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Development of Corrosion Risk Assessment Model for Downhole Production Equipment in Bouri Field

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Abstract— *Corrosion of offshore production facilities and structures is a major operating problem facing the Oil and Gas industry worldwide, which results in high costs of equipment repair or replacement, potential pollution, and even catastrophic accidents that cost lives. This paper presents a corrosion risk assessment model that has been developed to assess internal corrosion risks in downhole production equipment, mainly tubings, installed in one of the Libyan offshore fields (Bouri Field). The results show the criticality of the wells under study and the level of internal corrosion risks for each well.*

Keywords—*Bouri Field, Offshore, Internal Corrosion, Risk Assessment.*

I. Introduction

The main objective of the oil and gas production industry is the safe and cost-effective extraction of hydrocarbons from its underground natural resources into wells and flowlines. Then, other processes happen, ranging from the separation of any non-energy containing products, transferring to storage tanks before a refinery, and eventually distribution or exportation, usually through pipelines [1]. There is a huge network of facilities both onshore and offshore where these processes occur; these facilities with a wide range of ages and designs are exposed to varying operating conditions and environments. Thus, the integrity of the oil and gas networks could be compromised, resulting in failures [2]. One of the critical factors and a key reason behind failures in oil and gas well production systems is corrosion. In fact, corrosion-related failures account for more than 25% of these encountered within the oil and gas industry [3].

Corrosion is defined by Popoola et al. [4] as "the destructive attack of a material by reaction with its environment and a natural potential hazard associated with oil and gas production and transportation facilities." Corrosion attacks every single component at every stage within the life of a production system starting from the wellbore through tubing up to the surface facilities, posing a possible risk for health, safety, and the environment. Additionally, it can also bring with it economic losses as a result of production interruption or cessation.

Thus, characterization and management of the corrosion process, as well as the determination of the corrosion susceptibility of production equipment in the oil and gas industry, is of paramount importance in maintaining the technical integrity of all equipment. Ultimately, to prevent operational risks that lead to safety and environmental damages, while minimizing the overall costs from uncontrolled corrosion, such as the replacement of equipment, loss of production due to downtime for repairs, and unplanned shutdowns.

Corrosion risk assessment is the core activity of the corrosion management process. The task aims to identify the corrosion risk level of each item of a specific asset and can be conducted during the design stage, project development phase, or operation and production, to confirm the effectiveness and appropriateness of the corrosion mitigation and the adopted control solutions [5].

Several studies have been published over the last few years dealing with the evaluation and assessment of risks related to corrosion in oil and gas production systems [6, 7, 8, 9, 10]. After an in-depth review of the relevant available works of literature, it was found that most of the studies about corrosion risk analysis and assessment in oil and gas industries are mainly concerning transfer pipelines, flow lines, storage tanks, processing facilities, offshore structures, and surface facilities more than the downhole side of the production system. Moreover, these studies generally aimed at the moderate conditions on the surface, which are inherently different from the high temperatures and pressures found downhole.

The objective of this paper is to present a corrosion risk assessment model that can be used to assess the internal corrosion threats in downhole production equipment installed in offshore oil-producing wells during the operational phase, and the methodology used to develop that model, which can be applied at different other locations and operation conditions.

II. Overview of the Methodology

Fig. 1. shows the methodology as a generic framework. It consists of the following steps:

A. *Identification of the Downhole Production System*

Understanding thoroughly the system under study is the first step. For this to happen, full information regarding the downhole production system and reservoirs characteristics, including fluid flow properties and hydrodynamic and thermodynamic variables should be collected and identified. At this point, some preliminary observations can be made with respect to fluid corrosiveness; for example, the presence of corrosive gases, mainly CO_2 and H_2S.

B. *Hydrodynamic/ Thermodynamic Characterization of the System*

In order to estimate the corrosion rate for each well, hydrodynamic and thermodynamic characteristics should be known as they influence corrosion rate calculations directly. This can be done by using parameters identified from the previous step as an input to a simulator or modelling software.

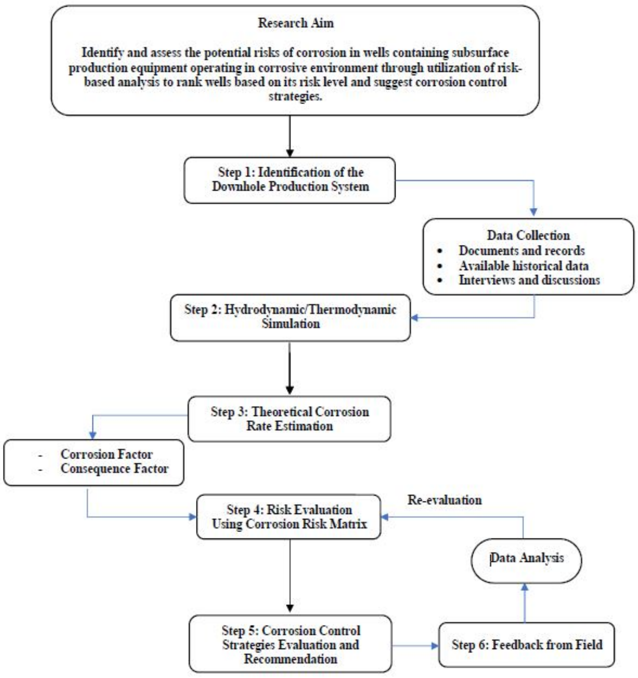

Fig. 1. The Methodology of the Study.

C. *Determination of Corrosion Rates and Characterization of The Corrosion Profile for Each Well*

The most commonly used model to estimate corrosion rate is that of the de Waard - Milliams correlation for CO_2 corrosion. For H_2S cases, the NACE Standard Material Requirements MR0175 is applied. This should be done to each well based on hydrodynamic and thermodynamic characteristics.

D. *Risk Evaluation using Corrosion Risk Matrix*

To evaluate the corrosion risk associated with each well, the following two components must be estimated:

- Likelihood of Failure: the probability of occurrence of fluid containment (production) from a mechanical integrity failure of an equipment of the system. In this case, the corrosion rates estimated from the previous step with other factors is used to determine the total likelihood of failure of the system.

- Consequence of Failure: corrosion failures result not only in loss of production, but also can cause environmental damage and threaten the safety of personnel.

Knowing the values of both the probability of corrosion failure and its consequences, a theoretical estimation of risks can be performed, and a corrosion risk matrix is developed.

E. *Corrosion Control Strategies Evaluation and Recommendation*

Based on the estimated risk level, corrosion control strategies are evaluated, and recommendations are made. For example, the use of corrosion resistant materials, the application of corrosion inhibitors, etc.

F. *Data Analysis and Feedback*

After evaluating the risk levels theoretically, feedback from the field regarding the controls in place is used as enhancement values to the theoretical results and estimated risks are re-evaluated, resulting in a different risk level.

III. CORROSION RISK ASSESSMENT MODEL

A. *Brief Description of the Model*

Fig. 2. presents the developed model. The model is semi-quantitative which provides an intermediary approach between the textual evaluation of a qualitative risk assessment and the numerical evaluation of a quantitative risk assessment. It is structured in three main steps for ultimately ranking wells in terms of their corrosion risks by a score based on a combination of their probability and impact, and a graphical representation by means of a risk matrix.

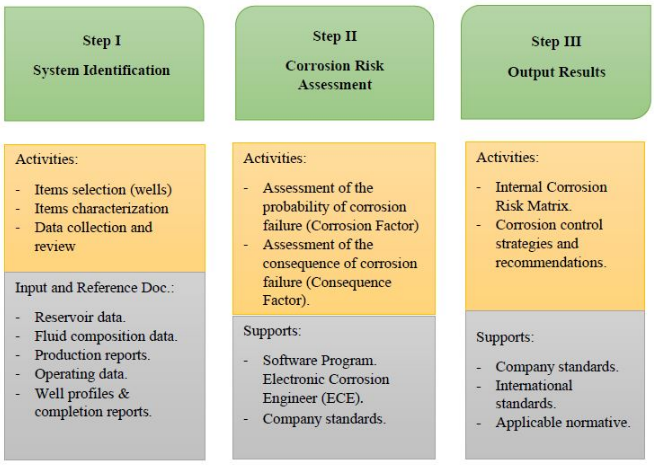

Fig. 2. Corrosion Risk Assessment Model.

The probability or likelihood of failure in this paper represents the corrosive potential of the evaluated wells, expressed quantitatively by the corrosion factor (F_O), while the impact is directly related to the economic consequences known as the operability consequence factor (F_{OC}). This will be explained more in the assumptions section. The results of the quantitative corrosion risk assessment were also illustrated qualitatively on a risk matrix by a color code that ranks the corrosion risks from safe, very low, low, medium, high, and very high. Fig. 3. shows the risk matrix used.

B. *Assumptions of the Model*

- Corrosion risk assessment has been performed during the operational and production phases, meaning that items being analyzed are already in service.

- Aqueous environment is fundamental for downhole corrosion to occur.
- For the purpose of predicting theoretical CO_2 corrosion rates using simulation software, all downhole tubing string materials are assumed to be carbon or low alloy steel with chromium content (up to 1.2% max., according to API 5CT) of the quenched and tempered tubing. The results of this simplistic approach will be adjusted to the actual field corrosion controls in place (actual tubing materials used).

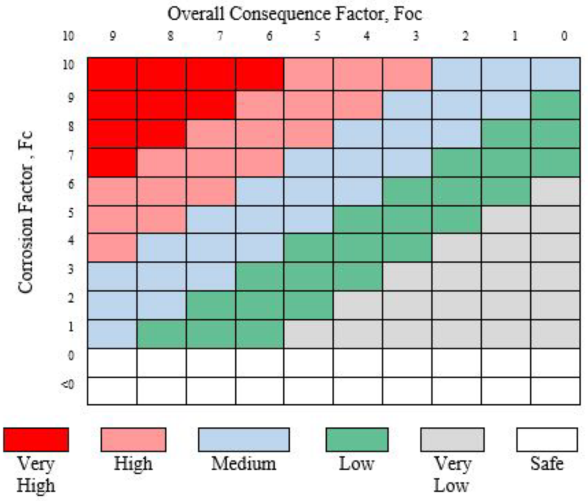

Fig. 3. Corrosion Risk Matrix and Color Codes.

- Items were assessed based on internal corrosive potential only. To guarantee well integrity, all wells are completed with packers which prevent communication through the annulus that is filled with packer fluid, and production is directed through the tubing string. Thus, casing strings are not exposed to produced fluid and therefore, no external corrosion would presumably occur to the outer walls of downhole equipment above packers.
- The fluid bubble point is assumed to coincide with the bottom of the tubing.
- Inhibition is assumed to provide an inhibitor efficiency of 80-85%. However, pitting corrosion rates were uninhibited in the simulation model used.
- Tubing design life (DL) is assumed to be 25 years; it represents a period assumed for the validity of the corrosion risk assessment study (medium evaluation period).
- For this study, only downhole equipment was evaluated; thus, only the economic consequences were considered. Other consequences were not considered because it is assumed that the casing is in good condition decreasing the possibilities of damage to an aquifer (for the case of environmental consequences), and wellheads are not considered in the analysis, therefore, downhole corrosion will not be a direct source of risk for the personnel on the surface installation (in the case of health, safety; and environmental consequences).
- Expected corrosion mechanisms resulting in loss of thickness (uniform or localized) and cracking in the internal exposure side dominated by the conveyed fluid should be evaluated.
- For the current well-flowing conditions, field reservoir pressures and drawdowns, the risk of solids production will be neglected. Therefore, internal particle erosion will not be included.
- The severity of the sour service environment causing internal sulfide stress cracking of carbon steels would be assessed against the criteria defined in ISO 15156-2 [11].

C. Corrosion Risk Assessment Model Procedure

a) System Characteristics Identification: Bouri field, the largest offshore field in the Mediterranean Sea is located offshore Libya in block NC-41, about 120 km (75 mi) north-western of the Libyan coast at an average water-depth of 146 – 176m (480–580ft). The field was developed with two platforms: the main DP4 and the secondary DP3. The reservoir consists of carbonate and dolomitic sediments; most of the current oil production is from the Upper Nummulitic Member formation, which is a carbonate reservoir. The field still produces under primary recovery mechanism; it is above bubble point pressure, and supported by strong bottom and edge water drive and strong gas cap drive. The reservoir has significant amounts of H_2S and CO_2.

The available historical reports regarding corrosivity analysis of the wells considered in this paper indicate that CO_2 and H_2S gases, in combination with liquid water are the main causes of corrosion threats in the oil-producing wells. As the field ages, the water cut increases up to 95% in some wells. This increase in water content will subsequently increase corrosion issues.

b) Corrosivity Determination and Corrosion Prediction Using Software Simulation: A number of corrosion prediction models have been proposed in the literature to calculate corrosion rates [12,13,14,15,16,17,18]. In this paper, theoretical quantitative estimation of corrosion rates due to CO_2 and pitting corrosion were calculated using Electronic Corrosion Engineer (ECE®) model software. The computer program is based on the modified model by De Waard and Milliams and incorporates critical factors such as oil API gravity, water-cut, flow rates, tubings deviation angles, carbonate and sulphide scaling, and flow regime.

The Corrosion Factor (Fc): The assessment of the probability of failure caused by corrosion (the corrosion factor (F_C)) is calculated based on the evaluation of corrosive potential by estimating corrosion rates as shown by the following formula [19]:

$$F_C = \frac{10}{DL} \times \left(DL - \frac{CA}{CR}\right) \tag{1}$$

Where:

CR is the theoretical corrosion rate.

DL is the design life.

CA is the corrosion allowance.

Only the highest value of the estimated corrosion rates for each expected corrosion form was considered to calculate the corrosion factor.

Consequence Factor Calculation (F_{OC}): The overall consequence factor is the summation of three weighted factors:

-Hazard consequence factor F_H.

-Environmental consequence factor F_E.

-Operability consequence factor F_O.

As explained in the assumptions, the consequences in this paper are directed primarily to only the economic consequences (Operability consequence factor F_O). The overall operability consequence factor (F_O) was determined by defining the following factors: Production loss percentage (fluid flow rate) ($F_{PL,\,O}$), Redundancy ($F_{R,\,O}$) and Shutdown (repair) time ($F_{ST,\,O}$). A corrosion risk matrix was prepared by assigning the numerical values of the two factors (F_C and F_{OC}) on the relative coordinates of the risk matrix to estimate the risk level of each item under study.

D. Field Evaluations and Feedback

Re-estimation of corrosion rates, based on information gathered from the field regarding corrosion control strategies that are already in place was performed and results were used to adjust some of the simulated conditions, to be as close as possible to the actual field conditions, thus, re-evaluate controlled corrosion risk levels.

Corrosion factor (Fc) assessment was made to determine localized corrosion susceptibility for the corrosion-resistant alloys (CRA) used in production tubing. Stability/ instability values are assigned for corrosion factor based on CRA pitting corrosion resistance evaluation. These values range from $F_C = 0$ " verified stability - safe" to $F_C = 10$ " verified instability - very low". The results of the assessment used to update the corrosion risk matrix and final evaluation.

IV. Uncertainties of Data

The applied corrosion risk assessment model is partially based on predictions of corrosion rates to calculate the corrosion factor, which involves a large number of data collected as an input to the corrosion prediction model. Lack of reliable input parameters and uncertainties in the data collected may significantly affect the accuracy of the predictions and thus the success of the model and its outputs. In this paper, the uncertainty of formation water analysis and lack of information regarding the presence of bicarbonates and acetic acid in the water phase was a challenge for the precise calculation of CO_2 corrosion rates. However, it should be recognized that the main aim of the model is to give an overall framework for the risk assessment and its applicability in the selected field under study rather than full quantification of corrosion risks apart from the extent and completeness of the input data, especially that the corrosion prediction models used in ECE® have a limited accuracy and tends to overpredict corrosion rates for very high salt content, and in the presence of H_2S and acetic acid.

Another limitation is that the model was built on some conservative assumptions that restricted the corrosion risk assessment to the internal side of the downhole tubing only. Nevertheless, it could be developed to include external corrosion threats and other well downhole components. In addition, the acquisition of corrosion data and interpretation processes required for the corrosion assessment of CRA tubulars was not available; thus, re-evaluation of the risk assessment by predicting corrosion rates of CRA will be much more complex than for conventional steel tubulars and difficult to be achieved quantitatively. This has restricted the application of the model in the re-evaluation stage to a qualitative description of the alloy's suitability to the operational parameters.

Since operating conditions are dynamic and continuously changing with time, some uncertainties will be associated with each input parameter. This means that the corrosion risk assessment needs to be checked and updated accordingly to consider the variation in corrosion rates. However, with no access to an integrated data management system, this was hard to be achieved with the large number of input parameters involved.

V. Results and Disscusion

A. Corrosion Rate Graphs

By means of Electronic Corrosion Engineer (ECE®) modelling, the results of downhole corrosion rate predictions were displayed graphically as a function of depth for potential general and pitting corrosion rates. For every well, a corrosion profile was obtained based on the input data. Each profile has regions of lower and higher corrosion rates, which are dependent on certain operating parameters that influence corrosion rate downhole; thus, changes in those parameters will be directly reflected in the corrosion rate graphs. The main operating factors considered to predict corrosion rates are:

- Fluid composition.
- Water composition (NaCl, bicarbonate and acetate concentration).
- Water cut.
- Gas impurities concentrations.
- Flow rates, and
- Temperature.

Generally, it has been found that the average predicted corrosion rates vary between 0.11 and 23.43 mmpy for general corrosion caused by CO_2, and between 0.47 and 45.94 mmpy for pitting corrosion. However, for the sake of analysis, only maximum values of the corrosion rates were used. Corrosion rate graphs are regarded as a useful tool for showing the sensitivity to each parameter since operating parameters are dynamic and always subject to change. For example, increasing water flow rates will increase corrosion rates. Temperature gradient also has a direct effect on corrosion rate as it affects the formation conditions of protective carbonate layers ($FeCO_3$) on steel surfaces. As the depth of the well increases, the temperature increases until it exceeds certain temperatures that depend on CO_2 partial pressure, then corrosion rates begin to decrease, which is clearly shown in the corrosion rate graphs.

In addition, it can be observed from these graphs the influence that the well's profile has on corrosion rates. Since all wells under study deep deviate with maximum deviation angles exceeding 90º in some cases, the changes in deviation angles correspond to changes in their downhole corrosion rates, which appears as sharp points in some of the corrosion rate graphs. Fig. 4. represents an example of the resulting corrosion rate graphs.

B. Risk Analysis Graphs

The accumulated risk of failure predicted by the ECE® model was displayed graphically in percentage versus time. For the current well downhole conditions, there is a high chance of failure (100%) due to corrosion of downhole equipment in the first few years of operation for 22% of the wells under study. The run-life expected ranges between 6 months for wells with the highest corrosion rates and 1 or 2 years for other wells.

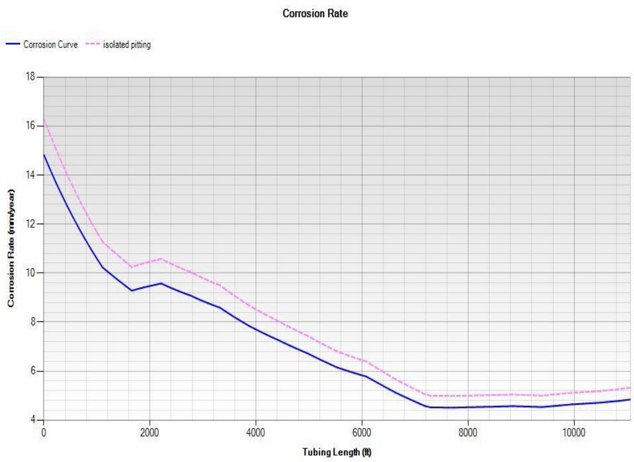

Fig. 4 Corrosion Rate Graph for Well No. 02.

As the predicted corrosion rate decreases, the risk percentage decreases and the time to failure extends, reaching the ultimate run-life of 25 years with a probability of failure ranging between 25-75% for 30% of the wells over that period. Fig. 5. represents an example of the resulted risk analysis graphs.

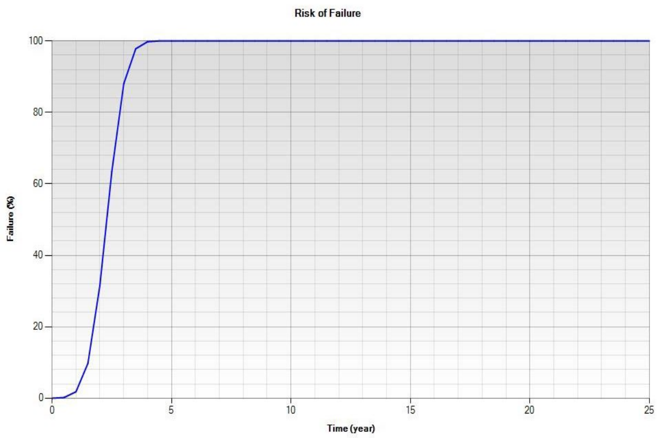

Fig. 5 Risk of Failure Graph for Well No. 03.

C. Corrosion Analysis Records

The output results of the corrosion predictions were compiled in full corrosion analysis records. In addition to estimated corrosion rates, these records include all input data along with the calculated values from the ECE® corrosion model. For example, pH values which are calculated from the water chemistry (dissolved salts (NaCl), and bicarbonate produced by corrosion, the expected flow pattern, the erosional gas velocity according to API RP 14E [20] based on the assumption of solid-free fluid production, and sour service region as per ISO 15156-2.

The resulted corrosion records are good documentation references that can demonstrate the scientific rationale behind the employed corrosion controls. Therefore, support information can be provided to the management decision-making process regarding further corrosion risk reduction measures, rather than the reliance on a subjective judgment or expertise only.

D. Quantitative Analysis

Corrosion risks for each well were quantified using probabilities (corrosion factor) and expected events (consequence factor). However, the results of this approach alone are not sufficient for comprehensive corrosion risk assessment, since risks cannot be adequately described and evaluated by reference only to the calculated and summarized probabilities and consequences. Therefore, the results of this approach were used to establish a corrosion risk matrix, and qualitative risk classification was obtained by the intersection of both probability and consequence values on the matrix.

E. Qualitative Analysis

A qualitative ranking of pitting risk factors due to the presence of H_2S has been proposed as Low/ Moderate/ High. This qualitative estimation was obtained from the ECE® corrosion model, and it is based on the stability of the iron Sulphide film and its possibility to break down under operating conditions. In addition, the studied wells were classified qualitatively in terms of their overall corrosion risks and risk levels were presented with color codes.

From the results of the theoretical corrosion risk assessment, all assessed items were classified as "very high risk", reflecting the highly corrosive nature of the downhole conditions and the critical situation of these wells, which makes corrosion control measures a high priority. Moreover, "very high" risk items are supposed to be monitored during production operations through a combination of procedures including corrosion monitoring, inspection, and fluid sampling.

F. Evaluation of Materials Suitability for Downhole Conditions

The evaluation for the suitability of downhole materials was conducted against technical acceptability criteria, which are based on ISO 15156-3: 2015 / NACE MR0175, ECE® developed rules, service, and environmental conditions. Based on the current operating and downhole conditions, it has been found that there will be a "high risk" of corrosion or cracking for downhole equipment made of 13Cr, 22Cr and 25Cr stainless steel, and acceptable results "low risk" for alloy 28, alloy 825, alloy 2550, and alloy C276 (CRA materials).

Feedback from the field on actual corrosion controls has been included for the re-evaluation of risk levels. Based on the re-evaluation results of the corrosion risk assessment that include corrosion control strategies already applied, mainly, the utilization of corrosion-resistant materials, and the estimation of its corrosive potential and stability, it has been found that the risk levels are no longer considered "very high". Rather, the wells can be categorized as "safe" in terms of corrosion risk by reaching the As Low as Reasonably Practicable (ALARP) value.

The corrosion risk assessment results are consistent with field operational experience. In fact, all Oil Country Tubular Goods (OCTG) and Down Hole Equipment (DHE) materials installed are made of corrosion-resistant alloys, mainly Alloy 28, Alloy 718, and Alloy 825. For production tubing, the material selected is Alloy 28, a Duplex Stainless Steel with a chromium content of up to 28%. It could withstand aggressive conditions where there is significant H_2S present, due to its excellent resistance to localized attacks such as pitting and crevice corrosion, as well as to both reducing and oxidizing acids. For other critical downhole components - including SSSV, packers, tubing hangers, flow couplings, and seating nipples - that are operating in a continuous corrosive environment and subjected to high temperatures and pressures where failure could lead to a loss in well's integrity and possible release of corrosive gases, the selected materials are high strength nickel-based alloys, namely, Alloy 718 (Inconel 718) and Alloy 825 (Incoloy 825). Both alloys have proven excellent resistance to stress-corrosion cracking and localized attacks such as pitting and crevice corrosion and protect against CO_2 corrosion.

Even though CRAs are relatively high-cost items and are likely to have very long lead times for delivery, the technical advantage behind standardizing all downhole equipment materials in Bouri oilfield to be corrosion resistant has been that it has reduced the operational costs that would arise from corrosion failures in case of using carbon steel equipment - even in combination with other corrosion control methods like inhibitors. Such failures would require a shut-in of the producing well, a subsequent loss in oil production, and associated costs related to workover intervention to replace the corrosion-failed equipment downhole.

VI. Conclusions

In this paper, a corrosion risk assessment model was presented to assess internal corrosion risks in naturally producing oil wells on one of the Bouri field platforms, considering the current operating conditions and downhole corrosive media. To this end, the Electronic Corrosion Engineer (ECE®) model was used as a tool to provide a basis for corrosivity assessment and risk analysis for internal corrosion of downhole equipment in the oilfield.

It has been concluded that the results of the corrosion risk assessment and analysis performed are in good alignment with the applicable corrosion control strategy, that is selecting corrosion-resistant materials for all downhole equipment, as a reliable option to minimize corrosion, and maximize the workover and re-tubing periods. Such a decision was based on original design assumptions for a range of operating conditions. The corrosion risk assessment and analysis performed have shown that the corrosion risk levels for the studied wells lie within the (ALARP) region, and there is no need for further reduction measures to lower internal corrosion risks below this level. In other words, the current operating conditions, though continuously changing, are still within the range of conditions to which the original corrosion control assumptions were made valid.

Further work is suggested to include both internal and external corrosion threats, and consequences of failure in terms of the health, safety, and environment so that a more comprehensive picture of corrosion risks can be created for each well. Also, other components of the well's completion including casings and wellheads may incorporated in future studies.

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