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Risk Mitigation and Mapping on Tubular System During Microbial Huff and Puff Injection Coupled with Lean Six Sigma Approach at Field X

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ABSTRACT

Increasing demand of oil in Indonesia is in contrast with the decreasing oil production every year. Enhanced oil recovery (EOR) has become one of the most favorable method in maximizing the production of mature fields with various applications and research has been done on each type, especially microbial EOR (MEOR). "X" field is a mature oil field located in South Sumatra that has been actively producing for more than 80 years and currently implementing MEOR using huff and puff injection. Based on the simulation results, the normal corrosion rate ranging from 0.0348 – 0.039 mm/year and the pH is around 4.03 – 5.25, while the ±30% fluid rate sensitivity results shown that the change of water lowrate is more sensitive than oil flowrate with the corrosion rate approximately 0.0275 – 0.048 mm/year. The fishbone diagram identifies that material selection and environmental condition as the main root causes, then corrosion resistant alloy (CRA) is used in the tubing string to prevent corrosion in the future by using super 13Cr martensitic steel (modified 2Ni-5Mo-13Cr) as the most suitable material. Further simulation on chromium content supports the selection that corrosion rate can be reduced by adding the chromium content in the steel. The completion design is then capped with choosing the Aflas® 100S/100H fluoro-elastomer as the optimum material for packer and sealing. Overall, the Lean Six Sigma approach has been successfully applied to help the analysis in this study.

Keywords: DMAIC framework; huff and puff injection; lean six sigma; microbial EOR; tubing corrosion risks mitigation

I. INTRODUCTION

In this modern era, energy needs in the world are still dominated by fossil fuels generated from the oil and gas sector with about 35% of the world's primary energy shares (BP Energy Outlook, 2019). However, the rapidly increasing demand in fossil fuels is not counterbalanced by the amount of oil production. **Figure 1** represents that the production of oil in Indonesia has been decreasing while the demand for consumption is continuously getting higher over time (Ministry of Energy and Mineral Resources, 2018). Therefore, creating a gap that needs to be fulfilled by bouncing back the oil production. One of the main problems faced in the oil and gas industry is that the majority of oil fields in Indonesia are categorized as mature fields, which requires a new method to recover the remaining oil reserves which are still possible to be produced from the reservoir such as Enhanced Oil Recovery (EOR).

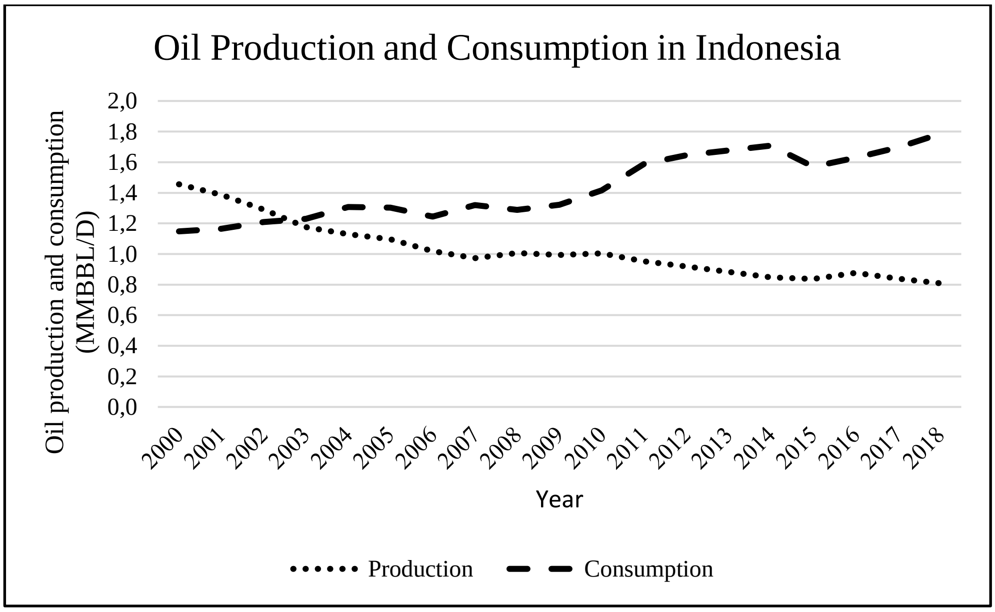

Figure 1. **Indonesia's Oil Demand and Supply**
Source: Ministry of Energy and Mineral Resources, 2018

EOR is a process done after the primary and secondary recovery phase which involves the injection of various type of fluids into a reservoir, then interacts with the system's physical and chemical properties in order to give subsidiary energy for a more favorable oil recovery (Green and Willhite, 1998). There are various types of EOR, such as miscible or immiscible gas injection, chemical injection, thermal recovery, microbial injection, and combination of EOR (Aladasani, 2010). The challenges of EOR development in Indonesia are varied from complicated bureaucracy and regulations by the government, many technical uncertainties, and most importantly the high-priced cost of an EOR study and project which make EOR is classified as a long-term solution. Moreover, recent fallout of oil price is causing most of oil companies to rethink whether EOR projects are economically feasible to be applied in the near future.

Microbial Enhanced Oil Recovery (MEOR) is one of EOR method that is best suited in these recent conditions due to its environmental and economic advantages. In addition, MEOR can also be applied in single or multiple wells simultaneously so that the Huff and Puff method can be potential as the short-term solution. The mechanism of MEOR requires the use of mixed or independent microbial population and their metabolic population to be injected into the reservoir to reduce the viscosity, lower the interfacial tension, change the wettability, and sometimes increase the permeability of the reservoir (Ansah, 2019). However, there are also some risk issues to be managed in MEOR applications, including (1) insufficient growth of bacteria, (2) plugging in the near wellbore caused by bacteria, (3) high adsorption of injected nutrients, (4) reservoir souring and increase of carbon dioxide (CO_2) & hydrogen sulfide (H_2S) due to the presence of sulphate-reducing bacteria (SRB), (5) and microbially induced corrosion (MIC) in the tubing (Alkan, 2016). The last two risks mentioned above are the most important issues faced by petroleum engineers in completion and production operations.

Therefore, this study will focus on the mitigation and prevention of MIC in tubing oil producers by designing the best completion strategy and selecting the best material for the tubing including the use of corrosion resistant alloys (CRA). The parameters and corrosion rate calculation are based on the field's reservoir fluid properties and production performance, then simulated using commercial software, in this case, the Electronic Corrosion Engineer (ECE^{TM}) by Intetech.

II. METHODS

This study was completed throughout several steps. **Figure 2** depicts the flowchart of methodology used in this study. The methodology of this study is as follows:

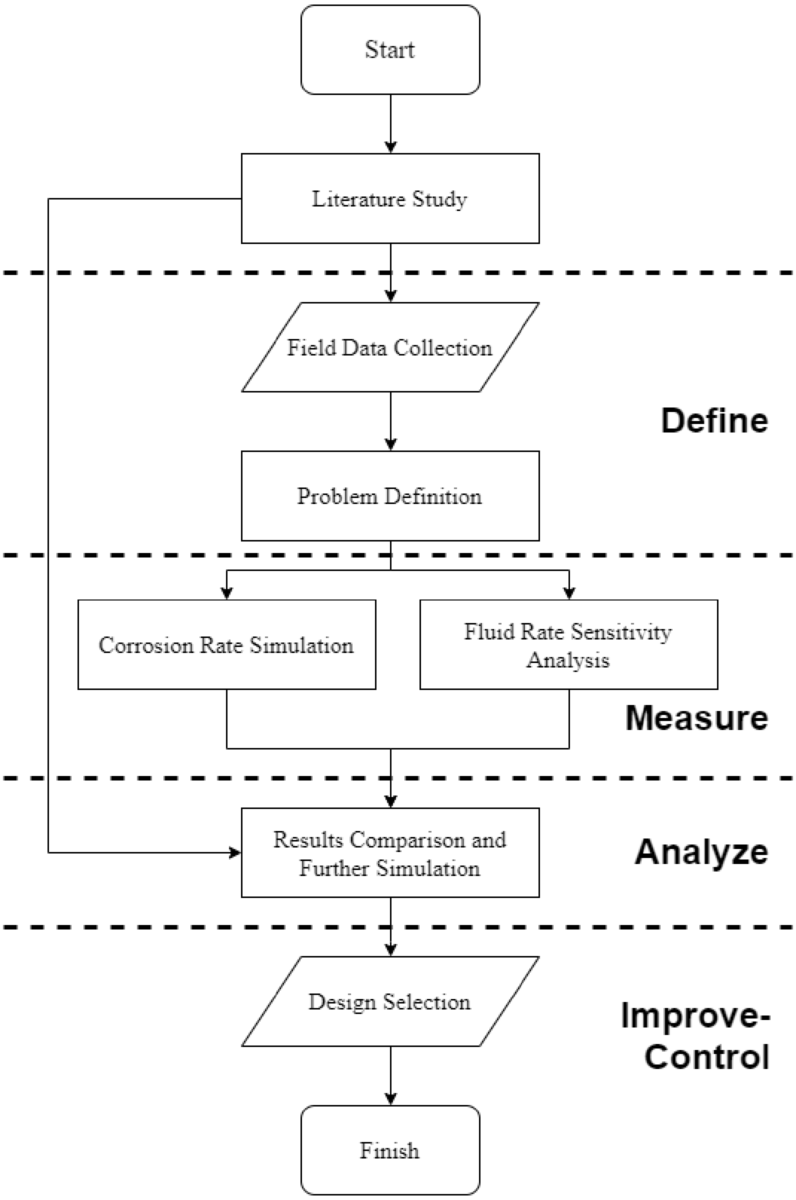

Figure 2. Methodology Flowchart of The Study

1. Literature Study

The first step is studying and gathering information from various literatures mainly from books, papers, and industry standards related to microbial enhanced oil recovery, huff and puff, corrosion, and completion processes.

This step is essential for implementing the basic theories and applications into the software simulation and result analysis. Then, later used as a comparison with the results to obtain the best scenario that will be selected.

2. Field Data Collection

The next step is to collect all the data needed from the field which had already implemented the MEOR Huff and Puff application. Data used for this study are listed in **Table 1.** The field's overview will be explained in the next chapter.

Table 1 Corrosion Rate Simulation Input Data

Parameter	Value	Unit
Wellhead Pressure (P_{wh})	100	psia
Wellhead Temperature (T_{wh})	90	ºF
Bottomhole Pressure (P_{wf})	400	psia
Bottomhole Temperature (T_{wf})	160	ºF
CO_2 Composition	6	%mol
H_2S Composition	17 –> 22	ppm
Total Dissolved Solids (TDS)	28513.67	mg/L
Oil Flowrate (Q_o)	89.31	bbl/d
Water Flowrate (Q_w)	163.87	bbl/d
Gas Flowrate (Q_g)	0.30	MMSCFD
Watercut	65	%
Total Depth	2528	m
	8293.96	ft
Deviation Angle	0	degree
Gas Erosional Velocity	150	$(lbs/ft)^{0.5}/s$
Tubing OD	7	in
%Cr	0.00	%
Wall Thickness	0.43	in

This step is necessary for the simulation of corrosion rate that might be occurred during production phase in the tubing. The data collecting process is done repeatedly corresponding to the software's calculation requirements.

3. Corrosion Rate Simulation

After collecting all the field's data required as input in the ECE™ software, the corrosion rate simulation is done by using some assumptions as followed:

1. The well trajectory is 90º vertical from surface KB to casing shoe with 0º deviation angle (all angles are equal).
2. The tubing used is categorized as non-tapered tubing.
3. There are no inhibition process and no dissolved Fe in the tubing.

This simulation is one of the main output of this study for predicting the risk of corrosion affecting the tubing resistance during production phase, thus the mitigation and prevention acts can be prepared.

4. Fluid Rate Sensitivity Analysis

The results from simulation are then followed with an extensive analysis by creating sensitivity for the oil and water rate, while the gas rate remains the same. Both parameter's values are then varied within a range of ±30% and an incremental of 10%.

Sensitivity analysis is one of the what-if analysis methods used for predicting the outcomes that may be different compared to the ideal condition stated initially. This method is also used for identifying the dependency of a certain variable to the results.

5. Results Comparison

The results from simulation and sensitivity analysis are then compared to the literatures of maximum corrosion rate for various tubing specifications, sourced from books, paper, and industry standards such as API, NACE, and NORSOK standardization.

This step is important for selecting the optimum completion design and making sure that the design is already suitable to be used in existing condition.

6. Design Selection

The last step of this study is to choose the most optimum design for the completion process including tubing specifications and addition of supporting materials like corrosion resistant alloys (CRA) and fluoro-elastomer (HNBR) packer.

The design is determined by considering all the risks possibilities that may occurred in a sour field and could be worsen by the interactions of bacteria injected to the reservoir, in order to prevent microbially induced corrosion (MIC).

III. CASE STUDY

“X” field is a mature oil field located in the South Sumatra that has been producing for more than 80 years. It currently has 18 active producing wells out of the total of 130 wells and already reached about 40% of its recovery factor. The wells are produced within 3 different Palembang Sand Formations, known for its shallow sand high basic sediment production.

The field is categorized as medium to heavy oil with API oil gravity ranging from 22° to 28°. It has oil viscosity of 2.5 cP and low reservoir pressure at approximately 1024 psi. The average water cut is valued at 78% with low Gas Oil Ratio (GOR). The field’s average porosity is at 27.5% with an average permeability of 120 mD, and still has about 97 MMSTB of remaining oil reserves (Ariadji, 2017). The complete field properties are summarized in **Table 2**, then matched with the EOR screening criteria of Aladasani (2010) and Bryant (1991) in **Table 3** to determine if MEOR is applicable to this field.

Table 2. "X" Field Properties for Screening

Parameter	Palembang A	Palembang B	Palembang C
Gravity (°API)	22 - 28	22 - 28	22 - 28
Viscosity (cP)	2.5	2.5	2.5
Porosity (%)	27.5	27.5	27.5
Oil Saturation (%PV)	0.55	0.55	0.55
Permeability (mD)	68	84	202
Depth (ft)	558	902	1197.5
Temperature (°F)	122	122	122
Formation Type	Shally Sand	Shally Sand	Shally Sand
Net Thickness (m)	55	70	30

Table 3. MEOR Screening Reference Parameter

Parameter	Reference	
	Aladasani	**Bryant**
Gravity (°API)	12 - 33	> 15
Viscosity (cP)	1.7 - 8900	-
Porosity (%)	12 - 28	-
Oil Saturation (%PV)	55 - 65	> 25
Permeability (mD)	60 - 200	> 50
Depth (ft)	1572 - 3464	< 8000
Temperature (°F)	86 - 90	< 170
Formation Type	Sandstone	-

Based on the screening results that can be seen in **Table 4**, it can be concluded that MEOR is suitable for "X" Field despite the temperature parameter of Aladasani criteria does not meet the requirements. Bryant's criteria is then chosen because of its generality and its applicability to all of the parameter regarding the "X" field properties. Therefore, MEOR will be applied to this field using Huff and Puff method. However, considering that "X" field is a mature field and consists of old producing wells, the tubing resistance against microbial effects on corrosion need to be concerned.

Table 4. "X" Field MEOR Screening Result

Formation	**Gravity (API°)**	**Viscosity (cP)**	**Oil Saturation (%PV)**	**Permeability (mD)**	**Depth (ft)**	**Temperature (°F)**	**Formation Type**	**Reference**
Palembang A								Aladasani (2010)
								Bryant (1991)
Palembang B								Aladasani (2010)
								Bryant (1991)
Palembang C								Aladasani (2010)
								Bryant (1991)

	Meet the requirement
	Does not meet the requirement

Prior to the next step of this study which is the simulation of corrosion rate, one producing well is selected to be analyzed for the data input in the ECE^{TM} software.

IV. RESULTS AND DISCUSSION

The corrosion rate modelling is done using the ECE^{TM} software based on the collected data and assumptions that have been made before. **Figure 3** and **Figure 4** shows the graph of minimum and maximum corrosion rate for every tubing length in mm/year and mpy (mils per year) respectively and **Figure 5** shows the pH range. In this study, the unit mm/year will be used as the primary unit for calculations as it is more widely used.

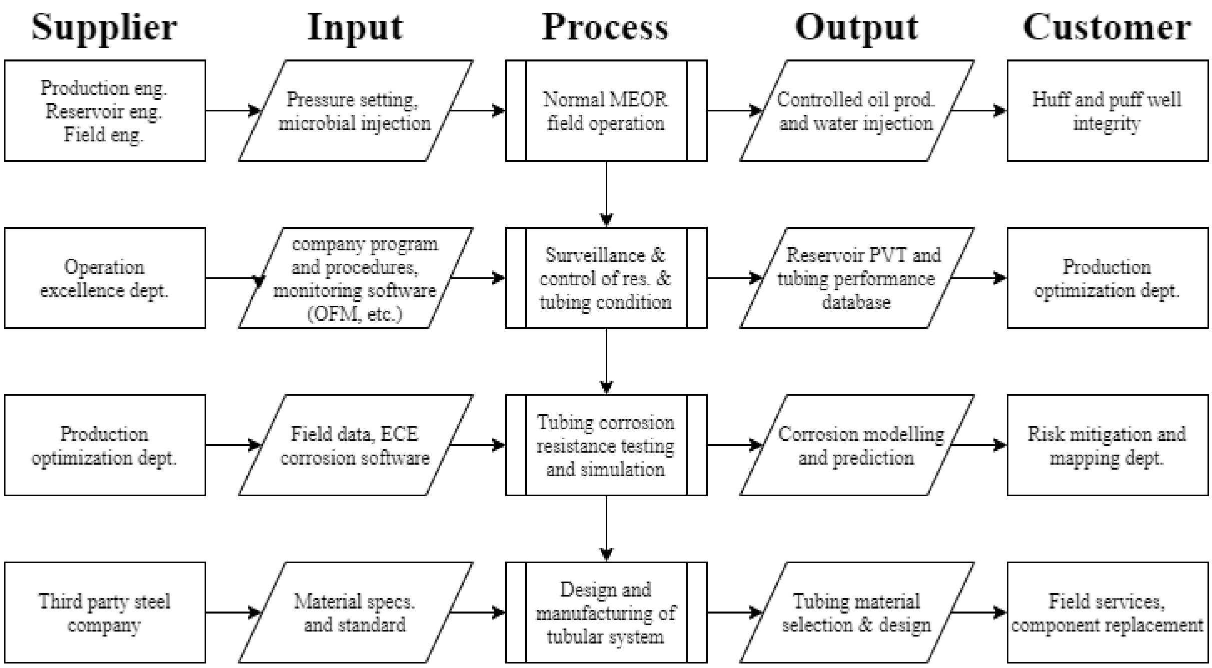

Figure 3. SIPOC Diagram

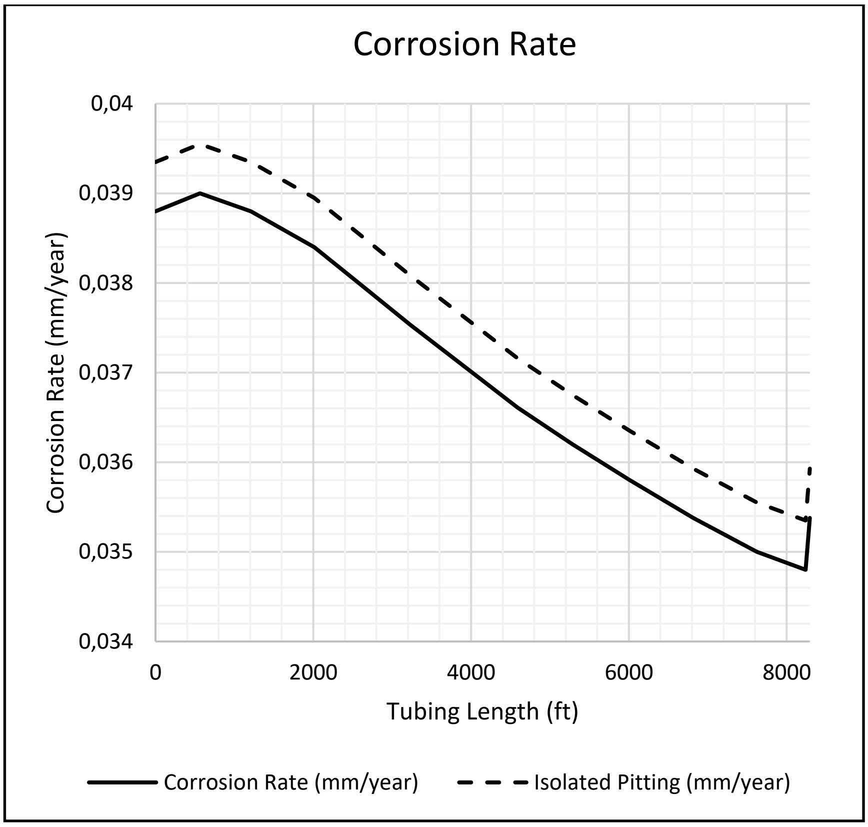

Figure 4. Corrosion Rate Modelling (Reproduced from ECE™)

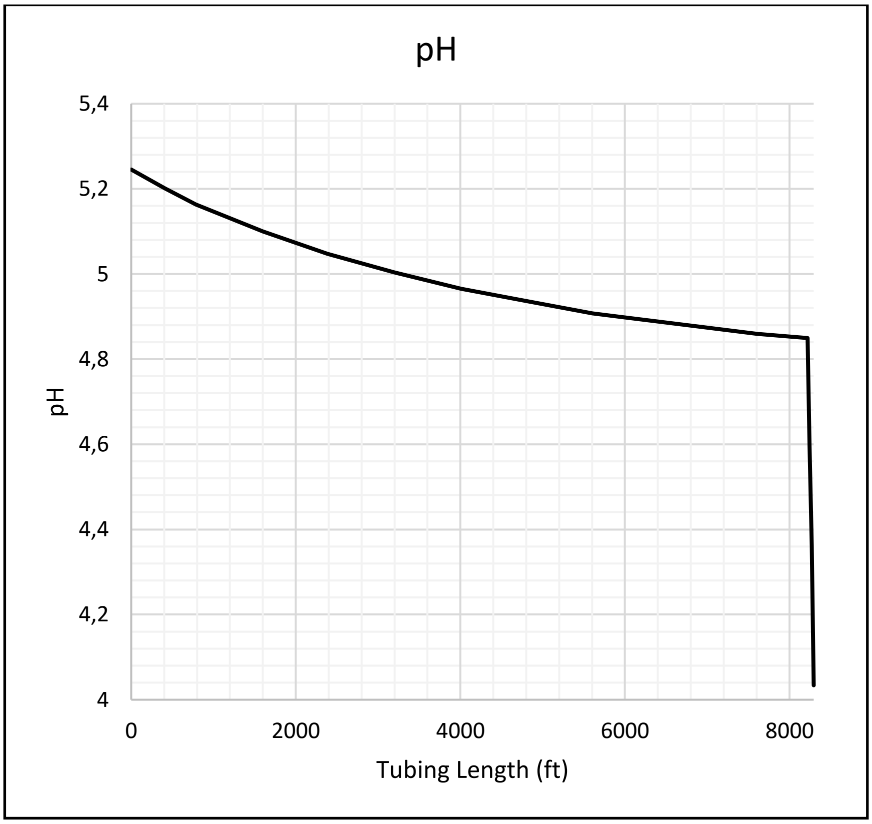

Figure 5. pH Range of the Environment (Reproduced from ECE™)

The base case results are as follows with the minimum of corrosion rate is 0.0348 mm/year and the maximum corrosion rate is 0.039 mm/year. The curve trends peaked at the tubing length at approximately 600 ft, then decreasing constantly until after 8000 ft where it goes up again. The isolated pitting curve followed the same trend as the corrosion rate but has a higher value of around 0.0005 mm/year.

However, there are many uncertainties that could happen in the real operations at the field. Therefore, sensitivity analysis is conducted to help summarize possible scenarios that would likely happen in the future by changing the values of some inputs to the model incrementally and measuring the related change in outcomes. The parameters input for the sensitivity analysis can be seen in **Table 5** while the results for minimum and maximum corrosion rate can be seen respectively in **Table 6** and **Table 7**.

Table 5. Sensitivity Analysis Input Parameter

Parameter	70%	80%	90%	100%	110%	120%	130%
Q_o (bbl/d)	62.51	71.45	80.38	89.31	98.24	107.17	116.10
Q_w (bbl/d)	114.71	131.10	147.49	163.87	180.26	196.65	213.03

Table 6. Minimum Corrosion Rate Sensitivity Analysis

Minimum Corrosion Rate (mm/year)							
Parameter	70%	80%	90%	100%	110%	120%	130%
Q_o	0.0370	0.0362	0.0355	0.0348	0.0341	0.0335	0.0329
Q_w	0.0274	0.0300	0.0325	0.0348	0.0370	0.0390	0.0410

Table 7. Maximum Corrosion Rate Sensitivity Analysis

Maximum Corrosion Rate (mm/year)							
Parameter	70%	80%	90%	100%	110%	120%	130%
Q_o	0.0405	0.0400	0.0395	0.0390	0.0386	0.0382	0.0378
Q_w	0.0294	0.0327	0.0359	0.0390	0.0421	0.0449	0.0478

From the sensitivity results, spider diagrams are constructed to easily visualize which parameter affect the most in changing of corrosion rate. Based on **Figure 6** and **Figure 7**, it can be concluded that the change of water flowrate is more sensitive than oil flowrate as it creates higher variance in corrosion rate. For a project life of 20 years, all the scenarios meet the safety requirements with a total of under 1 mm corrosion.

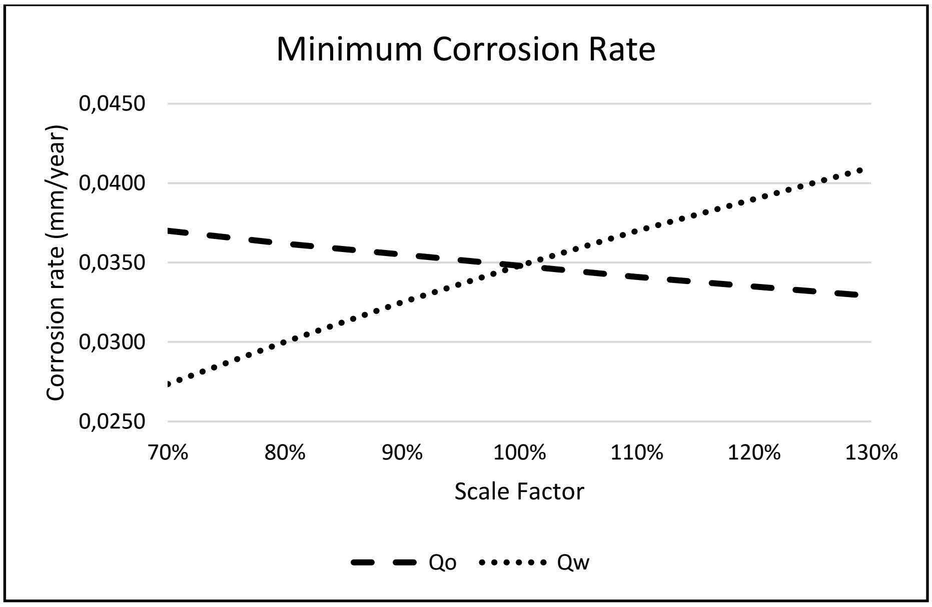

Figure 6. Minimum Corrosion Rate Spider Diagram

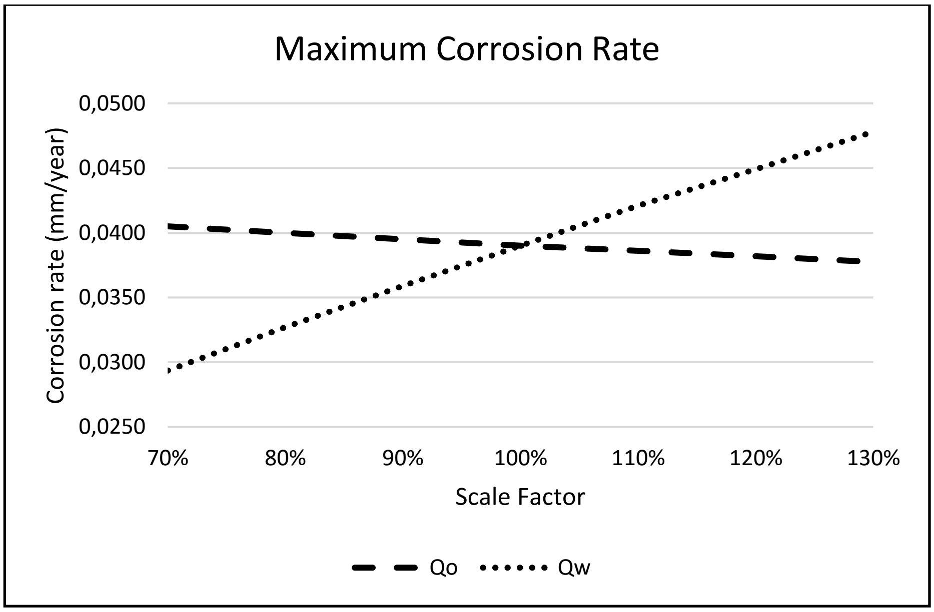

Figure 7. Maximum Corrosion Rate Spider Diagram

Based on the corrosion rate modelling and sensitivity analysis with the assumption of project life is 20 years, the possibility of the tubing corrosion resistance is calculated and then compared to the metals corrosion limits from the standard from NORSOK-M-DP-001 (1994) listed in **Table 8**. From the sensitivity results, if the corrosion rate is calculated for 20 years, none would exceed any corrosion allowances.

Table 8. Metals Corrosion Limits (NORSOK M-DP-001, 1994)

Type	**Corrosion Allowance**	**Comments**
Carbon steel piping	3 mm	-
Tanks in carbon steel	3 mm	Bottom section

Carbon steel submarine injection flowline	3 mm	- Titanium should not be used - max. flow velocity = 6 m/s

However, MEOR process involves mixtures of microbes that can occur reservoir souring due to the presence of sulphate-reducing bacteria (SRB) which increases the amount of H_2S in the reservoir. The toxicity of H_2S catalyzed the existence of microbially induced corrosion (MIC) of the metals used as tubing which damaged the production process. There is also possibility of sulfide stress cracking (SSC) and stress corrosion cracking (SCC) where the existence of water and H_2S increase the sensitivity of metals to be cracked involving corrosion and tensile stress.

Analysis based on H_2S partial pressure is needed to determine the severity of souring environments and classify the SSC zone for material selection consideration. Partial pressure is calculated using this formula:

$$P_x(\mathrm{MPa}) = \frac{\mathrm{ppm}\ H_2S}{10^6} \text{ x Pt x } 0.006895$$

$$P_x\ (\mathrm{psia}) = \frac{\mathrm{ppm}\ H_2S}{10^6} \text{ x Pt}$$

P_x = Partial pressure of H_2S or CO_2

Pt = Total absolute pressure of system, psia

In **Figure 8**, it can be concluded that the well is categorized as Zone SSC 0 (no need for considering sour environment cracking). However, the continuous process of MEOR huff and puff injection may increase the level of H_2S content in time. This statement is supported by the evidence of around 20 – 25% increase in H_2S content after six months of injection compared to the initial data and it might also increase exponentially, thus may result in shifting of the SSC zone and become more severe. Unfortunately, forecasting of the growth of H_2S could not possibly be done in this study due to lack of data.

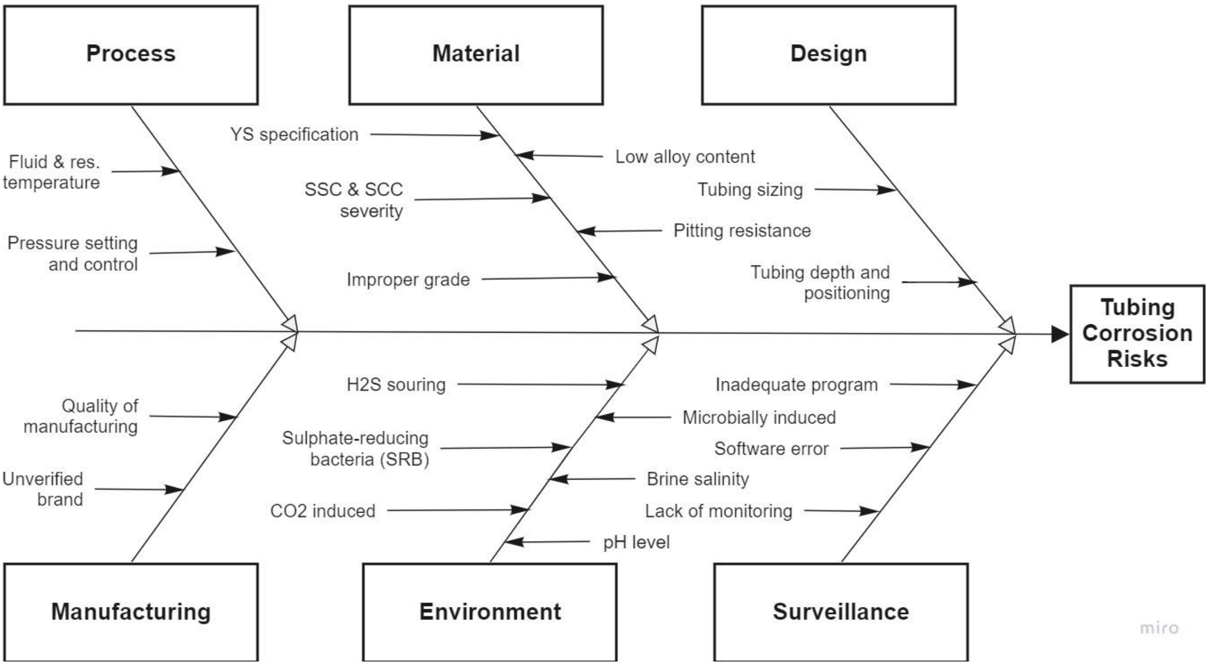

Figure 8. Fishbone Diagram of Tubing Corrosion Risks

Comprehensive strategy is needed in determining the selection of material and the design of completion in order to minimize the potential of MIC. Despite not having any special requirements for the steel material, presence of H_2S should still be considered in material selection for Zone SSC 0. According to Bellarby (2009) and Renpu (2011), factors that should be considered are:

1) If yield strength > 140 ksi, chemical composition and heat treatments are required.
2) Steel material that is highly sensitive to SSC

3) Physical and metallurgical properties of steel material to be resistance against SSC
4) Risk of stress concentration and cracking

One of the factors that should be considered in material is its sensitivity to SSC and pitting corrosion. Corrosion-resistant alloy (CRA) is one of the materials that meets the condition. It consists of stainless steel and alloy steel with higher percentage of alloy (mostly Cr, Ni, Mo) than low-alloy steel and carbon steel. The utility of CRA is more favorable for the industry as a corrosion control technique recently due to its advantages (Renpu, 2011):

a) No additional corrosion inhibitor system
b) Relatively high strength and thin tubing wall
c) Relatively large inside diameter and high throughput capacity compared to carbon steel with the same outside diameter.
d) Long-life tubing (almost the same as well life)
e) High reliability throughout service time
f) Higher quality than low-alloy steel tubing
g) Corrosion monitoring is not necessarily needed.
h) Adaptability in harsh environments (combination of CO_2 and H_2S)

However, CRA also has its trade-off that it could possibly occur galvanic corrosion during connection with carbon steel pipe. Galvanic corrosion occurs when there is significantly distinguishable electric potential between two materials, but it will not be discussed further in the study. In addition, according to ISO 15156-1 these factors should be considered when CRA is selected:

1) Partial pressure of carbon dioxide in gas phase (6 – 24 psia)
2) Partial pressure of hydrogen sulfide in gas phase (0.0022 – 0.0088 psia)
3) Temperature during service (90 – 160 ^oF)
4) pH value of water phase (4.03 – 5.25)
5) Concentration of Cl^- or other halideS (28500 ppm)
6) Existence of elemental sulfur (exist)

While the analysis from H_2S shown as a non-sour, based, the analysis using CO_2 partial pressure shown that the well is categorized as medium corrosion. Furthermore, the base case corrosion rate is classified as a strictly required for corrosion resistance based on Sumitomo Metal Standard detailed in **Table 9**. Therefore, CRA should be used and selected. To make it clear, here is the classification of CRA and its limitations:

1) High-alloy austenitic stainless steel

Usable conditions:

- Only the 28% Cr steel
- Coexistence of CO2, H2S, and Cl-
- Temperature < 204 ^oC

Restriction condition:

- Not used in manufacturing tubing (only component parts)

2) Martensitic stainless steel

Usable conditions:

- The 13% C steel and Super 13% Cr steel are commonly used
- Used in harsher environments
- H2S partial pressure PH2S < 0.01 Mpa
- Temperature < 150 ^oC (empirical value)

- No oxygen (pitting corrosion may be generated when corrosion inhibitor is added)

3) Diphase stainless steel

Usable conditions:

- Mainly 22% Cr steel, 25% Cr steel, and Super 25% Cr steel H2S partial pressure PH2S < 0.01 MPa
- HT wells that contain CO2 and a small quantity of H2S
- Steel with a higher strength can be used and a higher downhole temperature is allowed.
- It should have a higher resistance to Cl- and O2.

Restriction conditions:

- Partial pressure PH2S < 0.02 MPa (yield strength should also be considered).
- Temperature < 200C.
- A small quantity of O2 or no O2 and no H2S.
- Usable material grade: 448–965 MPa

4) Nickel-based stainless steel

Usable conditions:

- Very strong corrosiveness under the combination of H2S, Cl, and temperature
- Existence of free sulfur

Table 9. Sumitomo Metal Corrosion Resistance Classification Standard
Source: Renpu, 2011

Sumitomo Metal Standard	
Corrosion Rate (mm/year)	**Usable Range**
< 0.1	Corrosion resistance is strictly required
0.1 – 1.0	Corrosion resistance is not strictly required
> 1.0	Low corrosion resistance and low practical value

Based on the classifications above, the most suitable type to be used is the martensitic stainless steel, especially in its applicability in harsh environment. There are several types of martensitic stainless steel with their specifications listed in **Table 10**. The selection of martensitic steel as the most suitable CRA for this study is also supported by the guidelines from Nippon Steel (2019) in **Figure 9**. With CO_2 partial pressure ranging from 6 to 24 psia and H_2S partial pressure valued under 10^{-2} psia, steel with 13% Cr (martensitic) is the fittest one.

Table 10. Main Composition of Martensitic CRA
Source: Renpu, 2011

Type	**% Alloy**		
	Cr	Ni	Mo
L80 13Cr	12 – 14	0.5	-
13CrS	11.5 – 13.5	4.5 – 6.5	1.5 – 3
S/W 13 Cr	12 – 15	4 – 7	1.5 – 2

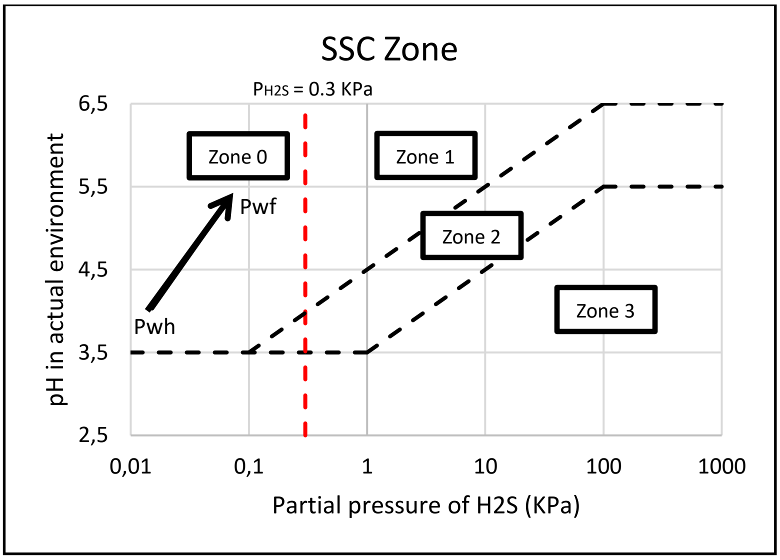

Figure 9. Cracking Severity Diagram for Carbon and Low-Alloy Steels
Source: NACE-MR-0175, 2015

Zone 0: No need for considering sour environment

Zone 1: Mild sour environment

Zone 2: Medium sour environment

Zone 3: Serious sour environment

p_{H2S} = 0.3 KPa (sweet/sour boundary)

Smith (1999) had also tested the environmental limits of CRA including the martensitic type to understand their limitations detailed in **Table 11.** This evidence is then considered for the next selection of which martensitic steels is the most optimum choice. The L80 13Cr is good for H_2S partial pressure below 1.5 psia, but it is too far from the condition in this study and susceptible to SSC in pH below 5.2 (Kushida, 1993). The L80 13Cr also cannot be used in an environment with H_2S (Renpu, 2011), while there is possibility in reservoir souring in this study. In addition, combination of H_2S and CO_2 resulted in creating harsher environment that L80 13Cr could not resist (Amani, 2016). Hence, it may not be the optimum selection for this condition.

Table 11. Environmental Limits for Martensitic CRA
Source: Smith, 1999

Type	**P_{H2S} (bar)**	**Temperature (°C)**	**%NaCl**	**Comments**
13Cr L80	0	150	-	Max. temp depends on Cl^- and CO_2
	0.001	RT test	5	pH < 3
	0.01	RT test	5	3 < pH < 3-5
	0.1	90	2	pH > 3-5, grade 90, 620 MPa max. YS
13Cr-5Ni-2Mo	0.03	150	5	30 bar CO_2, superior resistance to SSC
	0.1	150	0.01	Limit of H_2S is function of Cl^-

On the other hand, there is also the modified (2Mo-5Ni) 13Cr tubing, which is mostly known as a super 13Cr stainless due to its higher mechanical properties, pitting corrosion resistance, and SSC resistance (Renpu, 2011). It is designed to have strong resistance against combination of CO_2 and H_2S (Bellarby, 2009). The reservoir condition also similar with what Smith (1999) has tested looking back at **Table 11**, plus an evidence of superior resistance to SSC rather than the L80 13Cr. Hence, the modified (2Mo-5Ni) 13Cr tubing is the most optimum material and should be chosen for this study.

Many recent studies have researched about the effect of chromium materials used in corrosive environments. Marbun (2015) and Yan (2016) shown that by increasing the percentage of chromium content in the tubing materials can reduce the corrosion rate significantly. Sun (2016) also stated that the addition of chromium can eliminate the localized corrosion. Based on the formula in Bellarby (2009) and Renpu (2011) of pitting resistance equivalent number (PREN), the higher percentage of chromium also resulting in higher pitting resistance.

In order to support the analysis of this study, corrosion prediction is simulated with different percentages in chromium content. The prediction is adjusted with the ECE™ software limitations on maximum chromium content and done for several possible conditions:

1) Base Case: 0.00% Cr content (Grade K55 carbon steel tubing)
2) Case 1: 0.01% Cr content (Grade C90 carbon steel tubing)
3) Case 2: 1.2% Cr content (Grade J55, L80, P110 carbon steel tubing)

The result is shown in **Figure 10** that depicts the comparison of corrosion rates between each case. It can be concluded that increasing chromium content resulted in lower corrosion rates, thus supporting statements from previous recent studies.

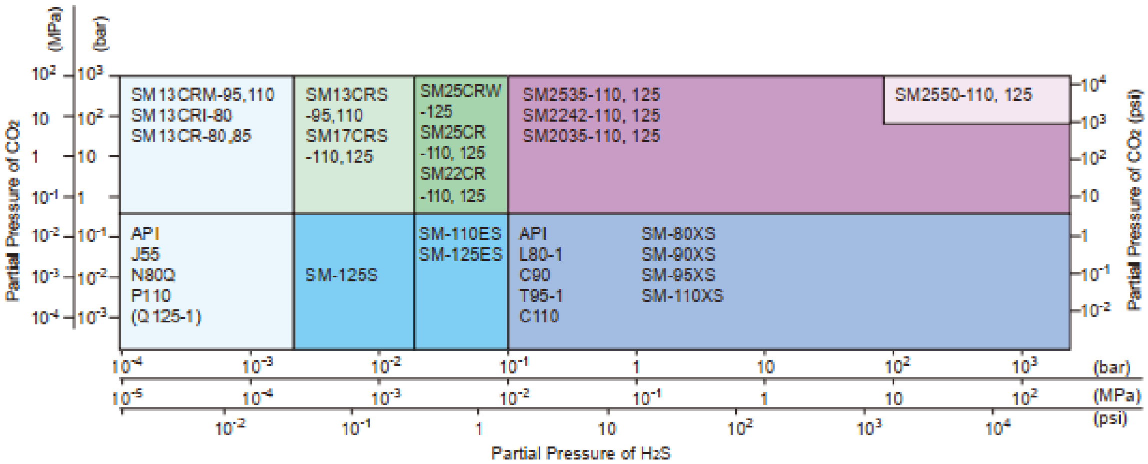

Figure 10. Material Selection Guidelines

Source: Nippon Steel, 2019

The tubing material and design had already been analyzed above which resulted in using corrosion resistant alloy of super 13Cr martensitic stainless steel as the most optimum solution for ensuring the safety tubing by exceeding the field's productive life, low maintenance, and low risk production. Another aspect in completion design that needs to be focused on is the packer. Nowadays, oil and gas company tend not to use the conventional steel packer due to less flexibility. Instead, elastomers are used as a common equipment for completion where a resilient seal is required.

Elastomers are a virtually incompressible and an easily deformed long-chain cross-linked products which generates resilient material. Elastomers should be selected based on continuous service such as souring of hydrogen sulphide in the reservoir, as well as to be strong, resilient, inert, and easily manufactured (Bellarby, 2009). There is various type of elastomers such as nitrile (NBR), hydrogenated nitrile (HNBR), and fluoro-elastomers (Viton®, Aflas®). Their common use and applicable conditions in oilfield are stated in **Table 12**.

Table 12. Common Oilfield Elastomers Classification

Source: Bellarby, 2009

Variable	Nitrile	Hydrogenated Nitrile	Fluoro-elastomers	Fluoro-elastomers
Code/Brand	NBR	HNBR Therban®	Viton®	Aflas®
Temp. Range	-20 – 250 °F	-10 – 300 °F	0 – 400 °F	30 – 450 °F
H_2S	Poor (<10 ppm)	Poor when hot (<20 ppm)	Poor (grade dependent)	Good

Amine inhibitors	Poor	Poor	Not Recommended	Good
Saline brines	Not recommended	Poor at high temperature	Good	Good
Hydrochloric acid	Poor	Poor	Some swelling	Some swelling
Aromatic HC	Not recommended	Poor	Good	Poor

Based on the specifications, the most suitable elastomers to be used in this study is the Aflas® fluoro-elastomers due to its resistance against sour and saline environments. There are three types of Aflas® fluoro elastomer: FKM, FEPM, and FFKM (see **Figure 11**). The Aflas® FFKM considered the best for its chemical, thermal, and steam resistance, but the most common type used in many oilfields is the Aflas® FEPM due to economical reason. The most suitable grade for packer and sealing material is either the Aflas® 100S or Aflas® 100H. These grades have the highest molecular weight and used to make various parts in oilfield operations due to its high strength and elongation as well as resistance to CO_2 and H_2S gas.

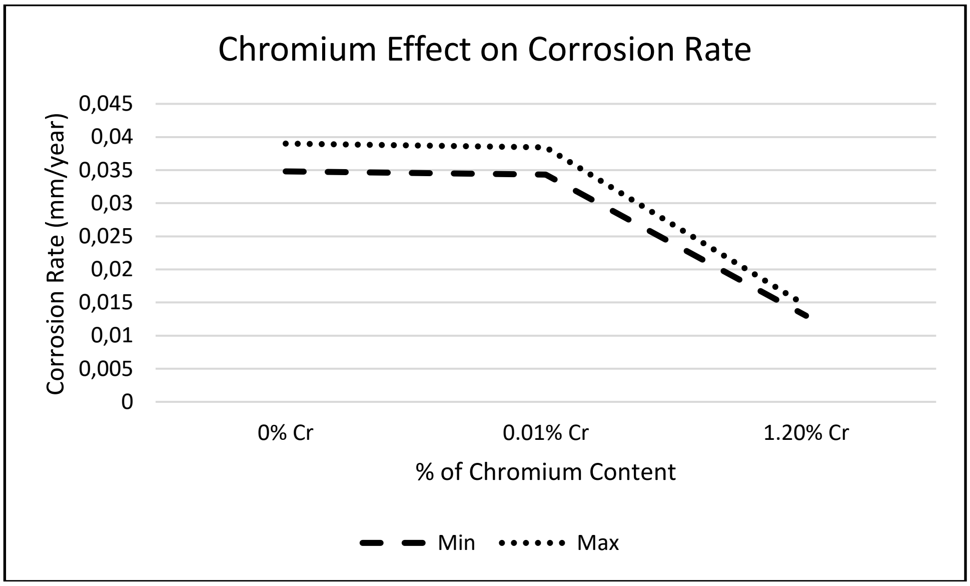

Figure 11. Chromium Effect on Corrosion Rate

VI. CONCLUSION

There are several conclusions made from this study of designing the most optimum completion design in microbial processes as followed:

1. In MEOR huff and puff operations, there are consequences of potential risks to be managed from microbially induced corrosion (MIC), such as:

- Potential activation of SRB
- Reservoir souring or increasing amount of H_2S in the reservoir
- CO_2 and H2S corrosion
- Isolated pitting corrosion
- Sulphide-stress cracking (SSC) and stress corrosion cracking (SCC)

2. The change of water flowrate is more sensitive than the change of oil flowrate regarding corrosion rates of tubing, thus making it necessary to control, maintain, and monitor the injection processes.

3. The most suitable tubing material selection in this study is the utilization of corrosion-resistant alloy (CRA) tubing string, specifically the super 13Cr martensitic stainless steel (modified 2Mo-5Ni-13Cr).

4. Chromium (Cr) content in steel material has significant effect in reducing the possibility of corrosion in this study, with increasing percentage of Cr content in the tubing leading to a lower corrosion rate predicted.

5. The most optimum completion design in this study is by using CRA tubing string and the fluoro-elastomer Aflas® 100S/100H especially for packer and sealing.

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