Integrated Analysis of Optimizing Tubing Material Selection for Gas Wells

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Abstract. Corrosion in production tubing strings is seen as a challenging problem in gas wells containing carbon dioxideand hydrogen sulfide. This paper presents a new comprehensive method of corrosion rate calculation with integrated study of reservoir condition, nodal analysis of the well, and well trajectory, which could also have an effect due to the possibility of different flow regimes of the production fluid. This method is applicable to evaluate and predict the performance of selected tubing size and material. This method can also give an economic evaluation for the consideration of using corrosion resistant alloy (CRA) or low-alloy steel and carbon steel. The measurement of corrosion rate can be done by several methods,such as using corrosion coupons, calculating the iron content inside the production fluid, or probes. Either way, when the corrosion rate measured in the field is still below the acceptable maximum corrosion rate, it can be said that the adequacy of this method is guaranteed. This method has been implemented in a gas field,where it successfully selected the best tubing material for the next development well in this field. Consequently, the lifetime of the tubing strings could be extended,resulting in an economical benefit as well.

Keywords: *corrosion; gas well; integrated analysis; production tubing; tubing material selection.*

1 Introduction

A literature review based on Bellarby [1] was performed to gain knowledge of corrosion and metals and understand their relationship.

1.1 Corrosion

Corrosion is defined as the destruction of a metal by chemical, electrochemical reaction or microbial reactions with its environment [1,2]. Based on Bellarby [1], for corrosion to occur the following basic conditions are required:

1. Metal surface exposed to environment
2. Electrolyte (i.e. water containing ions, the electrolyte must be able to conduct current)

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3. A corrodent or an oxidant (a chemical component causing corrosion, e.g. oxygen, carbon dioxide)

Based on Bellarby [1], corrosion cannot occur without water. The water remains as dispersed bubbles within the continuous phase at lower water cuts,preventing the tubing from becoming water wet. Free water may still be produced in a gas well without associated water production as the fluids cool and the water condenses. However, corrosion has been observed in wells with a water cut as low as 1%.

1.1.1 Corrosion Rate Model

The basic CO_2 corrosion rate is the combination of these two processes [3,4]:

$$V_{cor} = \frac{1}{\frac{1}{V_r} + \frac{1}{V_m}} \tag{1}$$

For normalized steels, the equation for the reaction-controlled part is [3,4]:

$$\log(V_r) = 4.84 - \frac{1119}{(t+273)} + 0.58\log(f_{CO_2}) - 0.34(pH_{actual} - pH_{CO_2}) \tag{2}$$

And for the mass-transfer controlled part [3,4]:

$$V_m = 2.8\frac{U^{0.8}}{d^{0.2}} f_{CO_2} \tag{3}$$

The results from previous equations are adjusted by the presence of protective scale, H_2S, crude oil or condensate, glycol, and inhibitor by means of a multiplier on the basis of the CO_2 corrosion rate [3-6]:

$$\text{Corrosion rate} = V_{cor} \times F_{scale} \times F_{H_2S} \times F_{cond} \times F_{oil} \times F_{inhib} \times F_{glyc} \tag{4}$$

1.2 Metals

All components used in the completion of a hole require metal or metallic alloys, and the vast majority of tubing is metal with plastic pipe available for low-pressure applications. Almost all metals used in tubing comprises steel. There are two main classifications of steel used for tubing based on Bellarby [1]: low-alloy steels and alloy steels.

2 New Method of Selecting Tubing Material

This study proposes a new methodofselecting the tubing material. This method calculates the corrosion rate and selects the tubing material by taking into account reservoir characteristics, reservoir fluid properties, nodal analysis, and well trajectory. These factors are explained in the next subsections.

2.1 Reservoir Characteristics and Reservoir Fluid Properties

It is well known that an accurate corrosion rate calculation can be achieved by first studying the properties of the reservoir and of course the fluids as well [7]. First thing to know is the composition of reservoir fluid samples obtained from drill stem testing (DST). As mentioned in the previous section, corrosion will occur when a corrodent such as carbon dioxide, hydrogen sulfide, or oxygen exists in the reservoir fluids [1]. That is why it is essential to know these components' mole fractions.

Corrosion is also dependent on temperature and pressure along the wellbore [8]. Obviously, data such as reservoir temperature and pressure, temperature and pressure gradient along the wellbore, and also wellhead temperature andpressure are required to study the corrosion rate from bottom hole to surface.

After getting all of the parameters mentioned before, the next step is PVT analysis. Construction of phase envelope, constant composition expansion (CCE), and constant volume depletion (CVD) should be conducted. From the PVT analysis it is possible to determine the type of reservoir fluids. For gas wells the condition when condensation occurs should be evaluated since this also affects corrosion. Condensation can occur because of reservoir formation along the wellbore or possibly on surface equipment [9]. Liquid dropout performance is another possible explanation for condensation occurrence, when the amount of water along the tubing length is different because there are changes in temperature and pressure along the tubing length. This condensation is important to be understood because water is the medium through which corrosion occurs.

2.2 Nodal Analysis

After getting the study of reservoir characteristics and reservoir fluid properties, it is essential to conduct a nodal analysis of the wells. Absolute open flow (AOF) and optimum production gas rate can be obtained from the intersection of the inflow performance relationship (IPR) and the tubing performance relationship (TPR). This study usedthe PROSPER software from Petroleum Experts to conduct the nodal analysis. For the nodal analysis,the other parameters to be evaluated are gas rate, water rate, oil/condensate rate, bottom hole pressure, and wellhead pressure at theinitial condition of the reservoir and also at the highest water production rate condition [10]. These parameters are essential to calculate the corrosion rate at the initial condition and at the worst possible case when the water production rate is high. A sensitivity analysis of these three rates can also be conducted to calculate the maximum corrosion rate for the lifetime of the well, so a more accurate tubing material selection can be made.

2.3 Corrosion Rate Calculation

This study used the Electronic Corrosion Engineer (ECE®) corrosion model for calculation of the corrosion rate. In his study, Nyborg [11] found that this model developed by Intetech is based on the De Waard 95 Model by adding a procedure to calculate pH from water chemistry and bicarbonate, oil wetting effect, H_2S effect, acetic acid and top of line corrosion. ECE® is able to calculate the corrosion rate in the tubing and flowline, and to evaluate the economics of the selected material as well [12]. Nyborg [11] also explains that the pH calculated from this model may be higher than that from other models because of the way the bicarbonate concentration is calculated, but the calculated

Table 1 Important factors in CO_2 corrosion prediction models [8,11].

Model	DW	NO	EC	TU
Lab data, Field data model, Mechanistic model	Lab data	Lab data	Lab data	Mechanistic data
Scale effect formation water*	No effect	Moderate effect	Weak effect	Strong effect
Scale effect condensed water*	Weak effect	Moderate effect	Weak effect	Strong effect
Effect of pH on corrosion rate*	Weak effect	Moderate effect	Weak effect	Strong effect
Oil wetting effect crude oil*	Strong effect	No effect	Strong effect	No effect
Oil wetting effect crude condensate*	No effect	No effect	Moderate effect	No effect
Effect of organic acid on corrosion	-	-	Yes	-
Top of line corrosion	Yes	-	Yes	-
Effect of H_2S on corrosion rate*	No effect	No effect	Strong effect	No effect
Multiphase flow calculation**	No multiphase flow calculation	Point calculation	Multiphase profile calculation	Point calculation
Max. temperature limit (°C)	140	150	140	115
Max. CO_2 partial pressure (bar)	10	10	20	17
Open, Commercial, Proprietary	Open	Open	Commercial	Proprietary

corrosion rates are not very sensitive to the calculated pH. On the other hand, the presence of H_2S can give a considerable decrease in the predicted corrosion rate due to the formation of protective iron sulfide films [5]. Nyborg [11] also compares ECE® with other corrosion models. See Table 1 for a comparison of ECE® with other models. The models compared in Table 1 are De Waard Model (DW), NORSOK M-506 Model (NO), ECE® Model (EC), and Tulsa Model (TU).

It should be noted that the corrosion rate calculation is conducted for all of the sensitivity cases with different gas rate, water rate, and oil/condensate rate as mentioned before. In addition, different tubing materials such as chromium, nickel, and molybdenum content should also be subjected to sensitivity analysis. However, the ECE® software is still unable to take into account materials other than chromium.

2.4 Tubing Material Selection

Proper tubing material is selected on the basis of the maximum corrosion rate from the sensitivity cases of the nodal analysis and the chromium content that have been conducted [13]. Figure 1 shows the interface of the ECE® software for tubing material selection. In this example, all types of tubing are technically acceptable to be used.

Table 2 shows the severity levels of the unmitigated predicted corrosion rate. In his study, Nyborg [11] explains that severity levels represent different ranges of corrosivity. Furthermore, the severity levels are evaluated in two steps. Step 1 is used in preliminary or early assessment, when limited data are available.Step 2 is used for the assessment of the predicted corrosion rate when more detailed data are available. The final design should use step-2 evaluation.

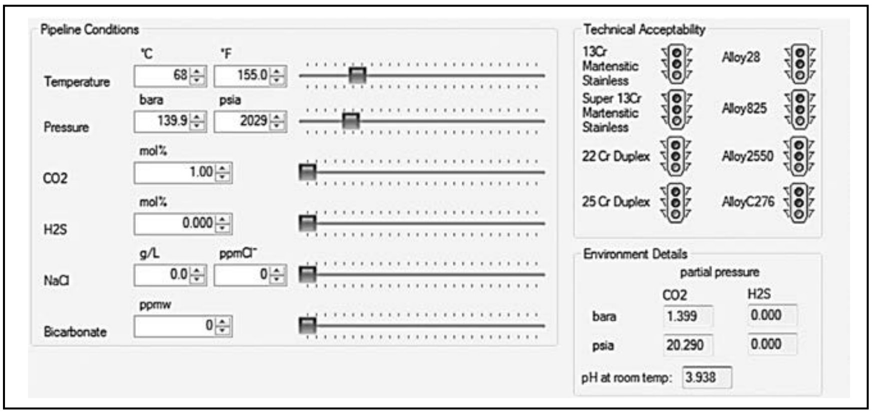

Figure 1 Tubing material selection (ECE® Software).

Table 2 Severity level for various corrosion rates [8].

Severity Level	Corrosion Rate(mm/year)		
1		<	0.01
2	0.01	-	0.1
3	0.1	-	1.0
4	1.0	-	10
5		>	10

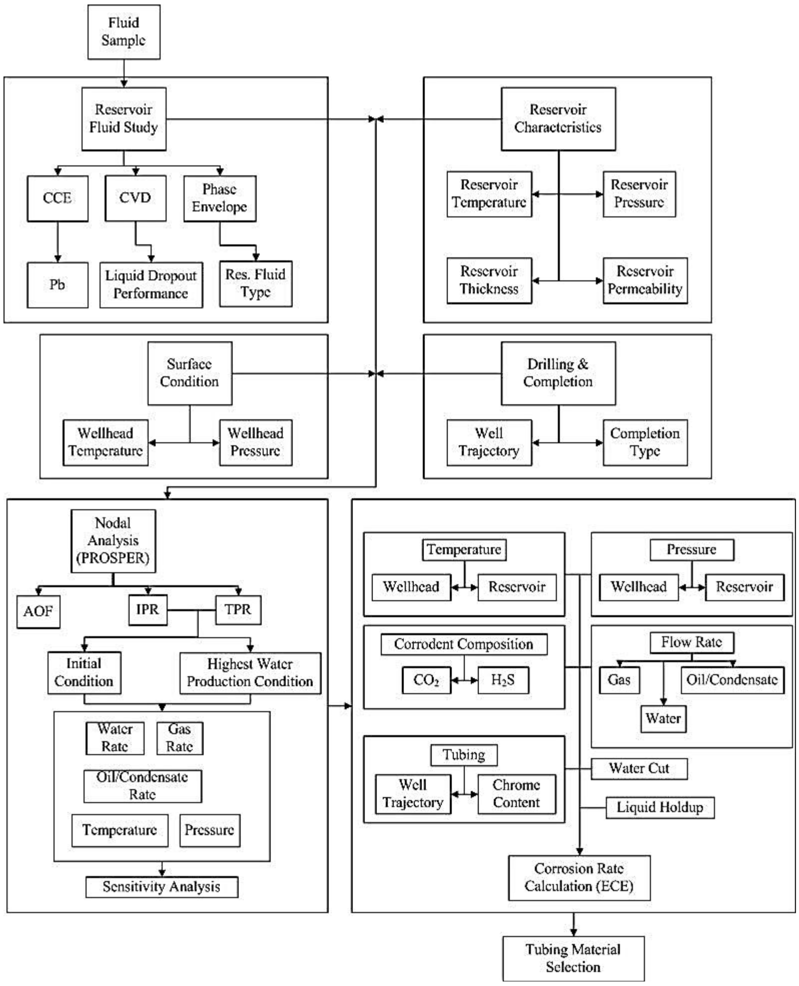

Figure 2 Tubing material selection workflow.

The objectives of selecting proper tubing material are avoiding corrosion, minimizing cost of purchaseand cost for repair or replacement when the tubing fails due to corrosion failure. Bellarby [1] gives approximations of the cost of tubing material types relative to the cost of carbon steel tubing. L80 carbon steel is one time the cost of carbon steel. On the other hand, L80 13Cr is three times the cost of carbon steel, and titanium is 10-20 times the cost of carbon steel.

Figure 2 shows a flowchart for tubing material selection based on the proposedmethod, which considers parameters from the reservoir fluids, reservoir characteristics, surface condition, drilling and completion, nodal analysis, and corrosion rate calculation [13]. It can be seen that selecting proper tubing material should be studied integratedlyfor the reservoir, production, and drilling aspects.

3 Case Study

Corrosion rate calculation as well as tubing material selection was conducted based on the data of reservoir fluids, reservoir characteristics, nodal analysis, and well trajectory.

3.1 Reservoir Fluid Properties (PVT Analysis)

Based on a reservoir fluid analysis report provided by the gas company there is no indication of condensate during the formation of the reservoir at the initial condition. The reservoir fluid type is dry gas based on the samples collected from four wells and five DST intervals, which indicate a similarity in gas composition and density [14]. Only small amounts (<1%) of inorganic impurities (carbon dioxide and nitrogen) were observed in the gas samples and no hydrogen sulfide, H_2S, was detected in any of the tests, based on measurements during DST and laboratory sample analysis. The Standing-Katz dry gas correlation was used to generate the fluid's PVT properties (gas formation volume factor, B_g, and z-factor) and the method fromLee,*et al*.[7]was used to determine gas viscosity. One type of reservoir fluid properties was used across the reservoir.

Samples were taken from a well. Based on the analysis, the samples had a methane content of more than 97% so the reservoir type is supposed to be dry gas reservoir. However, the analysis only provided fluid components measurement with no other experimental analysis such as constant composition expansion (CCE) or constant volume depletion (CVD), with the purpose to estimate liquid drop performance and analyze fluid behavior [9].

In order to estimate and analyze the reservoir fluid behavior, the PVT report (components measurement only) was used to calculate fluid saturation pressure and relative volume using the equation of state method [15]. Peng-Robinson, Zhou, *et al*., and the Standing-Katz correlation were used to estimate phase envelope, gas viscosity, and oil density respectively. The phase envelope for the well fluid sample illustrated using PVTP software is shown in Figure 3.

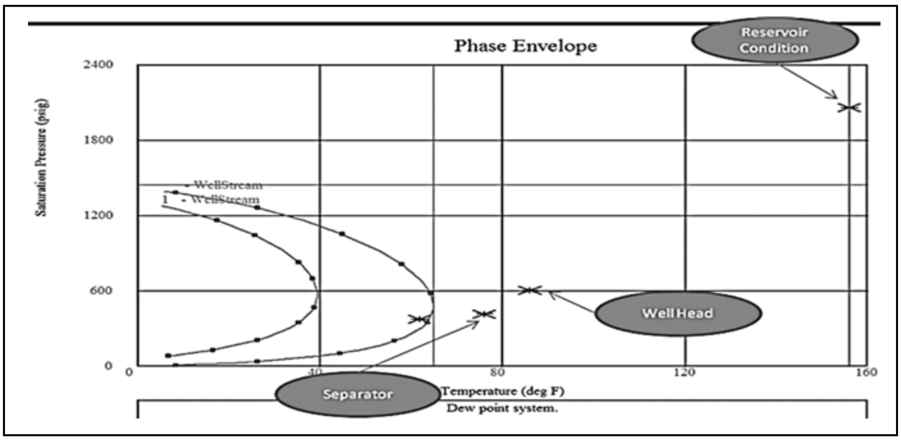

Figure 3 Phase envelope of well fluid sample.

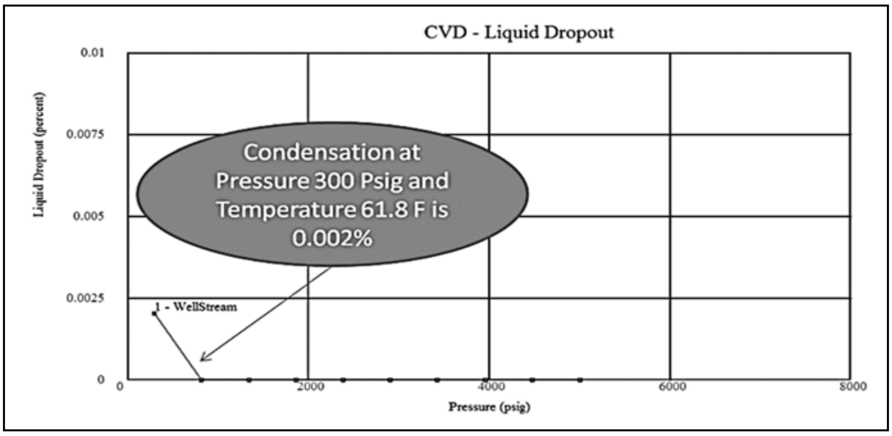

Figure 4 Liquid dropout performance of well fluid sample.

The red lines are the quality line that represents equal percentage of liquid and gas phase, the green points are test conditions obtained from the well test data (reservoir, wellhead, and separator conditions). As shown in Figure 3, there were no condensates formed in the reservoir throughout the production time. This type of reservoir fluid exists as a single-phase gas at reservoir condition and liquid hydrocarbons are only produced as a result of the pressure and temperature losses that occur as the gas is produced to the surface. The liquid dropout profile as a function of pressure drop for the well fluid sample is illustrated in Figure 4. As shown in this graph, the amount of condensate is relatively small: about 0.002% at pressure 300 psig and temperature 61.8°F.

3.2 Nodal Analysis

A complete gas production system includes reservoir, well, flowline, separators, pumps and transportation pipelines [16]. The well provides a path for the production fluid to flow from the bottom hole to the surface and offers a means of controlling fluid production [10]. Several problems such as scale and corrosion could cause reduction of the production rate and production lifetime. A 7" slotted liner 16 SPF is recommended based on the available data.

In this study, a review of the nodal analysis was conducted for a development well in order to reach an accurate calculation of the corrosion rate and to anticipate extreme conditions in the flow process.

Figure 5 shows the nodal analysis of the well that was conducted using PROSPER software, using the configuration of the well. Some assumptions and correlations that were used in this analysis are:

Fluid Properties

Fluid Type	: Dry gas
Calculation Method	: Equation of State (Peng-Robinson)
Separator	: Multi Stage Separator

In order to construct an integrated study from fluid analysis to completeddesign, the result of the PVT analysis for the well fluid sample is needed. Based on the PVT analysis of the well fluid sample, the CO_2 component has a mole percentage of 0.75%.

Well

Flow Type	: Tubing Flow
Well Type	: Producer

Well Completion

Type	: Open Hole
Sand Control	: Slotted Liner
Inflow Type	: Single Branch

Inflow Performance Relationship

Reservoir Model	: C and n
C	: 6.66142 MSCF/Day/psi^2
n	: 1

Reservoir Pressure : 2,022 psig
Reservoir Temperature : 148 °F
Water Gas Ratio : 0 STB/MMSCF
Condensate Gas Ratio : 1.04 STB/MMSCF

Vertical Lift Performance

Vertical Lift Correlation : Gray
Solution Node : Bottom Hole
Bottom Measured Depth : 6,757 ft
Bottom Vertical Depth : 4,419 ft

Figure 5 shows the nodal analysis for the well that was conducted for three wellhead pressures (115, 835, and 1,613 psig) and several slot densities. In Figure 5, the dotted points (•) represent the inflow performance relationship (IPR) curve and the crossed points (x) represent the vertical lift performance (VLP) curve. Based on Figure 6, utilization of slotted liner with 16 SPF would generate a 69.6 MMSCF/day gas production rate for this well. Due to the unavailability of data to validate these results, the sensitivity analysis for the fluid production rate used the available data.

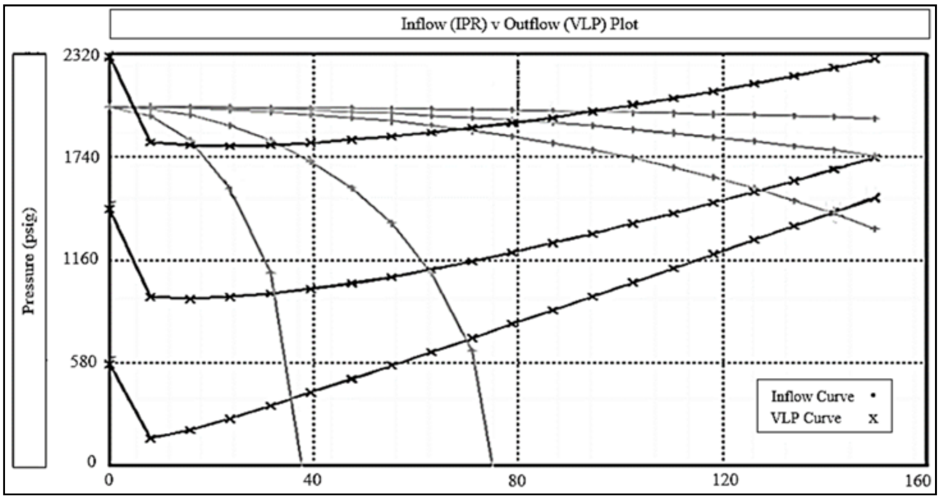

Figure 5 Development well nodal analysis.

3.3 Well and Field Data

In predicting corrosion there are many data that have to be available. In this study, the data available were CO_2 and H_2S content, velocity-production rate, operating temperature and pressure, condensing conditions, well trajectory, and tubing dimension. However, several data such as oxygen and other oxidizing content, organic acids, halide, metal ion and metal concentration, dissolved chloride and bicarbonate content of water, biological activity, and wettability were unavailable. These unavailable data were assumed to be the default value in modeling and determining the corrosion rate.

3.4 Corrosion Prediction

The prediction of the corrosion rate was done for several possible conditions:

1. The initial gas and water rate of each well, to predict the corrosion rate in the early life of the well.
2. The highest water rate of each well that is predicted for the future when the reservoir pressure is reduced significantly.
3. The utilization of 1.2% chromium content (which represents API 5CT tubing of C90) and 0.01% chromium content (which represents API 5CT tubing of J55, L80, P110) for each well. These two types of chromium tubing are the least resistant to corrosion and more economical than tubing with higher chromium content. [17]

The calculations of the corrosion rate utilizedthe ECE® software, which requires the following input data:

1. Gas rate, water rate, and oil rate (including API gravity)
2. Pressure and temperature at wellhead and reservoir
3. Depth and trajectory (inclination) of the well
4. Inhibition program
5. CO_2, H_2S, and bicarbonate content (H_2S and bicarbonate are assumed to be zero)
6. Tubing dimension and material content.

In this study, it is assumed that there is no inhibition program. Based on the reservoir fluid composition data, the condition of the environment is sweet without any H_2S. The $CO_2$is assumed to be 0.75 mole% as the highest value based on the well DST. There is no condensate production with the low water production of the wells. Figures6-10 show the input data values of temperature, pressure, and tubing dimension for the developmentwells, which wereanalyzed using the ECE® software.

4 Results and Discussion

4.1 Result of Corrosion Rate for Each Development Well

The corrosion rate prediction calculation was done for the well with two conditions, initial pressure condition and highest water production condition, and two different chromium compositions, 0.01% chromium and 1.2% chromium, which have been discussed in the previous section. At the initial pressure condition, the well has reservoir pressure 2,029 psi, gas rate 23.6 MMSCFD, and water rate 3 bpd. At the highest production condition, the well has reservoir pressure 677 psi, gas rate 23.47 MMSCFD, and water rate 10 bpd.

Figures 6-10 illustrate the plot of corrosion rate versus tubing length for several of the aforementioned conditions. The tubing length of the well is 6,338 ft MD with KOP at 550 ft and a maximum inclination of 56.1°. From bottom hole to surface, it can be seen from the graph that the corrosion rate starts to increase at a depth of approximately 3,000 ft for the initial conditions, and 5,800 ft for the highest water production conditions. This is due to the difference in flow regime, where from the bottom hole to3,000 ft or 5,800 ft the flow regime is a mist flow with the water phase still in little droplets form and flow as a discontinued phase within a gas. However, from 3,000 ft or 5,800 ft to the surface, the droplets of water have been connected to each other and constitute an annular-mist flow. This continuous water phase contacts the steel surface and acts as an electrolyte, which causes corrosion to occur,increasingly to the surface level.

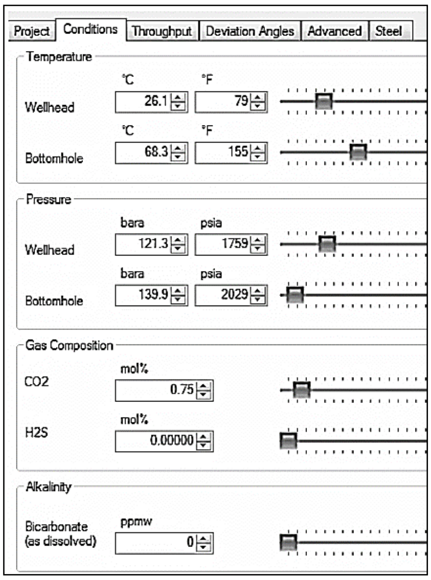

Figure 6 Input of well condition data.

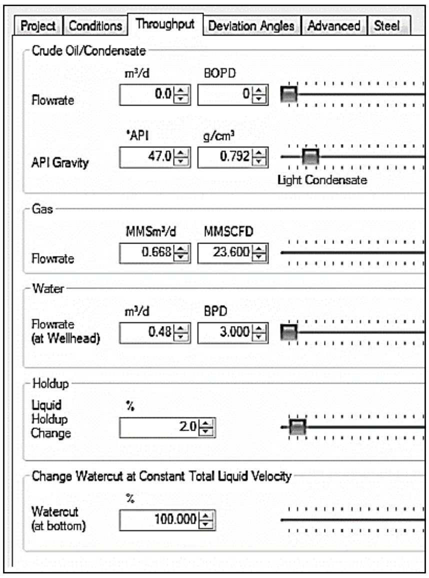

Figure 7 Input of production data.

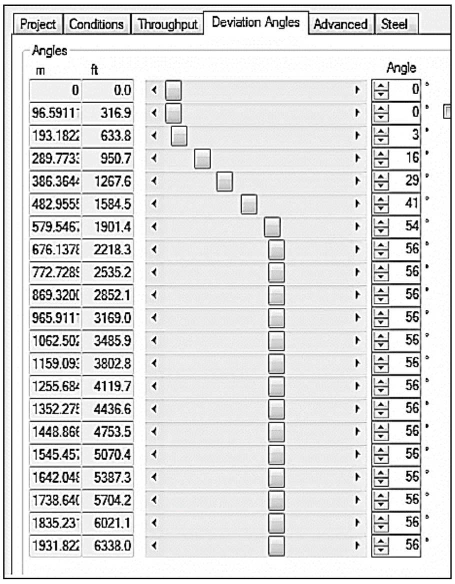

Figure 8 Input of well trajectory.

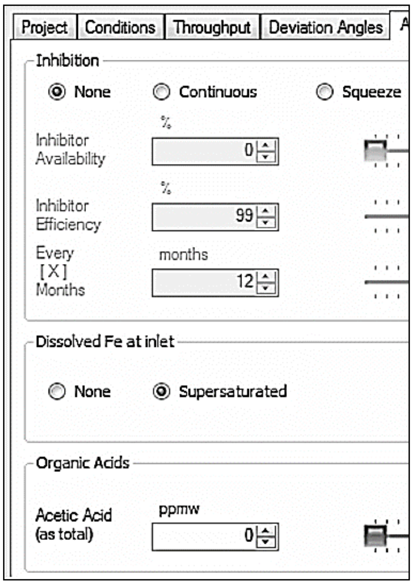

Figure 9 Input of inhibition, iron, and organic acid content data.

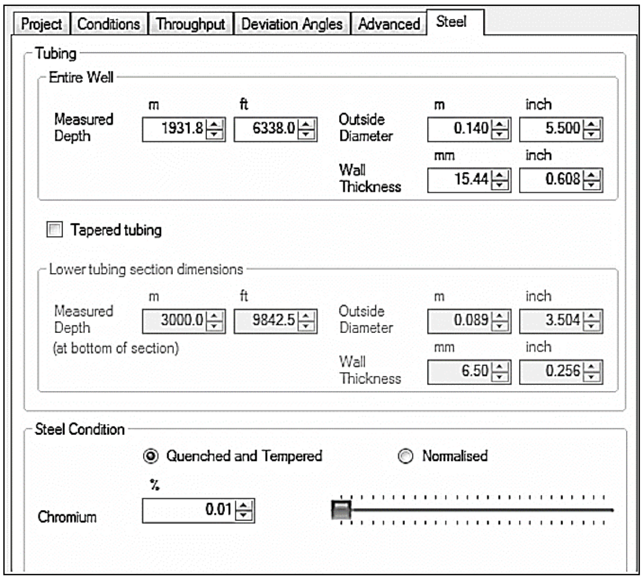

Figure 10 Input of tubing dimension data.

The corrosion rate of the well for the given conditions are shown in Figures 11-14. Figures 11 and 13 show the corrosion rate of the well at the initial gas rate production. Figures 12 and 14 show the corrosion rate of the well at the highest water rate production. Based on Figures 11-14, the value of the corrosion rate is around 0.105-0.15 mm/year for tubing with 0.01% chromium content. For tubing with 1.2% chromium content, the corrosion rate is around 0.038-0.055 mm/year. Both these ranges are still below the acceptable value which is 0.1-0.2 mm/year. Thus, based on this result, tubing with 0.01% chromium content is technically and economically appropriate for the next development well.

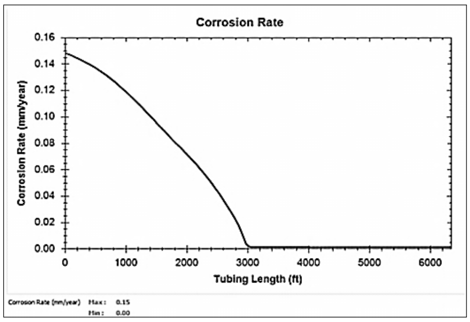

Figure 11 Corrosion rate of the well at initial gas rate production (with 0.01% chromium content of tubing material).

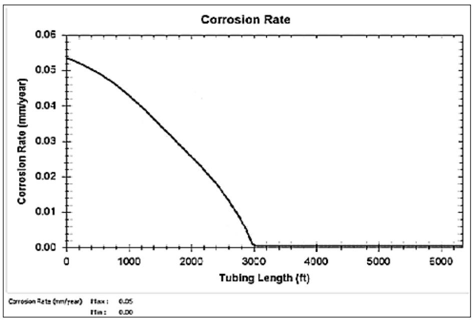

Figure 13 Corrosion rate of the well at initial gas rate production (with 1.2% chromium content of tubing material).

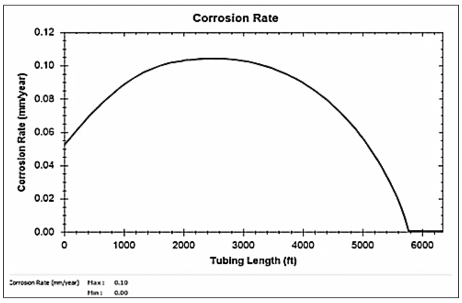

Figure 12 Corrosion rate of the well at highest water rate production (with 0.01% chromium content of tubing material).

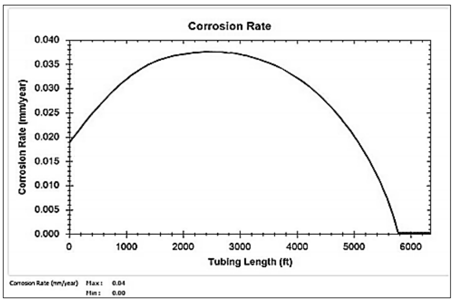

Figure 14 Corrosion rate of the well at highest water rate production (with 1.2% chromium content of tubing material.

Based on the results above, it can be deduced that by adding from 0.01% to 1.2% chromium the corrosion rate can be reduced significantly. The adding of chromium to the steel has the effect of enriching the iron carbonate film, which makes it more stable. The economic analysis must also consider the chromium content of the tubing material since more chromium will make the price higher.

5 Conclusions

A new comprehensive method for optimizing tubing material selection of gas wells has been presented. This method calculates the corrosion rate and selects the tubing material by taking into account reservoir characteristics, reservoir fluid properties, nodal analysis, and well trajectory. With this method, a case study of tubing material selection in a gas well was performed.

Based on the reservoir data, all reservoir fluid samples had methane content higher than 97% and the reservoir type was supposed to be dry gas reservoir. There were no other experimental analyses such as constant composition expansion (CCE) or constant volume depletion (CVD), with the purpose of estimating liquid drop performance and analyzing fluid behavior. The analysis of the reservoir fluid behavior from a wellfluid sampleshows that there were no indications that condensate would be produced around the perforation/production interval. Using the data from the gas well, the results show that the highest corrosion rate is around 0.105-0.15 mm/year for tubing with 0.01% chromium content. Thus, the highest value for the corrosion rate is around 0.038-0.055 mm/year for tubing with 1.2% chromium content. These two values are still below the acceptable value, which is 0.1-0.2 mm/year. Therefore, tubing with chromium content 0.01% is technically and economically appropriate for utilization in the development well.

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Nomenclature

V_{cor}	=	Corrosion rate due to CO_2, mm/year
V_r	=	Corrosion rate due to maximum kinetic reaction rates, mm/year
V_m	=	Corrosion rate due to mass transfer rates of dissolved CO_2, mm/year
t	=	Temperature, °C
f_{CO_2}	=	Fugacity of CO_2, bar
pH_{actual}	=	Actual pH including effect of dissolved bicarbonate

pH_{CO_2}	=	pH arising only from dissolved CO_2
U	=	Flow velocity, m/s
d	=	Internal tubing diameter, m
F_{scale}	=	Scaling factor
F_{H_2S}	=	Hydrogen sulfide factor
F_{cond}	=	Condensate factor
F_{oil}	=	Oil factor
F_{inhib}	=	Inhibitor factor
F_{glyc}	=	Glycol factor
p_{CO_2}	=	Partial pressure of CO_2, bar

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