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Beyond the Limitations of API RP-14E Erosional Velocity -A Field Study for Gas Condensate Wells

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Fluid velocity has the potential to cause severe erosion damage to oil and gas production infrastructure. Therefore, erosional velocity governs allowable production rates from existing oil and gas wells. In order to avoid or alleviate damage due to erosion, the American Petroleum Institute Recommended Practice (API RP-14E) recommends a threshold fluid velocity for production tubing and pipelines. This standard utilizes an empirical formula from which erosional velocity can be calculated. However, field and laboratory data have proven that the applied empirical constant, known as *C*-factor, within the formula is not valid for all conditions. In many cases, according to the API RP-14E standard, erosional velocity is significantly underestimated or overestimated due to insufficient consideration of fluid characteristics. In addition, accurate field data on erosional velocity can assist proper pipe sizing calculations for prospective oilfield projects. Oversizing of tubing unnecessarily increases construction costs whilst underestimating the required size of tubular can lead to catastrophic erosion/corrosion failures. In this study, new values for erosional velocity constant, beyond those suggested by API RP-14E, are proposed based on the experimental data achieved from the sidestream pilot test units. The experimental pilot test units were installed on four different gas condensate production fields in the south of Iran. Electrical resistance (ER) probes were employed to gather online erosion-corrosion data from the pilot units, each of which was in service for about nine months. The results showed that higher C-factors can be safely applied for these gas condensate fields in comparison with those recommended by API RP-14E. Furthermore, it was revealed that the pilot test units exposed to a higher condensate gas ratio (CGR) experienced a greater rate of erosion.

Keywords: Erosional velocity, API RP-14E, Erosion rate, ER probe, Erosion/corrosion, CGR

INTRODUCTION

Demand for natural gas as a cheaper fossil fuel energy source is rising worldwide. Natural gas has gradually taken over the traditional position of crude oil as the key energy source [1,2]. Consequently, gas producers are seeking either new reserves or enhancing rates of production from existing wells. There two major issues and related questions associated with increasing the production rate from existing gas wells:

1-Productivity index. Can the well produce hydrocarbon at higher rates?

2-Erosion velocity. Can the production tubing withstand the higher erosion/corrosion imposed by higher fluid velocity?

The first concern refers to the well/reservoir characteristics while the second depends on the material properties of the production tubing. Normally downhole components of gas wells are more vulnerable to erosion damage than oil wells due to the higher encountered fluid velocity. If the answers to the aforementioned questions are “yes” then a higher production rate is achievable without having to drill new wells. That is translated into the tremendous savings in costs associated with drilling, operation, and maintenance of new wells. However, higher flow rate equals higher velocity.

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This can lead to a considerable degradation of materials used to fabricate the production infrastructure, especially if the fluid contains entrained particulates and/or liquid droplets. Erosion is a mechanical process caused by flowing fluids. It is defined as the removal of materials from solid surfaces by repeated impingement of solid particles and/or liquid droplets. Erosional destruction is more obvious and severe at higher velocities. However, in real conditions, such as oil production, erosion and corrosion impacts are synergistic [3,4]. A long list of different types of corrosion has been identified in the oil industry [5-8]. Corrosive components such as CO_2 and/or H_2S dissolved in produced hydrocarbons initiate corrosion reactions that can be accelerated by erosion exposing bare material in contact with the fluid, making the metal even more vulnerable to erosion. If the processes are not considered as occurring simultaneously, it is not possible to demonstrate which phenomenon, erosion or corrosion, occurs first. However, it is widely accepted that in oilfield conditions erosion/corrosion phenomena take place [9].

API RP-14E Eq. (1) proposes an empirical correlation to determine the erosional velocity below which erosion and/or erosion/corrosion is not expected [10]:

$$V_e = \frac{C}{\sqrt{\rho}} \tag{1}$$

where V_e is the maximum allowable velocity (erosional velocity), ρ is the gas/liquid mixture density at flowing pressure and temperature and C is an empirical constant.
Gas/liquid mixture density can be calculated by Equation (2) [11]:

$$\rho = \frac{12409\ S_l P + 2.7 R S_g P}{198.7 P + RTZ} \tag{2}$$

where P: pressure (psi), T: temperature (°R), S_l: liquid density, S_g: gas density, R: gas to liquid ratio (cubic foot per barrel) and Z: gas compressibility factor.

This standard suggests values of C = 100 for continuous service and C = 125 for intermittent service while the flowing fluid is solid free. If solid particles are present, C should be substantially reduced. Although this equation has been extensively used in the petroleum industry, field and laboratory experiences have shown that the recommended values of these C-factors are conservative or not dependent upon the system condition. Thus, modification of the C-factors based on individual fluid characteristics can be performed. Furthermore, erosional velocity greatly influences tubing sizing in the design stage. Oversizing of tubing unnecessarily increases construction costs whilst underestimating the required size of tubular can lead to catastrophic erosion/corrosion failures.

PREVIOUS STUDIES ON THE ACCURACY OF API RP-14E

Here, a brief summary of the previous studies on the accuracy of API RP-14E is discussed. Salama [12] reviewed works of some previous researchers on C-factors and stated that the API RP-14E limitation on the C-factor can be very conservative for clean services and is not applicable for conditions where corrosive components or sand are present. He proposed a C-factor of 450 for water injection systems with solid free and non-corrosive conditions and C-values up to 250 for corrosive conditions. Russell *et al.* [13] reviewed erosion in pipes and stated that API RP-14E C-factors of 100 to 200 are too conservative for production and injection tubing associated with wells and downhole valves. Jordan [14] investigated erosion rate in multiphase production of oil and gas. He presented examples of different values for C-factors used by some oil companies and concluded that API RP-14E criteria for calculating limiting velocity are inadequate. In some cases, these criteria give a false sense of security and in other cases it unnecessarily limits production. Ericson [15] reported that operators in the North Sea used a C-value of 726 for gas condensate wells and C-values up to 300 for water injection wells. Esmaeilzadeh [16] studied the feasibility of increasing C-factor for South Pars gas field and presented a C-factor of 175 as a justified erosional velocity constant. Mansoori *et al.* [17] studied the possibility of increasing the C-factor for a gas field in southern Iran. Their results showed that C-factors in the range of 149-195 can be used for wells at the point of their initial design. Arabnejad et al. [18,19] presented a method based on the experimental data to calculate erosion rate due to liquid impact for oil and gas pipelines. They verified the model by comparing their predicted results with the experimental data in the literature. The results showed that the API RP-14E predictions do not follow the trend of calculated values from their model. Zahedi, *et al.*, [20] used the experimental data and the CFD calculations to predict liquid film thickness and flow characteristics in the annular flow regime. The simulated results of the liquid film thickness trends were in agreement with the experimental data in the literature. They stated that erosion rate in elbows is highly dependent on the liquid film thickness. Parsi, *et al.*, [21] studied the effects of sand particle size and superficial gas velocity on the erosion of elbows in vertical slug/churn flow regimes; their results showed that churn flow is a very erosive flow regime. They also claimed that increasing the particle size and superficial gas velocity would increase the erosion rate.

Motivation

Possible failures in downhole equipment is a nightmare for operators due to the difficulties of accessing the failed parts and the extreme costs of repair or replacement. That is why operators prefer not to produce at risky conditions (higher *C*-values) unless they are convinced that erosion/corrosion is not a problem at higher fluid velocities. However, operating with lower *C*-values confines well productivity and loss of income. There are significant discrepancies in the literature regarding optimal C-values (reported from 100 up to 800). Most previous studies have been performed with synthetic fluids (mixtures of air, water and/or sand) in the laboratory at moderate temperatures and pressures. Indeed, the test of duration for previous studies was relatively short. These conditions cannot represent real oilfield conditions. Moreover, the effect of CGR on erosion/corrosion phenomena has been ignored. This study aims to bridge the existing gap of reliable *C*-factors in API RP-14E in oilfield conditions. To achieve this, a unique sidestream apparatus has been designed to be accommodated for use in four gas production fields (Varavy, Kangan, Shanoul, and Tabnak) located in southern Iran.

EXPERIMENTAL WORK

Corrosion specimens and ER probes are widely used in the oil industry as corrosion monitoring techniques. Corrosion specimens provide a quantitative determination of corrosion rates and offer a visual insight of the corrosion type occurring within the system under observation. The ER probes measure erosion/corrosion rate based on an increase in the electrical resistance over time due to loss of material. The ER probes are considered as an online monitoring technique since gathering data from them does not require interruption of the system. The electrical resistance of a conductive material such as a metal or alloy element is expressed by Eq. (3):

$$R = r\frac{L}{A} \qquad (3)$$

where R is the electrical resistance, L is the element length, A is the cross-section area and r is the specific resistance. According to Eq. (3) for a specified alloy at a constant temperature, the ER of the specimen increases as the cross-sectional area decreases. ER probes are known as a reliable tool to acquire online erosion/corrosion data.

Four unique sidestream pilot test units (2″ internal diameter) were designed and constructed to determine optimum erosion velocity by acquiring erosion/corrosion data in wellhead conditions. These pilot units were capable of handling high pressure and temperature existing at the studied gas fields. A schematic view of the sidestream pilot test units is shown in Fig. 1. The pilot units were mounted on the main 6″ ID flowline at the wellhead. The upstream side of each pilot unit was connected to a convenient point prior to the choke valve and the downstream side connected to a lower pressure point somewhere after the wellhead choke valve. The pressure difference between the inlet and outlet ensures that the fluid stream flows through the pilot test units. The length of the pilot units varies from 8 to 10 meters, depending upon the physical characteristics of each wellhead. The following components and instruments were installed on each pilot test unit:

1-Two ball valves to isolate the test units from the main flowline

2-Globe valve to control the flow

3-Orifice flange/plate and flowmeter to measure flowrate

4-Pressure and temperature gauges

4-ER probes for online measurement of erosion/corrosion data

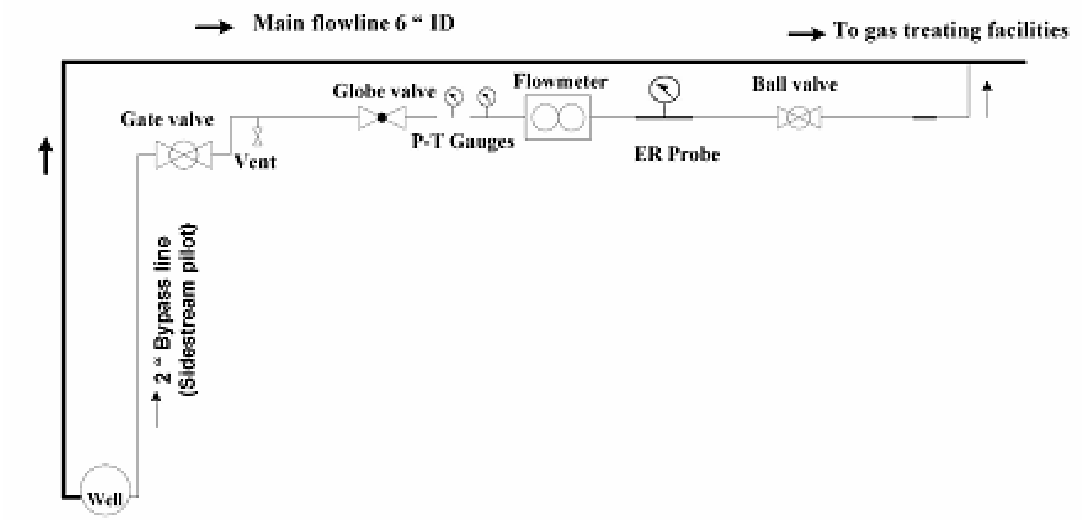

Fig. 1. Schematic view of sidestream pilot unit for determination of erosion/corrosion rate.

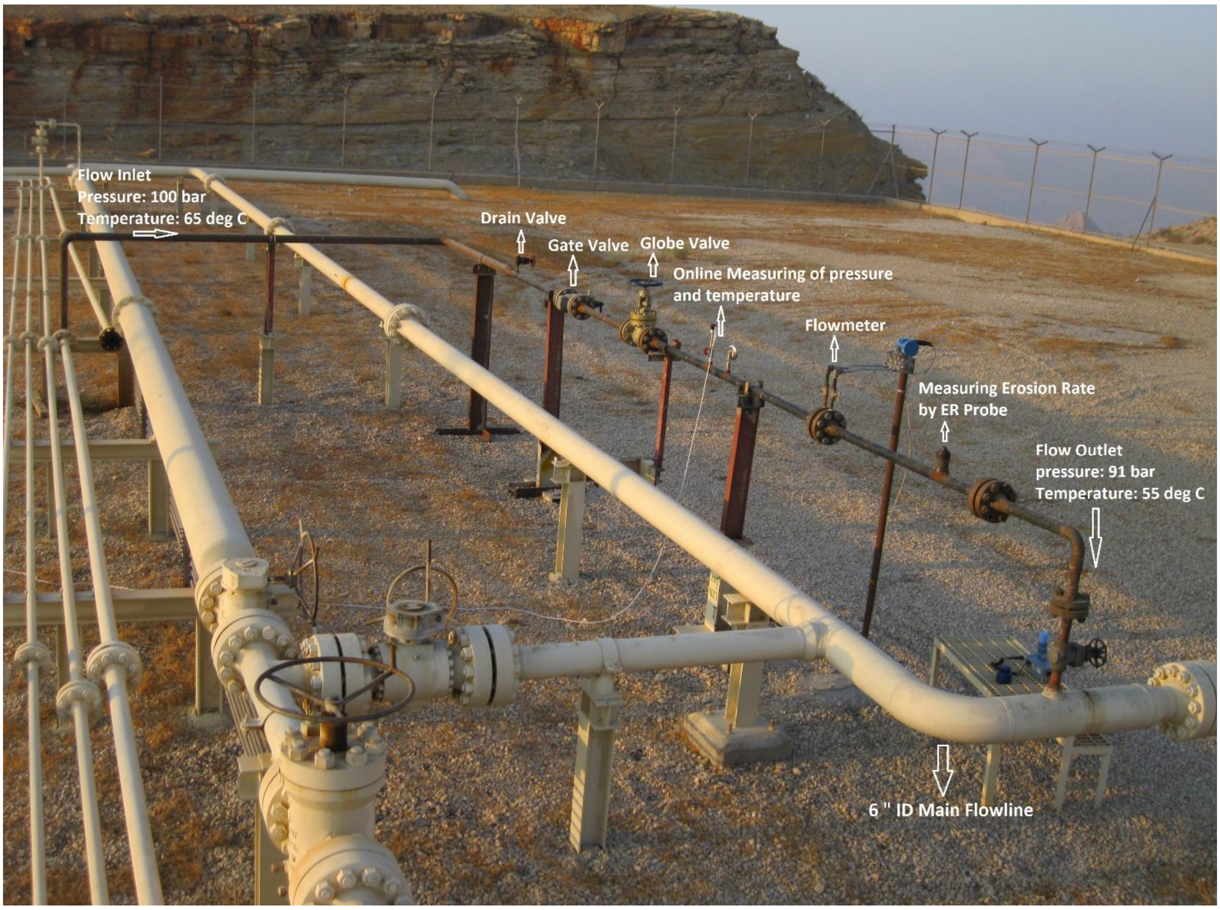

Fig. 2. A view of sidestream pilot unit installed on Kangan gas field.

Table 1. Production Data and Fluid Properties of the Studied Fields

Property \ Field name	Varavy	Kangan	Shanoul	Tabnak
CGR (bbl./mmscf)	3.92	8.90	10.33	14.07
MW	18.52	18.96	19.14	19.98
Gas specific gravity	0.640	0.655	0.661	0.690
Water vapor content (bbl./mmscf)	1	1	1	1

Table 2. Fluid Composition of the Studied Fields

Composition (mole fraction) \ Field name	Varavy	Kangan	Shanoul	Tabnak
H_2O	0.007336	0.007336	0.007336	0.007336
CO_2	0.010400	0.029383	0.006849	0.013200
N_2	0.031300	0.097281	0.039012	0.022600
CH_4	0.889640	0.793735	0.888236	0.862264
C_2H_6	0.036200	0.037920	0.028688	0.049500
C_3H_8	0.009800	0.011713	0.008239	0.015500
iC_4H_{10}	0.002700	0.002879	0.002382	0.003900
n C_4H_{10}	0.003200	0.004169	0.003077	0.005100
i C_5H_{12}	0.001700	0.002085	0.001688	0.002600
n C_5H_{12}	0.001300	0.001588	0.002382	0.002100
C_6	0.002100	0.002581	0.002779	0.003300
C_7	0.001900	0.004070	0.002482	0.003700
C_8	0.001400	0.002879	0.001588	0.003300
C_9	0.000700	0.001191	0.001191	0.002000
C_{10}	0.000400	0.000596	0.000794	0.001300
C_{11}	0.000300	0.000298	0.001985	0.000800
C_{12+}	0.000300	0.000298	0.001290	0.001500
Sum.	1.000000	1.000000	1.000000	1.000000

It is important to mention that the pilot units underwent all the necessary inspections including radiographic tests for the welded sections and hydrostatic tests. After being scrutinized by the inspection division of Zagros Oil Company, the operator, the pilot units received approval for installation on the high pressure and temperature wellheads.

As shown in Fig. 1, gas flows through the pilot unit and after contacting the sensitive surface of ER probe, returns to the main flowline. An actual photograph taken from one of the pilot units installed in the Kangan gas field is shown in Fig. 2.

At the time of the experiments, all the selected fields were producing sweet gas (without H_2S) below their dew points. During the experiment, no significant signs of the presence of solid particles in the production fluid were observed both in the sidestream components and in the main production facilities. Since the production fluid is solid-free and its corrosive components are negligible (H_2S = 0 and CO_2 < 0.02-mole percent), it is safe to assume that erosion is more dominant than corrosion in these fields. Indeed, high flow velocity inside the sidestream pilot test units ensures that material degradation due to erosion phenomena, such as liquid impingement and shear stress, are dominant over corrosion. Tables 1 and 2 show production data and the fluid composition of the studied gas fields, respectively. Fluid composition influences the density, and thus C-factor in the empirical equation proposed by API RP-14E Eq. (1). Indeed, corrosive components of the fluid (CO_2 in the studied field) trigger corrosion reactions.

Experiments were performed at different flow rates. Since the internal diameter of the sidestream pilots (2″ ID) was much smaller than the main flowline (6″ ID), it was possible to develop higher velocities through the pilot units in comparison with the main flowlines. On each gas field, one well with the highest productivity index was selected to undergo an erosion/corrosion experiment for about nine months. Over the course of experiments, erosion/corrosion data was periodically accumulated by the ER probe by employing a portable data logger made by Cormon Company. The flow meter and globe valve facilitate reaching and controlling the desired flow velocities passing through the pilot test units.

The production tubing has a vertical position inside the wells. However, due to operational limitations, vertical installation of pilot units was impractical. Therefore, they were horizontally mounted on the main flowlines. Theoretical simulation of flow regimes by the Pipesys software package (v2.4.73.0) revealed that an annular mist flow regime would develop within the pilots for both vertical and horizontal orientations. Therefore, horizontal installation of sidestream pilots would not cast doubt on the validity of the acquired data. A brief summary of flow simulations for the Kangan field for horizontal and vertical positions of the pilot unit are represented in Tables 3 and 4, respectively. The performed simulations are in agreement with findings reported by Boriyantoro and Adewumi [22]. They stated that for gas condensate systems, while the amount of condensate is relatively small, the gas Reynolds Number is high and the flow regime for horizontal pipes is expected to be annular mist or stratified flow. In annular mist flow, a thin film of liquid forms around the pipe wall [23].

Each of the nominated gas fields inherits an individual CGR based on their reservoir characteristics ranged from 3.92-14.07 bbl/MMscf (Table 1). As stated above, the main purpose of this study is to evaluate the effect of CGR on *C*-values. To achieve this goal, pilot units were exposed to different flow rates and CGRs. Therefore, the installed ER probes experienced different flow velocities over the course of nine-month experiments. The average production rate of the wells in the studied fields was 62 million standard cubic feet per day (MMscfd). This rate is high enough to create extreme velocities in the experimental pilot units and causes erosion/corrosion damage to the surface of the ER probes. Temperature and pressure vary from 55 °C to 80 °C and 90 bar to 200 bar, respectively. Temperature and pressure affect CGR and fluid density calculations. CGR and density influence erosion rate. Moreover, temperature accelerates the kinetics of possible corrosion reactions [24].

When gas travels from downhole to the wellhead, condensate drops out of the gas stream due to changes in temperatures and pressures associated with operational conditions. In all flow regimes in horizontal pipes, except annular mist, the liquid tends to move to the lower parts of the pipes so erosion in such locations is postulated to be higher. In the annular mist flow regime, an annular ring of liquid forms around the pipe wall while the gas flows as a continuous phase through the center of the tube [25].

Table 3. PIPESYS Flow Simulation for Horizontal Sidestream Pilot Test Unit-Kangan Gas Field

aspentech	Calgary, Alberta CA NeotecPIPESYS v2.4.73.0	Case Name: Vertical sidestream pilot-Kangan Unit Set: EuroSI Date/Time: Thu Feb 04 14:07:18 2016

Pressure temperature summary

Pipeline Unit	Cum. Length	Pressure (bar)	Temperature (C)	DeltaP (bar)	DeltaT (C)	Label
Pipe	1.91	90.86	54.96	0.14	-0.04	Pipe #1
Fitting	2.81	89.85	54.68	1.00	-0.27	Fitting #1
Pipe	4.44	89.61	54.61	0.24	-0.07	Pipe #2

Fluid transport properties

Cum. Length (m)	Inside Diameter (mm)	Gas density (kg m^{-3})	Liquid density (kg m^{-3})	Gas viscosity (cP)	Liquid viscosity (cP)	Vsg (m s^{-1})	Vsl (m s^{-1})	Flow pattern	Surface tension (dyne cm^{-1})
1.91	42.85	77.256	701.273	0.016	0.290	28.775	0.091	Annular Mist	16.818
2.81	42.85	76.262	700.853	0.015	0.290	29.133	0.093	Annular Mist	16.774
4.44	42.85	76.157	700.808	0.015	0.290	29.171	0.093	Annular Mist	16.770

Table 4. PIPESYS Flow Simulation for Vertical Sidestream Pilot Test Unit-Kangan Gas Field

aspentech	Calgary, Alberta CA NeotecPIPESYS v2.4.73.0	Case Name: Vertical sidestream pilot-Kangan Unit Set: EuroSI Date/Time: Thu Feb 04 14:07:18 2016

Pressure temperature summary

Pipeline unit	Cum. Length	Pressure (bar)	Temperature (C)	DeltaP (bar)	DeltaT (C)	Label
Pipe	1.91	90.86	54.95	0.14	-0.05	Pipe #1
Fitting	2.81	89.86	54.68	1.00	-0.27	Fitting #1
Pipe	4.44	89.62	54.60	0.24	-0.08	Pipe #2

Fluid transport properties

Cum. Length (m)	Inside diameter (mm)	Gas density (kg m^{-3})	Liquid density (kg m^{-3})	Gas viscosity (cP)	Liquid viscosity (cP)	Vsg (m s^{-1})	Vsl (m s^{-1})	Flow pattern	Surface tension (dyne cm^{-1})
1.91	42.85	77.257	701.271	0.016	0.290	28.774	0.091	Annular Mist	16.817
2.81	42.85	76.266	700.847	0.015	0.290	29.131	0.093	Annular Mist	16.774
4.44	42.85	76.163	700.800	0.015	0.290	29.169	0.093	Annular Mist	16.769

Table 5. Different Flow Rates and the Corresponding C-factor and Erosion Rate-Varavy Field

Fluid flow rate ($lb\ h^{-1}$)	Equivalent C-factor	Average erosion rate (mpy)
26,000	183	0.73
27,663	194	1.05
29,170	205	1.32
31,026	218	1.48
32,731	230	1.68

Table 6. Different Flow Rates and the Corresponding C-factor and Erosion Rate-Kangan Field

Fluid flow rate ($lb\ h^{-1}$)	Equivalent C-factor	Average erosion rate (mpy)
18,193	141	0.84
20,641	160	0.94
22,042	176	0.98
24,432	195	1.03
26,000	209	1.1

Table 7. Different Flow Rates and the Corresponding C-factor and Erosion Rate-Shanoul Field

Fluid flow rate ($lb\ h^{-1}$)	Equivalent C-factor	Average erosion rate (mpy)
22,080	156	0.75
24,067	170	1.02
26,000	186	1.29
30,728	211	1.62
34,240	235	1.825

Table 8. Different Flow Rates and the Corresponding C-factor and Erosion Rate-Tabnak Field

Fluid flow rate ($lb\ h^{-1}$)	Equivalent C-factor	Average erosion rate (mpy)
18,634	132	0.87
20,768	147	1.18
22,531	159	1.31
26,000	192	1.6
33,802	234	2.2

Therefore, erosion/corrosion due to liquid droplets in annular mist flow is expected to be uniform on the pipe wall. Consequently, installing ER probes on top of the sidestream pilot units is reasonable for this particular flow condition and is expected to provide almost the same result as if the installation is at the bottom.

RESULTS AND DISCUSSION

Erosion data was gathered from the ER probes at different flow rates and CGR. When exposing them to a new operational condition, the pilot test units are kept in service long enough (usually one month) to ensure the system is in a stable condition and the data can be duplicated. Total exposure time for each field was around nine months and the overall degree of data reproducibility was over 90 % for all fields.

Erosion rate was calculated according to Eq. (4) for each pilot unit at different operational conditions:

$$Erosion\ rate\ (MPY) = \frac{X_2 - X_1}{\Delta t} \times \frac{K}{1000} \times \frac{365\ days}{year} \qquad (4)$$

Where

X_1 is instrument reading at time t_1

X_2 is instrument reading at time t_2

Δt is time elapsed (days) between X_1 and X_2

K is a constant which depends on the probe characteristics; K = 10 for the current probes

The average erosion rate (mils per year) at different flow rates (pounds per hour) along with the equivalent calculated *C*-factor for each field are shown in Tables 5-8. The equivalent C-factor is calculated by Eq. (5):

$$C = V * \sqrt{\rho} \qquad (5)$$

In the above equation, *V* is the actual fluid velocity through the experimental pilot units.

According to Tables 5-8, the erosion rate is proportional to the flow rate in the four studied fields; an increase in the flow rate resulted in a growth of the average erosion rate. In order to characterize the effect of CGR on C-factor and the average erosion rate, all fields underwent an identical flow rate (26,000 lb h^{-1}) for one month. Table 9 shows these specific data for all fields. Different fields are associated with different C-factors although they experienced the same flow rate of 26,000 lb h^{-1}. This is related to the fact that each field has a different fluid density which influences C-factors. Another important point from Table 9 is that CGR has a significant effect on erosion rate. For the same flow rate, Tabnak field has the highest erosion rate which can be attributed to its higher CGR. On the other hand, the lowest erosion rate is associated to Varay fields with the lowest CGR. Although CGR has an impact on fluid density through Eq. (2) and thus C-factor, its influence on erosion rate is more dominant due to higher shear stress on pipe wall and/or more chance for liquid impingements.

The allowable metal loss for hydrocarbon production facilities is 1 mpy according to the NACE RP0775-99 standard [26]. Considering 1 mpy as the allowable erosion rate, the corresponding *C*-factor can be calculated based on the data presented in Tables 5-8. The calculation of optimum *C*-factor for these fields is shown in Figs. 3-6. Indeed, Table 10 shows the obtained *C*-factors for all the studied field conditions based on NACE RP0775-99 and their deviation from what API RP-14E has proposed. For all of the studied fields, a value of *C*-factor equal to 100 had been considered to determine the erosional velocity by the operator. The results of this study show that the *C*-factor of 100 is extremely conservative and production tubing is able to withstand higher erosion velocities without risk of failure. Table 10 shows that the Varavy gas field obtained the maximum *C*-factor with a value of 193 (93% higher than API RP-14E) and that C-factor for Tabnak gas field cannot be higher than 138 (38% higher than API RP-14E) for a safe production schedule. These modified empirical *C*-factors can be used to determine erosional velocity and they may be valid for other gas fields worldwide, considering the characteristics of the produced fluid. Moreover, a comparison between C-factors form previous studies and this research is shown in Table 11.

$$\%\ Deviation = \frac{Optimum\ Cfactor - Standard\ Cfactor}{Standard\ Cfactor} \qquad (6)$$

The effect of CGR on *C*-factor is also evaluated based on the overall data from all the studied fields. Figure 7 illustrates how *C*-factor has responded to CGR variation in

Table 9. Effect of CGR on C-factor and Erosion Rate

Field name	Flow rate (bbl h^{-1})	Equivalent C-factor	Erosion rate (mpy)	CGR
Varavy	26,000	183	0.73	3.92
Kangan	26,000	209	1.10	8.90
Shanoul	26,000	186	1.29	10.33
Tabnak	26,000	192	1.60	14.07

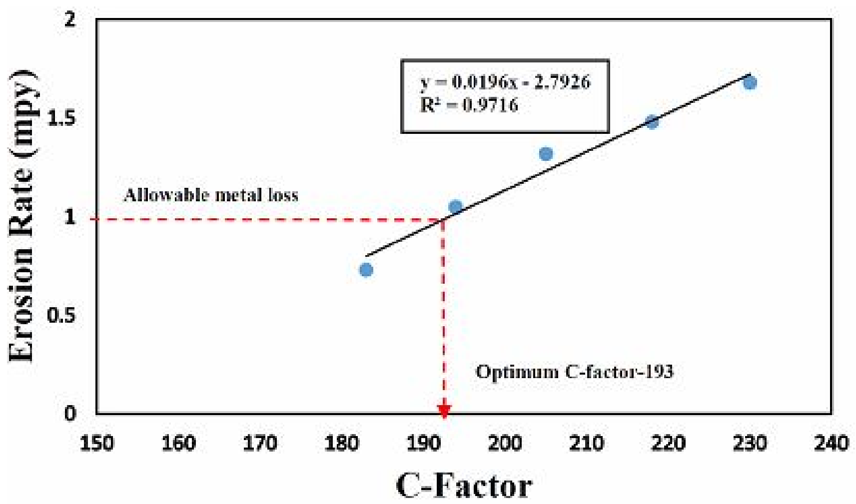

Fig. 3. Erosion rate *vs*. C-factor; determination of optimum C-factor for Varavy gas field.

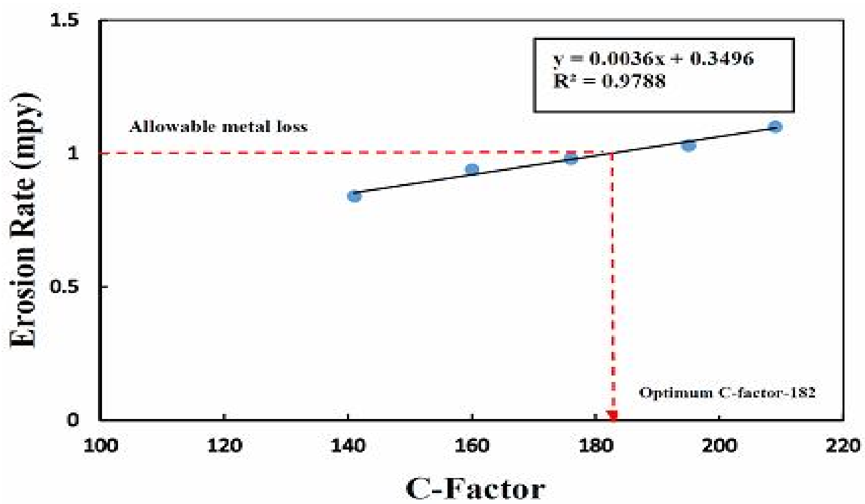

Fig. 4. Erosion rate *vs*. C-factor; determination of optimum C-factor for Kangan gas field.

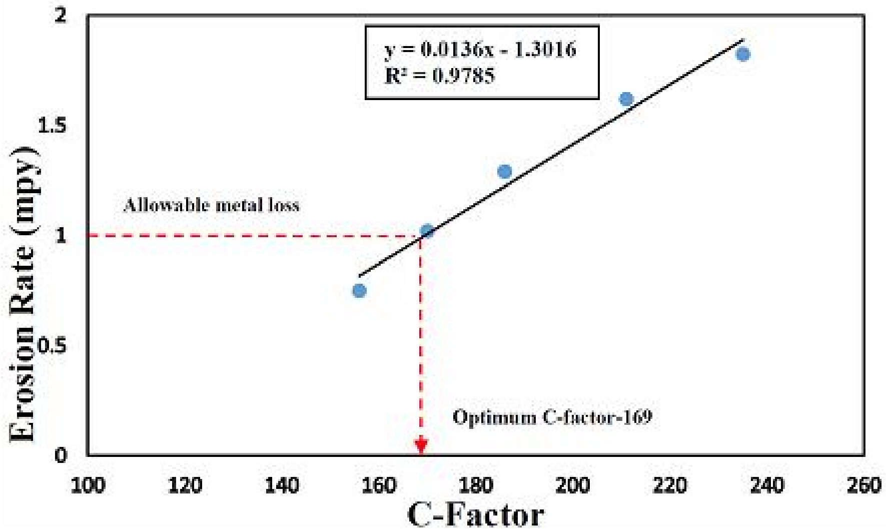

Fig. 5. Erosion rate *vs*. C-factor; determination of optimum C-factor for Shanoul gas field.

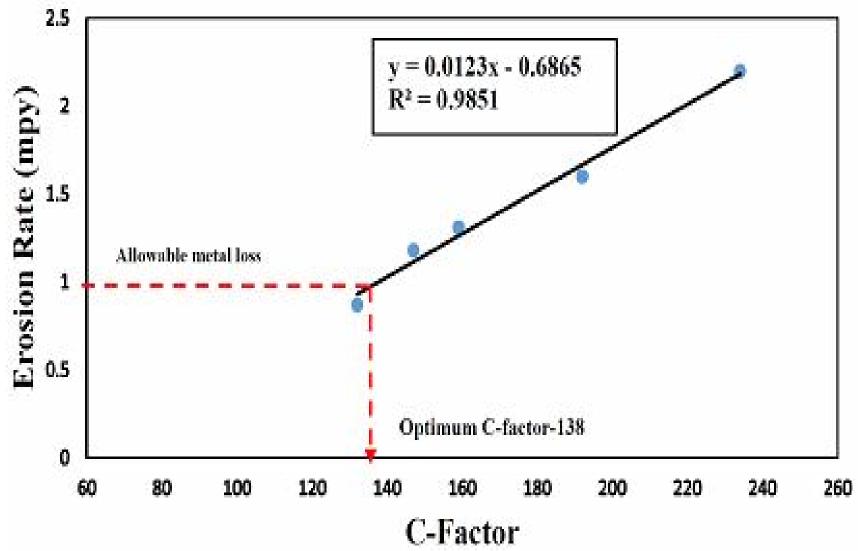

Fig. 6. Erosion rate *vs*. C-factor; determination of optimum C-factor for Tabnak gas field.

Table 10. Optimum C-factors for the Studied Gas Fields Based on NACE RP0775-99 Criterion

Field Name	Optimum C-factor	Deviation form API RP-14E recommendation for clean continues services (C-factor = 100)
Varavy	193	93%
Kangan	182	82%
Shanoul	169	69%
Tabnak	138	38%

Table 11. Comparison Between Measured C-factor by Various Researchers

Researcher (s)	System	Standard C-Factor	Measured C-factor	Deviation (%)
Salama [12]	Water injection systems with solid free	100	450	350
	Water injection systems with solid free	100	250	150
Ericson [15]	Gas condensate	100	726	626
	Water injection wells	100	300	200
Esmaeilzadeh [16]	Gas field	100	175	75
Mansoori, *et al.*, [17]	Gas field	100	149-195	49-95
This study	Gas field	100	138-193	38-93

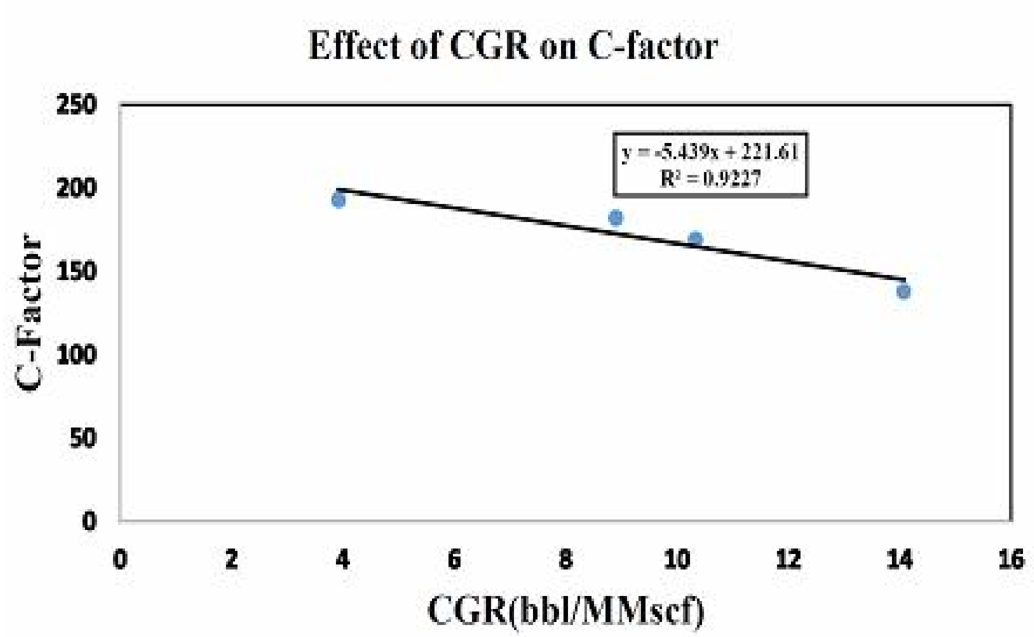

Fig. 7. Effect of CGR on C-factor-based on the overall data from all fields.

the experimental conditions. The correlation expressed in Fig. 7 can be used in any identical gas condensate fields while the dominant regime is annular mist flow with a CGR range between 4 and 14 and sand-free system. Based on Fig. 7, a higher CGR results in lower *C*-factor due to increasing erosion rate. Therefore, the erosional velocity is a real concern for those wells with high CGR even when sand-free.

CONCLUSIONS

1-Unique experimental sidestream pilot test units were designed, constructed and installed on four Iranian gas condensate fields to acquire erosion data in production conditions. These pilot units were capable of handling high pressure and temperature existing at the studied gas fields. Indeed, high flow velocity inside the sidestream pilot test units ensures that material degradation due to erosion phenomena, such as liquid impingement and shear stress, are dominant over corrosion.
2-New empirical C-factors were obtained based on real-field data. These values are much higher than what API RP-14E recommended for clean services. The results of this study shows that the *C*-factor of 100 is extremely conservative and production tubing is able to withstand higher erosion velocities without risk of failure.
3-Among the studied gas fields, the Varavy field had the maximum *C*-factor with a value of 193 (93% higher than the value suggested by API RP-14E) and C-factor for Tabnak gas field cannot be higher than 138 (38% higher than API RP-14E) for a safe production schedule. These modified empirical *C*-factors can be used to determine erosion velocity and can be applicable for any gas condensate fields with similar characteristics to those of the studied fields.
4-CGR had a prominent impact on the erosion rate due to a higher chance of liquid impingements and higher shear stress on the pipe wall. A simple empirical correlation was proposed that relates CGR to *C*-factor based on the overall data acquired from the studied fields. This correlation can be valid for any identical gas condensate fields while the dominant regime is annular mist flow with a CGR range between 4 and 14 and sand-free system.

RECOMMENDATION FOR FUTURE WORKS

It is suggested that the above tests are performed on the gas condensate reservoirs with CGRs and pressures different than those tested in this study. In addition, the effect of sour gas can also be considered. Moreover, for testing the effect of shear stress on the pipe wall due to liquid impingements, it is suggested using a fixed fluid composition with different fractions of liquid in laboratory or in the field.

ABBREVIATIONS

MPY	Mils per year	CGR	Condensate gas ratio
ER	Electrical resistance	MMscmd	Million standard cubic meter per day

NOMENCLATURES

V_e	Erosional velocity	L	Element length
ρ	Gas/liquid mixture density	A	Cross section area
C	Empirical constant	r	Specific resistance
bbl	Barrel	Z	Gas compressibility factor
P	Pressure (psi)	R	Gas to liquid ratio (cubic foot per barrel)
T	Temperature (°R)	S_l	Lliquid density
S_g	Gas density		

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