for well components exposed to low corrosive conditions (e.g., conductor casing, surface casing).

13Cr, Alloy 825, and Alloy 925[2] are CRAs with formulations that materially improve corrosion resistance vs. carbon steel in aggressive environments while also providing adequate strength, ductility, and other mechanical properties. 13Cr is a quenched and tempered martensitic stainless steel that contains ~13% chromium to improve corrosion resistance. PCC utilizes 13Cr for well components exposed to sweet CO_2 and sweet CO_2+formation fluid environments with limited levels of hydrogen sulfide, where the adjective "sweet" denotes an environment with little or no hydrogen sulfide. Other steels should be used in "sour" CO_2 and "sour" CO_2+formation fluid environments when the hydrogen sulfide content exceeds the application limit for 13Cr.

Alloy 825 and Alloy 925 are super alloy steels with similar compositions containing nickel, chromium, and other elements to provide excellent corrosion resistance to all of the relevant corrosion mechanisms discussed later in Section A.II-1.4-2. The slight differences in composition and manufacturing processes allows Alloy 825 to be used in tubular products such as injection tubing while Alloy 925 has higher strength and better machinability so it is better suited for parts such as packers. Corrosion resistance for the two alloys is similar, so corrosion data taken with Alloy 825 is applicable to Alloy 925 and vice versa.

Nickel-plated carbon steel also provides outstanding corrosion resistance as nickel is essentially inert under conditions encountered in most (if not all) GS projects. PCC used nickel-plated carbon steel in sensitive applications such as the internals of gauges.

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[2] Alloy 825 and Alloy 925 are a generic names. Incoloy 825® and Incoloy 925® are common brands of Alloy 825 and Alloy 925, respectively, for which the trademarks are owned by Special Metals Corporation.

Table A.II-1.4-1. Composition of Relevant Metals

Compiled from ANSI 2021, API 2023, and Representative Manufacturer Data Sheets;
All % are on weight basis

	Carbon Steel (L80)	Carbon Steel (H40)	13Cr (UNS S42000)	Alloy 825 (UNS N08825)	Alloy 925 (UNS N09925)	Nickel-Plated Carbon Steel
Nickel	0.25% (max)	-	0.05% (max)	38.0 - 46.0%	42.0 - 46.0%	100%
Chromium	-	-	13%	19.5 - 22.5%	19.5 - 22.5%	-
Molybdenum	-	-	-	2.5 - 3.5%	2.5 - 3.5%	-
Copper	0.35% (max)	-	-	1.5 - 3.0%	1.5 - 3.0%	-
Titanium	-	-	-	0.6 - 1.2%	1.9 - 2.4%	-
Aluminum	-	-	-	0.2% (max)	0.1 - 0.5%	-
Manganese	1.90% (max)	-	0.75%	1.0% (max)	1.0% (max)	-
Silicon	0.45% (max)	-	-	0.5% (max)	0.5% (max)	-
Niobium	-	-	-	-	0.5% (max)	-
Sulfur	0.03% (max)	0.03% (max)	-	0.03% (max)	0.03% (max)	-
Carbon	0.43% (max)	-	0.19%	0.05% (max)	0.03% (max)	-
Phosphorus	0.03% (max)	0.03% (max)	-	-	-	-
Iron	Balance	Balance	Balance	22% (min)	22% (min)	-
PREN	0	0	13	31	31	0

A.II-1.4.2. Relevant Metal Corrosion Types

Corrosion is the deterioration of a material (usually metal) by chemical or electrochemical reaction with its environment. This subsection covers metal corrosion types of potential interest for the site-specific conditions encountered at the PCC wells.

A.II-1.4.2.1. General Corrosion General corrosion (aka uniform corrosion) is the most common form of corrosion and the term is used to describe the attack of the metal substrate occurring in a manner that is evenly distributed across the surface. General corrosion rates are often expressed by loss of thickness per year, which are expressed as mils/yr in US customary units or mm/yr in SI units[3]. For perspective, Table A.II-1.4-2 shows the breakpoints utilized in the NACE Corrosion Data Survey (NACE 1985) to classify suitability of metals for specific applications.

Calculations utilizing general corrosion rates combined with other factors (e.g., design service life, evaluations of metal stresses) can be used to demonstrate the suitability of a specific metal in a specific application as shown later in Sections A.II-1.6 and A.II-1.7. However, these calculations are generally invalid when other corrosion mechanisms beyond general corrosion are present at the service conditions.

Table A.II-1.4-2. Classification of Metals By General Corrosion Rate
From: NACE 1985

Corrosion Rate		Classification
0 mils/yr to < 2 mils/yr	0 mm/yr to < 0.0508 mm/yr	Completely Resistant
2 mils/yr to < 5 mils/yr	0.0508 mm/yr to < 0.127 mm/yr	Recommended
5 mils/yr to < 20 mils/yr	0.127 mm/yr to < 0.508 mm/yr	Mild Corrosion, Suitable for Use with Increased Corrosion Allowances
20 mils/yr to < 50 mils/yr	0.0508 mm/yr to < 1.27 mm/yr	Generally Not Adequate
≥ 50 mils/yr	≥ 1.27 mm/yr	No Merit

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[3] 1 mils = 0.001 inch = 0.0254 mm

A.II-1.4.2.2. Pitting Corrosion Pitting corrosion is extremely localized corrosion characterized by random creation of small holes in the metal. Figure A.II-1.4-1 presents a photo of pitting corrosion on an engine valve and an illustration of sub-surface pore shapes. Pitting is caused by a local breakdown and non-healing of the metal passivation film that leads to an anodic oxidation reaction at the surface and a corresponding cathodic reduction reaction spread across the larger surface of the damaged passivation film. Initially the pits can be nearly invisible to the human eye, and as this type of corrosion progresses the pits can remain nearly invisible as the loss of metal expands by undercutting beneath the metal surface.

Pitting creates a loss of metal and thus contributes to the loss of mass measurements used to quantify general corrosion, however pitting is most often reported qualitatively from visual observation and quantitatively by measuring the number of pits for a given surface area. When pitting is present with general corrosion, pitting penetration rates rather than general corrosion rates usually control mechanical integrity of the metal. Currently there are no generally accepted methods for predicting pitting penetration rates, so evidence of pitting at testing conditions that are fully representative of the service conditions should disqualify the metal from further consideration. However, engineering judgement is often exercised since laboratory testing conditions are rarely fully representative of service conditions.

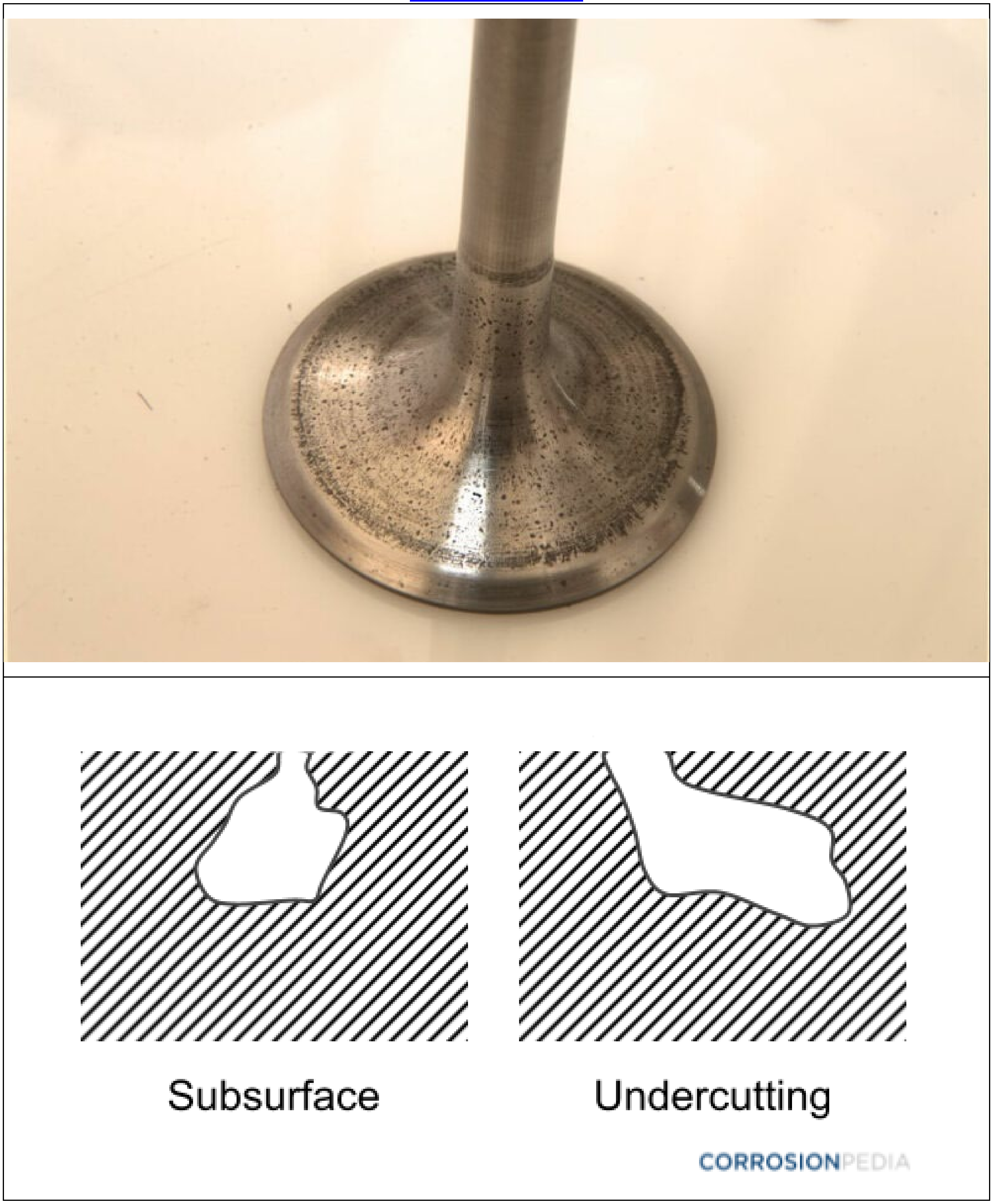
Pitting in liquid water environments is generally accelerated by the presence of chlorides and dissolved oxygen. For CRAs, the pitting resistance number (PREN) is a helpful tool for ranking resistance to pitting and crevice corrosion in aerated brines. There is not a single accepted formula to compute PREN from metal composition, but all PREN formulas are similar in form to the formula below with differences in the weighting factors for compositions:

$$PREN = Chromium,\% + 3.3(Molybdenum,\% + 0.5 * Tungsten,\%) + 16 * Nitrogen,\%$$

Craig (Craig et al. 2023) states it is generally accepted that CRAs need to have PREN ≥ 40 to be immune to pitting and crevice corrosion in aerated seawater, but there is a dearth of public data available covering the wider range of conditions of interest for GS applications especially with respect to dissolved oxygen concentrations. PREN values for 13Cr and Alloy 825/925 are 13 and 31, respectively, which does not necessarily preclude use of these materials in GS applications given the wide range of site-specific conditions encountered in the industry.

Figure A.II-1.4-1. Examples of Pitting Corrosion

From: https://www.corrosionpedia.com/how-to-effectively-recognize-prevent-and-treat-pitting-corrosion/2/6738



<u>A.II-1.4.2.3. Mesa Attack Corrosion</u> Mesa attack corrosion is another form of localized corrosion that commonly occurs when carbon or low alloy steels are exposed to a CO_2 and liquid water environment. These steels typically form a protective iron carbonate film that normally protects the underlying metal from additional corrosion. However when the protective film is damaged by high flow rates or other means, the un-protected areas corrode further while the protected areas remain intact, resulting in mesa shaped islands on the metal surface. Figure A.II-1.4-2 contains photos of mesa attack corrosion in both carbon and low alloy steels.

Figure A.II-1.4-2. Photos of Mesa Attack Corrosion
From: Nyborg and Dugstad 2003

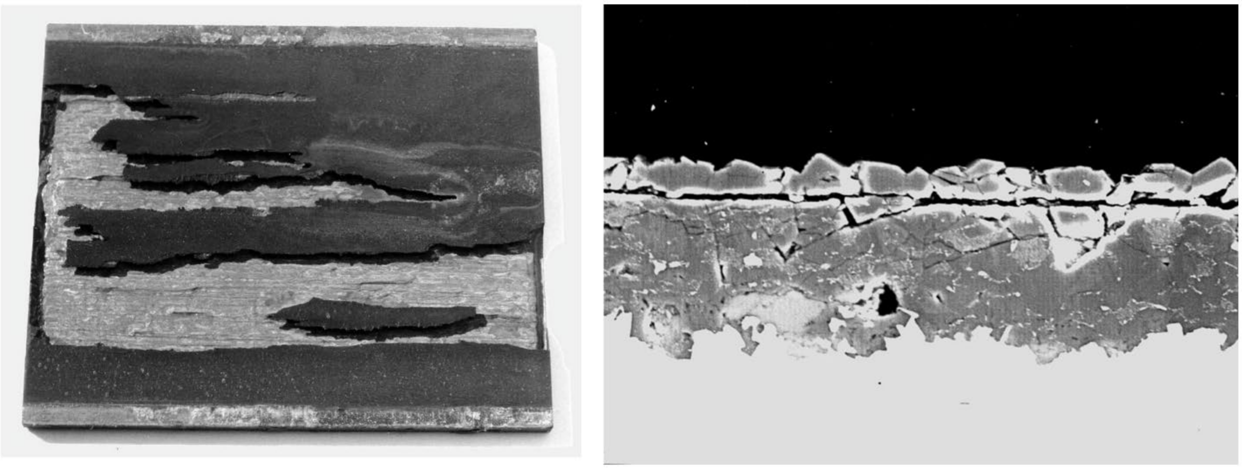


FIGURE 1. Carbon steel specimen with mesa attack. 1.2 x.

FIGURE 2. Iron carbonate corrosion film formed at 80 °C. 350 x.

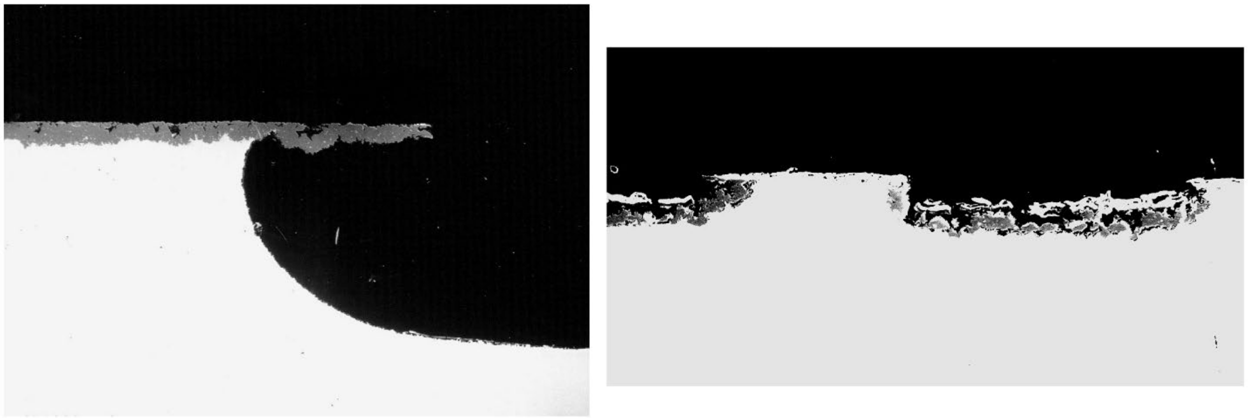


FIGURE 3. Deep mesa attack in carbon steel without chromium. 20 x.

FIGURE 4. Shallow, film-covered local attack in carbon steel with 0.5 % chromium. 50 x.

A.II-1.4.2.4. Crevice Corrosion Crevice corrosion (aka contact corrosion) occurs in tight spaces (typically a few micrometers wide) in which a stagnant solution is trapped and not renewed, which commonly occurs between metal joints. The mechanism is similar to pitting corrosion, however it is treated as a distinct phenomenon since one has to consider geometry of the crevice and other factors that lead to the differential local chemistry. The top panel of Figure A.II-1.4-3 is a cut-away of a 304L stainless steel pipe where crevice corrosion was initiated in a crevice created by lack of full penetration in an orbital weld. The bottom panel of Figure A.II-1.4-3 shows crevice corrosion underneath a 316 stainless steel washer+bolt combo used to secure the underlying 316 stainless steel part.

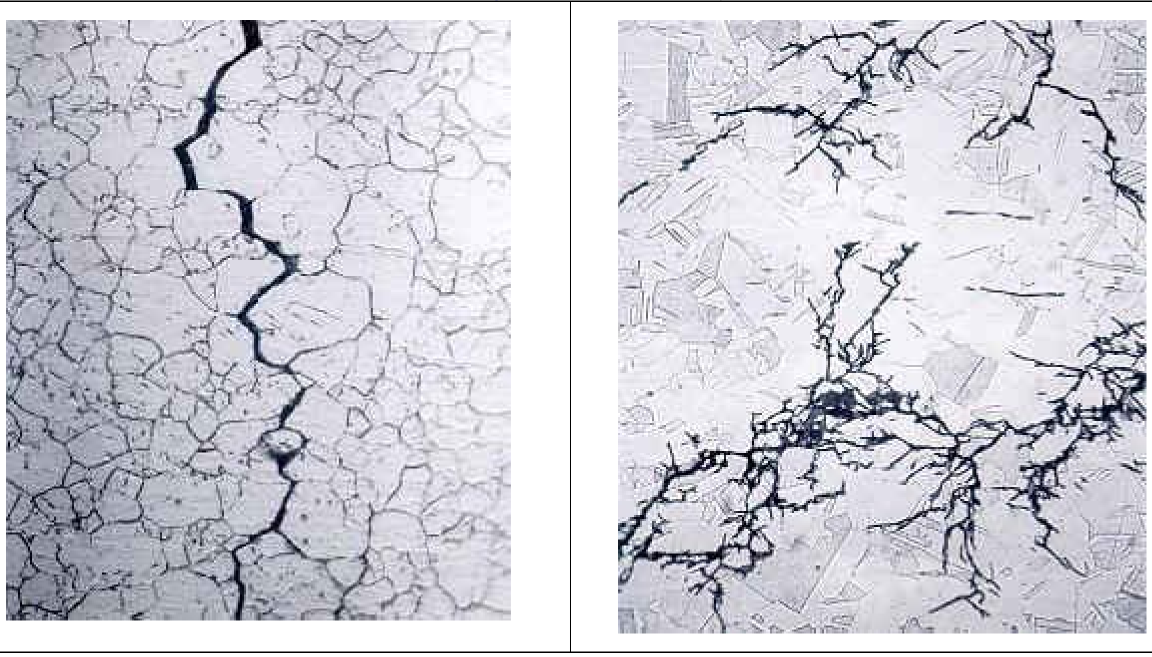
Figure A.II-1.4-3. Examples of Crevice Corrosion

From: https://www.ssina.com/education/corrosion/pitting-and-crevice-corrosion/

A.II-1.4.2.5. Stress Corrosion Cracking (SCC) The combination of tensile stress and a specific anodic corrosive environment can lead to progressive fracturing and catastrophic failure of the metal with minimal overall loss of material. The photo micrograph (500X magnification) in the left panel of Figure A.II-1.4-4 illustrates intergranular SCC of an Inconel heat exchanger tube with the crack following the grain boundaries. The photo micrograph (300X magnification) in the right panel of Figure A.II-1.4-4 illustrates chloride-induced SCC in a 316 stainless steel pipe with its characteristic multi-branched "lightning bolt" trans-granular crack pattern.

Figure A.II-1.4-4. Example Photos of Stress Corrosion Cracking

From: https://www.ampp.org/technical-research/impact/corrosion-basics/group-3/stress-corrosion-cracking ; Photos courtesy of Rimkus

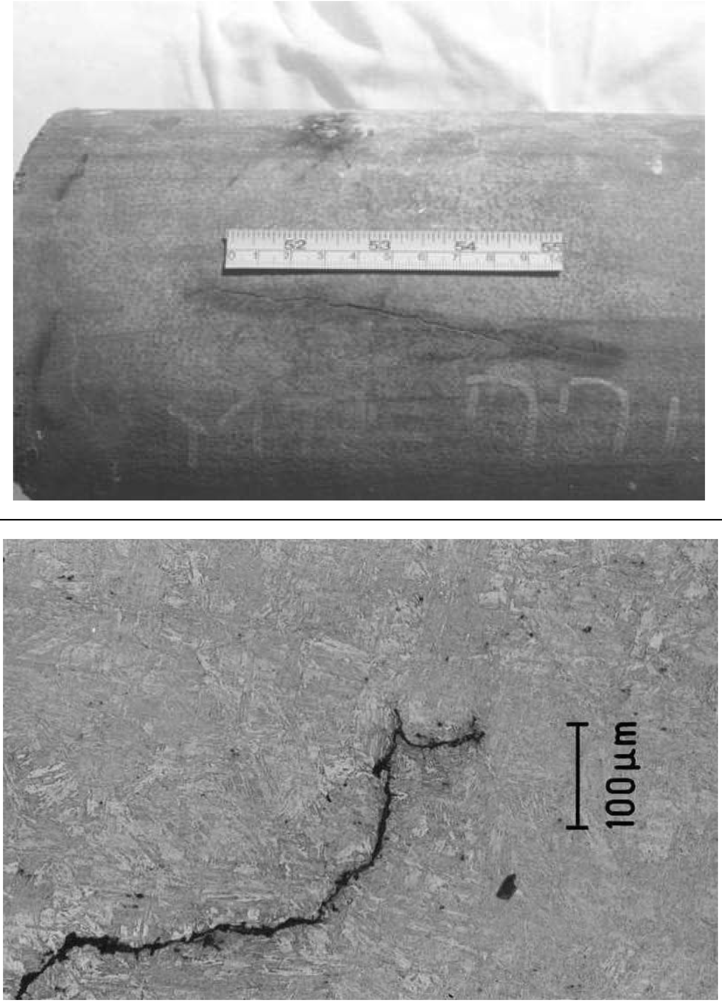


A.II-1.4.2.6. Sulfide Stress Cracking (SSC) SSC is a form of hydrogen embrittlement where spontaneous cracks appear in metal under the combined action of tensile stress and cathodic corrosion in the presence of liquid water and hydrogen sulfide (H_2S). It is often associated with welds, where atomic hydrogen derived from H_2S diffuses into the metal and causes embrittlement of the very narrow hard zones in the heat-affected zones adjacent to a weld. A crack can initiate in regions of high tensile strength (residual or applied), leading to crack propagation in a direction perpendicular to the tensile stress.

Figure A.II-1.4-5 contains photo micrographs of sulfide stress cracking in an API 5L X52 carbon steel pipeline that failed after only two weeks of service transporting sour crude oil at 1,200 psig. The upper panel shows the axial crack just beneath the ruler, with crack propagation being perpendicular to the radial stress induced by operating pressure. The lower panel is a close-up showing both trans-granular and branched cracking.

Figure A.II-1.4-5. Example Photos of Sulfide Stress Corrosion Cracking

Upper: As Received; Lower: Close-up, etched with Nital 3%; From: Masouri et al. 2008



A.II-1.4.3. Effect of Temperature, Chloride Content, and CO_2 Partial Pressure

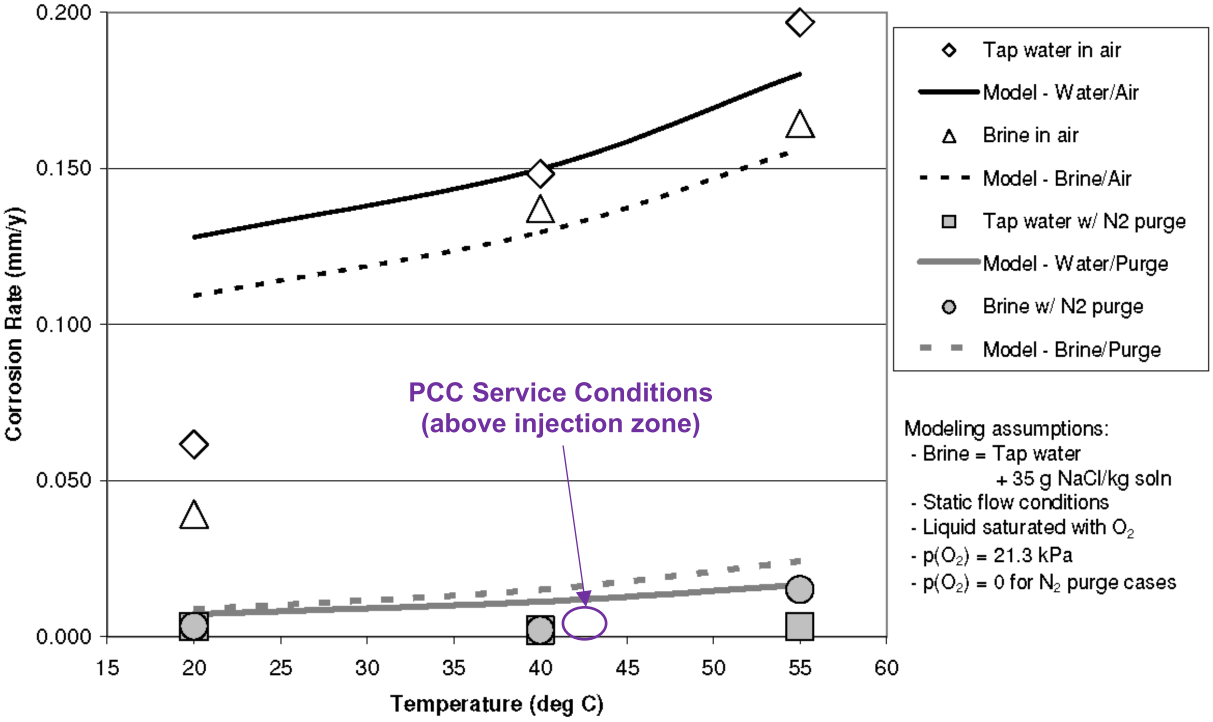
PCC determined that carbon steels are suitable metals for well construction in zones above the injection zone. The injection zone properties (temperature, formation fluid salinity, pressure) are relatively mild, which allowed PCC to utilize 13Cr for most tubulars exposed to injectate+formation fluid mixtures, with Alloy 925 and nickel-plated carbon steel reserved for key components (e.g., packers, instruments) to improve their reliability. Not all GS projects encounter the relatively mild service conditions of the PCC project. The metals used to construct the wells for each GS project should be selected using available guidelines (supplemented as needed with coupon test data) in combination with the anticipated temperature, salinity, and injection pressures for the project.

Carbon steel is suitable for use in zones above the injection zone where temperature and salinity are mild and there is an absence of oxygen and CO_2. Figure A.II-1.4-6 shows corrosion rates of a carbon steel in a static environment as a function of temperature, salinity, and p_{O2} in the headspace. The lower region of the figure presents data for the case where the headspace is purged with nitrogen (i.e., $p_{O2} \approx 0$ psia), showing a corrosion rate less than 0.4 mils/yr (0.01 mm/yr) at the PCC service conditions for temperature and salinity. The upper region of the figure presents data for the case where the headspace contains atmospheric air (i.e., $p_{O2} \approx 3$ psia), displaying corrosion rates that are an order-of-magnitude higher than rates when the headspace is purged with nitrogen. In the late 1950s, the American Petroleum Institute provided a rule-of-thumb criteria for corrosion of carbon steels exposed to a CO_2+liquid water environment (Paul et al. 2012). This rule suggested corrosion rates > 39 mils/yr (> 1 mm/yr) occur when $p_{CO2} >$ 29 psia (> 2 bar), whereas corrosion rates < 3.9 mils/yr (< 0.1 mm/yr) occur when $p_{CO2} < 7$ psia (< 0.5 bar). More recently, Figure A.II-4.7 from Zeng (Zeng et al. 2016) shows corrosion rates of carbon steel as a function of salinity at room temperature in a CO_2 saturated solution for a 100 hr test, showing a corrosion rate of 39-78 mils/yr (1-2 mm/yr) depending upon cathode conditions. Together, these studies show carbon steel is not well suited for use in saline environments containing dissolved oxygen or CO_2, which is why PCC restricted its use to zones above the injection zone.

An initial evaluation on the suitability of various CRAs for PCC service conditions can be made using the general CRA service guidelines published by the Nickel Institute (Craig and Smith 2011). Figure A.II-1.4-8 displays the Nickel Institute guideline on the safe upper temperature limit of 13Cr as a function of chloride content and CO_2 partial pressure (p_{CO2}) in the absence of oxygen, hydrogen sulfide, and other impurities. Extrapolating the chart to the PCC conditions of $p_{CO2} = 2{,}161$ psia and salinity of 24,900 mg/L as TDS (~ 41.5 g/l NaCl) results in a safe upper temperature limit of ~284 °F (~140 °C), which is far above the expected injection zone temperature of 110 °F (43 °C), thus 13Cr appears to be provisionally suitable for the CSS #1 and MW #1 services pending evaluation of other factors.

Figure A.II-1.4-6. Carbon Steel Corrosion – Impact of T, Salinity, and O₂

Demonstrates carbon steel is suitable above injection zone; From: Grise and Saldanda 2008

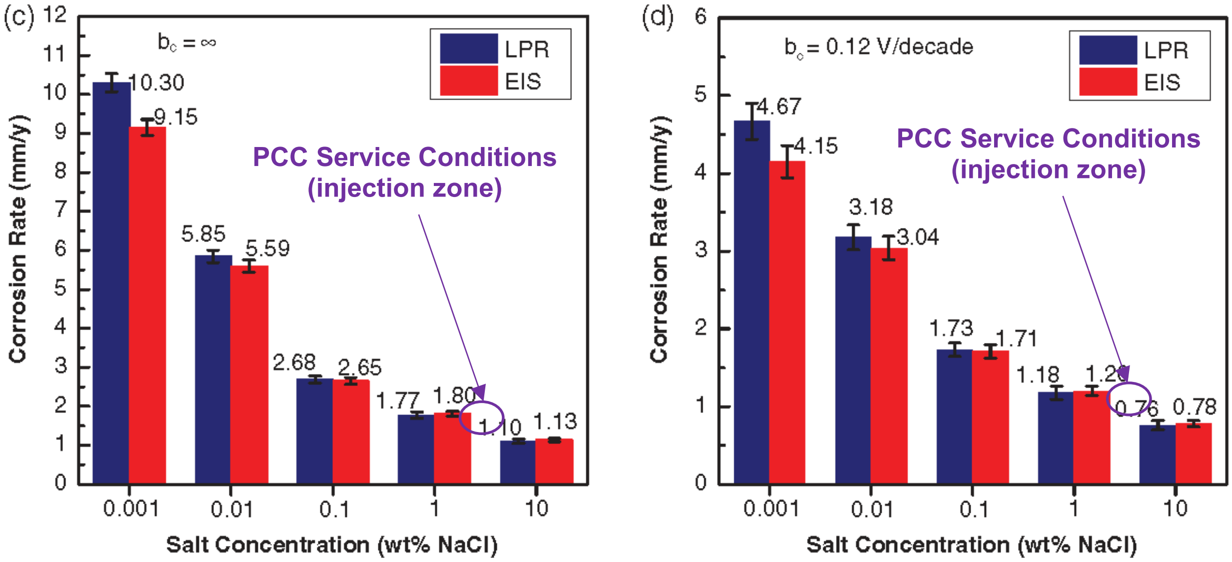


PCC Service Conditions (above injection zone)

Modeling assumptions:
- Brine = Tap water + 35 g NaCl/kg soln
- Static flow conditions
- Liquid saturated with O_2
- $p(O_2) = 21.3$ kPa
- $p(O_2) = 0$ for N_2 purge cases

Figure A.II-1.4-7. Carbon Steel Corrosion – Impact of Salinity at CO₂ Saturation

Left: Cathodic kinetics under diffusion control; Right: Cathodic kinetics under activation control; Demonstrates carbon steel is unsuitable for use in the injection zone; From: Zeng et al. 2016

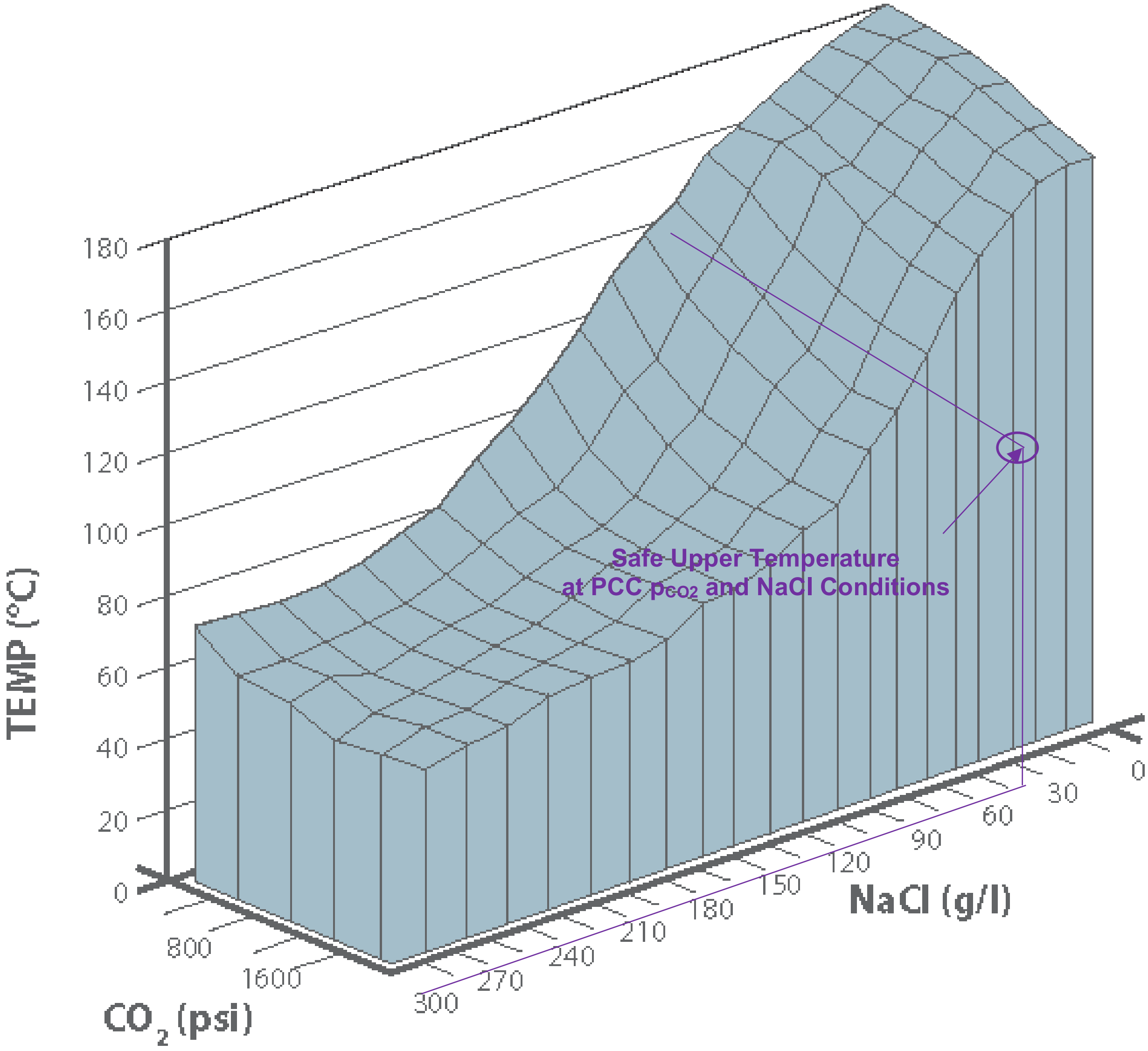


PCC Service Conditions (injection zone)

PCC Service Conditions (injection zone)

Figure A.II-1.4-8. Service Guideline for 13Cr

From: Craig and Smith 2011



Figures A.II-1.4-9a through A.II-1.4-9c summarize several published laboratory test results using 13Cr coupons at conditions loosely similar to the PCC service conditions:

- Pfennig et al. 2021: Figure A.II-1.4-9a shows corrosion and pitting rates for static testing of 13Cr coupons exposed for 8,000 hours to CO_2 partial pressure of 1,450 psia (100 bar) and 140 °F (60 °C) in a simulated brine with salinity of 59,000 ppm as chlorides. The simulated brine was pH = 9.2 prior to CO_2 exposure and pH = 5.2 – 5.6 after CO_2 exposure. The corrosion rates fell over time, reaching 0.35 mils/yr (0.009 mm/yr) at 8,000 hour for the portion of the coupon exposed to the aqueous layer, and 0.04 mils/yr (0.001 mm/yr) at 8,000 hours for the portion of the coupon exposed to the supercritical CO_2 layer. Pitting was observed after 2,000 hours of testing.
- Hassani et al. 2014: The left panel of Figure A.II-1.4-9b shows corrosion rates from 48-hr testing of 13Cr coupons exposed to CO_2 partial pressure of 1,160 psia (80 bar) and 140 °F (60 °C) in a simulated brine with salinity of 42,809 mg/L as chlorides. The simulated brine was pH = 6.3 prior to CO_2 exposure and pH = 3.2 after CO_2 exposure, thus testing conditions are materially more acidic than the PCC service conditions. The results show an initial 13Cr corrosion rate of 16 mils/yr (0.4 mm/yr) before stabilizing at an acceptable corrosion rate of 4 mils/yr (0.1 mm/yr). The right panel clearly shows the polishing marks on the surface, indicating the formation of a stable passivation film.
- Kamo et al. 2023: Figure A.II-1.4-9c summarizes test results for 13Cr coupons and two modified versions of 13Cr with Nickel and Molybdenum additions, where the tests were conducted for 168 hr at 19 MPa (2,756 psia) and 60 °C (140 °F) at two different salinity levels using NaCl solutions. No pH values were reported either before or after CO_2 exposure. The test conducted at 18,200 ppm Cl^- showed an acceptable corrosion rate of 3.0 mils/yr (0.075 mm/yr) with no observable pitting, while the test conducted at 121,200 ppm Cl^- showed an excessive corrosion rate of 15.0 mils/yr (0.381 mm/yr) with observable pitting.

The PCC service conditions are most closely aligned with the test conditions of Pfennig, which yielded low general corrosion rates but found pitting occurred after 2,000 hours of testing. It is unclear whether this pitting is due to the relatively high salinity of the Pfennig test conditions (nearly 5X salinity of PCC service conditions) and/or the potential for inadvertent oxygen contamination of the test fluids (i.e., the original source papers [Pfennig and Bassler 2009, Pfennig and Kranzmann 2011, Pfennig and Kranzmann 2012] provide insufficient description of degassing procedures to assure dissolve oxygen was adequately removed from the simulated brine, which was changed out every 700 hours). The short-term test by Hassani and the short-term/low-salinity test by Kamo both suggest that 13Cr pitting is not a concern at the PCC service conditions. None of the cited literature test procedures account for the cement sheath on the exterior of the casing, which provides additional corrosion protection of the metal.

Figure A.II-1.4-9a. Relevant 13Cr Corrosion Laboratory Studies

From Pfennig et al. 2021; Test Conditions: P = 1,450 psia (100 bar), T = 140 °F (60 °C), Simulated Brine with Salinity = 59,000 ppm as Chlorides, final pH = 5.2 – 5.6. Top: Corrosion rates for exposure to aqueous phase or supercritical CO_2 phase, Bottom: Pitting measurements

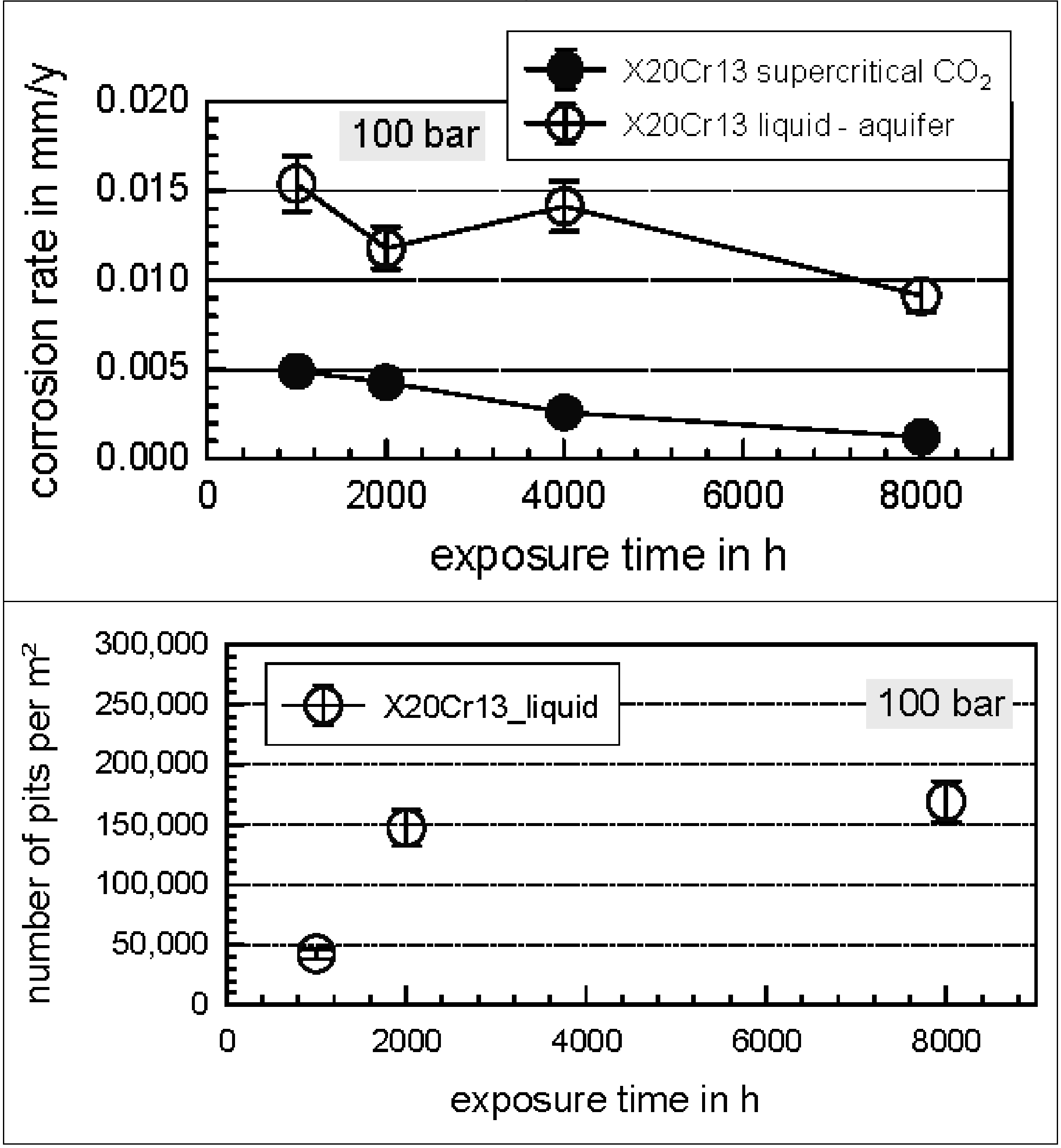


Figure A.II-1.4-9b. Relevant 13Cr Corrosion Laboratory Studies

From Hassani et al. 2014; Test Conditions: P = 1,160 psia (80 bar), T = 140 °F (60 °C), Simulated Brine with Salinity = 42,809 mg/L as chlorides, pH = 6.3 prior to CO_2 exposure

Left: 13Cr Corrosion Rates (blue); Right: SEM image and EDS Spectra of the 13Cr Coupon After Testing

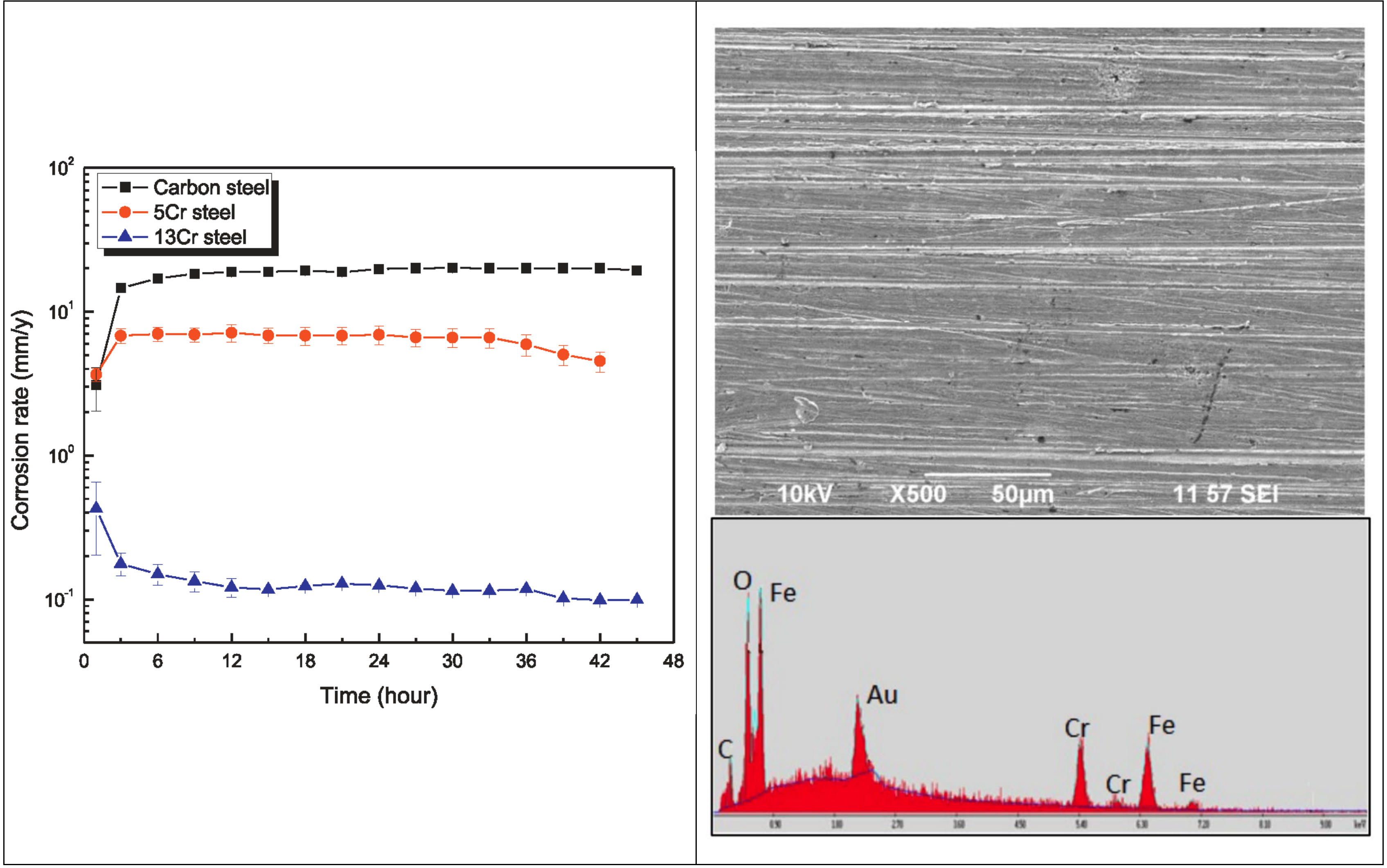


Figure A.II-1.4-9c. Relevant 13Cr Corrosion Laboratory Studies

From: Kamo et al. 2023; All Tests Conducted for 168 hr at 2,756 psia (19 MPa) and 140 °F (60 °C) at Two NaCl Concentrations;
Left: Corrosion Rates for 13Cr and two modified 13Cr with added Nickel and Molybdenum;
Upper Right: Coupon Photos After Testing at 18,200 ppm Cl$^-$; Lower Right: Coupon Photos after Testing at 121,200 ppm Cl$^-$

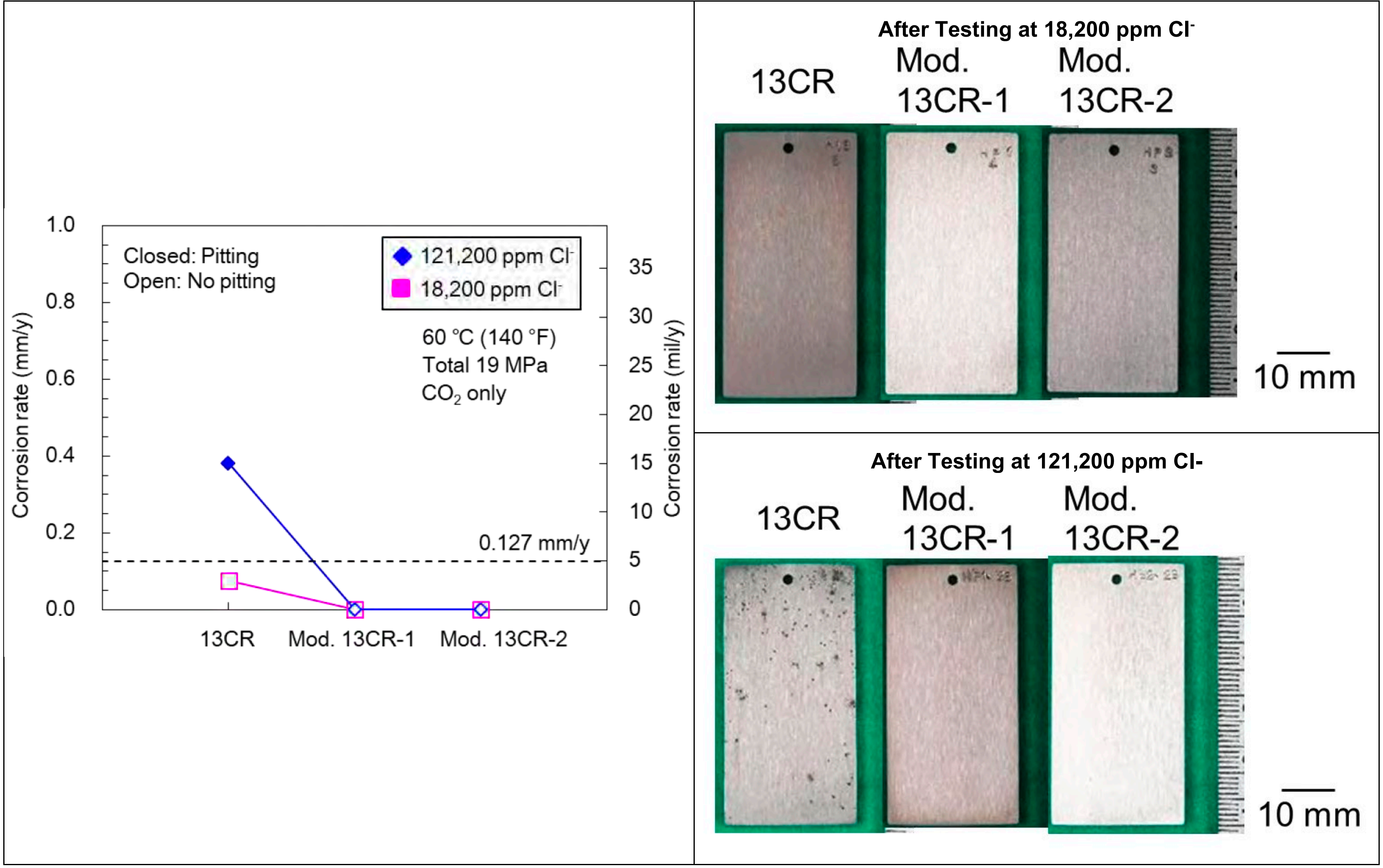
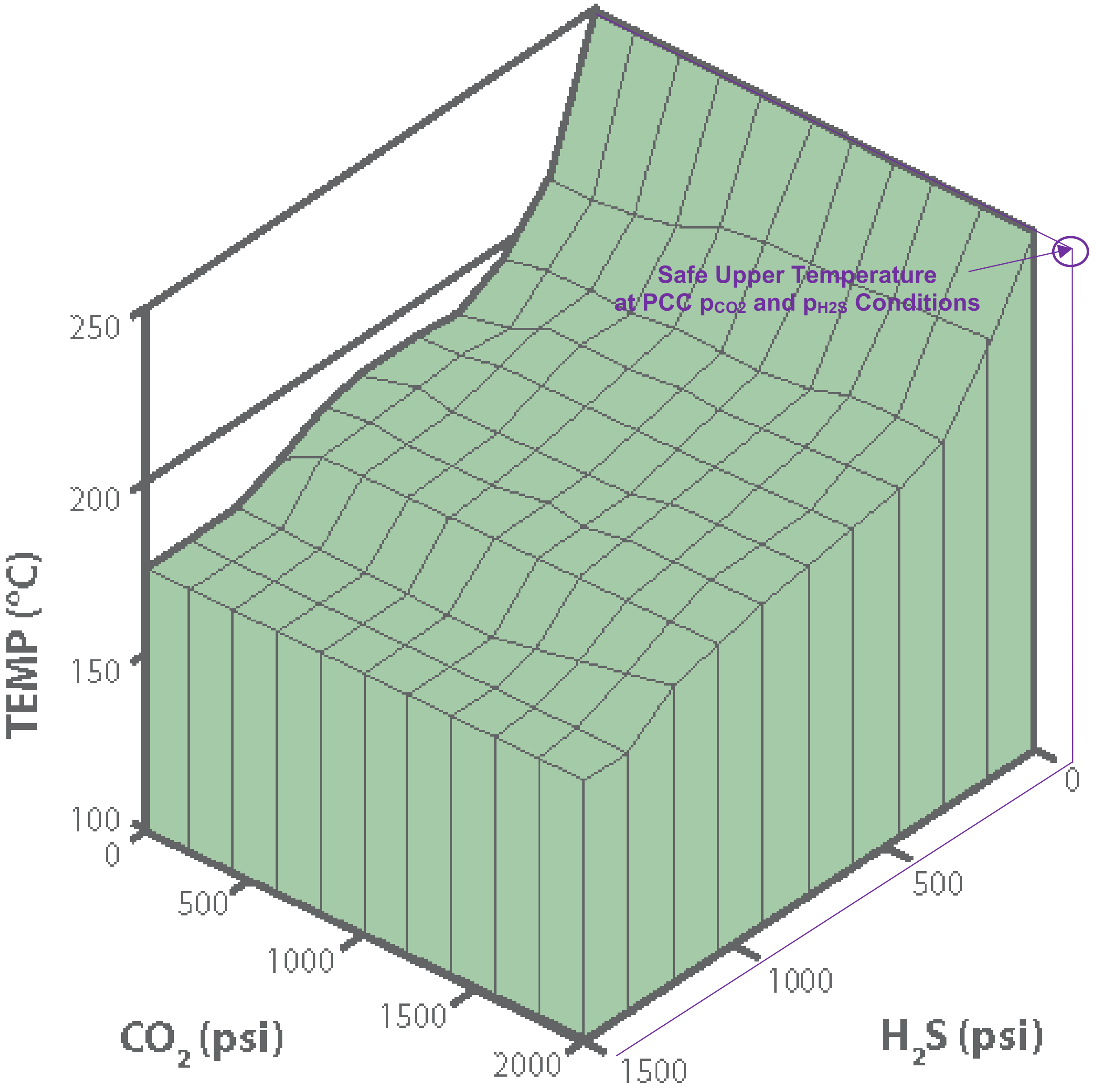


Figure A.II-1.4-10 displays the Nickel Institute guideline on the safe upper temperature limit of Alloy 825 as a function of p_{CO2} and p_{H2S} in the absence of elemental sulfur, where corrosion rates ≤ 2 mils/yr (≤0.05 mm/yr) and no SSC or SCC are expected. Per the Nickel Institute, the service window for this alloy is defined primarily by temperature and p_{H2S} since the metal is generally immune to changes in p_{CO2} and high salinity levels (>100,000 ppm as chloride). Extrapolating the chart to the PCC conditions of p_{CO2} = 2,161 psia and p_{H2S} = 0 psia results in a safe upper temperature limit of ~482 °F (~250 °C), which is far above the expected injection zone temperature of 110 °F (43 °C), thus Alloy 825/925 appears to be provisionally suitable for the CSS #1 and MW #1 services pending evaluation of other factors.

Figure A.II-1.4-10. Service Guideline for Alloy 825

From: Craig and Smith 2011



A.II-1.4.4. Effect of pH

pH is a key parameter that influences the corrosion resistance of metals. pH is meaningful when a liquid water phase is present; pH is not meaningful in the absence of a liquid water phase since there are no ions present. The discussion shows that pH is affected by the presence of acid gases (e.g., CO_2 with liquid water), ions provided by the formation fluid, and ions provided by the reservoir rock. Evidence is provided to support the use of carbon steel and 13Cr for construction of the injection and deep monitoring wells, with carbon steel generally suitable for well components not exposed to CO_2+liquid water mixtures and 13Cr generally suitable for well components exposed to CO_2+liquid water mixtures. Alloy 925 and nickel-plated carbon steel are even more resistant to pH induced corrosion than 13Cr, so little data on pH resistance for these two metals are provided here since the decision to utilize these metals is driven by other considerations (e.g., reliability) rather than pH-induced corrosion resistance.

A.II-1.4.4.1. Background

pH is a meaningful parameter when a liquid water phase is present, where pH is approximated by the concentration of hydrogen cations (H^+) in an aqueous solution using the formula:

$$pH = -\log_{10}[H^+]$$

pH values range from 0-7 for acidic conditions, 7 at neutral, and 7-14 for alkaline conditions. pH is a meaningful parameter when casing and other well components are exposed to formation fluids or injectate+formation fluid mixtures.

CO_2 in the presence of liquid water generates hydrogen cations plus bicarbonate (HCO_3^-) and carbonate (CO_3^{2-}) anions via the dissociation reactions:

CO_2 Dissociation Reactions: $CO_2 + H_2O \rightleftharpoons H^+ + HCO_3^- \rightleftharpoons 2H^+ + CO_3^{2-}$

The exact position of the CO_2 dissociation reactions depends upon the presence or absence of other cations and anions in the liquid water phase, temperature, and other parameters.

Field measurements taken from CSS #1 while in stratigraphic well service found pH = 6.8 for the injection zone formation fluid prior to CO_2 injection, and pH = 7.1 – 7.9 for formation fluids in zones other than the injection zone – See Section A.I.9.2 of Site Characterization. The PCC computational model incorporates an equilibrium thermodynamic model to predict pH = 4.5 – 5.5 within the CO_2 plume of the injection zone after the start of Injection - See Appendix B.1 in the Area of Review and Corrective Action Plan.

A.II-1.4.4.2. General Case: pH of Supercritical CO_2+Formation Fluid+Rock Mixtures

This general case is of interest since it applies to bulk regions of the injection zone within the CO_2 plume, in particular the near wellbore environment of the injection well when there is sufficient water present for a meaningful pH and the near wellbore environment of the deep zone monitoring well. The near-wellbore environment of the injection well far away from the perforation intervals should always have sufficient water for a meaningful pH. This attachment makes the simplifying assumption to ignore the impact on pH of the cement sheath around the exterior of the casing, so pH in this region is essentially the same as the pH in the bulk regions of the CO_2 plume. However, the near-wellbore environment at the injection well perforation intervals is quite different and will vary over time. This region will desiccate during the Injection period since the injectate flushes all but the irreducible water out of the rock into the bulk region of the reservoir. The irreducible water that remains is inaccessible and not in direct contact with the casing, thus there is not a meaningful pH at the injection well perforations during the Injection period. Generally over time, formation water returns to the injection well perforation intervals during the Post Injection Site Care (PISC) period, re-establishing a pH at the perforation intervals that is close to the pH of bulk regions within the CO_2 plume.

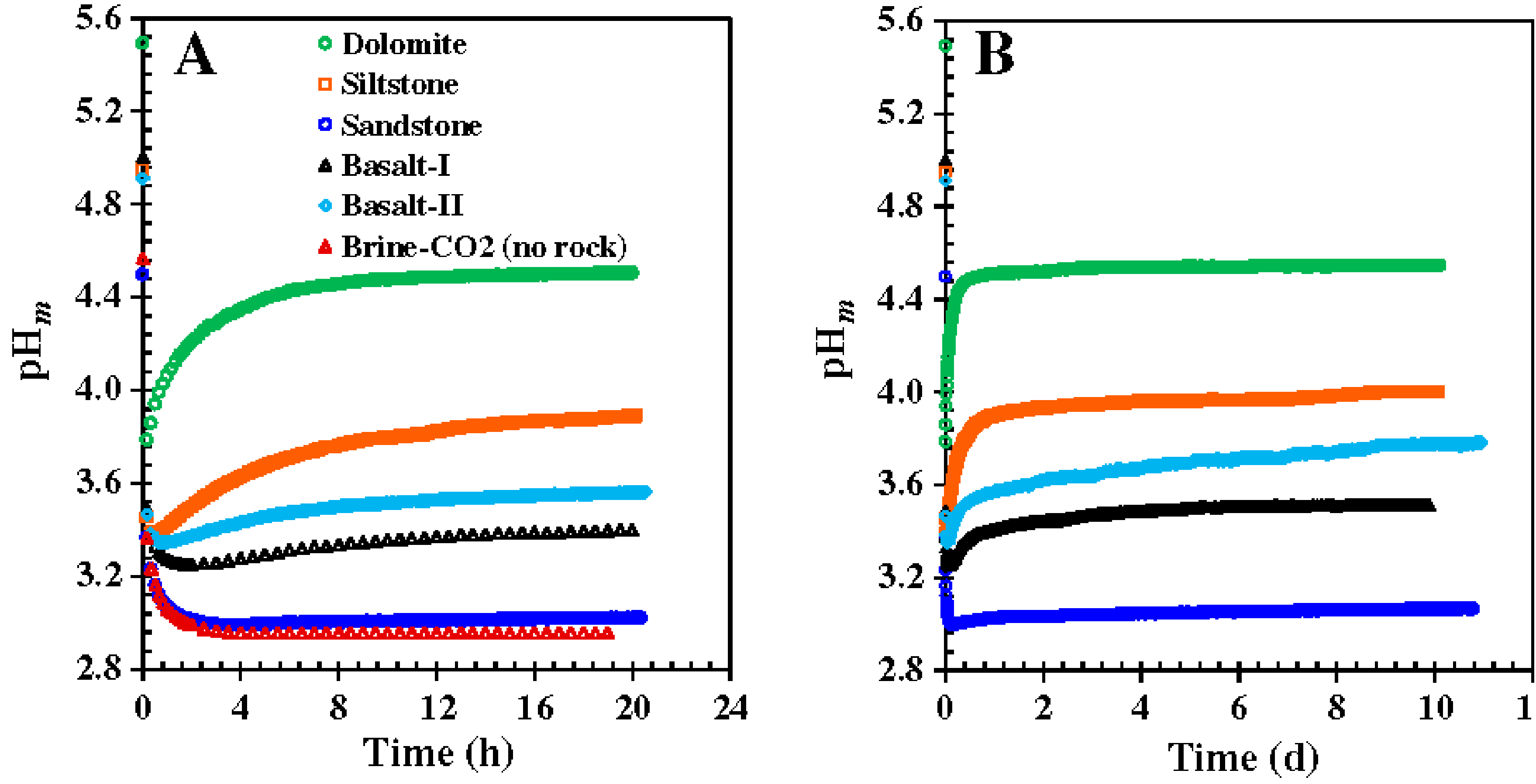
The pH of an aqueous solution containing dissolved CO_2 is set by the types and concentrations of ions present in the water phase. The source of these ions can be from injectate acid gas components (e.g., CO_2 dissolves in liquid water and dissociates into hydrogen cations and bicarbonate/carbonate anions), from the native formation fluid (e.g., salinity of formation fluid contributes sodium cations, chloride anions, many other cations and anions), and dissolution/precipitation from the formation rock (e.g., dolomite is a source for magnesium, calcium, and bicarbonate/carbonate ions). Carbonic acid is a weak di-protic acid ($pK_{a1} \approx 6.4$, $pK_{a2} \approx 9.9$) where the actual pKa values for the first and second dissociations are functions of temperature, ionic strength, identity of the ions in solution, and other factors. While the CO_2 dissociation reactions do tend to lower pH within the CO_2 plume, other ion sources (formation fluid, rock, and non-CO_2 acid gases in the injectate) can have material impact on the pH of the injection zone, so detailed pH calculations need to account for these other ion sources.

Figure A.II-1.4-11 presents laboratory results by Shao (Shao et al. 2013) on pH measurements for CO_2/brine/rock mixtures. The asymptotic pH values ranged from 3.0 to 4.5 depending upon rock type, showing that rock type has a material impact on pH within a CO_2 plume. The measurements were made using a spectrophotometric method. The source of materials for CO_2 and synthetic brine were the same across all runs, only the rock type varied. Pressure, temperature, and initial salinity of the brine were also constant across all runs. In all cases, the pH reached its asymptotic value within ~8 hours and stayed constant over the remaining 10-11 days.

The Shao experimental results qualitatively validate the pH predictions of the PCC computational model. The Shao measurements for dolomite rock found an asymptotic pH = 4.5, which agrees well with the computational model prediction of pH = 4.5 – 5.5 for regions within the CO_2 plume with dolomite rock and sufficient water for a meaningful pH. The small difference in pH values is likely due to differences in pressure, temperature, salinity, and rock properties between the experimental and PCC service conditions.

Figure A.II-1.4-11. Laboratory pH Measurements of Supercritical CO_2/Brine/Rock Mixtures

Top: Spectrophotometric pH in Batch Pressure Vessels, Pressure = 1,470 psia (100 atm), Temperature = 167 °F (75 °C), High-Purity CO_2 from Cylinders, Synthetic Brine from NaCl with Salinity = 58,000 g/L as TDS; Bottom: Rock Properties; From Shao et al. 2013



Formation	Rock type	Location	Depth (feet)	Particle size (mm)	BET surface area (m^2/g)	TOC (mg/g)	Crystalline components[a]
Grand Ronde Basalt	Basalt	Wallula, WA	2730	0.50–1.00	12.9	0.07	Andesine (45%) Anorthite (15%) Augite (40%)
Grand Ronde Basalt	Basalt	Wallula, WA	2730	0.10–.25	13.2	0.07	Andesine (45%) Anorthite (15%) Augite (40%)
Bass Island	Carbonate	Otsego County, Gaylord, MI	3472	0.50–1.00	0.40	–	Dolomite (100%)
Eau Claire	Sandstone	Illinois Basin, IL/IN/KY	3866	0.25–0.50	0.12	–	Quartz (80%) Microcline (20%)
Eau Claire	Siltstone	Illinois Basin, IL/IN/KY	3809	0.50–1.00	4.70	–	Quartz (58%) Fluorapatite (40%) Dolomite (<1%) Pyrite (<1%).

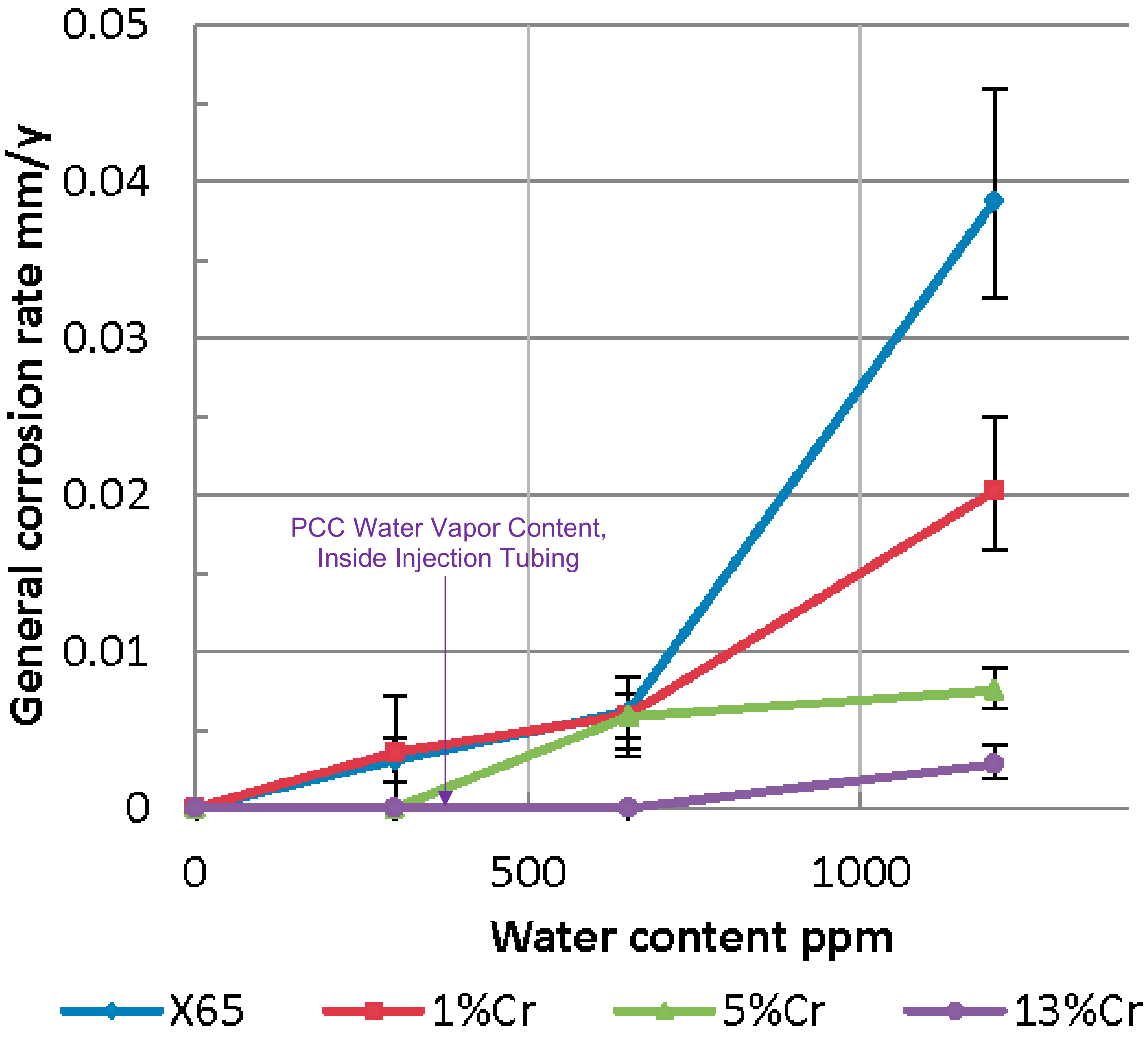
–: below detection limit.
[a] Based on semi-quantitative XRD analysis.

A.II-1.4.4.3. Special Case 1: pH of Supercritical CO_2 Undersaturated with Water Vapor

This case is of interest since it applies to the interior of the wellhead for the injection well and the interior of the tubing for the injection well. The injectate stream is purposely dehydrated during the upstream compression steps to prevent the formation of a liquid water phase in the pipeline, wellhead, and injection tubing under normal operating conditions. pH is not a meaningful parameter at these locations since the injectate has insufficient water content to form a liquid phase. Figure A.II-1.4-12 shows general corrosion rates for carbon steel (X65) and 13Cr coupons exposed for 48-hr to CO_2 at 1,160 psia (8 MPa) and 95 °F (35 °C) and various under-saturated water vapor concentrations. Reported carbon steel and 13Cr corrosion rates are 1.2 mils/yr (0.03 mm/yr) and 0 mils/yr (0 mm/yr), respectively, at the PCC injectate water vapor concentration of < 400 ppm.

Figure A.II-1.4-12. Lab Testing of Coupons in CO_2 + Under-Saturated Water Vapor

From: Hua et al. 2016; Test Conditions: 48-hr, 1,160 psia (8 MPa), 95 °F (35 °C)

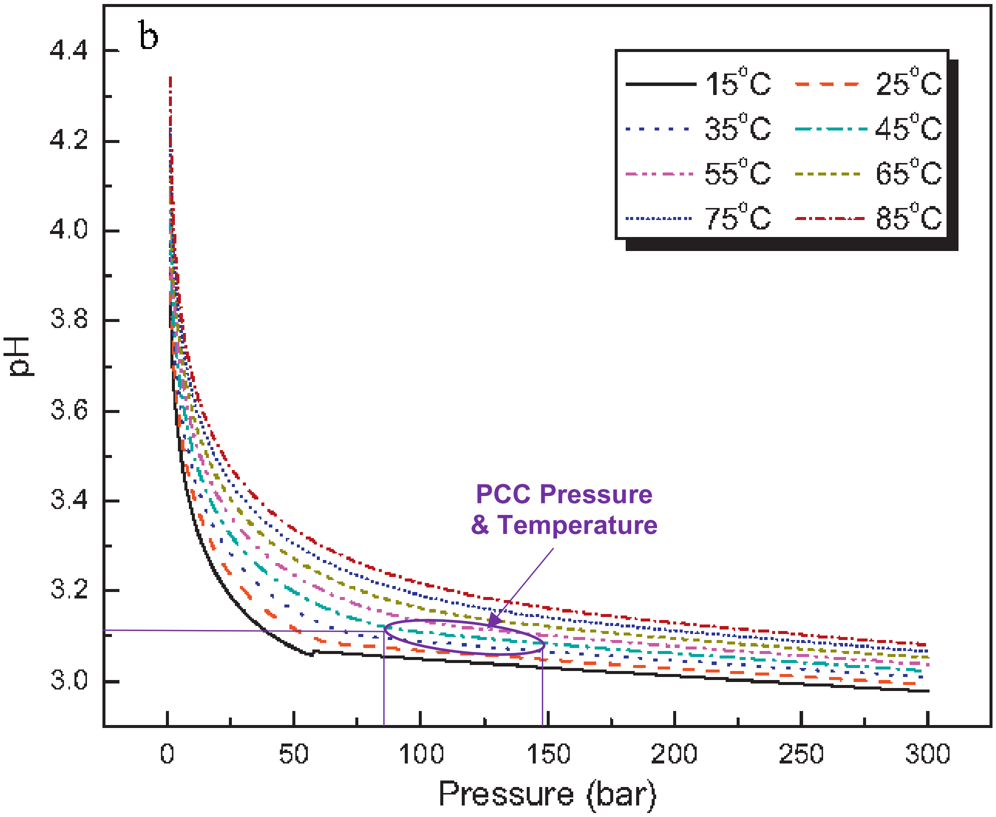


A.II-1.4.4.4. Special Case 2: pH of Supercritical CO_2 + Pure Liquid Water

This special case is not of interest under the PCC service conditions, but is discussed here since it is raised as a concern in the literature. General articles on selection of materials for GS projects often raise the potential for precipitation of liquid water from the injectate, which could lead to excessive corrosion in the pipeline, injection well wellhead, and injection tubing. Figure A.II-1.4-13 shows the pH of any condensate that formed would be quite low (pH = 3.1 at PCC service conditions), which is why PureField purposely dehydrates the CO_2 in the upstream compression steps to avoid the need for low-pH resistant metals to convey the injectate.

This special case also applies to the hypothesis offered by Craig (Craig et al. 2023) that pH in the near-wellbore environment of an injection well approaches the pH of pure CO_2+water mixtures, leading to a conclusion that injection zone casing for injection wells in all GS projects should have corrosion resistance down to pH ≈ 3 (or lower). PCC does not believe the hypothesis is well founded; Craig ignores the impact of formation fluid and rock in the analysis, does not provide experimental evidence to support the hypothesis, and does not provide a rate-based mass transfer model with kinetics that supports the hypothesis. Rather, PCC selected materials based on the position that pH in the near-wellbore environment of the injection well is either not meaningful (due to lack of liquid water) or is equal to the pH within the bulk CO_2 plume, as explained earlier in Section A.II-1.4.4.2.

Figure A.II-1.4-13. pH as Function of Pressure for CO_2+Liquid Water
Pure Components (i.e., no ions from formation fluid or rock); From: Choi and Nesic 2011



A.II-1.4.4.5. Application Domain Maps for Metal Selection

CO_2 corrosion (aka sweet corrosion) can occur when steels are exposed to CO_2 and liquid water, promoting the following reaction between steel and the liquid aqueous phase:

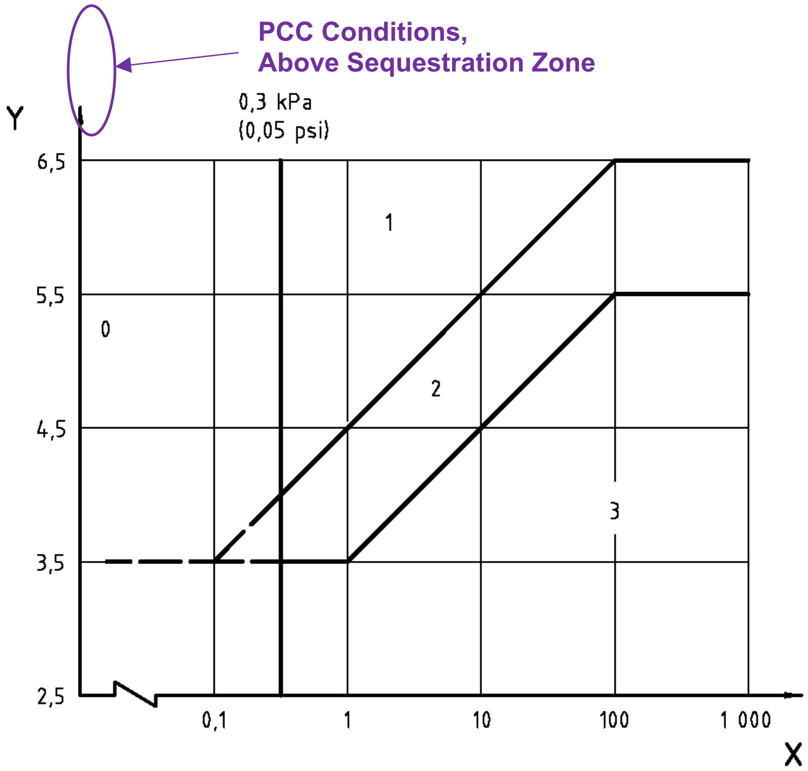
CO_2 Corrosion: $CO_2 + H_2O + Fe \rightarrow FeCO_3 + H_2$

CO_2 corrosion usually manifests as general, pitting, and/or mesa attack corrosion with rates influenced by temperature, pH, steel composition, and the degree of protection provided by the iron carbonate corrosion film (Popoola et al. 2013, Nyborg and Dugstad 2003).

PCC selected carbon steel for the conductor and surface casing strings for CSS #1 and MW #1, and carbon steel for the long string of MW #1 far above the injection zone where no exposure to injectate+formation fluid mixtures is expected. Carbon steel has been successfully used for decades to construct well casings in the oil & gas industry. Figure A.II-1.4-14 is an application domain map for carbon steel in a CO_2-free environment as a function of H_2S exposure. Region 0 indicates where carbon steel is suitable, which is bounded on the low end by pH = 3.5 and H_2S partial pressure (p_{H2S}) < 0.3 kPa (0.05 psia). Steels with higher resistance to sulfide stress corrosion are required outside Region 0. The purple highlighted region shows PCC's use of carbon steel falls within the application guideline for the upper casing strings in both CSS #1 and MW #1 where little exposure to CO_2 or H_2S is anticipated.

Figure A.II-1.4-14. Application Domain Map for Carbon Steel

From: ANSI 2021



Key

X	H_2S partial pressure, kPa
Y	*in situ* pH
0	Region 0
1	SSC Region 1
2	SSC Region 2
3	SSC Region 3

In defining the severity of the H_2S-containing environment, the possibility of exposure to unbuffered condensed aqueous phases of low pH during upset operating conditions or downtime, or to acids used for well stimulation and/or the backflow of stimulation acid, after reaction should be considered.

NOTE 1 The discontinuities in the figure below 0,3 kPa (0,05 psi) and above 1 MPa (150 psi) partial pressure H_2S reflect uncertainty with respect to the measurement of H_2S partial pressure (low H_2S) and steel's performance outside these limits (both low and high H_2S).

NOTE 2 Guidance on the calculation of H_2S partial pressure is given in Annex C.

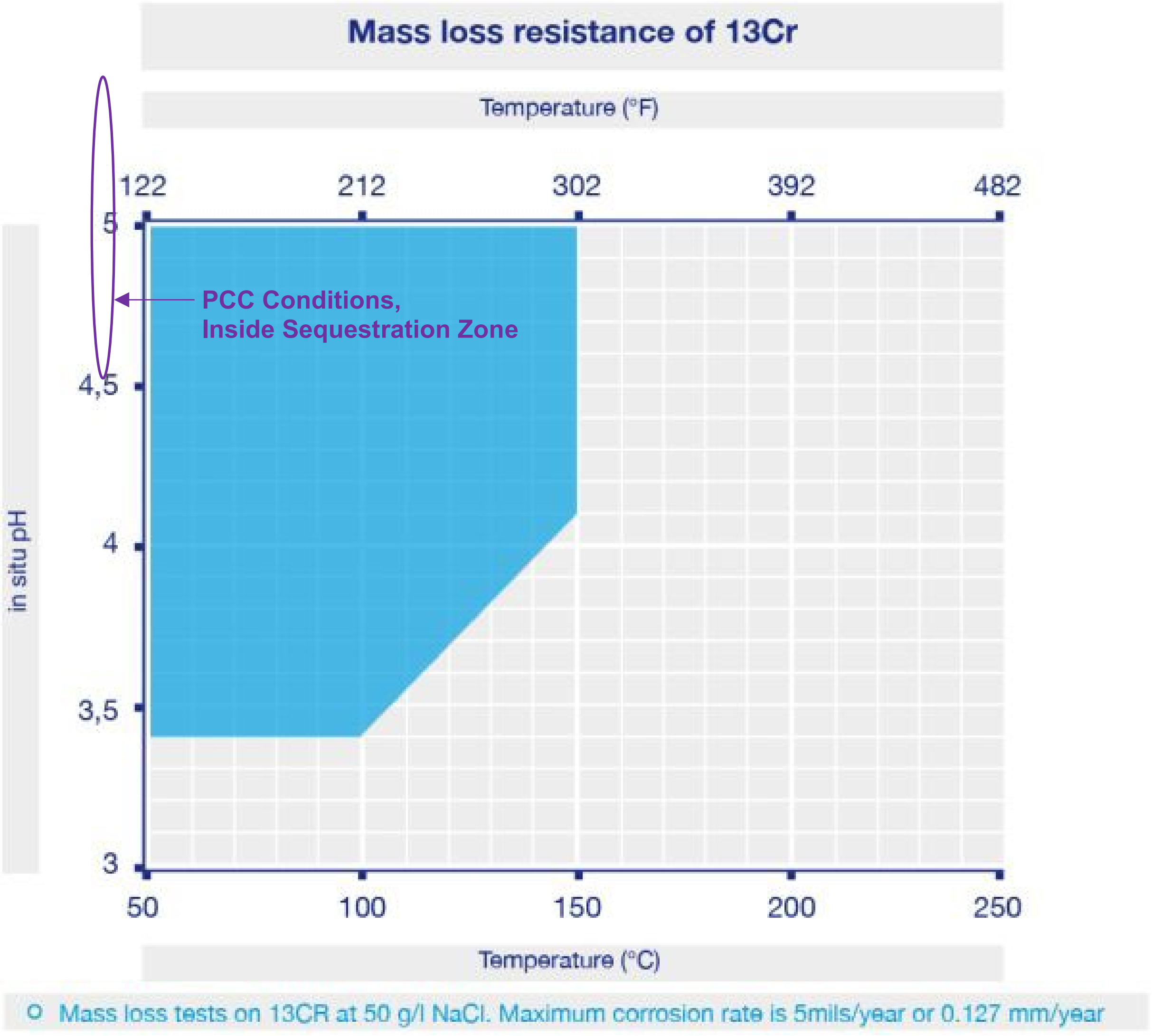
NOTE 3 Guidance on the calculation of pH is given in Annex D.

Figure 1 — Regions of environmental severity with respect to SSC of carbon and low alloy steels

Figure A.II-1.4-15 is an application domain map for 13Cr as published by Vallourec – a leading supplier of casing, tubing, and connectors to the oil & gas and GS industries. Extrapolation to the PCC injection zone service conditions of 110 °F (43 °C) and pH of 4.5-5.5 provisionally supports the selection of 13Cr in liquid water contact applications for both CSS #1 and MW #1, pending further evaluation of other factors.

Figure A.II-1.4-15. Application Domain Map for 13Cr

From: Vallourec 2024



A.II-1.4.5. Effect of Stream Contaminants

A.II-1.4.5.1. Hydrogen Sulfide

Fuel ethanol production generates a CO_2-rich offgas that can be easily captured and upgraded into suitable injectate for geologic storage projects. The H_2S concentration of injectates derived from this source can vary widely; it is site dependent and is a function of the mill type, yeast strain, and CO_2 processing approach as illustrated in Figure A.II-1.4-16. The color coding in the figure is based on the upper suitability limit for use of 13Cr in a mildly sour environment, which the application guideline presented later in Figure A.II-1.4-17 shows is a hydrogen sulfide partial pressure $p_{H2S} = 0.15$ psia for temperatures below 270 °F (132 °C). Relating this to the injectate mole fraction of H_2S (y_{H2S}, in ppmv) requires knowledge of the injection pressure:

$$y_{H2S}, ppm = \left(\frac{p_{H2S}}{P_{Injection}}\right) 1x10^6$$

$$40\ ppm = \left(\frac{0.15\ psia}{3{,}750\ psia}\right) 1x10^6$$

Using a "typical" injection pressure of 3,750 psia for the GS industry results in a maximum allowable $y_{H2S} = 40$ ppmv in the injectate (i.e., upper limit of yellow color code), and dividing that in half gives the $y_{H2S} = 20$ ppmv upper limit of the green color code in Figure A.II-1.4-16.

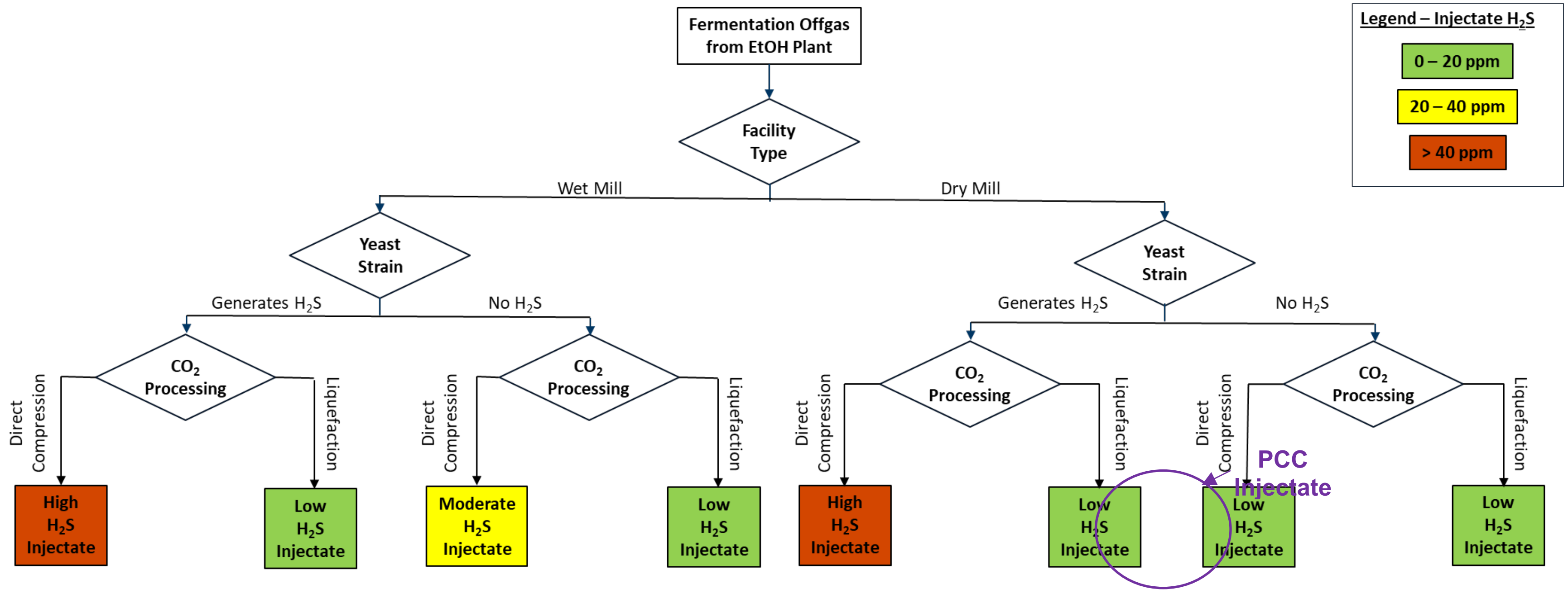
PureField utilizes a dry mill process that produces a fermentation medium that contains little organic sulfur or other sulfur species, employs fermentation yeast strains that do not generate high levels of H_2S via metabolism of sulfur species in the fermentation media), utilizes a direct compression route for CO_2 processing that does not preferentially remove H_2S from the stream, and has a maximum injection zone pressure of 2,166 psia. The maximum allowable injectate H_2S for use of 13Cr at PCC conditions is:

$$y_{H2S}(maximum\ for\ 13Cr\ at\ PCC\ conditions) = 69\ ppm = \left(\frac{0.15\ psia}{2{,}166\ psia}\right) 1x10^6$$

Pre-Construction testing of the source gas found H_2S to be below the 0.01 ppm detection limit of the analytical test method (ASTM D6628). PureField occasionally changes the yeast used to conduct fermentation as improvements are made through strain development. Future strains may generate source gas with detectable H_2S levels, however injectate from the PureField process should always be in the green color code range ($y_{H2S} = 0 – 20$ ppm) on Figure A.II-1.4-16. Other ethanol producers employ different approaches that may result in materially higher levels of H_2S in the injectate, as indicated by the various branches in Figure A.II-1.4-16 that lead to yellow or red color codings.

Figure A.II-1.4-16. Variation in H_2S Content of Injectates from Ethanol Plant Offgas

Color coding based on “typical” GS industry conditions and 13Cr application guideline (see text for additional discussion)



H_2S in the presence of liquid water lowers pH when it dissociates to create hydrogen cations plus bisulfide (HS^-) and sulfide (S^{2-}) anions:

H_2S Dissociation Reactions: $H_2S \rightleftharpoons H^+ + HS^- \rightleftarrows 2H^+ + S^{2-}$

H_2S corrosion (aka sour corrosion) of steels occurs in liquid water environments and typically manifests as general, pitting, and/or SSC corrosion (Popoola et al. 2013):

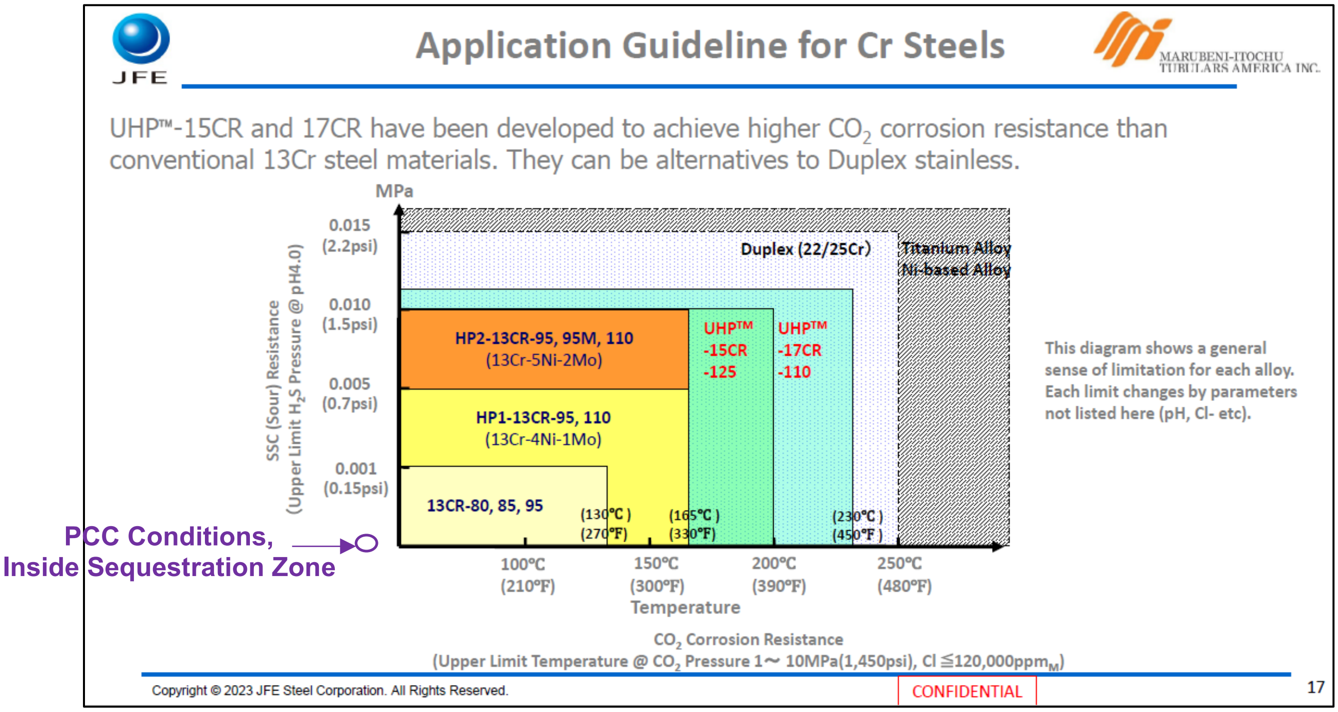
H_2S Corrosion: $H_2S + H_2O + Fe \rightarrow FeS + H_2 + H_2O$

PCC does not utilize carbon steel in its well designs at locations expected to be in contact with material concentrations of H_2S in liquid water so no further discussion of H_2S corrosion for carbon steels is presented here – see Figure A.II-1.4-14 and ANSI/NACE MR0175/ISO 15156 (ANSI 2021) for further information on carbon steels in sour applications.

Figure A.II-1.4-17 displays an application guideline for chromium steels provided by JFE Steel Corporation – the second largest steel manufacturer in Japan and the world's largest producer of 13Cr steels for well components. Extrapolation down to the PCC service conditions of 110 °F (43 °C) and setting $p_{H2S} = 0.01$ psia for PCC conditions (i.e., $y_{H2S} = 5$ ppm as an allowance should PureField make future changes in the yeast it uses to ferment sugars, and $P_{Injection} = 2{,}166$ psia) indicates 13Cr steel has suitable SSC resistance. Similarly, Figure A.II-1.4-18 provides an application guideline for 13Cr steel as published by the Nickel Institute. This guideline indicates 13Cr steels have suitable SSC resistance at the PCC conditions of pH = 4.5 – 5.5 and $p_{H2S} = 0.01$ psia (0.0007 bar).

Figure A.II-1.4-17. Application Guideline for Chromium Steels

From: JFE-TC 2024



Application Guideline for Cr Steels

UHP™-15CR and 17CR have been developed to achieve higher CO_2 corrosion resistance than conventional 13Cr steel materials. They can be alternatives to Duplex stainless.

This diagram shows a general sense of limitation for each alloy. Each limit changes by parameters not listed here (pH, Cl- etc).

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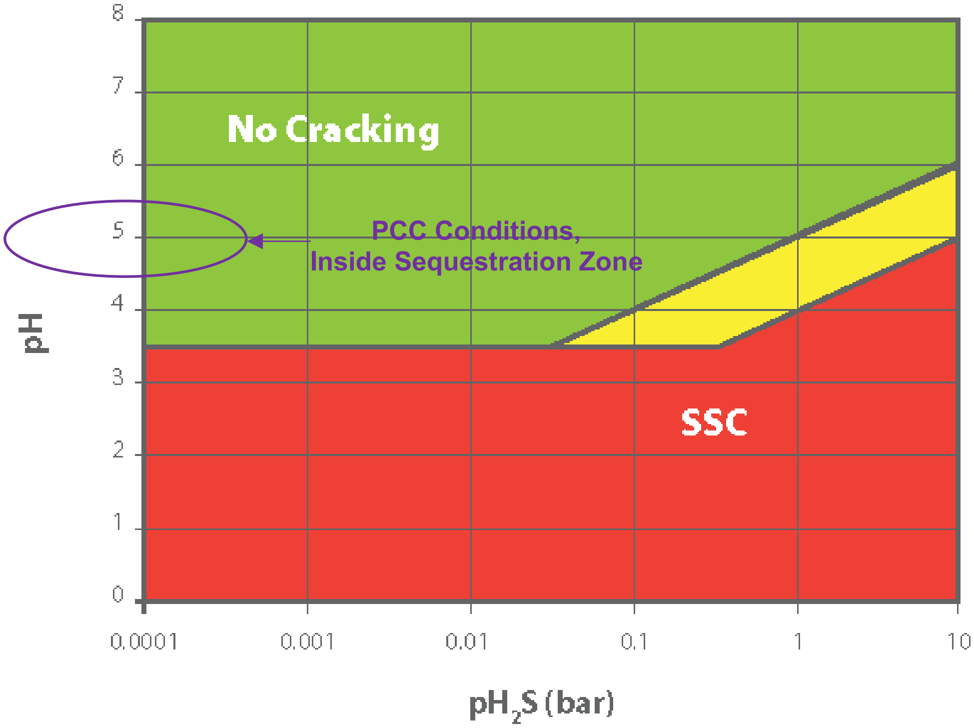
Figure A.II-1.4-18. Limits for 13Cr in Sour Service

From: Craig and Smith 2011



A.II-1.4.5.2. Oxygen

PCC only utilized carbon steel in low-corrosion environments for some of the CSS #1 and MW #1 casing strings and MW #1 internals above the packer. None of these environments contain appreciable concentrations of oxygen, so no further discussion is needed on the impact of oxygen for corrosion rates of carbon steels.

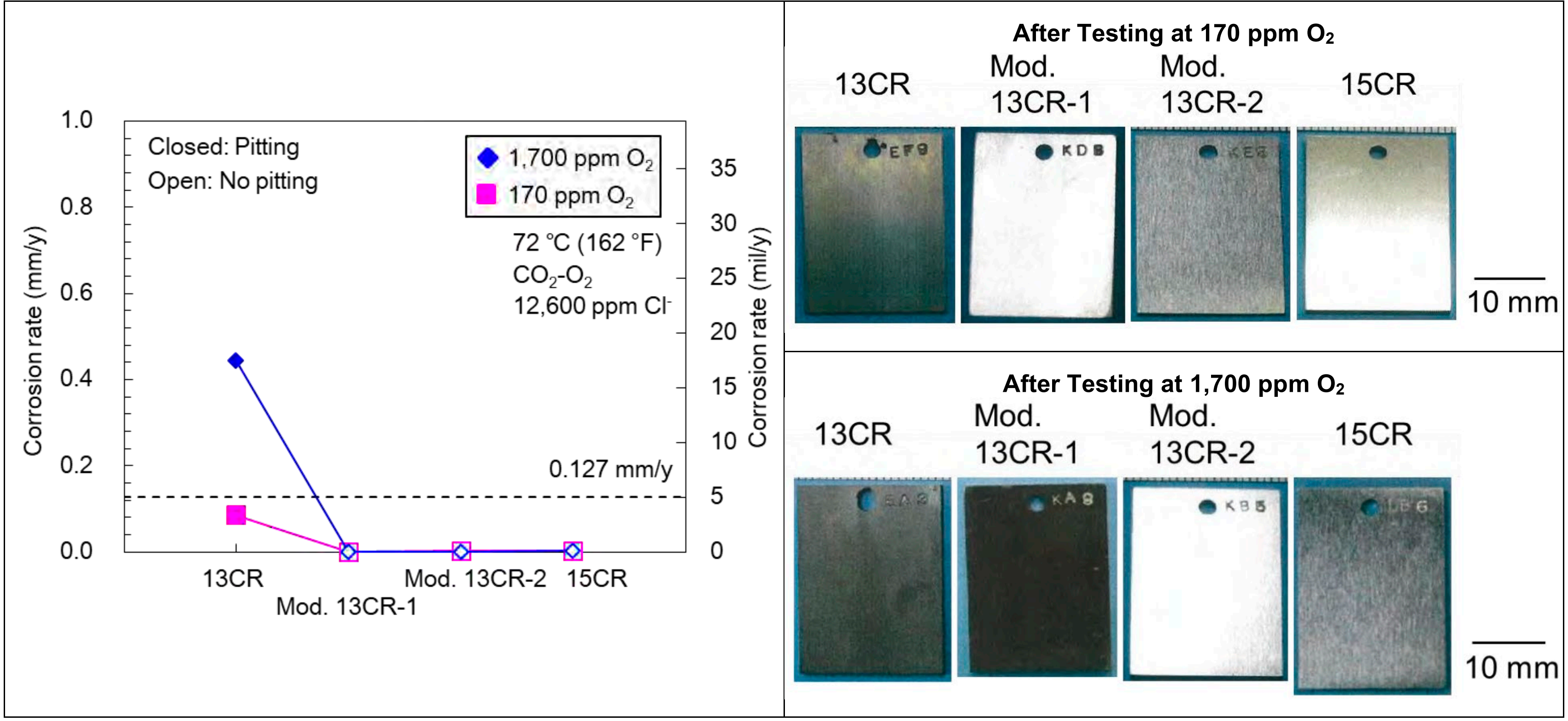
PCC utilizes CRAs at several locations in CSS #1 that may have trace concentrations of oxygen. The source of PCC's injectate is CO_2-rich offgas generated by conversion of carbohydrates into ethanol via yeast-based fermentation. The production fermentors are operated under anaerobic conditions at a slight positive pressure to atmosphere, thus there should be little to no O_2 present in the offgas since the yeast would scour any residual dissolved O_2 in the media and there are no pathways for air ingress through any un-intentional leaks into the fermentor headspace. Unfortunately, Pre-Construction testing of the raw offgas was unable to confirm the absence of O_2. Initial grab sample testing showed obvious signs of contamination by a small amount of air ingress during sampling, which is a common occurrence for grab sampling of near atmospheric sources. Follow-on testing used an on-line probe inserted into the raw gas stream but the instrument showed significant calibration drift and limited resolution, with measured O_2 concentrations over a 4 ½ day period ranging from -500 ppm to +500 ppm with a ±100 ppm resolution. To be conservative, the discussion herein examines the impact if the injectate contains 0-100 ppm O_2, although process reasoning suggests there should be an absence of O_2 in the injectate. The oxygen partial pressure (p_{O2}) of the injectate will be 0.2 psia at an O_2 content of 100 ppm and maximum downhole injection pressure of 2,166 psia, which corresponds to a dissolved oxygen concentration of 0.6 ppm using a Henry's law constant of 1.3×10^{-3} gmol/(L atm) for fresh water at 25 °C (Sander 1999). The presence of dissolved O_2 in liquid water accelerates CRA corrosion rates for pitting, crevice corrosion, and stress corrosion cracking (SCC) above the rates observed at similar conditions in the absence of dissolved O_2.

It is very difficult to design laboratory corrosion coupon tests in which all of the pertinent variables are controlled at representative field conditions as discussed earlier in Section A.II-1.2.2. Experimental shortcomings become especially apparent when examining literature for the impact of oxygen impurities on CRA corrosion rates, nonetheless it is worth discussing pertinent published studies since they do show the potential for pitting of CRAs:

Kamo (Kamo et al. 2023) Figure A.II-1.4-19 presents results for laboratory coupon testing of 13Cr and three other metals. The tests were conducted for 720 hr at 3,060 psia (21.1 MPa), 162 °F (72 C), with a NaCl solution at 12,600 ppm as Chloride. No pH values were reported either before or after CO_2 exposure. The test at $y_{O2} = 170$ ppm (corresponds to dissolved $O_2 \approx 1.6$ ppm) showed an acceptable corrosion rate of 3.3 mils/yr (0.085 mm/yr) with observable pitting, while the test at $y_{O2} = 1{,}700$ ppm O_2 (corresponds to dissolved $O_2 \approx 16$ ppm) showed a high corrosion rate of 17.4 mils/yr (0.443 mm/yr) with observable pitting.

Figure A.II-1.4-19. Laboratory Coupon Testing for Impact of O_2

From: Kamo et al. 2023; All Tests Conducted for 720 hr at 3,060 psia (21.1 MPa) and 162 °F (72 °C) with a NaCl solution at 12,600 ppm as Chloride; Left: General Corrosion Rate; Upper Right: Coupons After Testing at y_{O2} = 170 ppm; Lower Right: Coupons after Testing at y_{O2} =1,700 ppm



Hashizume (Hashizume et al. 2013) Table A.II-1.4-3 presents results for laboratory coupon testing of 13Cr. The tests were conducted for 720 hr at total pressure of 2,175 psia (150 bar), 212 °F (100 °C), with a 5 wt% NaCl solution (30,330 ppm as Chloride). No pH values were reported either before or after CO_2 exposure.

Table A.II-1.4-3. 13Cr Laboratory Coupon Testing for Impact of O_2

From: Hashizume et al. 2013; All tests conducted for 720 hr at total pressure of 2,175 psia (150 bar), 212 °F (100 °C), with a 5 wt% NaCl solution (30,330 ppm as Chloride).

Run	p_{O2}		General Corrosion Rate		Comments
	psia	bar	mils/yr	mm/yr	
4	0	0	6.3	0.16	Negligible Localized Corrosion
6	0.0003	0.045	3.2	0.08	Localized Corrosion
3	0.03	0.45	9.9	0.25	Localized Corrosion

Comparisons between these two short-term data sets and the PCC service conditions are somewhat meaningless given the differences in conditions, lack of reporting of pH in the laboratory studies, and the inconsistency in general corrosion rates as a function of oxygen partial pressure reported by Hashizume.

Pitting of the 13Cr casing and injection tubing in the injection zone of the CSS #1 well is not of concern for the following reasons:

- Pitting of 13Cr depends upon exposure to both dissolved O_2 and chlorides in a liquid water phase. The concentrations of O_2 and chlorides in the PCC conditions are materially less than the laboratory coupon testing trials that exhibited pitting.
- The outside of the CSS #1 casing in the injection zone is encased in a protective layer of cement, which reduces pitting by limiting contact of the metal surface with liquid water, dissolved oxygen, and chlorides.
- The inside of the CSS #1 casing beneath the packer and above the perforations will fill with the CO_2-rich injectate during the Injection period since it is more buoyant than the formation fluid, thus eliminating pitting on the inside of the casing and the tubing extension below the packer by eliminating contact with liquid water.
- The casing at the top perforation and below will be exposed to both formation fluid and injectate during PISC and thus potentially subject to pitting; however, pitting corrosion in this region will not impact mechanical integrity of the well over the GS project lifetime.

Pitting of 13Cr casing and tubing in the injection zone of the MW #1 well is not of concern since the dissolved oxygen content will be essentially zero. Oxygen in the injectate will either adsorb on rock or be microbially metabolized as it travels through the sequestration zone with the CO_2-rich injectate from the injection well to the monitoring well.

A.II-1.4.5.3. Other Common Stream Contaminants

Sulfur Dioxide (SO_2) in the presence of liquid water lowers pH when it dissociates to form hydrogen cations plus bisulfite (HSO_3^-) and sulfite (SO_3^{2-}) anions:

$$SO_2 + H_2O \rightleftharpoons H^+ + HSO_3^- \rightleftharpoons 2H^+ + SO_3^{2-}$$

Similar dissociation reactions occur when other sulfur oxides (SO_x) are dissolved in liquid water. PureField uses a dry mill ethanol production process that does not utilize SO_2, and furthermore the production fermentors operate under anaerobic conditions so any sulfur species in the media metabolized by the yeast will likely be reduced rather than oxidized, thus there are no process reasons to expect measurable levels of SO_2 in the fermentation offgas. Pre-Construction testing of the offgas found SO_2 concentrations to be below the 0.05 ppmv detection limit of the test method (ASTM D6628), which is aligned with expectations from process reasoning, thus there is no need for further evaluation of the corrosiveness of SO_2 and other sulfur oxides.

Nitrogen Dioxide (NO_2) in the presence of liquid water lowers pH when it dissociates to form nitric acid (HNO_3) and nitrous acid (HNO_2) that in turn dissociate into hydrogen cations plus nitrate (NO_3^-) and nitrite (NO_2^-) anions:

$$2NO_2 + H_2O \rightleftharpoons HNO_3 + HNO_2 \rightleftharpoons 2H^+ + NO_3^- + NO_2^-$$

Similar dissociation reactions occur when other nitrogen oxides (NO_x) are dissolved in liquid water. Nitrogen oxides are typically produced from nitrogen gas during high-temperature oxidation reactions such as those occurring in natural gas-fired boilers and combustion turbines. PCC's CO_2 source is generated from near ambient temperature anaerobic yeast fermentation so there are no process reasons to expect the presence of NO_2 and other nitrogen oxides in the fermentation offgas, thus there is no need for further evaluation of the corrosiveness of NO_2 and other nitrogen oxides.

Hydrogen (H_2) gas can form under some anaerobic microbial processes, but Pre-Construction testing of the PureField offgas found H_2 concentrations to be below the 0.1 vol% detection limit of the test method, thus there is no need for further evaluation of the corrosiveness of H_2.

Nitrogen (N_2) is an inert gas at the conditions of interest, thus there is no need for further evaluation of the corrosiveness of N_2.

Elemental sulfur is a solid at the conditions of interest. The injectate is filtered at the end of the compression train, so any potential source of elemental sulfur in the CSS #1 injection tubing would be generated via chemical reactions of reactive injectate impurities. Expected concentrations of H_2S, SO_x and NO_x are below the 20 ppm individual thresholds needed to generate elemental sulfur (Morland et al. 2022, Dugstad et al. 2014), thus there is no need for further evaluation of elemental sulfur as a stream contaminant.

A.II-1.5. Selection Factors For Non-Metallics

40 CFR 146.86 requires all materials used in Class VI well construction to be compatible with fluids with which the materials may be expected to come into contact. This section discusses CO_2 compatibility of various non-metallics utilized to fabricate flexible components such as O-rings, valve stem packings, and seals. It is reasonable to limit discussion to dense phase CO_2 exposure since the injectate for this project is of high purity (i.e., ignore impact of impurities in the injectate). Furthermore, the analysis here does not consider compatibility with the aqueous glycol solution used for the annulus fluid in CSS #1 since this is not a demanding application, for which nearly all non-metallics are suitable.

AMPP (AMPP 2023) advises the use of carbon, graphite, and even metals to the greatest extent possible for non-metallics exposed to CO_2 since these materials are largely impervious to CO_2. However, polymers and elastomers are subject to damage from CO_2 exposure via swelling, blistering from rapid gas decompression, and/or poor chemical resistance. The solubility parameter (δ) can be used as a screening tool for compatibility of these materials with CO_2. Figure A.II-1.5-1 shows the solubility parameter for CO_2 is approximately 21 $MPa^{1/2}$, plus the figure shows typical ranges of solubility parameter for several types of polymers and elastomers. Materials with solubility parameter equal to the CO_2 solubility parameter will readily absorb CO_2, which leads to the potential damage from swelling, blistering, or poor chemical resistance. Thus nearly all forms of HDPE, PTFE, EPDM, and FEPM should be resistant to damage from CO_2 exposure, but closer examination is needed for FKM, HNBR, and NBR[4]:

FKM No further discussion is needed since PCC does not use this material in well construction.

HNBR Hydrogenation increases the hardness of NBR by creating crosslinks in the material and saturating double bonds. Hardness is typically measured by a Shore durometer. Several references (Meyer 2007, Paul et al. 2012) recommend HNBR for CO_2 contact applications provided the HNBR has a durometer measurement between 80-90.

NBR No further discussion is needed since PCC does not use this material in CO_2 contact applications.

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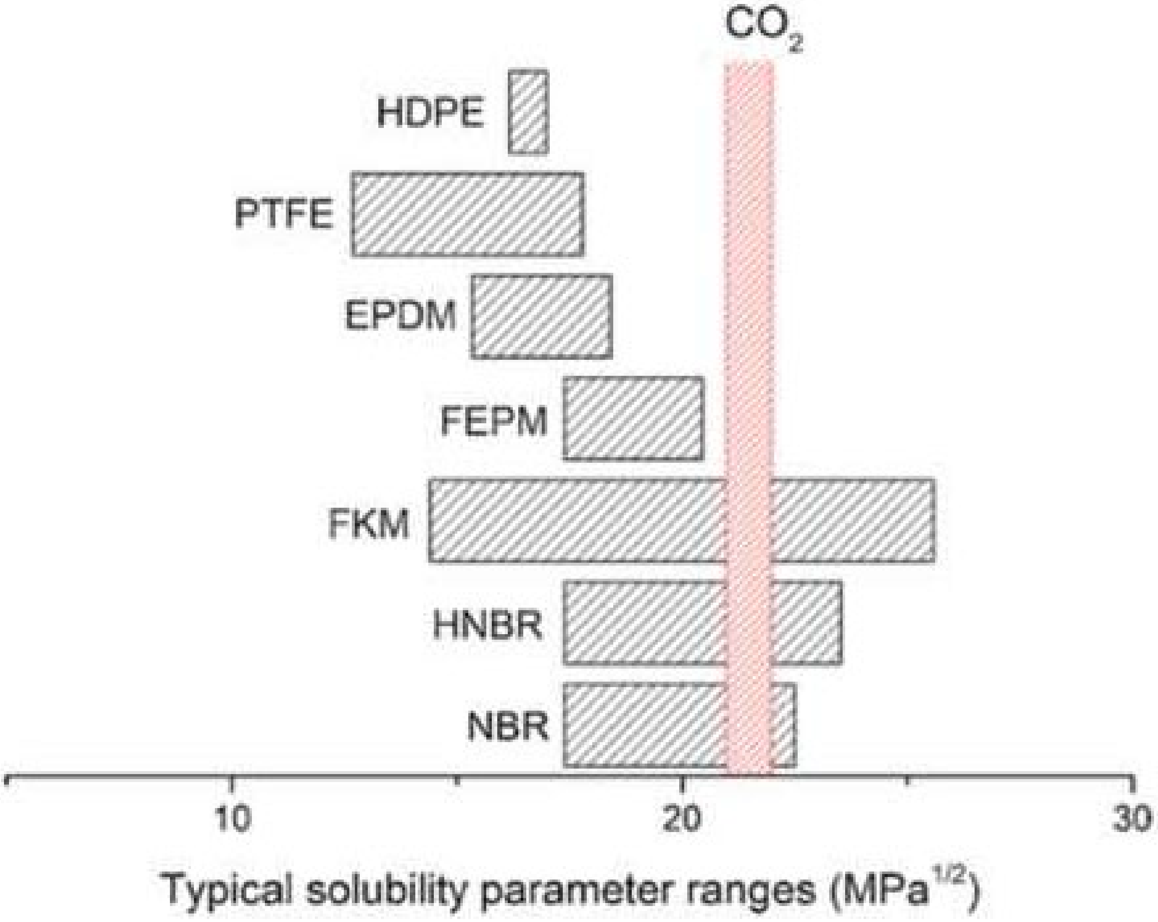
[4] HDPE = High Density Polyethylene, PTFE = Polytetrafluoroethylene, EPDM = Ethylene Propylene Diene Monomer rubber, FEPM = Tetrafluoroethylene Propylene Copolymer rubber, FKM = Fluorine Kautschuk Material – a family of fluoroelastomers, HNBR = Hydrogenated Nitrile Butadiene Rubber, NBR = Nitrile Butadiene Rubber

Figure A.II-1.5-1. Solubility Parameters for Supercritical CO_2 and Some Polymers

Room Temperature, From: AMPP 2023



A.II-1.6. Materials of Construction Analysis for CSS #1

Evaluation of the CSS #1 materials of construction determined the cement, metal, and non-metallic components should satisfy the structural strength, design life, and fluid compatibility requirements of 40 CR 146.86. Standard general-purpose cement formulations are utilized in zones outside the sequestration zone, and suitable CO_2-resistant cements are utilized in the sequestration zone. A combination of carbon steel and CRAs such as 13Cr, Alloy 925, nickel-plated carbon steel are utilized for metallic components with the choice of metal dependent upon the anticipated fluid exposures. PCC utilizes a two-prong approach for construction in the sequestration zone, using a combination of CO_2 resistant cement in tandem with CRAs to avoid spalling. Non-metallic components (e.g., O-rings, valve stem packings, seals) are constructed from compatible materials for CO_2 contact applications.

A.II-1.6.1. Cements

The conductor cement and surface casing cement are not anticipated to be in contact with CO_2+formation fluid mixtures over the life of the GS project, so these cements were chosen for long term compressive strength, hydraulic isolation, and pumpability considerations rather than corrosion resistance. General purpose ASTM Type 1 Portland cement was used for conductor cement, and API Class H cement was utilized for surface casing cement. The long string cement is the primary barrier for the injection well, as it is the material in direct contact with the sequestration formation and potentially corrosive CO_2+formation fluid mixtures that form between the confining layers. A 50/50 pozzolon/API Class H cement with 2% bentonite and latex cement was chosen as the long string cement to cover this interval as it is cement specifically designed for CO_2 resistance. Once set, this blend is anticipated to have a water permeability of less than 0.001 mD that effectively inhibits degradation of the cement (Schlumberger 2006).

A.II-1.6.2. Metals

The metals used in the construction of the CSS #1 casing, tubing, packer, and other internals are shown to meet the requirements of 40 CFR 146.86 using a general corrosion analyses of the casing strings. Additional compliance with the metal-fluid compatibility requirements of 40 CFR 146.86 was demonstrated previously in Section A.II-1.4, where it was shown the metals used by PCC are suitably resistant at their service conditions to other forms of corrosion beyond general corrosion (e.g., pitting, mesa attack, crevice, SCC, SSC).

A.II-1.6.2.1. Casing

40 CFR 146.86(b)(1) states several requirements for casing and cement of Class VI injection wells including requirements that materials used in the construction of the well have sufficient strength and be designed for the life of the sequestration project regardless of the design life for the injection well, plus all well materials (including casing) must be compatible with fluids with

which the materials may be expected to come into contact. The general corrosion calculations presented in Table A.II-1.6-1 show all three casing strings should have sufficient mechanical strength at the end of the sequestration project.

Below are definitions for terms in Table A.II-1.6-1:

Service Life Set to 62 years (12 years for Injection, plus 50 years for PISC) for all strings per the requirements of 40 CFR 146.86(b)(1).

Surface The corrosion calculations examine both the outside and inside surfaces of the casing.

Design Corrosion Rate The numerical value and its basis are provided in the table.

Design Corrosion Amount Set equal to the service life multiplied by the design corrosion rate for each surface.

Wall Thickness - Initial Casing dimensions are set by manufacturer compliance with API Specification 5CT (API 2023).

Wall Thickness - End of Life Computed as the initial thickness less the sum of the outside and inside corrosion amounts, where the corrosion amounts are divided by 1000 to convert from mils to inch.

Wall Thickness - Minimum Required at End of Life Calculated as:

$$t_{min} = \max\left(0.1\ inch, t_{min-burst}, t_{min-collapse}, t_{min-axial}\right)$$

where 0.100 inch is a practical floor for acceptable wall thickness at end of life. This floor is needed since wall thickness calculations for burst, collapse, and axial strength failures lead to zero in many cases. A key assumption in the burst and collapse calculations is the differential pressure across the conductor and surface string is negligible, so the minimum wall thickness to prevent a burst of the casing strings from internal pressure is:

$$t_{min-burst} = \begin{cases} 0, for\ conductor\ and\ surface\ strings \\ \dfrac{d_0 \Delta P}{2\, Y_i}, for\ long\ string \end{cases}$$

where d_o is the outer diameter of the casing, ΔP is the pressure differential caused by hydrostatic head of the annulus fluid less the hydrostatic head of formation fluid pressure, and Y_i is the burst rating of the casing. The minimum wall thickness to prevent collapse of the casing strings from external pressure is:

$$t_{min-collapse} = \begin{cases} 0, for\ conductor\ and\ surface\ strings \\ \dfrac{d_0 \Delta P}{2\ Y_i}, for\ long\ string \end{cases}$$

where do and ΔP have the same meaning as before and Yi is the collapse resistance of the casing. One purpose of cement is to anchor the strings to either an exterior string or the formation wall, in which case the minimum wall thickness to meet axial strength requirements is essentially zero (i.e., $t_{tmin\text{-}axial} = 0$).

Safety Factor Computed from the following:

$$Safety\ Factor = \left(\frac{Wall\ Thickness_{End\ of\ Life}}{Wall\ Thickness_{Min\ for\ Mechanical\ Strength}} - 1 \right) * 100\%$$

Pass/Fail? A “Pass” is given for each component when the safety factor is greater than or equal to zero; A “Fail” is given when the safety factor is negative.

The following assumptions are used in the basis for the casing general corrosion calculations:

- Corrosion rate for metal surfaces protected by cement:
    - 0 mils/yr when there is no anticipated exposure to fluids (e.g., the interior of the conductor casing is protected by both cement and the upper portion of the surface casing and thus not expected to be exposed to fluids)
    - 0.1 mils/yr for protection by a general cement
    - 0 mils/yr for protection by a CO_2-resistant cement
- Corrosion rate is zero for metal surfaces exposed to the annulus fluid (i.e., exposure to an aqueous glycol solution with corrosion inhibitor)
- Corrosion rate for carbon steel exposed to formation fluid with no cement protection set to 0.4 mils/yr, equal to the lab result presented in Section A.II-1.4.3 for Grise and Saldana 2008
- Corrosion rate for 13Cr exposed to formation fluid set to 0.35 mils/yr, equal to the lab result presented in Section A.II-1.4.3 for Pfennig et al. 2021
- Corrosion rate for 13Cr exposed to injectate+formation fluid mixtures set to 3.2 mils/yr, equal to the lab result presented in Section A.II-1.4.5.2 for Hashizume et al. 2013 with the presence of trace oxygen.

A.II-1.6.2.2. Tubing, Packer, and Other Internals

40 CFR 146.86(c)(1) requires the tubing and packer of Class VI injection wells to be compatible with fluids with which the materials may be expected to come into contact, however the regulation does not specify the tubing & packer has to be designed for the life of the

sequestration project since EPA recognizes that tubing, packers, and other well internals can be readily replaced as stated in Section III.C. of the Preamble to the Class VI rule.

The general corrosion calculations presented in Table A.II-1.6-2 indicate the tubing, packer, and other internals should have sufficient mechanical strength for the indicated service life. The calculations follow the same approach utilized for analysis of the casing presented previously in Section A.II-1.6.2.1 but the pressure differential for the burst and collapse calculations refers to the fluids indicated in the exposure column of the table. The following assumptions are used in the basis for the general corrosion calculations:

- Corrosion rate is zero for metal surfaces exposed to the annulus fluid (i.e., exposure to an aqueous glycol solution with corrosion inhibitor)
- Corrosion rate is zero for 13Cr surfaces exposed to injectate without the presence of liquid water, equal to the lab result presented in Section A.II-1.4.4.3 for Hua et al. 2016
- Corrosion rate for 13Cr surfaces exposed to injectate+formation fluid set to 5 mils/yr, equal to the maximum corrosion rate for acceptable regions of the 13Cr application domain map presented in Section A.II-1.4.4.5 for Vallourec 2024
- Corrosion rate is zero for Alloy 925.

A.II-1.6.3. Non-Metallics

Table A.II-1.6-3 lists non-metallics used in the construction of CSS #1. All non-metallics that are anticipated to be in contact with the CO_2-rich injectate are determined to have suitable compatibility.

Table A.II-1.6-1. General Corrosion Analysis of Metals for CSS #1 Casing

Casing String	Material of Construction	Service Life, yr	Location	Surface	Exposure	Design Corrosion			Wall Thickness, in			Safety Factor	Pass/ Fail?
						Rate, mils/yr	Amount, mils	Basis	Initial	End of Life	Minimum Required at End of Life		
Conductor	Carbon Steel 16" 65 lb/ft H-40	62	Surface to 40 ft bgs	Outside	ASTM Type 1 Cement	0.1	6.2	Default for protection by general cement	0.750	0.744	0.1	644%	**Pass**
				Inside	API Class H Cement	0	0	Default for cement protection with no exposure to fluids					
Surface	Carbon Steel 9-5/8" 36 lb/ft J-55	62	Surface to Below Base of Lowermost USDW	Outside	API Class H Cement	0	0	Default for cement protection with no exposure to fluids	0.704	0.679	0.1	579%	**Pass**
				Inside	Formation Fluid	0.4	24.8	Section A.II-1.4.3, Grise and Saldanda 2008					
Long String	7" 26 lb/ft 13CR-80	62	Surface to 1,676 ft bgs	Outside	Formation Fluid	0.35	21.7	Section A.II-1.4.3, Pfennig et al. 2021	0.724	0.702	0.1	602%	**Pass**
				Inside	Aqueous Glycol w/ Corrosion Inhibitor	0	0	Default for inhibitor package protection					
			1,676 bgs to Packer	Outside	50/50 Pozmix w/ Liquid Latex Cement	0	0	Default for protection by corrosion resistant cement	0.724	0.724	0.1	624%	**Pass**
				Inside	Aqueous Glycol w/ Corrosion Inhibitor	0	0	Default for inhibitor package protection					
			Packer to Top Perforation	Outside	50/50 Pozmix w/ Liquid Latex Cement	0	0	Default for protection by corrosion resistant cement	0.724	0.526	0.1	426%	**Pass**
				Inside	Injectate + Formation Fluid	3.2	198.4	Section A.II-1.4.5.2, Hashizume et al. 2013					
			Top Perforation and Below	Outside	Injectate + Formation Fluid	3.2	198.4	Section A.II-1.4.5.2, Hashizume et al. 2013	0.724	0.327	0.1	227%	**Pass**
				Inside	Injectate + Formation Fluid	3.2	198.4	Section A.II-1.4.5.2, Hashizume et al. 2013					

Table A.II-1.6-2. General Corrosion Analysis of Metals for CSS #1 Internals

Component	**Material of Construction**	**Service Life, yr**	**Location**	**Surface**	**Exposure**	**Design Corrosion**			**Wall Thickness, in**			**Safety Factor**	**Pass/ Fail?**
						Rate, mils/yr	**Amount, mils**	**Basis**	**Initial**	**End of Life**	**Minimum Required at End of Life**		
Tubing	13Cr-80	12	Surface to Packer	Outside	Aqueous Glycol w/ Corrosion Inhibitor	0	0	Default for inhibitor package protection	0.254	0.254	0.1	154%	**Pass**
				Inside	Injectate	0	0	Section A.II-1.4.4.3, Hua et al. 2016					
Subsurface Safety Valve	Alloy 925	12	Proximate to Packer	Outside	Aqueous Glycol w/ Corrosion Inhibitor	0	0	Default for inhibitor package protection	0.618	0.618	0.233	165%	**Pass**
				Inside	Injectate	0	0	Default for Alloy 925					
Packer	Alloy 925	12	Packer	Upper	Aqueous Glycol w/ Corrosion Inhibitor	0	0	Default for Alloy 925	Not Applicable	Not Applicable	Not Applicable	-	**Pass**
				Lower	Injectate + Formation Fluid	0	0	Default for Alloy 925					
Tubing	13CR95	12	Below Packer	Outside	Injectate + Formation Fluid	5	60	Section A.II-1.4.4.5, Vallourec 2024	0.254	0.134	0.1	34%	**Pass**
				Inside	Injectate + Formation Fluid	5	60	Section A.II-1.4.4.5, Vallourec 2024					

Table A.II-1.6-3. Non-Metallic Materials of Construction for CSS #1

Component	Sub-Component	Material of Construction	Anticipated to Contact Injectate?	Compatible with Injectate?	Comments
Tubing Head	Valve Stem Packing	PTFE	Yes	Yes	PTFE is compatible with CO_2 - See Section A.II-1.5
Tubing Hanger	Packing Assembly	HNBR	No	Not Applicable	
	Hanger Neck Seal	HNBR	No	Not Applicable	
Tree	Valve Stem Packing	Graphite/PTFE	Yes	Yes	Graphite and PTFE are compatible with CO_2 - See Section A.II-1.5
Packer	End Elements	HNBR	Yes	Yes	Constructed from HNBR with 90 durometer rating - See Section A.II-1.5
	Center Elements	HNBR	No	Not Applicable	

A.II-1.7. Materials of Construction Analysis for MW #1

Evaluation of the MW #1 materials of construction determined the cement, metal, and non-metallic components should satisfy the structural strength, design life, and fluid compatibility requirements of 40 CR 146.86. Standard general-purpose cement formulations are utilized in zones outside the sequestration zone, and suitable CO_2-resistant cements are utilized in the sequestration zone. A combination of carbon steel and CRAs such as 13Cr, Alloy 925, nickel-plated carbon steel are utilized for metallic components with the choice of metal dependent upon the anticipated fluid exposures. PCC utilizes a two-prong approach for construction in the sequestration zone, using a combination of CO_2 resistant cement in tandem with CRAs to avoid spalling. Non-metallic components (e.g., O-rings, valve stem packings, seals) are constructed from compatible materials for CO_2 contact applications.

A.II-1.7.1. Cements

The conductor cement and surface casing cement are not anticipated to be in contact with CO_2+formation fluid mixtures over the life of the GS project, so these cements were chosen for long term compressive strength, hydraulic isolation, and pumpability considerations rather than corrosion resistance. General purpose ASTM Type 1 Portland cement was used for conductor cement, and Halliburton’s Swiftcem Portland-based cement was utilized for surface casing cement. The long string cement is the primary barrier for the injection well, as it is the material in direct contact with the sequestration formation and potentially corrosive CO_2+formation fluid mixtures that form between the confining layers. Halliburton’s CorrosaCem blend was utilized for the entire long string from bottom to surface. CorrosaCem is a pozzolan/Portland blend cement with latex additives specifically designed for CO_2 resistance. Similar to the CSS #1 long string cement, this blend is anticipated to have a water permeability approaching zero that effectively inhibits degradation of the cement, as illustrated in the Halliburton CorrosaCem data sheet presented previously in Section A-II.1.3.2.

A.II-1.7.2. Metals

The metals used in the construction of the MW #1 casing, tubing, packer, and other internals are shown to meet the requirements of 40 CFR 146.86 using a general corrosion analyses of the casing strings. Additional compliance with the metal-fluid compatibility requirements of 40 CFR 146.86 was demonstrated previously in Section A.II-1.4, where it was shown the metals used by PCC are suitably resistant at their service conditions to other forms of corrosion beyond general corrosion (e.g., pitting, mesa attack, crevice, SCC, SSC).

A.II-1.7.2.1. Casing

The general corrosion calculations presented in Table A.II-1.7-1 show the conductor casing, the surface casing, and the long string casing from surface to the packer should have sufficient mechanical strength at the end of the sequestration project. These calculations follow the same approach utilized for analysis of the casing presented previously in Section A.II-1.6.2.1.

Calculations for the long string casing from the packer and below require some additional discussion. The corrosion rate for 13Cr in a CO_2+formation fluid environment in the absence of dissolved oxygen was set to 0.32 mils/yr, which is 1/10th the lab result of 3.2 mils/yr presented in Section A.II-1.4.5.2 for Hashizume et al. 2013 with the presence of dissolved oxygen. The 1/10th factor is used to account for the absence of dissolved oxygen, and is based on the observed reduction of corrosion rates with respect to absence or presence of dissolved oxygen as discussed in Section A.II-1.4.3 for the carbon steel data from Grise and Saldanda 2008.

A.II-1.7.2.2. Tubing, Packer, and Other Internals

The general corrosion calculations presented in Table A.II-1.7-2 indicate the tubing, packer, and other internals should have sufficient mechanical strength for the indicated service life. The calculations follow the same approach utilized for analysis of the tubing presented previously in Section A.II-1.6.2.2, plus a corrosion rate of 0.32 mils/yr for 13Cr in a CO_2+formation fluid environment in the absence of dissolved oxygen per the discussion in Section A.II-1.7.2.1.

A.II-1.7.3. Non-Metallics

Table A.II-1.7-3 lists non-metallics used in the construction of MW #1. All non-metallics that are anticipated to be in contact with the CO_2-rich injectate are determined to have suitable compatibility.

Table A.II-1.7-1. General Corrosion Analysis of Metals for MW #1 Casing

Casing String	Material of Construction	Service Life, yr	Location	Surface	Exposure	Design Corrosion			Wall Thickness, in			Safety Factor	Pass/ Fail?
						Rate, mils/yr	Amount, mils	Basis	Initial	End of Life	Minimum Required at End of Life		
Conductor	Carbon Steel 16" 65 lb/ft H-40	62	Surface to 40 ft bgs	Outside	ASTM Type 1 Cement	0.1	6.2	Default for protection by general cement	0.375	0.369	0.1	269%	Pass
				Inside	SwiftCem	0	0	Default for cement protection with no exposure to fluids					
Surface	Carbon Steel 10-3/4" 40.5 lb/ft J-55	62	Surface to Below Base of Lowermost USDW	Outside	SwiftCem	0	0	Default for cement protection with no exposure to fluids	0.350	0.350	0.1	250%	Pass
				Inside	CorrosaCem	0	0	Default for cement protection with no exposure to fluids					
Long String	7" 29 lb/ft HCL-80	62	Surface to top of Heebner	Outside	CorrosaCem	0	0	Default for protection by corrosion resistant cement	0.362	0.337	0.1	237%	Pass
				Inside	Formation Fluid	0.4	24.8	Section A.II-1.4.3, Grise and Saldanda 2008					
	7" 29 lb/ft 13CR-80	62	Heebner to Packer	Outside	CorrosaCem	0	0	Default for protection by corrosion resistant cement	0.362	0.340	0.1	240%	Pass
				Inside	Formation Fluid	0.35	21.7	Section A.II-1.4.3, Pfennig et al. 2021					
		62	Packer to Lower Perforation	Outside	CorrosaCem	0	0	Default for protection by corrosion resistant cement	0.362	0.342	0.1	242%	Pass
				Inside	Injectate + Formation Fluid	0.32	19.8	See supporting text					
		62	Lower Perforation and Below	Outside	Injectate + Formation Fluid	0.32	19.8	See supporting text	0.362	0.322	0.1	222%	Pass
				Inside	Injectate + Formation Fluid	0.32	19.8	See supporting text					

Table A.II-1.7-2. General Corrosion Analysis of Metals for MW #1 Internals

Component	Material of Construction	Service Life, yr	Location	Surface	Exposure	Design Corrosion			Wall Thickness, in			Safety Factor	Pass/ Fail?
						Rate, mils/yr	Amount, mils	Basis	Initial	End of Life	Minimum Required at End of Life		
Tubing	2-7/8" 6.5 lb/ft L-80	12	Surface to Packer	Outside	Formation Fluid	0.4	4.8	Section A.II-1.4.3, Grise and Saldanda 2008	0.217	0.207	0.194	7%	**Pass**
				Inside	Formation Fluid	0.4	4.8	Section A.II-1.4.3, Grise and Saldanda 2008					
X-Nipple	Alloy 925	12	Proximate to Packer	Outside	Formation Fluid	0	0	Default for Alloy 925	0.651	0.651	0.183	255%	**Pass**
				Inside	Formation Fluid	0	0	Default for Alloy 925					
Packer	Alloy 925	12	Packer	Upper	Aqueous Glycol w/ Corrosion Inhibitor	0	0	Default for Alloy 925	Not Applicable	Not Applicable	Not Applicable	-	**Pass**
				Lower	Injectate + Formation Fluid	0	0	Default for Alloy 925					
Tubing	2-7/8" 6.4 lb/ft 13CR-95	12	Below Packer	Outside	Injectate + Formation Fluid	0.32	3.8	See supporting text	0.217	0.209	0.1	109%	**Pass**
				Inside	Injectate + Formation Fluid	0.32	3.8	See supporting text					

Table A.II-1.7-3. Non-Metallic Materials of Construction for MW #1

Component	Sub-Component	Material of Construction	Anticipated to Contact Injectate?	Compatible with Injectate?	Comments
Casing Hanger	Seal Ring	HNBR	No	Not Applicable	
Tubing Head	Valve Stem Packing	PTFE/HNBR	No	Not Applicable	
Tubing Hanger	Packing Assembly	NBR	No	Not Applicable	
	Hanger Neck Seal	HNBR	No	Not Applicable	
Tree	Hanger Neck Seal	NBR	No	Not Applicable	
Sliding Door			No	Not Applicable	
Packer	End Elements	HNBR	Yes	Yes	Constructed from HNBR with 90 durometer rating - See Section A.II-1.5
	Center Elements	HNBR	No	Not Applicable	

A.II-1.8. References

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