1 **Corrosion model of CO₂ injection based on non-isothermal wellbore hydraulics**

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Abstract

In this study, the corrosion behaviors of carbon steel and stainless steel are investigated for water-saturated CO₂ system to examine the condition of CO₂ injection wells in CO₂ sequestration and enhanced oil recovery (EOR) applications. In our model, potential nonisothermal effects resulting from CO₂ injection activities including Joule-Thomson effect, heat transfer between CO₂ stream and surrounding well/rock formation, the adiabatic (de-) compression of CO₂, and the frictional losses are accounted. The model is applied to onshore and offshore wells using realistic data. In the offshore well, from the sea floor to the perforation, the depth is considered to vary as a power function of lateral distance. Depending on scales of injection, our calculations show that the corrosion rates in the tubing wall from the wellhead to bottomhole is on the order of 1 mm/y for carbon steel. For stainless steel, the rate obtained is 0.0057 mm/y. Results of this study provide insights on the material selection of CO₂ injection wells, accurate design of injection operations, and leakage monitoring and risk assessment in wellbore.

46

47 **Nomenclatures.**

48 A cross sectional area [m^2]

49 b Tafel slope [-]

50 c concentration [kmol/m^3]

51 C specific heat [$\text{J}/\text{kmol}/^\circ\text{K}$]

52 d diameter [m]

53 D diffusion coefficient [m^2/s]

54 f friction factor [-]

55 E potential [V]

56 F Faraday constant [=96485 C/mol_e]

57 g gravity [m/s^2]

58 i current density [A/m^2]

59 k mass transfer coefficient [m/s]

60 K equilibrium rate constant [kmol/m^3]

61 H molar enthalpy [J/kmol]

62 ΔH activation energy [kJ/kmol]

63 L length [m]

64 M molecular weight

65 U overall heat transfer coefficient [$\text{J}/\text{s}/\text{m}^2/\text{K}$]

66 μ viscosity [Pa.s]

67 n electron numbers for reducing or oxidizing a given species [$\text{kmol}_e/\text{kmol}$]

68	P	wellbore pressure [bar]
69	q	volumetric flux [m^3/m^2]
70	r	radius [m]
71	R	universal gas constant [=8.314 kJ/kmol/°K]
72	$\hat{A}$	electrochemical reaction rate [kmol/ m^2/s]
73	ρ	density [kg/m^3]
74	T	wellbore temperature [°K]
75	v	velocity [m/s]
76	U	overall heat transfer coefficient [$\text{J}/\text{s}/\text{m}^2/\text{°K}$]
77	V	molar volume [m^3/kmol]
78	z	vertical downward depth [m]
79	Re	Reynolds number [= $\frac{dvr}{\mu}$]
80	Sc	Schmidt number [= $\frac{m_{H_2O}}{r D}$]
81	Sh	Sherwood number [= $\frac{kd}{D}$]

82 Subscripts

83	ii	grid cell no.
84	m	mixture
85	p	pressure
86	s	solid
87	in	<i>in-situ</i>

88 *corr* corrosion

89 *rev* reversible

90 *wh* wellhead

91 **Superscripts**

92 0 reference condition (298.15 °K, 1.0 bar)

93 **Acronyms**

94 *CR* corrosion rate [mm/y]

95 *PI* productivity index [m/s/N]

96 *SS* supersaturation [-]

97 *Vol* volume [m³]

98

99

100 **Introduction.** Industrial scale and economically competitive carbon capture and storage (CCS)
101 require CO₂ injection on the order of tens of thousands to a few million metric tons per year¹.
102 Typical depths of CO₂ storage reservoirs range from one to several kilometers to keep the
103 injected CO₂ in liquid or supercritical state. Changes in thermophysical properties of CO₂ stream
104 with depth and its interactions with ambient formation govern the temperature and pressure
105 profiles along the well. Heat transfer occurs between surrounding environment (wellbore and
106 formation) and injecting CO₂ stream². As CO₂ is transported down the well, the CO₂ is heated
107 due to compression and to a lesser extent heated due to frictional forces. Since the critical point
108 of CO₂ (the critical temperature, pressure, and density are 31 °C, 73 bar, and 467.6 kg/m³,
109 respectively) may often be encountered in wells, distinct phase transitions are possible. When
110 CO₂ enters a two-phase equilibrium state it renders two significantly different densities that

111 evolve along the vapor-liquid saturation curve. In the saturation region, the densities of both
112 liquid and vapor change with pressure (or, associated temperature) and, large error may occur if
113 concurrent mechanical and thermal effects are ignored. If the injected CO₂ is near surface
114 temperature (~20 °C), conditions in the upper part of a well can cross the saturation line causing
115 H₂O (present in CO₂ stream) boiling and condensation in the well given that pressure exerted is
116 near critical.

117
118 CO₂ has been used as a solvent in EOR operations for many years³. In the case of shallow wells
119 conditions of phase change may not occur in typical EOR operations⁴. This includes CO₂
120 injection into pressure depleted gas reservoirs⁵ and CO₂ storage at depths less than 2000 m. Both
121 the deep⁶ and shallow reservoirs have been used for CO₂ storage, for examples, Sleipner²,
122 Nagaoka⁷, and Frio⁸, among others. In the case of no phase alteration, the single phase flow from
123 wellhead to bottomhole becomes nearly linear. In offshore operations, the CO₂ may arrive at the
124 well at very low temperature and it may be important to know whether the CO₂ is below or
125 above the hydrate temperature when CO₂ contacts reservoir water. If the accurate pressure drop
126 is known the wellhead pressure can also be used to monitor reservoir pressure at the bottom of
127 the well. Accurate prediction of non-isothermal flow in wellbores is important for engineering
128 design of the well diameters and perforations which depend on the capacity and pressure present
129 at the wellhead.

130
131 Modeling of subsurface injection and fluid flow in relation to CCS can provide detailed
132 information on how the non-isothermal behavior is generated and under what conditions these

can affect integrity of wellbore materials. To date, much of the research of wellbore integrity in CCS has focused on CO₂-cement interactions⁹. Flow characteristics were examined to analyze Joule-Thomson phenomenon^{5, 10-12} and natural convection of water in the annulus between tubing and cement¹³. A significant body of research suggests that CO₂ is reactive with tubing materials which has direct effect in corrosion^{14,15}. However, detailed corrosion of the tubing wall during CO₂ injection over the course of 30 – 50 years has not been studied. This is the motivation of this current investigation.

CO₂ corrosion is of great concern in CCS, oil and gas production, transportation and processing¹⁶⁻¹⁷. However, only few studies have attempted to address this in high CO₂ partial pressures (> 10 bar). This is especially true for supercritical (sc) CO₂ transport despite having wide interests and applications. Detailed corrosion model is important for CCS tubing materials selection in order to prevent development of unsafe situation and to optimize capital and operating costs of the system. It is important that unexpected and sudden failures do not occur where even small corrosion is possible. It also is essential to monitor and inspect well integrity at regular intervals. Severe corrosion may eventually create leakage pathways for fluid migration to the surface. So far, the cost of corrosion control has not been incorporated explicitly in most monitoring designs¹⁸. Therefore, in addition to important factors to consider and balance during the design stage are initial costs of corrosion resistant materials, the expense of regular repairs, replacements as well as potential costs of shutdowns¹⁹. In CO₂ injection, it is possible to have both low (≤ 10 °C) and relatively high temperature (70 – 120 °C) corrosion. The studies of scCO₂ corrosion were mostly carried out under stagnant batch conditions²⁰⁻²⁶ leaving question of flow effects unanswered. Nor et al.²⁷ performed laboratory experiment of corrosion measurement

156 using a high-pressure, high-temperature rotating cylinder electrode autoclave and a pipe flow
157 loop system. Strong flow effect was observed.

158

159 The typical components of an injection well are shown in **Fig. 1**. The inner tubing wall, which is
160 the main focus of this study, runs inside the long string production casing from the surface all the
161 way down to the injection zone. The injected CO₂ flows down the tubing, out through the
162 perforations in production casing, and into the injection zone¹⁹. The tubing must be designed to
163 withstand the stresses and corrosion by CO₂.

164

Fig. 1. Schematic of a CO₂ injection well (after Carey⁹ with modification).

Flow and corrosion electrochemistry models. Wellbore flow has two distinct patterns. One is a strongly time dependent flow process in which the variation in wellbore storage is changing rapidly and strongly affecting flow behavior. Another pattern is the quasi-steady state flow. The unsteady flow is particularly associated with the early times of injection or immediately after a change in operational conditions of the well. During this flow there are steep transient pressure gradients along the well and then between bottomhole and reservoir. Compared to total injection time the period of unsteady flow in the wellbore is relatively short, typically less than a few days

^{2,4}. The early short period unsteady flow then reaches a quasi-steady flow state where transients are largely determined by the rate of change of the reservoir flow in the vicinity of the well. Hereafter we will refer to this quasi-steady state as the steady state flow. In practice, estimation of P - T profiles along an injection well is complicated by several different mechanisms, such as frictional energy losses, gravity (hydrostatic pressure gradient), conductive heat exchange between the injected CO₂ and its surrounding fluid/rock, and the adiabatic (de-) compression. Some of these mechanisms may compete with each other and yield opposite effects on the pertinent P - T distributions. To describe the non-isothermal flow effects, the following wellbore hydraulic models ^{1,28,29} are used. Assuming cylindrical flow conduit with cross sectional area A , the horizontal inclination angle θ , inner radius r , and length (from wellhead to bottomhole) L , we have

$$r_m \frac{dv_m}{dz} + v_m \frac{dr_m}{dz} = 0 \quad (1)$$

$$\frac{dP}{dz} + r_m v_m \frac{dv_m}{dz} = -f \frac{r_m v_m^2}{4r} + r_m g \sin \theta \quad (2)$$

$$\frac{dH_m}{dz} + v_m \frac{dv_m}{dz} = g \sin \theta - \frac{Q(z)}{p r^2 r_m v_m} \quad (3)$$

$$\frac{dP}{dz} = \hat{P}(\rho_m, T, z) = \frac{\partial P}{\partial T} \left(\frac{\partial T}{\partial z} \right) + \frac{\partial P}{\partial \rho_m} \left(\frac{\partial \rho_m}{\partial z} \right) \quad (4)$$

$$\frac{dH_m}{dz} = \int_{P_i}^{P_{i+1}} \left[V_m - T \left(\frac{\partial V_m}{\partial T} \right)_{P_m} \right] \frac{dP}{dz} + c_p^0 \frac{dT}{dz} \quad (5)$$

In the flow system Eqs. (1), (2), and (3) represent mass, momentum, and energy balances, respectively. Eq (4) solves thermodynamics phase changes and Eq. (5) quantifies volume expansion (or compression) of flowing fluids. These all equations are strongly coupled, therefore density (ρ_m), velocity (v_m), pressure (P), temperature (T), and enthalpy (H_m) need to be solved simultaneously. $Q(z)$ is the heat exchange between the wellbore fluid and the surrounding formation. This is calculated by $Q(z) = -2\pi r U (T_{in} - T)$. T_{in} is the *in-situ* temperature based on geothermal gradient. c_p^0 , the thermal conductivity, is predicted from NIST (<http://webbook.nist.gov/cgi/cbook.cgi?ID=124-38-9>, accessed on Mar 16, 2016) database. In the flow model development we have made following assumptions.

a) The well diameter is very small compared to its length. The pressure, temperature, and flow velocity are uniform across a cross section. Hence the flow can be approximated as one dimensional.

b) The change in wellbore flow is slow enough to be treated as steady state and thus the kinetic energy term can be omitted.

c) The well is dry (except in CO₂ stream no initial water content inside the tubing).

d) The equations are based on averaged-flow model rather than the compositionally separated.

The operating injection rate, wellhead pressure and temperature are the inlet boundary conditions. The boundary condition at bottomhole outlet is defined by Peaceman's model³⁰

$$q = PI' (P - P_r), \quad (6)$$

where P_r notes as the reservoir pressure. In each spatial first order forward discretization Eqs (1) - (5) are computed concurrently to obtain r_m, v_m, P, T , and H_m . In Eq (4) the modified Redlich-Kwong equation-of-state³¹ is used. In cases where the CO₂ is in one phase far from the critical point, segment size $\Delta z = 6$ m is sufficient, while near the critical point in the two phase region step size less than 0.1 m is needed². In our simulations, unless specified, we used 0.05 m size for the complete domain to avoid any possible discretization error. After solving flow equations v_m, P , and r_m are then used in corrosion electrochemistry model. In this case P represents the CO₂ pressure (P_{CO_2}).

The electrochemical dissolution of iron in a water solution is given by

This is the dominant anodic reaction in CO₂ corrosion. The reaction is pH dependent in acidic solutions with a reaction order with respect to OH⁻ between 1 and 2, decreasing toward 1 and 0 at pH>4, which is the typical range for CO₂ corrosion³². P_{CO_2} increases the rate of corrosion primarily by increasing the rate of the hydrogen evolution reaction.

The corrosion is limited by the rate at which H^+ ions are transported from the bulk solution to the steel surface. In CO₂ solutions where pH>4 the limiting flux would be small and in that case H₂CO₃ would enable H₂ evolution at much higher rate. Thus for pH>4 the P_{CO_2} leads to a much higher corrosion rate than would be found in a solution of a strong acid at the same pH. The H₂CO₃ reduces to³³

233 The rate of reaction (9) is limited primarily by the hydration step (10) and CO₂ dissolution
234 reaction (11),

237 At pH>5 the direct reduction of the bicarbonate ion becomes important³⁴

239 Though comparatively very slow H₂ evolution is also caused from water reduction.

241 The electrochemical processes outlined above (7-13) are quantified using the well-established
242 Faraday's theory,

243 $i = nF\hat{A}$. (14)

244 Upon solving speciation using appropriate thermodynamic model, currents from all reactions are
245 summed up. The resulting total current is the corrosion current which is solved as

246 $i_{corr} = i_{Fe} = i_{H^+} + i_{H_2CO_3} + i_{H_2O}$. (15)

247 The anodic dissolution of *Fe* at the corrosion potential (E_{corr}) is expressed by

248 $i_{Fe} = i_{0(Fe)} 10^{\frac{E_{corr} - E_{rev(Fe)}}{b_{a(Fe)}}}$. (16)

249 The temperature dependence of exchange current density of Fe oxidation is given as:

$$250 \quad i_{0(Fe)} = i_{0(Fe)}^{ref} e^{-\frac{DH_{Fe}}{R} \frac{1}{T} - \frac{1}{298.15} \frac{\Delta G}{T}} \quad (17)$$

251 The Tafel slope of this reaction is expressed by:

$$252 \quad b_{a(Fe)} = \frac{2.303RT}{1.5F} \quad (18)$$

253 Similarly from appropriate relations and parameters values (FREECORP manual,

254 <http://www.corrosioncenter.ohiou.edu/software/freecorp/>, accessed on Mar 16, 2016) the

255 cathodic dissolution currents i_{H^+} , $i_{H_2CO_3}$, and i_{H_2O} are computed by solving E_{corr} iteratively using

256 Eq. (15). The expressions of all equilibrium reaction constants are obtained from this manual. In

257 solving i_{H^+} , $i_{H_2CO_3}$, and i_{H_2O} the limiting current density and non-dimensional Sh , Re , and Sc

258 numbers are required. V_m and r_m are used to calculate these numbers. m_m is obtained from^{35,36}.

259 Finally, corrosion rate is calculated by the relation,

$$260 \quad CR = \frac{i_{corr} M_{Fe}}{r_{Fe} nF} \quad (19)$$

261 **2.1 Scale formations.** In CO₂ corrosion if Fe^{+2} and CO_3^{2-} exceed the solubility limit, they form

262 solid $FeCO_{3(s)}$ according to:

264 Actually $FeCO_{3(s)}$ is frequently observed in the aqueous solution at concentrations higher than

265 the equilibrium composition. This supersaturation is defined as:

$$SS = \frac{C_{Fe^{+2}} C_{CO_3^{2-}}}{K}. \quad (21)$$

The precipitation is the process of the solution returning to equilibrium and is driven by the magnitude of SS . If $SS > 1$ the precipitation rate ($\hat{A}_{FeCO_3}$) is calculated as below (**otherwise** $\hat{A}_{FeCO_3} = 0$ and calculation of this part is terminated).

$$\hat{A}_{FeCO_3} = k_{r(FeCO_3)} \frac{A}{Vol} K(SS - 1). \quad (22)$$

where $k_{r(FeCO_3)}$ is a kinetics constant which can be derived from Sun and Necis³⁷

$$k_{r(FeCO_3)} = e^{21.3 - \frac{64851.4}{RT}}. \quad (23)$$

After $\hat{A}_{FeCO_3}$ is obtained, the scaling factor is quantified by the empirical relation (FREECORP manual) of

$$SF = SS^{-0.7}. \quad (24)$$

Finally, CR is updated as follow:

$$CR = \frac{\hat{A}_{FeCO_3}}{SF}. \quad (25)$$

In a few cases Magnetite (Fe_3O_4) can also be detected as the scale formation, however is not considered in our calculations. It is important to note that scale formation calculation is not as straightforward as is demonstrated here. Both corrosion and scale formation can occur simultaneously. Moreover, scale formation is time dependent. Although the bulk SS can be less than 1, the surface SS may exceed 1 because of higher pH and Fe^{+2} concentration. Here we have

presented a simple scheme assuming $\text{FeCO}_{3(s)}$ formation is in early stage and it relates to corrosion in a cascade process.

Results and discussion. To validate the flow model a sanity test is performed first to compare with the literature results presented in Lu and Connell²⁹. The same well and fluid data were used in calculations except we have assumed fluid as the CO_2 with saturated dissolved H_2O . The saturation phase equilibrium model of Refs.^{31,38} was applied to quantify H_2O composition. Our results presented in **Fig. A1** agree well both qualitatively and quantitatively with the figures 6 and 7 therein. Our justification of adding H_2O dissolved is that 100% dry status of CO_2 stream is not guaranteed because of high process engineering cost¹⁹. The model captures how CO_2 loses heat to ambient cold formation and unsteady transition in the vicinity of critical point where gas phase transforms into supercritical state. As geotemperature increases the flowing CO_2 starts to gain heat and propagates. In this particular type of fluid flow heat transfer occurs primarily as a result of natural convective heat transfer between tubing pipe and surrounding strata environment. The heat generation by flow friction with internal surface of the tubing can be omitted due to small pipe friction factor and low CO_2 viscosity.

After flow model is checked and before sequential coupling, corrosion calculations are validated separately. **Fig. A2** shows results of carbon steel corrosions in CO_2 - and H_2O -rich phases at 50 °C as a function of pressure. Symbol (circles) refers to experimental data obtained from Choi and Nesic²⁵ and Wang et al.³⁹, respectively. In this case satisfactory matches are noticed. Simulation

of CO₂ rich phase corrosion is our interest here which indicates that the corrosion rate is on the order of 1 mm/y.

For EOR and commercial scale CCS CO₂ injection can vary from thousands to million(s) metric tons per year. Hence we have performed simulations for two different hypothetical, however realistic data sets^{1,29} representing small and large scale injections. The parameters involved in simulations are compiled in **Table 1**.

Table 1. Well and formation data.

Model parameter	values
L	1000 m
Θ	90°
d	0.14, 0.21 m for small and large size injection, respectively (wall thickness 0.0064, 0.0082 m, respectively)
U	1.0 J/s/m ² /K
surface temperature	293.15 °K
geothermal gradient	0.03 °K/m
hydrostatic gradient	0.1 bar/m
T_{wh}	308.15 °K
P_{wh}	60 bar
injection rate (with saturated dissolved H ₂ O)	
small scale	4282, 9634, 1505, 2000 ton/y
large scale	200800,550000,1000000,1500000 ton/y

During steady-state flow in small scale injections temperature and pressure distributions exhibit much non-linearity. Relative uneven change of temperature and pressure results in very random trend of corrosion rates along the length shown in **Fig. 2** especially in the upper part of the well before the flows become relatively smooth. In the upper part CO₂ stream cools due to the heat conduction to the neighboring formation. Below this as the flow stabilizes with increasing depth temperature becomes nearly parallel to the geothermal gradient causing almost linear increase of corrosion rates. As the temperature increases the processes involved in corrosion: electrochemical, speciations, transport, etc. accelerate. Destabilized corrosions in the upper part are also because the fluid has experienced complex phase changes. Initially it is in a single gas/vapor state and then starts to enter the two-phase (vapor-liquid) coexistence. The liquid state persists in a short length until the fluid becomes completely supercritical. CO₂ flows as supercritical for more than lower half length of the well. As mentioned the non-rational changes of temperature and pressure throughout the length which ultimately affect the flow velocity result in uneven corrosions. Localized corrosions such as pitting and crevice corrosion may cause leaks or deposition of H₂O condensate. The uneven corrosion can make the tubing wall rough.

Fig. 2. Corrosion rates in small scale injections.

Fig. 3 shows results of large scale injections. As expected, also observed in previous results that the flow becomes linear with increasing injection rates. The $Q(z)$ tends to be less effective (see Eq. 3) under larger injection rates and consequently absolute difference of $(T_{wh}-T_{bh})$ decreases. This affects corrosion results directly making it less variations. Actually in these cases high velocity becomes important in controlling temperature and pressure distributions. The flow enhances transport of species towards and away from the metal surface which can lead to corrosion increase. Because of high velocity the limiting mass transfer current density increases resulting in more H_2 evolution. To observe how temperature, pressure, and velocity vary at different injections from small to large scales more clearly their distributions are displayed in **Fig. 4**. As we can see at the same wellhead temperature and pressure injecting velocity can vary even by orders of magnitudes governing the flow profiles and as a result of corrosion. Due to

345 short retention time flow with higher velocity acts as adiabatic. Besides the flow and material
 346 properties temperature development is dependent on geothermal gradient which determines the
 347 heat conduction. Temperature changes along the tubing because of two factors: one is the
 348 compressible work done; the other is the enthalpy change. The resultant effects determine
 349 temperature's rise or fall. In all cases pressures develop almost same way except some difference
 350 in minor head losses from varying stream densities. Unless the well is slant ($q \neq 90^\circ$) the
 351 gravity plays same.

352
 353 **Fig. 3.** Corrosion rates in large scale injections.
 354
 355

(a)

(d)

(b)

(e)

(c)

(f)

356

357 **Fig. 4.** Temperature, pressure, and velocity profiles for (a), (b), (c) small scale; (d), (e), (f) large
 358 scale injection rates.

359

360 We have simulated flow characteristics of offshore CO₂ injections. **Fig. 5** shows typical offshore
361 well (similar to Sleipner CO₂ injection project) which is strongly deviated and the distance along
362 the well from wellhead to perforation is 2500 m. The upper 180 m is insulated running in sea
363 water through the platform leg to the sea floor. Hence the flow in this part is assumed to be
364 adiabatic. Sea water temperature from its surface to the floor decreased from 293.15 °K to 184
365 °K, and then the *in-situ* temperature increases with the geothermal gradient of 0.041 °K/m.
366 Wellhead temperature and pressure are 298.15 °K and 64 bar, respectively. From the sea floor to
367 the perforation interval, 962 m well depth varies vertically according to:

$$368 \quad z = ax^b + c. \quad (24)$$

369 Here $a = 146.6$, $b = 0.237$, and $c = 25$ m. In simulation longitudinal grid size changes adaptively
370 with respect to the slant angle, $\sin^{-1}\left(dz / \sqrt{dz^2 + dx^2}\right)$. Initial dz and dx were 1.0 and 1.25 m,
371 respectively.

Fig. 5. Offshore CO₂ injection well.

We have tested flow results of two injection rates, 9776 and 1.5MM ton/y. The profiles are shown in **Fig. 6**. Like in the case of vertical flows temperature and velocity profiles render more instability in small injection. However, as the flow direction changes continuously with the rising depth flow behavior still remains non-linear to some extent in large injection unlike the case of vertical flow. Because upper 180 m flow is adiabatic positive Joule-Thomson effect causes the temperature to increase steadily and after that CO₂ begins to lose heat to the cold strata. In small injection after half of vertical depth enthalpy begins to reserve and as a result flow becomes hotter. Small heat losses occur in large injection due to high fluid momentum. Pressure distributions tend to be constant at the end of pipe length as the flow direction alters to nearly horizontal ($q \gg 5^\circ$). Head loss from continuously changing gravity also adds instability in flow. The precipitation of ferrous carbonate protective layer has not been found ($SS < 0.1$) in any of above cases. At low pH (< 4.5) this is expected¹⁵.

(b)

(e)

(c)

(f)

388

389 **Fig. 6.** Temperature, pressure, and velocity profiles of offshore flows for (a), (b), (c) 9776; (d),
 390 (e), (f) 1.5 million ton/y CO₂ injection.

391

392 **Fig. 7** presents very non-uniform corrosion results from the two resultant flows. Though CO₂
 393 stream flows 2.5 km distance temperature, pressure, and velocity developments are relatively
 394 small than the counterpart vertical flows. Therefore, maximum corrosion rate is three to ten times
 395 less at the same operating conditions.

(a)

(b)

Fig. 7. Carbon steel corrosion rates of offshore well for (a) 9776 and (b) 1.5MM ton/y CO₂ injection.

Contrary to the carbon steel stainless steel (Austenitic, or 200 and 300 series) poses useful characteristic in resisting corrosion in that they perform best under oxidization events. Stainless steel demonstrates practically very strong resistance to the CO₂ corrosive effects. They not only

resist surface damage, but in addition, they retain original bright appearance even for long periods. They perform similar both in hot and cold environments. We have obtained very small corrosion (0.0058 mm/y) in stainless steel throughout the pipe length irrespective of any flow combinations discussed above. For instance, **Fig. 8** shows corrosion results for the case in which carbon steel showed maximum corrosion rate (1.5 MM ton/y vertical injection). Our results clearly show the utility of stainless steel. It has small uniform corrosion and is unlikely to suffer from localized corrosion.

Fig. 8. Stainless steel corrosion rates.

Conclusions. The flow, thermal, and corrosion behaviors of CO₂ injection are extensively analyzed. The study solves non-isothermal hydraulics of CO₂ with saturated H₂O flows in on- and off-shore wells constructing with carbon and stainless steel tubing applied to CCS and EOR. The results presented have significant practical relevance to optimize wellhead operation design,

materials selection by trading off corrosion loss versus capital cost, and temperature and pressure based leakage monitoring and risk assessment in wellbore. CO₂ choking before injection is highly cost intensive, hence prior engineering analysis based on current research is substantially important. The very non-linear flow patterns exhibit non-uniform carbon steel corrosions along the tubing length in the case of small scale injections. On the other hand, the costly large scale injections corrode nearly smoothly. In carbon steel CR is on the order of 1 mm/y. The stainless steel tubing surface remains almost unaffected resulting in more than two orders of magnitude less corrosion, 0.0057 mm/y. Though the CO₂ stream flows few times longer distance in offshore well compared to vertical injection CR is three to ten times less because of low temperature and pressure developments.

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