Analysis of the application and impact of carbon dioxide media on the corrosion state of oil and gas facilities

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How to cite this article: Kantyukov R.R., Zapevalov D.N., Vagapov R.K. Analysis of the application and impact of carbon dioxide media on the corrosion state of oil and gas facilities. Journal of Mining Institute. 2021. Vol. 250, p. 578-586. DOI: 10.31897/PMI.2021.4.1

Abstract. Products of several currently operated production facilities (Bovanenkovskoye, Urengoyskoye oil and gas condensate fields, etc.) contain an increased amount of corrosive CO₂. Effect of CO₂ on the corrosion of steel infrastructure facilities is determined by the conditions of its use. Carbon dioxide has a potentially wide range of applications at oil and gas facilities for solving technological problems (during production, transportation, storage, etc.). Each of the aggregate states of CO₂ (gas, liquid and supercritical) is used and affects the corrosion state of oil and gas facilities. Article analyzes the results of simulation tests and evaluates the corrosion effect of CO₂ on typical steels (carbon, low-alloy and alloyed) used at field facilities. The main factors influencing the intensity of carbonic acid corrosion processes in the main conditions of hydrocarbon production with CO₂, storage and its use for various technological purposes are revealed. Development of carbon dioxide corrosion is accompanied and characterized by the localization of corrosion and the formation of defects (pitting, pits, etc.). Even alloyed steels are not always resistant in the presence of moisture and increased partial pressures of CO₂, especially in the presence of additional factors of corrosive influence (temperature, aggressive impurities in gas, etc.).

Keywords: oil and gas facilities; production and storage of gas; carbon dioxide; corrosion aggression of medium; carbon dioxide corrosion

Introduction. Carbon dioxide (CO₂) has applications in various fields and has been used by various oil and gas infrastructure facilities. Recently, at some gas facilities, for example, at Bovanenkovskoye [11], Urengoyskoye [7], Yubileynoye [1] oil and gas condensate fields (OGCF), corrosion problems have arisen due to the increased content of CO₂ in the produced products. In this regard, increased attention is paid to the problem of corrosion risks as a result of carbon dioxide corrosion (CDC) and its control [5, 38]. To control the technical condition of gas production and underground storage facilities, a set of measures is used, including geophysical [9], diagnostic investigations [2] and corrosion monitoring [40].

There is a triple point \( P_{cr} = 7.38 \text{ MPa} \) and \( T_{cr} = 31.1 \text{ °C} \) for the aggregate states of CO₂ (gas, liquid and supercritical), which links them. CO₂ can transfer from one state to another with a change in pressure and temperature. Supercritical state is characterized by the absence of difference between the liquid and gas phases. CO₂ in the supercritical state (SCS) has intermediate characteristics between the properties of gas and liquid: compressibility like gas, and density like liquid. CO₂ in SCS is able to dissolve many organic substances. It has a significantly lower viscosity than other compounds in a liquid state. In addition, the diffusion coefficient of CO₂ in SCS is several orders of magnitude higher than that of other liquids.

Partial pressure is relatively low at gas production facilities and CO₂ is in a gaseous aggregate state. Carbon dioxide is not only a component in the composition of extracted products, but can also be used at oil and gas facilities to solve technological problems, where the special properties of CO₂, including in SCS, can be effectively used [3, 10].

One of the promising trends is the use of CO₂ as a buffer gas in underground gas storage (UGS) to maintain pressure in the formation [4]. This makes it possible to partially replace the buffer volume of methane (CH₄) with CO₂ and obtain additional volumes of commercial natural gas.
CO₂ is often used in liquid form or in SCS, since, being heavier than CH₄, it allows CO₂ to be located in the lower part of the storage facility, preventing losses during the extraction of commercial gas from UGS [13].

The most proven is the use of CO₂ for injection into the formation at the oil fields in order to increase oil production. In recent decades, this technology has been a widespread method for enhancing oil recovery in the world, for example, in the case of developing oil fields with hard-to-recover oil reserves, or when an effective additional development of fields at the late and final stages of hydrocarbon production is required. Application of CO₂, including in SCS, is able to provide an effective reduction in oil viscosity in formation conditions and the mutual dissolution of oil and CO₂. Regarding some oil formations, which are characterized by thermodynamic conditions that allow CO₂ to pass into the SCS, the advantages of its use over the use of reagents and other methods of oil production intensification are obvious. It is noted in the article [14] that in China, tests are being carried out in the field of rheogasochemical technologies for in-situ generation of CO₂. CO₂ obtained as a result of the reaction has the properties of the directed effect on stagnant zones and weakly drained areas of the formation.

CO₂ can be used to increase gas condensate recovery at OGCF by analogy with oil fields, which is another area of its application in oil and gas industry. Article [6] reports on the possibility of using such a technology at the Orenburg OGCF (OOGCF). Authors note that as a result of the hydrocarbons production and watering of wells, gas confinement in porous rocks can occur. At the later stages of development, with a drop in pressure, the gas energy in such a structurally confined gas volume becomes insufficient to break the continuity of the liquid phase (oil, water). In such places, along with gas, liquid hydrocarbons (gas condensate, oil) can be found, which makes the use of CO₂ with properties of a good solvent, very promising for intensification of production at the OOGCF. In this case, the products of extraction can be gas, gas condensate and oil, including those from thin rims. According to the authors, application of this technology can significantly increase the gas recovery factor at the Orenburg OGCF, and the use of CO₂ will increase both oil recovery and gas production.

Work [8] considers the options for re-injection of either acid gases (a mixture of H₂S and CO₂, consisting of fluids separated from the fluids produced at the field during treatment of raw materials), or CO₂, for the Astrakhan gas condensate field (AGCF). This will improve the efficiency of the gas facility development. Application of this technology is aimed at maintaining reservoir pressure at AGCF to minimize formation losses during gas condensate production.

The issue of reducing anthropogenic emissions into the environment is a topical one. One of the negative factors is the increase in the concentration of greenhouse gases, including CO₂. Measures to reduce greenhouse gas emissions, adopted under the Kyoto Agreement, provide a set of solutions. One of the directions is the creation of underground reservoirs to utilize the excess CO₂ for long-term storage. Analysis of the world experience in capturing and pumping CO₂ into formation systems has shown that this can be a promising way to reduce CO₂ emissions into the atmosphere [12].

Transportation of recoverable CO₂ (in liquid state or in SCS) to the places of its geological burial in underground storages (carbon capture and storage – CCS) is realized, as noted in [19]. CO₂ pipelines are quite long (hundreds of kilometers), which limits the use of corrosion-resistant steel for their manufacture. Carbon steel/low-alloy steel is predominantly used, so it is important to ensure the safe operation of facilities.

For example, gas from the Askeladd, Albatross and Snøhvit fields, developed on the Norwegian shelf using subsea production systems, is transported to the coast 160 km, where it is liquefied. However, the gas contains up to 5–8 % CO₂, which needs to be removed to produce liquefied natural gas (LNG) (down to a low level of 50 ppm). Removed CO₂ is transported and pumped back into the underground (underwater) storage, into the formation below the productive horizon of the Snøhvit
field [27]. For example, according to Russian regulations, the molar fraction of \( \text{CO}_2 \) in LNG should not exceed 0.005-0.03 %. At many fields, the content of \( \text{CO}_2 \) in the produced gas significantly exceeds these standards.

Often, not gas reservoirs, but aquifers are used for \( \text{CO}_2 \) injection [16]. Creation of \( \text{CO}_2 \) storage facilities in underground cavities, for example, after the end of the operation of a gas or oil field, has also become widespread. In addition to various technological risks during their operation, it is necessary to take into account the danger of CDC in case of contact of the increased \( \text{CO}_2 \) quantities transported and pumped into underground reservoirs with equipment and pipelines made of carbon or low-alloy steels. In the presence of an aqueous phase of a condensation or formation nature, its saturation with \( \text{CO}_2 \) will occur, accompanied by acidification, which intensifies the CDC process [30]. More and more projects are being launched in the world to use abandoned oil and gas fields, for example, Weyburn and Midale in Canada [37]. In this regard, it is reported that the corrosion rate can reach 20 mm/year and will depend, among other things, on corrosion products that can contribute to a decrease in the corrosion rate.

\( \text{CO}_2 \) can, under certain conditions, lead to corrosion damage in all considered fields of application. The most dangerous property of CDC is that corrosion effects are not characterized by general (uniform over the entire metal surface) corrosion losses, but mainly by the most dangerous type of local corrosion, with the formation of local defects such as pitting, pits, etc. [40].

In this regard, the article discusses topical issues of assessing the corrosion aggression of carbon dioxide media and the resistance of steel objects in such conditions.

**Methodology.** Corrosion tests under conditions of moisture condensation were carried out at normal (20-25 °C) temperature. Test methods for moisture condensation, sample processing, assessment of corrosion defects, statistical data processing were carried out according to the procedures [34]. After the tests, the general corrosion rate \( K_{\text{gen}} \) was determined by the loss of the sample mass and the local corrosion rate by the depth of corrosion damage (average \( K_{\text{loc.av}} \) – by averaging over all local defects, maximum \( K_{\text{loc.max}} \) – by the deepest local damage).

Corrosion tests were carried out using the gravimetric method. Partial pressure effect of corrosive gases on the corrosion of the samples was evaluated in an autoclave unit (static conditions), after oxygen was removed by blowing with an inert gas. Exposure time of gravimetric samples in an autoclave unit was 120 h.

Phase composition of the corrosion products was analyzed by the X-ray diffraction method. It is based on recording the dependence of the intensity of the X-ray radiation reflection by the crystal lattices of the compounds on the value of the diffraction angle, followed by the interpretation of the diffraction pattern. Scanning was carried out on an ARL X’TRA X-ray diffractometer. Identification of crystalline phases was carried out by comparing the array of reflections obtained from the test sample with the reference diffractograms of individual compounds contained in the international database of diffraction standards.

Carbon steels (St20 and X65), low-alloy steels (0.05-0.2 % Cr) and corrosion-resistant steels (12X18H10T) were used during the tests.

**Results.** It is known [39] that the most metal-consuming and most corrosive type of equipment at gas production facilities are well equipment and field pipelines (well connections, collectors, drags) in contact with untreated gas (until the removal of corrosive gases and moisture). When considering the corrosive aggression of the medium at gas production facilities in conditions of increased \( \text{CO}_2 \) content, it should be taken into account that corrosion can occur in the lower part of the pipe when moisture accumulates (bottom-of-line corrosion, BOL), in the upper part of the pipe in case of moisture condensation (top-of-line corrosion, TOL), in places where moisture accumulates (cracks, gaps, stagnant zones, elevation differences, etc.).
The main reason for the development of corrosion is the presence of moisture, which can interact with steel in the bulk of solution (BOL) or during condensation, in a thin film of moisture on steel (TOL). TOL corrosion, in contrast to the corrosive conditions of oil facilities, occurs only at gas fields. Under the conditions of field transport for wet, untreated gas, when leaving the well water vapor in the gas phase condenses on the inner surface of the pipe due to the temperature difference between the wet gas flow and the environment, which leads to the appearance and development of TOL corrosion. BOL corrosion is typical for sections of the pipeline system when the water phase is in constant contact/movement with the inner surface of the pipeline steel [31, 35].

TOL tests carried out in the presence of CO₂ showed that at a low (less than 0.1 mm/year) rate of general corrosion on carbon steel X65 (API 5L), a high local corrosion is observed (Fig.1).

As can be seen, development rate of local defects (0.5-1.5 mm/year) is observed to the greatest extent on specimens from the weld seam. Weld seam, due to their heterogeneity with respect to the parent metal, turned out to be more susceptible to uneven types of corrosion damage.

Analysis of the data obtained shows (Table 1) that low-alloy steels with a low chromium content (0.05-0.2 %) are not resistant to local CDC. Local defects with a depth of 50-84 µm are formed on the samples. Only on the surface of high-alloy steel 12X18H10T there were no corrosion manifestations, either general or local (Table 1).

### Table 1

| Sample            | Depth of corrosion damage, µm | Local corrosion rates K_loc, mm/year |
|-------------------|------------------------------|-------------------------------------|
|                   | average | maximum | by average values K_loc,av | by maximum values K_loc,max |
| 12X18H10T (18 % Cr) | 50      | 80       | 0.681              | 0.949              |
| Steel (0.2 % Cr)   | 50      | 66       | 0.608              | 0.803              |
| Steel (0.05 % Cr)  | 50      | 56       | 0.608              | 0.818              |

After TOL tests, deep pitting damage of the samples are observed on both low-alloy and carbon steels (Table 2). Tested steels are used in various areas of oil and gas facilities – tubing of well equipment, other steels – for the manufacture of field pipelines.

An increase in CO₂ pressure can increase the solubility of the gas in the aqueous phase, increasing the corrosion rate. This will primarily relate to the local corrosion rate in the vapor phase. Also, the localized corrosion rate will rise with increasing water content in the test chamber, while general corrosion may remain unchanged. First of all, this is due to moisture condensation: with a lack of air humidity, the dew point will not be reached, and a moisture film will not precipitate on the steel surface. In addition to the content of CO₂ and moisture in the vapor phase, other factors can also affect the CDC [33]. Let us consider some of them in more detail.
Corrosion resistance of steel P110 (0.5 % Cr) was investigated in [36] under the following conditions: 3.5 % NaCl, 80 °C and 9.5 MPa CO₂. Investigations were carried out in two modes: in an aqueous electrolyte saturated with CO₂ in SCS (steel is in contact with the aqueous phase, conditions are similar to BOL corrosion), and in a water-saturated CO₂ in SCS (steel is in contact with wet CO₂, conditions are similar to TOL corrosion). In the first mode (in an aqueous electrolyte), both general (6.12 mm/year) and local (1.8 mm/year) corrosion rates are equally high. In the second mode, a relatively low general rate (0.35 mm/year), but a high level of local corrosion (1.17 mm/year) is observed. According to the authors, the reason for this is that in the second mode, local corrosion defects are observed only in the places of drops condensation on steel (such as TOL corrosion), corrosion does not spread over the entire surface of the steel.

Table 2

Corrosion rate of steels after testing under conditions of water condensation in the presence of CO₂ (0.1 MPa) at temperature 20-25 °C

| Steel                                      | Corrosion rate, mm/year | Sample appearance after testing |
|--------------------------------------------|-------------------------|---------------------------------|
|                                            | General  | Local (pitting)*               | General | Zoomed in |
| St 20                                      | 0.04     | 0.32-0.384                     |         |           |
| Steel (0.2 % Cr)                           | 0.03     | 0.67-1.0                       |         |           |
| Tubing steel                               | 0.015    | 0.368-0.61                     |         |           |
| Steel (0.05 % Cr)                          | 0.03     | 0.61-0.8                       |         |           |
| 12X18H10T                                  | 0.0001   | –                               |         |           |

*Range of average $K_{loc,av}$ and maximum $K_{loc,max}$ values of local corrosion.
Test results confirm that gas facilities operated under conditions of the CO₂ presence in the extracted products are subject to increased corrosion hazard in the aqueous and vapor phases, especially local corrosion typical for the CDC. Corrosion products formed in the corrosion process on the metal surface play a certain role in the protection of steels from corrosion. Investigations carried out in an aqueous medium (Fig.2) to determine the phase composition of the film formed on steel after autoclave tests showed that crystallized siderite (FeCO₃) with a small amount of X-ray amorphous substances is predominantly formed during CDC.

Depending on the phase composition, the precipitate of corrosion products can be either close-packed or porous. More porous corrosion products will be less resistant to the action of chloride anions, which provoke the nucleation and development of pitting, in contrast to the denser siderite layer.

Long-term simulation tests of several pipe steels (containing 1 and 13 % Cr), used in one of the underground CO₂ storages in Germany, showed [29] that the model of aquifer water in the presence of CO₂ is quite corrosive. General corrosion rate in vapor phase is 0.35 mm/year (13 % Cr) and 0.8 mm/year (1 % Cr). When exposed to the aqueous phase, a thick layer of corrosion products forms on the surface of steels, and pitting up to 4.7 mm deep are observed, which can be explained by the high mineralization of the aqueous medium and the increased content of chloride anions.

A significant acceleration of corrosion processes at 35 °C and 8 MPa CO₂ was observed for steels X65 (0.11 % Cr) and 5Cr (5 % Cr) with the addition of 0 to 1000 ppm O₂ [24]. Tests were carried out in water-saturated CO₂ (SCS). With an increase in O₂ concentration, an increase in pitting corrosion occurred: local corrosion rate ranged from 0.2 to 1.4 mm/year for X65 steel, and from 0.3 to 1.4 mm/year for 5Cr steel. An important role in the development of corrosion is played by the fact that the presence of O₂ suppresses the formation of siderite (FeCO₃), forming a film on the steel surface, mainly consisting of iron oxide (Fe₂O₃), which has an amorphous structure. The growth of local corrosion on both steels depends on the water saturation of CO₂, and corrosion increases with increasing water content.

An important role in the corrosion aggression of CO₂ in the SCS is played by the presence of impurities in it, which may be typical for greenhouse gases emitted for injection and storage into underground reservoirs. These gases, in addition to O₂, include SO₂, NO₂, H₂S. Results of investigations at a temperature of 35 °C and in SCS (8 MPa CO₂) for steels X65 (0.11 % Cr) and 13Cr (13 % Cr) are given in [20]. The addition of two other corrosive gases (SO₂ and O₂) to CO₂ in the presence of moisture leads to a synergistic effect in the development of the corrosion process. General corrosion rate for both steels is equally high: 0.95 mm/year for X65 steel, and 0.65 mm/year for 13Cr...
steel. Pitting corrosion is even higher for both steels (X65 and 13Cr) and is in the range of 7-80 mm/year. Presence of impurities leads to the formation of other corrosion products: iron oxides and sulfate instead of iron carbonate. Dissolution of SO₂ in an aqueous film leads to the formation of extremely corrosive sulfuric acid, the destructive effect of which is enhanced by the presence of a strong oxidant O₂. Similar data are given on the corrosion rate of carbon and alloy steels under analogous test conditions in the work of other authors [22]: up to 1 mm/year – general corrosion rate, and about 10 mm/year and more – for local defects. It is reported that localization of corrosion begins when water is present in a concentration of 300 ppm and higher.

Study of steel X65 at 8 MPa CO₂ and a temperature of 35 °C showed that in the presence of SO₂ less water is required for the development of corrosion than only with CO₂. Local corrosion rate reaches 0.5-1.5 mm/year, increasing with the addition and increase of SO₂ concentration [25].

Tests of carbon and low-alloy steels at a pressure of 8-12 MPa CO₂ and an ambient temperature of 25-80 °C showed that the addition of 200 ppm H₂S leads to a significant 50-fold increase in the corrosion rate in the vapor phase of CO₂. With moisture condensation, the growth of the corrosion rate is slightly lower (5-10 times), since at CDC it is initially higher than 0.1 mm/year [23].

Data were obtained on the dependence of the corrosion resistance of steels with different chromium content (9, 13, and 25 %) on the partial pressure of CO₂ and the temperature of the environment in the study [26]. For example, for steel 9 % Cr, corrosion rate of steel increases with a growth in the partial pressure of CO₂: 0.1-0.3 mm/year at 0.1 MPa CO₂ in the temperature range 50-250 °C; 0.5 mm/year (50 °C) and 5 mm/year (150 °C) at 0.3 MPa CO₂. In this case, for steel 13 % Cr, critical temperatures are 200 °C (at 0.1 MPa CO₂) and 150 °C (at 0.3 MPa CO₂), when the corrosion rate begins to grow and exceeds 0.1 mm/year. Steel 25 % Cr was the only one that was stable at all the above temperatures and partial pressures of CO₂.

Work [14] notes that chemical compositions injected for in-situ CO₂ generation and enhanced oil recovery in the process of injection into the formation contact with underground well equipment. This increases the risk of corrosion destruction of metals, for the protection of which anti-corrosion protection should be used.

In such aggressive conditions of CDC, high-alloy steels can be used to protect the steel equipment and pipelines, which, however, in some particularly aggressive conditions also require the use of anti-corrosion protection [15]. Carbon and low-alloy steels that are not resistant to CDC, as well as some alloyed ones, can be protected by inhibitors or coating.

Tests have shown [32] that the corrosion rate of carbon steel at 50 °C and a CO₂ pressure of 2-8.5 MPa is 1.87-3.0 mm/year. In the presence of a corrosion inhibitor, which is chemisorbed on steel, it decreases to 0.061-0.137 mm/year. The article [18] reports on the effectiveness of corrosion inhibitor protection under conditions of intensification of oil production at 60 °C and CO₂ pressure up to 8 MPa.

Coatings that should be non-porous can also find use in protecting objects from CDC. Experience for the successful use of a metal coating for protection under the conditions of SCS CO₂ is presented in the study [21]. Another type of metal coating based on Ni-W (with additions of Y₂O₃ and ZrO₂ nanoparticles), which has a low energy of CO₂ adsorption on its surface, remains dense, stable and without pitting after operation under CDC conditions [28]. The work [17] discusses the possibility of using conversion coatings of a complex composition to protect pipelines transporting CO₂, including under conditions of acidification by the aqueous phase.

**Conclusion.** CO₂ extracted at oil and gas fields together with fluids has a corrosive effect on steel equipment and pipelines with the formation of local damage. Carbon and low-alloy steels used at hydrocarbon production facilities are unstable in the presence of CO₂ and moisture. Corrosion rate of such steels can reach high values. Tests carried out in carbon dioxide media of carbon (St20 and X65) and low-alloy steels (0.05-0.2 % Cr) showed that they undergo corrosion destruction with the formation of deep defects (pitting, etc.) under conditions of water condensation (TOL-corrosion), which can be the most dangerous at gas production and storage facilities. Local corrosion rate of such
steels is high and reaches 1 mm/year. Comparative analysis in identical tests for the surface of high-alloy steel 12X18H10T (18 % Cr) showed that its resistance under CDC conditions is high, no corrosion manifestations of either a general or a local nature appeared on the surface of the sample. CO2 is widely used at some oil and gas facilities for injection into the formation in order to support technological tasks (for stimulation of production, disposal of surplus, underground gas storage, etc.). In such conditions, it can also pose a corrosive hazard to equipment and pipelines due to the increased salinity of the aqueous phase, high pressures and temperatures of the medium, and the presence of impurity gases. Even corrosion-resistant steels (with a chromium content of 13 %) are unstable in these media. To ensure the protection of oil and gas infrastructure facilities, more corrosion-resistant steels or the use of other means of protection against corrosion (corrosion inhibitors or others) are required. It is needed to carry out experimental investigations of corrosion in conditions of SCS CO2.

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The authors declare no conflict of interests.

The paper was received on 15 April, 2021.
The paper was accepted for publication on 27 July, 2021.