Exploring Sweet Corrosion at Different Partial Pressures of CO_2 (Carbon Dioxide) Using LPR and Weight Loss Methods

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Abstract

The contribution of dissolved carbon dioxide (CO_2) on the corrosion behavior of carbon steel was investigated using weight loss (WL) and Linear Polarization Resistance (LPR) methods.

CO_2-saturated environment was generated at room temperature by injecting CO_2 (99.9% pure) into an oilfield water at different partial pressures (up to 1,000 psi). CO_2-saturated oilfield water was then transferred into a high-pressure cell and was allowed to contact a steel coupon (WL) or electric probe (LPR) for 72h.

The results showed that WL and LPR methods were both able to detect CO_2-induced corrosion owing to the acidic environment induced by CO_2 dissolution. It was further found that the corrosion rate increases with the increase in CO_2 partial pressure for WL method. A reverse trend was observed for LPR, however.

Not only the corrosion rate decreases with the increase in CO_2 partial pressure but also, LPR overestimated the corrosion rate leading to the conclusion that WL method was the more accurate of the two techniques tested.

Introduction

The United States Environmental Protection Program (EPA), through its Greenhouse Gas Reporting Program (GHGRP), reported that 14 million metric ton of carbon dioxide (CO_2) were emitted by the state of Alaska in 2021; 61% of which were produced from petroleum and natural gas industry [1].

As part of efforts to reduce the carbon footprint, CO_2 capture and storage technology seeks to capture CO_2 from large emission sources, store it in underground reservoirs or use it for Enhanced Oil Recovery (EOR) operations [2].

At all stage of production, transportation and storage, the pipelines are susceptible to be corroded (**Fig. 1**) due the operating conditions including temperature (16– 163 °C), the presence of wet hydrocarbon, as well as the gas/liquid velocities (5–20 m/s).

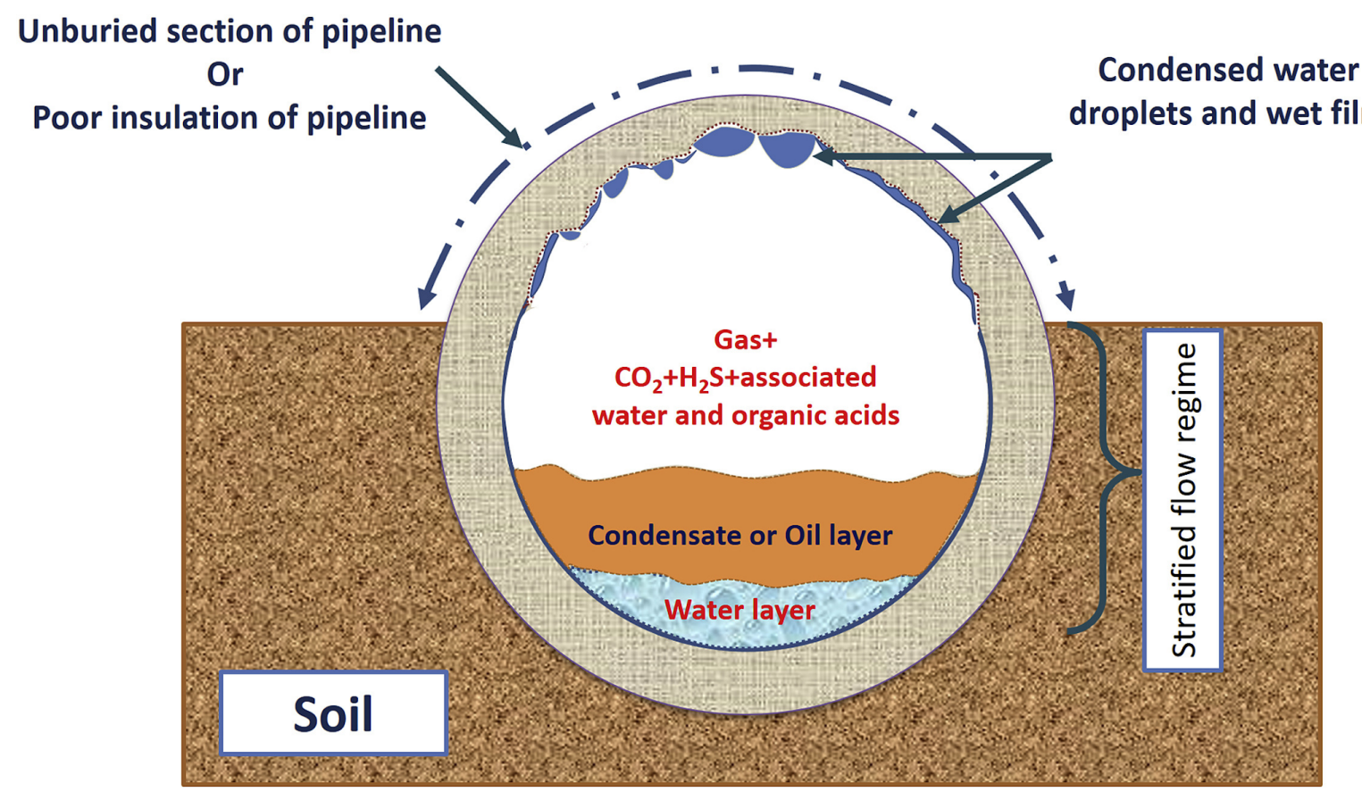

Fig.1: Cross-section of a standard oil pipeline with hydrocarbons, water and gas in it; taken from Ref. 3

Sweet corrosion or CO_2-induced corrosion is therefore one of the three main types of corrosion encountered in oil and gas industry. The two others are sour corrosion (H_2S-induced) and corrosion induced by the presence of oxygen (O_2) water. When CO_2 contacts an aqueous phase (water for example), a corrosive substance (carbonic acid) is formed and eventually reacts with the metals from the pipe as shown in **Equation 1**,

$$Fe + CO_2 + H_2O = FeCO_3 + H_2 \qquad (1)$$

Corrosion levels vary based on the different temperatures and the amount of CO_2 present in the aqueous and thus the pH of the given environment [4]. Monitoring and understanding how CO_2 plays a role in corrosion can help future pipelines and transportation methods to become more efficient and less susceptible to corrosion, therefore.

Materials and Methodology

Materials

The materials for the experiments included a synthetic formation water prepared in-house from sodium chloride, potassium chloride, magnesium chloride and calcium chloride. The synthetic water has a total dissolved solid of 21,853 ppm and a salinity of 91.97 wt.% NaCl. It should be noted that the water composition replicated that of an active Alaskan oilfield. CO_2 and nitrogen (N_2) were used as primary gasses. Both gasses have a purity of 99.99%.

Experimental Design

Sweet corrosion was investigated in an equipment shown in **Fig. 2**.

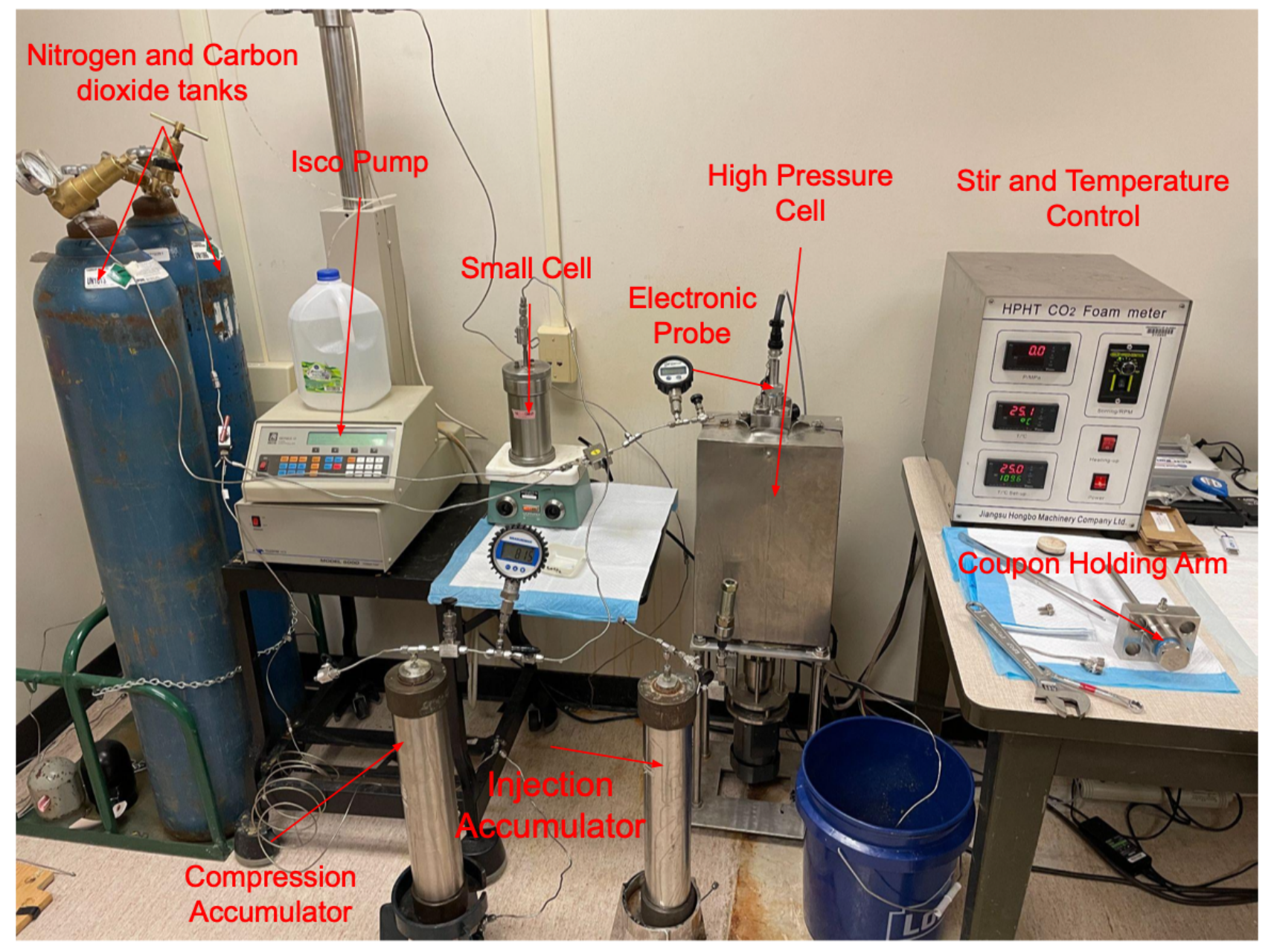

Fig.2: Experimental design set up, consistent throughout all experiments.

The equipment consists of an Isco pump, one reacting small (500ml) and high pressure cell (575ml)), electronic probe and coupon holder, a stirrer and temperature control. 2 accumulators (compression and injection).

To evaluate the sweet corrosion using a weight loss approach, the following procedure was followed:

1. prepare a fresh coupon (Steel Coupon C1010) by sandblasting, cleaning, and retrieving start weight. Most often tests were conducted in the small cell with 250mL of water.
2. Inject CO_2 into the formation water at desired pressure. Four pressures were considered including 200,400, 600 and 800 psi
3. Allow CO_2 to contact water for 24 hours and transfer CO_2-saturated water either into the small cell or the high pressure cell.
4. Turn on the magnetic stirring (20 RPM) and begin the test.
5. Run the test for 72 hours. At the end of test, collect the effluent water and measure the pH.
6. To measure the corrosion rate, clean coupon in hydrochloric acid and sodium bicarbonate then measure final weight. Enter start and final weight into the software to retrieve corrosion rate.

Similar procedure was followed to evaluate the corrosion rate using Linear Polarization resistance (LPR) approach. The differences with above procedure is described below:

1. For electric probe; restart software and replace probe covers before inserting into the high pressure cell with 450mL of water.
2. Measuring corrosion rate for electric probe; open CorrTran software and retrieve final corrosion rate.

Results

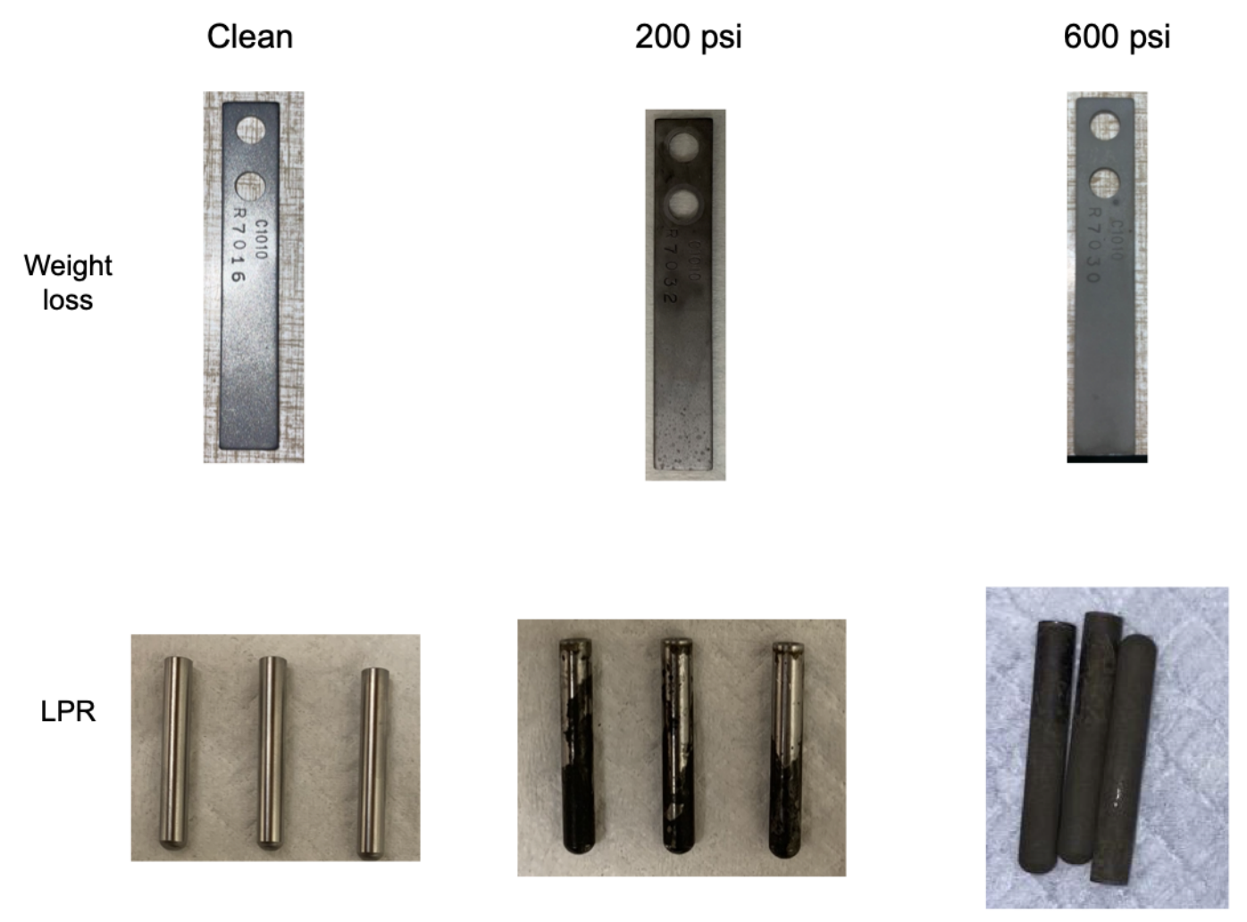

Fig.3: Comparing the physical look of the coupon vs. the probe.

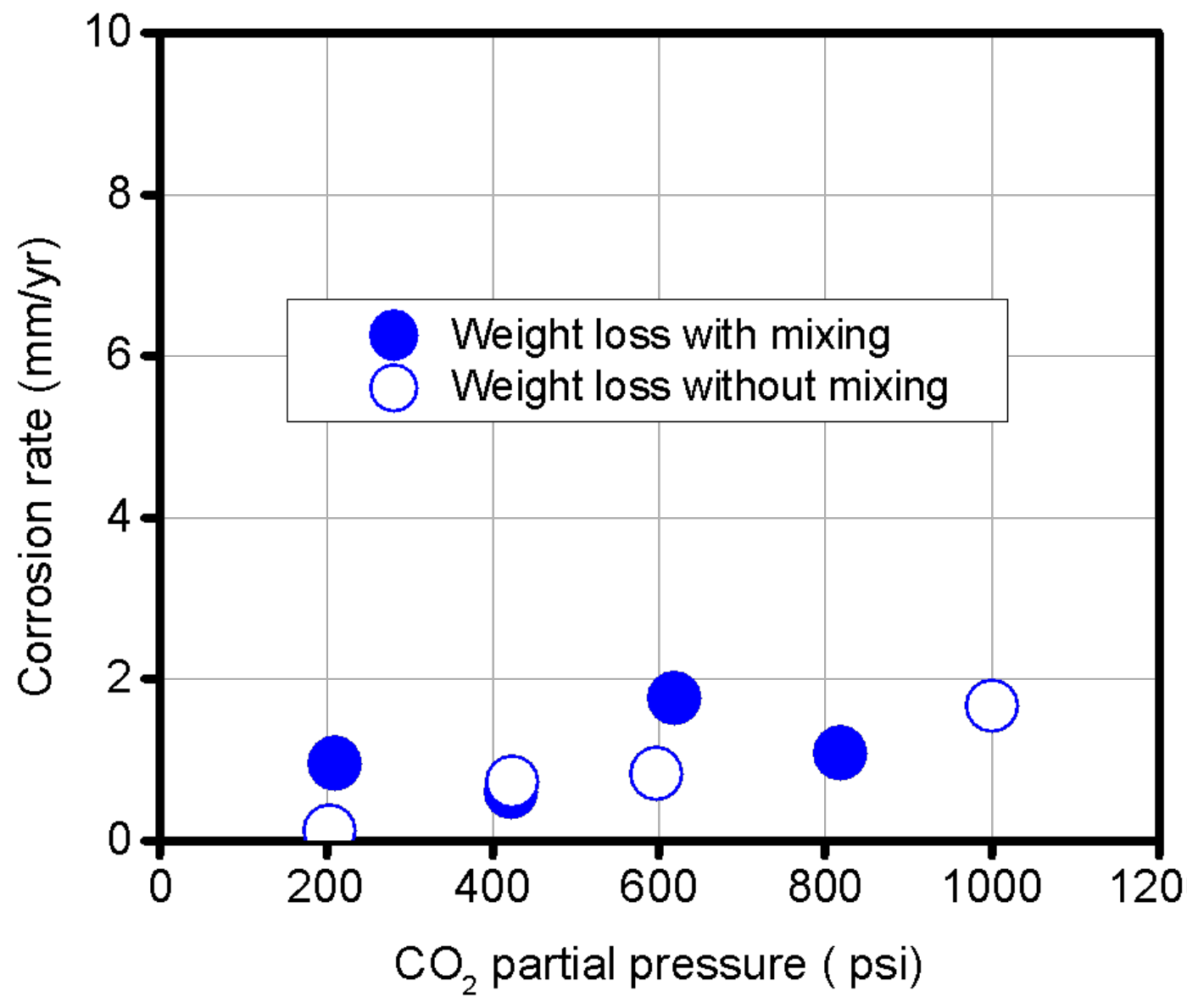

Fig. 4: Comparing corrosion rates of coupons with and without agitation at different partial pressures of carbon dioxide.

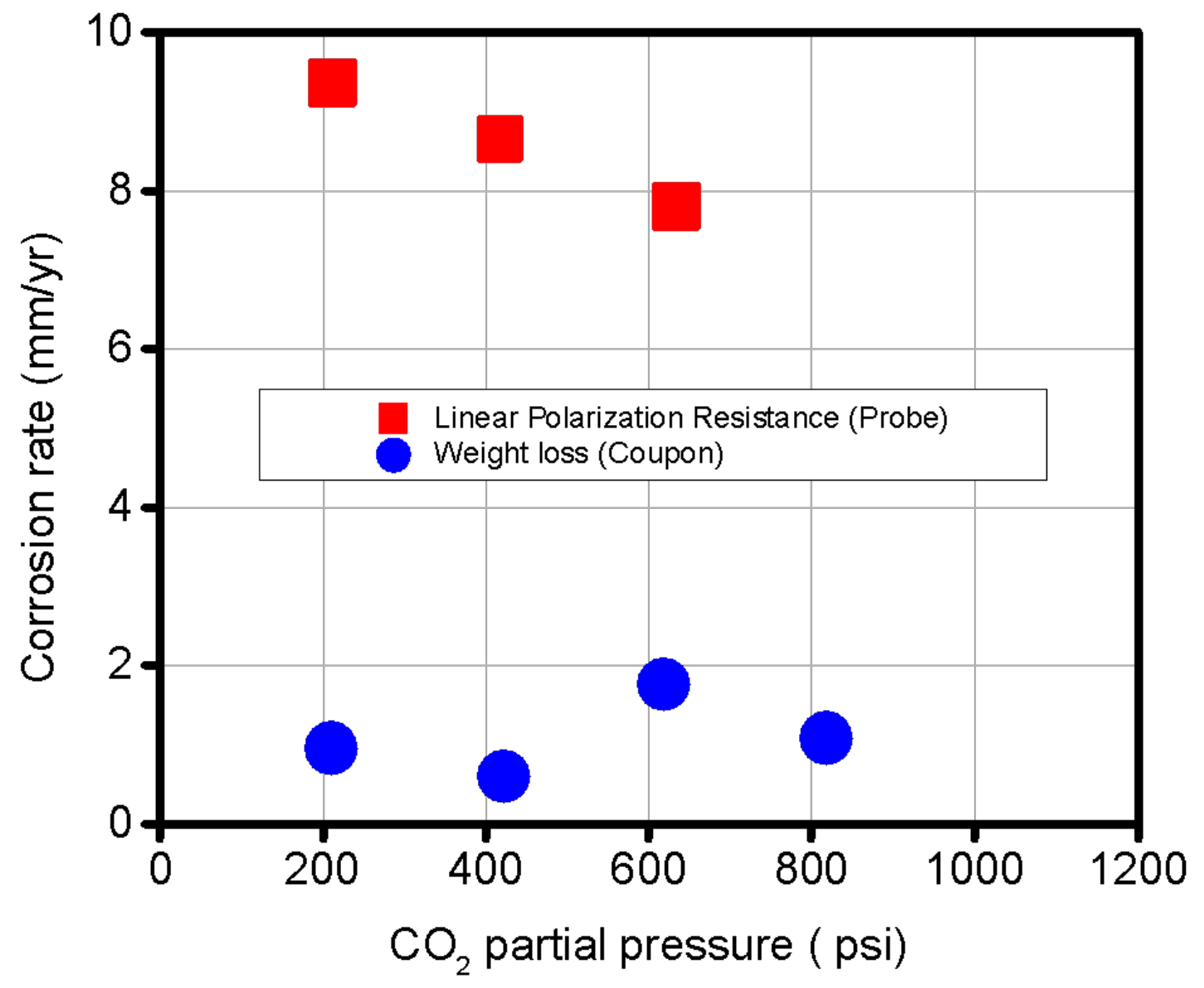

Fig. 5: Comparing corrosion rate measured from the electric probe with agitation vs. the coupon with agitation.

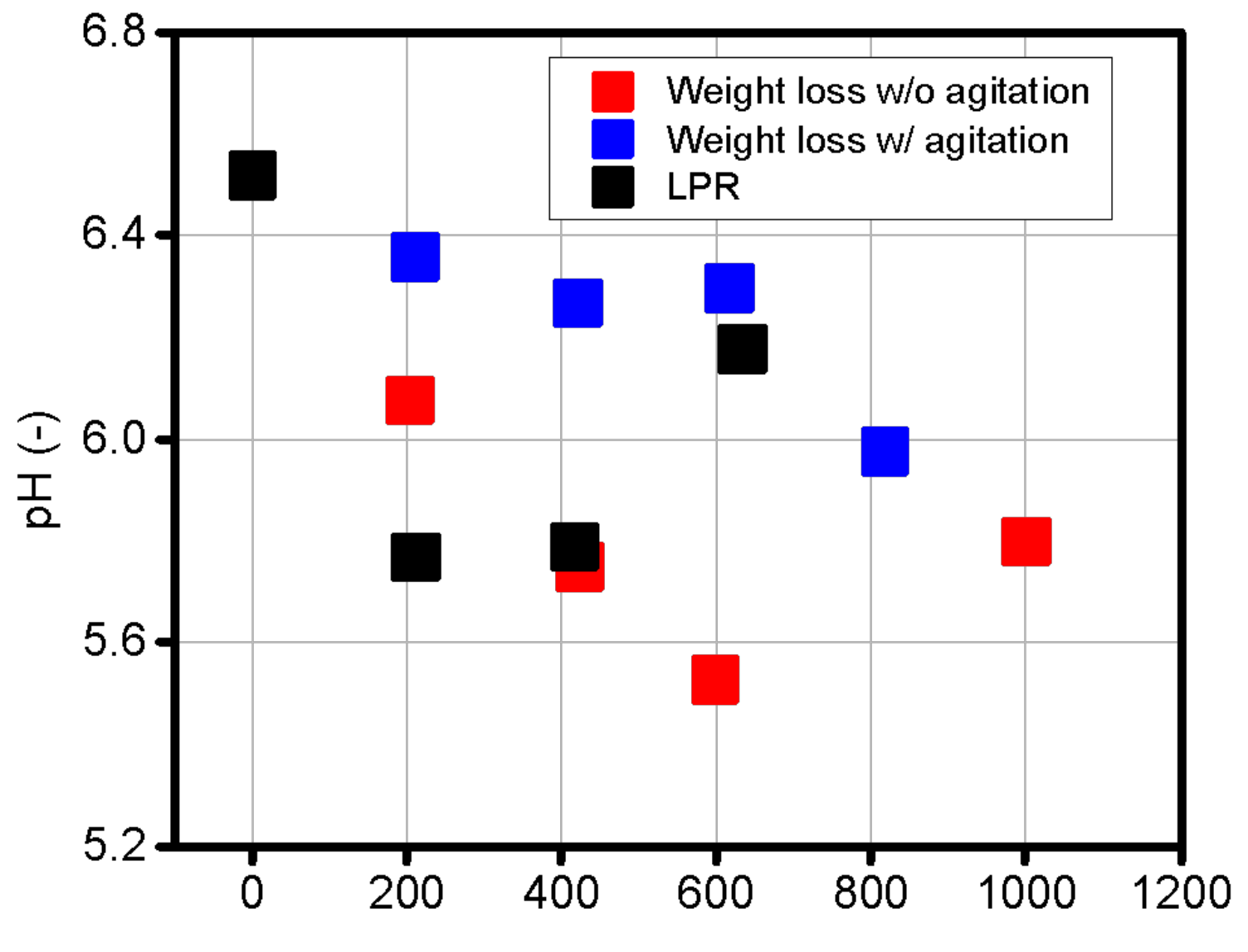

Fig. 6: Comparing the final pH of the formation water at different partial pressure of carbon dioxide.

Discussion

As far as differences in appearances go, the weight loss tests show more of a localized corrosion through pitting on the coupons, whereas the probe covers are a more generalized corrosion (**Fig. 3**).

The general trend for weight loss approach (coupon tests) shows an increase in corrosion as the partial pressure increased (**Fig. 4**). However, the coupons immersed in the stand still water had a noticeably less corrosion rate compared to the coupons with agitation presumably due to a limited mass transfer of CO_2 into the solution.

When comparing LPR (electric probe) to the weight loss (coupon), the probe readings in the water cause the corrosion rate to be estimated a lot more than what the metal coupons corrosion rate was (**Fig. 5**). Furthermore, the corrosion rate seemingly decreases with the increase in CO_2 partial pressure. With this inaccuracy, it might be best to try new probes and compare.

The presence of the acid increased with more pressure of CO_2 making it known that the increase in partial pressure caused the water to become more acidic which leads to a higher corrosion rate in stand still water (**Fig. 6**).

Conclusions

1) Although the measured corrosion rate varies between the LPR and weight loss measurement techniques, both methods detect increased corrosion caused by increasing pressure.
2) The LPR measurement technique overestimates the true corrosion rate, thus the Weight Loss method is the more accurate of the two techniques tested.
3) CO_2 saturated water corrodes steel more at a faster rate if it is flowing. Conversely, the corrosion rate is slower if the water is not moving.
4) More acidic water leads to higher corrosion rate.

References

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Acknowledgments

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