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Some considerations regarding the influence of working conditions on the corrosion wear of the injection water treatment plant equipment

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Abstract. One of the methods used for the secondary exploitation of oil deposits is the water injection. The injected water is obtained after the separation of the well extracted fluid that contains a mixture of crude oil, water, gases and solid particles. Prior to injection, water must meet the following requirements: a high degree of purity obtained thought the lowest possible mechanical and oil content; lower degree of aggressiveness (corrosion); the highest stability; compatibility with the fluids and minerals in the reservoir formation; low oxygen content and bacteria. The fulfilment of these requirements must be ensured by the water treatment plant whose equipment is subjected to corrosion wear. The equipment degradation are occurring mainly at pipelines and connecting elements of the flotation skid, in the form of advanced corrosion wear because the water injection contains an inconsistent composition mixture of dissolved gases, hydrocarbons, solid particles. The paper presents the regression analyses that emphasize the influence of chemical water composition and fluid speed on the corrosion rate of the different equipment parts. The corrosion rates were obtained using metallic samples according with the NACE SP0775-2013 standard that were placed in different points of the plant. The paper results can be used both at the water plant exploitation and also to next studies concerning the effectiveness of the corrosion inhibition on the corrosion rate.

1. Introduction

The exploitation of oil deposits presumes at least two stages. In the first stage, so called primary exploitation, the fluid that consists in a mixture of crude oil, water, gases and suspended solids is pushed out from the subterranean deposits to the surface under the effect of deposit internal pressure. After the subterranean pressure is exhausted, the fluid is extracted by pumping using different types of pumps. This stage is called secondary exploitation. One of the methods used for displacement the crude oil from the rock of the deposit is water injection. On both stages, the fluid mixture from the wells is directed to the collection park where the constituent phases are separated [1]. It has to be mentioned that under the exploitation conditions in Romania, the water from deposits represents on average about 60 ... 70% of the total amount of fluid extracted from the wells.

After separation from the other components of the fluid (crude oil and gas) on a plant called Separation Park, the water is sent to the treatment plant where it is treated to meet the following

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conditions [2]: a high degree of purity obtained thought the lowest possible mechanical and oil content; lower degree of aggressiveness (corrosion); the highest chemical stability; compatibility with the fluids in the subterranean deposit; compatibility with the minerals in the subterranean oil deposit; low oxygen content and bacteria.

The water resulting from separation and treatment is sent to specially prepared tanks from where is injected into specially prepared wells (technological water) in secondary exploitation process or is eliminated by injection (waste water) in specially designed wells [2].

2. Injection water treatment plant

Factors that are taken into account when an injection water treatment system it is chosen are related to the distances to sources and injection points and also to the possibilities of location on the ground so that gravitation can be used in the process of pumping water.

The treatment and injection systems (open, closed or semi-closed systems) are selected according to the characteristics of the injection water.

The influence of working conditions on the corrosion wear was determined in different points of a water treatment plant that are considered to belong at the last generation of this kind of equipment.

A modern water treatment plant (figure 1), is composed from a chemical conditioning kit, a dissolved gas flotation unit (SPINSEP) and a nutshell filter (MONOSEP) [3].

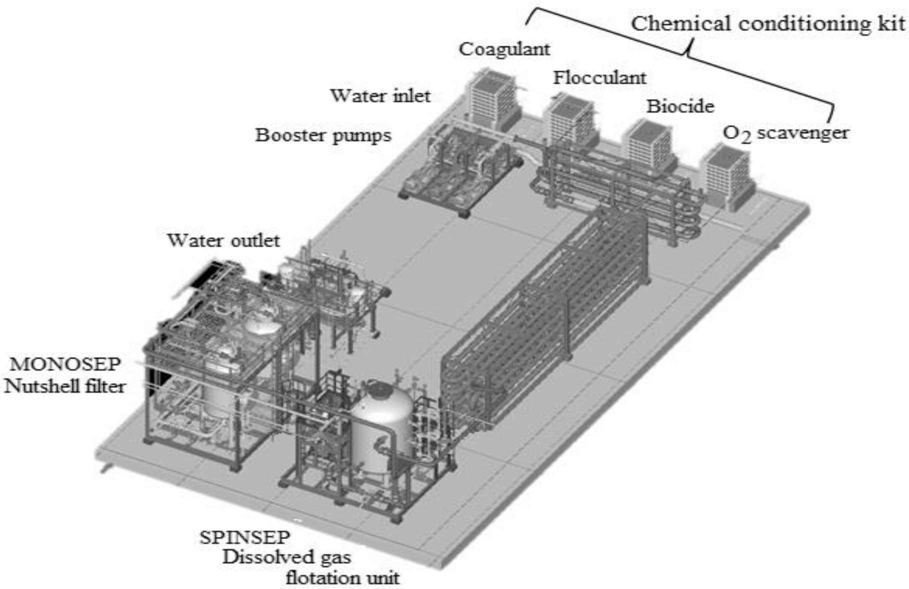

Figure 1. Water treatment plant design [3].

The water that was separated from crude oil and gas is pumped from storage tanks to the treatment plant, with three centrifugal water transfer pumps (booster pumps). In the first stage the water is treated in the chemical conditioning subsystem by injection with flocculants and coagulant substances and, in addition, with an oxygen inhibitor to remove dissolved oxygen in water and a biocide to remove bacteria. After this treatment, the water is introduced in the SPINSEP flotation system where the finest crude oil drops are separated, and finally in the nutshell filter MONOSEP where it carried out the finest ultimate filtration [3].

The main degradations occurred at the equipment in the water treatment plants were recorded mainly in the pipes and the connecting elements of the SPINSEP gas flotation skid, in the form of their advanced corrosion. Locations of the these degradations were found at bends and elbows where the direction of the pipes is changed to 90° in order to ensure a turbulent tangential flow of the fluid at the entrance to the flotation vessel, at section changes of the pipes, to the connecting elements (flanges, threads) of the pipes of the gas flotation skid and at the welding joints [4], [5], [6].

3. Experimental conditions

The corrosion rates were obtained using metallic samples (corrosion coupons) [7] according with the NACE SP0775-2013 standard [8] that were placed in different points of the water circuit between the separation parks and the outlet of the treatment plant (figure 2).

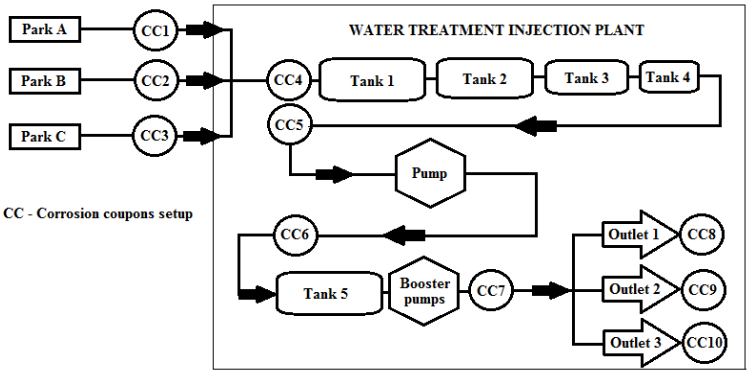

Figure 2. The setup points of corrosion coupons.

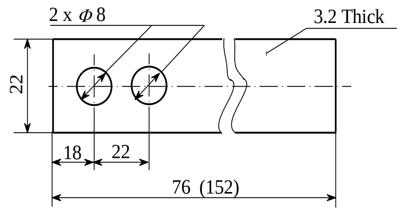

Figure 3. The sample (corrosion coupon) piece [10].

There were used strip coupons (figure 3) fixed in every setup point in pairs [8].

Coupons were made of the same steel, P285NH type, with the pipe elements used in the water treatment plant. Chemical composition of P285NH steel is presented in table 1.

Table 1. Chemical composition (wt.%) of steel P285NH (1.0477).

	C	Si	Mn	Ni	P	S	Cr	Mo	V	N
EN 10222-4	max 0.18	max 0.4	0.6 - 1.4	max 0.3	max 0.025	max 0.015	max 0.3	max 0.08	max 0.05	max 0.02
Experimental	0.189	0.23	0.908	0.006	0.007	0.003	0.02	0.001	0.003	-

Coupons were processed without affecting the structure of the material with a water jet cutting machine and subsequently by grinding with low intensive parameters using cooling fluids. Finally the surface exposed to corrosion test medium was polished with abrasive paper of 500 Mesh gradually [8].

Exposure time must be considered when interpreting corrosion coupon data. Short-term exposure (15 to 45 days) provides quick answers but may give higher corrosion rates than long-term exposures. Aggravating conditions, such as bacterial fouling, may take time to develop on the coupon. Short exposure times may be advantageous when evaluating inhibitor effectiveness. Longer exposures (60 to 90 days) are often required to detect and define pitting attack. Because exposure time affects test results, exposure periods should be as consistent as practical [9], [10]. Taking account of the above statements, the corrosion coupons used for determining corrosion rate were exposed for 90 days of water plant functioning.

For emphasizing the influence of injection water on corrosion rate were determined the chemical and electrochemical characteristics of water (table 2) in each point where the corrosion coupons were located (figure 2).

In the same time with the exposure of corrosion coupons to effect of injection water, it was determined the reducing of pipes wall thickness. Determination of wall thickness was done for different pipes diameter, especially at the elbows, where the erosion phenomenon is amplified due of the flow regime changed.

Table 2. Chemical and electrochemical characteristics of water for corrosion coupons location place.

Characteristic	Location place of the corrosion coupons									
	1	2	3	4	5	6	7	8	9	10
Density, g/cm^3	1.0407	1.0516	1.0465	1.0482	1.0495	1.0505	1.051	1.0494	1.0493	1.0495
pH	6.71	6.69	6.65	6.39	6.52	6.55	6.57	6.49	6.35	6.52
Conductivity, μs/cm	81800	96600	93000	94600	94400	95800	99100	93900	92800	92300
CO_2, mg/l	44	79	88	114	101	141	110	97	150	150
H_2S, mg/l	0.31	0.07	0.04	0.49	0.14	0.17	1.35	0.14	0.17	0.17
Chlorides, mg/l	34330	45720	39440	42600	43980	44760	44450	44120	43900	44220

4. Results and discussions

According with the NACE SP0775-2013 standard, the calculation of the average corrosion rate expressed as a uniform rate of thickness loss per unit time in millimeters per year or millimeters per annum (mm/y or mm/a), is shown in equation (1) [8]:

$$CR = \frac{W \cdot 365 \cdot 1000}{A \cdot T \cdot D} = \frac{3.65 \cdot 10^5 \cdot W}{A \cdot T \cdot D} \tag{1}$$

where: *CR* is average corrosion rate, millimeters per year (mm/y or mm/a); *W* – mass loss, grams (g); *A* – initial exposed surface area of coupon, square millimeters (mm^2); *T* – exposure time, days (d); *D* – density of coupon metal, grams per cubic centimeter (g/cm^3).

Corrosion rate was determined, using equation (1), for coupons placed in the points shown in figure 2. Regarding the influence of water characteristics (table 2) on corrosion rate it can be done the following remarks:

- the highest variations of water characteristics were registered for concentration of CO_2, H_2S and chlorides;

- the other parameters like conductivity, pH and concentrations of Ca, Mg, Ba, Na, Fe, K, Li do not registered major variations that can influenced on corrosion rate.

Taking account of above remarks, there were done regression analyses that evidencing the influence of CO_2, H_2S and chlorides concentration on corrosion rate.

Thus, the influence of CO_2 on the corrosion rate is modeled by equation (2):

$$CR = -15.514 \cdot \ln(CO_2) + 3.185 \cdot (CO_2)^{0.5} + 39.652 \tag{2}$$

where: *CR* is the corrosion rate (mm/year); CO_2 – concentration of carbon dioxide (mg/l).

The dependence expressed by equation (1) is in accordance with experimental results presented in figure 4. The determination coefficient for regression analysis expressed with equation (2) is R^2 = 0.98.

Similarly, the dependence between corrosion rate and hydrogen sulphide concentration is shown in figure 5, and is emphasized by equation (3) obtained after a regression analysis.

$$CR = 5.6 \cdot \ln(H_2S + 0.614) + 2.021 \tag{3}$$

where: *CR* is the corrosion rate (mm/year); H_2S – concentration of hydrogen sulphide (mg/l).

The determination coefficient for regression analysis equation (3) is R^2 = 0.978.

The influence of chlorides concentration on corrosion rate is shown in figure 6, and is evidenced with the regression analysis equation (4).

$$CR = -0.232 \cdot \ln(Cl - 34.327) + 0.751 \tag{4}$$

where: *CR* is the corrosion rate (mm/year); *Cl* – concentration of chlorides (g/l).

The determination coefficient for regression analysis equation (4) is R^2 = 0.968.

The reducing of pipes wall thickness as the effect of corrosion and the erosion of the water was determined for different flow speeds of the fluid (figure 7). The flow speeds were calculated for different sections values of the pipes considering the constant flow of 35 m^3/hour value.

The influence of flow speed on the reducing of pipe wall thickness can be expressed with equation (5) obtained as a result of a regression analysis.

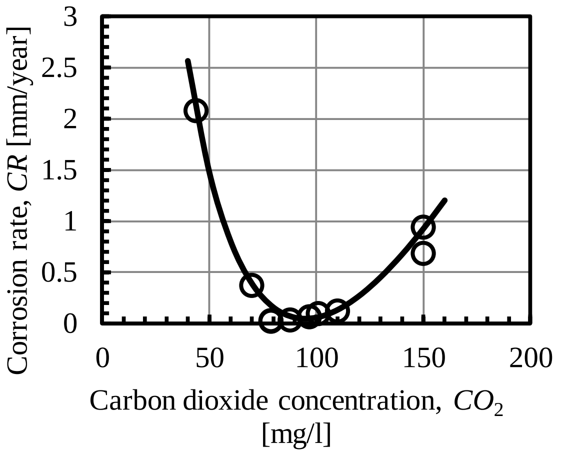

Figure 4. The dependence between corrosion rate and carbon dioxide concentration.

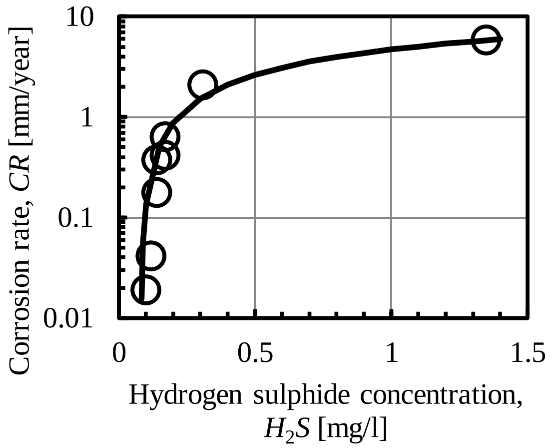

Figure 5. The dependence between corrosion rate and hydrogen sulphide concentration.

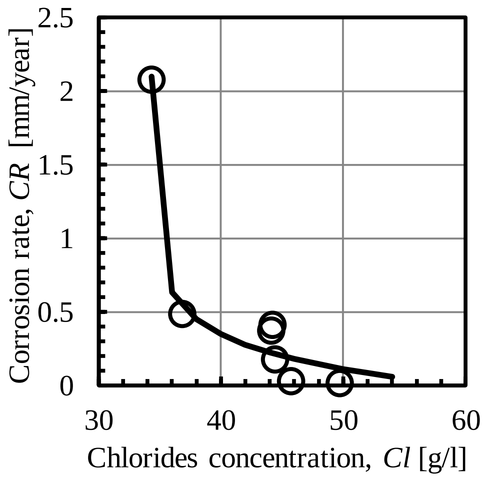

Figure 6. The dependence between corrosion rate and chlorides concentration.

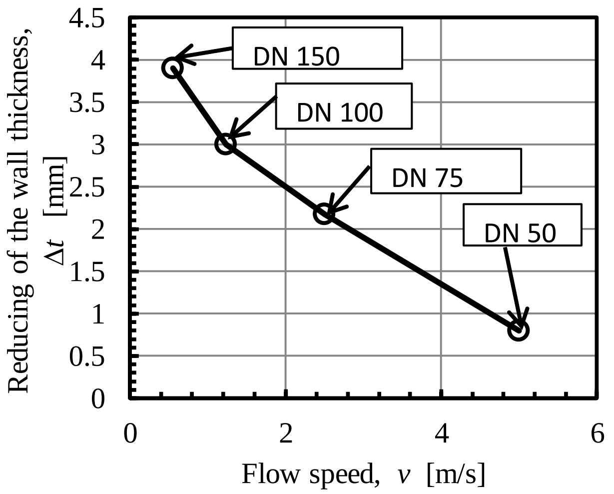

Figure 7. The influence of flow speed and nominal diameter of the pipes (mm) on reducing of the wall thickness.

$$\Delta t = 4.819\exp(-0.353v) \tag{5}$$

where: Δt is the reducing of pipe wall thickness (mm); v – the flow speed (m/s).

The determination coefficient for regression analysis equation (5) is $R^2 = 0.9929$.

About the above presented experimental results the following observations can be done:

- minimum corrosion rates were registered for CO_2 concentrations in the range of 80 … 110 mg/l (figure 4) that corresponding of the corrosion coupons placed in points 5, 6, 7, (figure 2 and table 2), while the maximum values correspond to minimum and maximum CO_2 concentrations;
- maximum corrosion rate value corresponding to minimum CO_2 concentration is in accordance with the flow speed (figure 7) that has minimum value for points 1, 2, 3 (figure 2);
- the increase of H_2S concentration implies the corrosion rate fast increase (figure 5) especially in the range of 0.04 … 0.3 mg/l, the highest value being registered for point 7 corresponds to a pipe diameter of 150 mm and to a low flow speed (figure 7);

- flow speed influences, also the effect of chlorides on the corrosion that is reduced for high chlorides concentrations (figure 6) corresponding to highest flow speed while for the low values of flow speed and chlorides concentration the corrosion rate has the maximum value (figure 7);
- determination coefficients of regression analyses indicate a high level of correlation between the experimental data and analytic results obtained with equations (2), (3), (4) and (5);
- flow speed value has a major influence both on reducing of the pipe wall thickness and corrosion produced by CO_2 and chlorides that registered low values for the highest flow speeds.

5. Conclusions

Effectiveness exploitation of a water treatment plant presumes not only the knowledge of the corrosion rate of equipment but also the influence of working conditions on the corrosion.

In the water treatment plant, the pipes and the connecting elements like elbows are the parts most damaged by corrosion and erosion phenomena.

The main conclusions of the paper are the following:

- in the case of CO_2 and chlorides, the high flow speeds that are associated with a turbulent regime, implies the corrosion rate decrease, while for the H_2S this is not influenced by flow regime;
- the equations obtained as the result of regression analyses can be used both for chemical conditioning of the water and establishing a proper flow regime;
- because the damage of the pipes are produced by corrosion and erosion phenomena, for separating the effects of these components, the corrosion rate has to be determinates by electrochemical techniques;
- for a better exploitation of water treatment plant it is imposing determination the influences of corrosion inhibitors, flocculants, biocides, coagulants and oxygen inhibitor on corrosion rate.

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