IC-003 SUPPLEMENTAL READING

# $CO_2$ (Sweet) Corrosion in Pipelines: Mechanism, Risks, Diagnostics, and Mitigation

Part 1 of the Field Notes article Internal Corrosion: Sweet and Sour — the carbonic-acid mechanism, where sweet corrosion shows up, how to recognize it, and how to mitigate it. Companion reading for IC-003 — $CO_2$ (Sweet) Corrosion. (The sour half of the article accompanies IC-004.)

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$CO_2$ corrosion, commonly known as sweet corrosion, is a prevalent and challenging form of internal corrosion affecting pipelines and associated facilities in the oil and gas industry. For corrosion field technicians, pipeline integrity specialists, and engineers, understanding the detailed mechanism of $CO_2$ corrosion, its risk factors, diagnostic indicators, and mitigation strategies is essential for effective corrosion management and asset protection.

The first part of this article provides an advanced, comprehensive overview of $CO_2$ sweet corrosion, bridging fundamental electrochemical principles with practical field applications. It covers where this corrosion occurs, how to recognize it visually and diagnostically, and how to prevent and mitigate its effects, including common challenges encountered in the field and how to overcome them.

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## Mechanism and Fundamentals of $CO_2$ (Sweet) Corrosion

At its core, $CO_2$ corrosion is an electrochemical process driven by the dissolution of carbon dioxide gas into water, forming carbonic acid ($H_2CO_3$), which lowers the pH of the aqueous phase inside pipelines. This acidic environment promotes the anodic dissolution of iron from carbon steel surfaces, leading to metal loss. The fundamental reaction can be summarized as:

> $Fe\ (metal) + H_2CO_3 \rightarrow FeCO_3\ (iron\ carbonate) + H_2\ (hydrogen\ gas)$

The carbonic acid dissociates to bicarbonate ($HCO_3^-$) and hydrogen ions ($H^+$), which participate in the corrosion reactions. The iron ions released can combine with carbonate ions to form iron carbonate ($FeCO_3$), which may precipitate as a protective scale under certain conditions. However, this scale is often porous or unstable, especially under turbulent flow or elevated temperatures, allowing continued corrosion beneath or around it.

Key electrochemical aspects include:

- **Anodic reaction:** Iron dissolves into ferrous ions ($Fe^{2+}$) releasing electrons.
- **Cathodic reaction:** Hydrogen ions (from carbonic acid) are reduced to hydrogen gas.
- **Electrolyte:** The aqueous phase containing dissolved $CO_2$ and ions acts as the electrolyte facilitating ion transport.

The corrosion rate is influenced by the balance between scale formation and scale removal, which depends on flow velocity, temperature, $CO_2$ partial pressure, and water chemistry.

# Where $CO_2$ Corrosion Occurs and Risk Factors

$CO_2$ corrosion is typically encountered in pipelines and equipment handling $CO_2$-rich fluids, including:

- Produced water lines in oil and gas production where $CO_2$ is dissolved.
- Gas condensate pipelines with $CO_2$ presence.
- Injection wells and enhanced oil recovery (EOR) operations involving $CO_2$ injection.
- Mature fields where reservoir $CO_2$ content increases over time.

Risk factors that exacerbate $CO_2$ corrosion include:

- **Water presence:** Water is essential as the electrolyte; areas with water accumulation such as low points, separators, or stratified flow regimes are particularly vulnerable.
- **High $CO_2$ partial pressure:** Elevated $CO_2$ increases carbonic acid concentration, lowering pH and increasing corrosivity.
- **Temperature:** Corrosion rates peak typically between 60°C and 80°C; higher temperatures can destabilize protective scales.
- **Flow velocity:** Turbulent or high flow can erode protective scales, exposing fresh metal.
- **Water chemistry:** Presence of bicarbonate ions can buffer pH; chloride ions and other impurities may increase corrosion risk.

# Visual and Diagnostic Indicators

In the field, $CO_2$ corrosion often manifests as:

- **Uniform thinning:** General wall loss detectable by ultrasonic thickness measurements (UTM).
- **Localized pitting:** Mesa-like pits with flat bottoms and steep sides due to partial scale breakdown.
- **Iron carbonate scale:** Sometimes visible as a brownish or reddish deposit, though often porous.

Diagnostic tools and methods include:

- **Ultrasonic Thickness Measurement (UTM):** To detect and quantify wall thinning.
- **Magnetic Flux Leakage (MFL):** For identifying localized metal loss.

- **Corrosion coupons and probes:** Inserted into the system to monitor corrosion rates; rates above 0.1 mm/year typically indicate active corrosion requiring intervention.
- **Fluid sampling and analysis:** Measuring $CO_2$ partial pressure, pH, and water chemistry per AMPP TM0177 standards.

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# Prevention and Mitigation Strategies

Effective mitigation of $CO_2$ corrosion involves altering the corrosive environment or protecting the metal surface. Key strategies include:

## Corrosion Inhibitors

- Film-forming amines or imidazolines that adsorb onto the steel surface, creating a barrier to corrosion.
- Dosage typically ranges from 10 to 50 ppm, adjusted based on lab simulations and field monitoring.
- Continuous injection upstream of vulnerable areas is preferred; batch treatments combined with pigging can enhance distribution.

## pH Stabilization

- Adding alkalizing agents such as sodium hydroxide to raise the pH above 6.5, reducing carbonic acid formation and corrosivity.

## Material Selection

- Upgrading to corrosion-resistant alloys (CRAs) like 13Cr stainless steel in highly corrosive zones.

## Operational Controls

- Managing flow rates to prevent scale erosion and water accumulation.
- Temperature control to maintain conditions favorable for stable scale formation.

## Monitoring

- Regular use of corrosion coupons, electrical resistance (ER) probes, and fluid analysis to track corrosion rates and inhibitor effectiveness.

# Step-by-Step Procedure for Implementing Corrosion Inhibitors

### System Assessment

- Collect fluid samples to measure $CO_2$ partial pressure, pH, temperature, and flow rates.
- Analyze samples in accordance with AMPP TM0177 for accurate corrosivity assessment.

### Inhibitor Selection

- Choose inhibitors compatible with the fluid chemistry and operational conditions.
- Confirm compatibility with other chemicals in use to avoid emulsions or adverse reactions (per AMPP SP0194).

### Injection Setup

- Install continuous injection points upstream of corrosion-prone areas.
- For batch treatments, coordinate pigging schedules to distribute inhibitors effectively.

### Monitoring and Adjustment

- Deploy corrosion coupons and ER probes to monitor corrosion rates.
- Adjust inhibitor dosage based on monitoring data to maintain corrosion rates below target thresholds (e.g., <0.1 mm/year).

# Common Challenges and How to Overcome Them

- **Flow Effects:** High velocity or turbulent flow can strip inhibitor films, reducing effectiveness. Mitigate by modeling flow regimes (using software like OLGA) and adjusting inhibitor dosing or adding flow loops.
- **Chemical Compatibility:** Inhibitor incompatibility with other chemicals can cause emulsions or deposits. Conduct compatibility testing before implementation.
- **Scale Instability:** Protective iron carbonate scales can be eroded or destabilized by operational changes; maintain stable flow and temperature conditions.
- **Monitoring Accuracy:** Delays in fluid sampling or improper coupon placement can yield misleading data; ensure timely sampling and representative coupon locations.

## Summary and Key Takeaways

- $CO_2$ (sweet) corrosion is a significant internal corrosion threat in $CO_2$-rich pipeline environments, driven by carbonic acid formation and iron dissolution.
- It commonly occurs in produced water lines, gas condensate pipelines, and $CO_2$ injection systems, especially where water accumulates.
- Visual indicators include uniform thinning and mesa-like pitting, with diagnostic tools such as UTM, MFL, and corrosion coupons essential for detection.
- Mitigation focuses on corrosion inhibitors, pH control, material upgrades, and operational management, supported by rigorous monitoring.
- Challenges such as flow-induced inhibitor film stripping and chemical incompatibility require proactive management and testing.

By knowing these fundamentals and applying best practices, corrosion field technicians and engineers can effectively manage $CO_2$ corrosion risks, ensuring pipeline integrity and operational safety.

## Referenced Standards and Guidelines

- **AMPP TM0177:** Laboratory Testing of Pipeline Fluids for Corrosion Assessment
- **AMPP SP0194:** Chemical Compatibility Testing for Corrosion Inhibitors
- **AMPP SP0472:** Welding and Materials for Sour Service ($H_2S$)
- **NACE SP0169:** Control of External Corrosion on Underground or Submerged Metallic Piping Systems
- **49 CFR 192.476:** Internal Corrosion Control Requirements for Gas Pipelines

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