Integrated Design and Analysis of Corrosion Rate Model on Tubular Pipe of Oil and Gas Production Well

B T H Marbun\textsuperscript{1}, B Z Fadholi\textsuperscript{1}, S Z Sinaga\textsuperscript{1}, and B A Purbantau\textsuperscript{1}

\textsuperscript{1} Petroleum Engineering Study Program, Bandung Institute of Technology (ITB), Jalan Ganesha 10, Bandung 40132, Indonesia

*Email: bonar.marbun@tm.itb.ac.id

Abstract. Corrosion occurrence in the oil and gas production system is an example of an unavoidable problem. This problem is caused by the presence of water and corrosive material fraction along with the produced hydrocarbon. On the way from the reservoir to the surface, the mixture between water fraction and the corrosive substance might adhere to the wall of conduit steel pipe (e.g. tubing, casing, and flowline) and can lead to corrosion on the wall. The corrosion problem can have a major impact on the economics of the production because the cost of production equipment is relatively expensive and workover operation is very costly. Therefore, planning and mitigation for a better production system need to be performed, so that the rate of corrosion can be controlled, and its economic impacts can be minimized. The purpose of this study was to create an integrated model of the corrosion rate calculation on the tubing by the Petroleum Engineering Study Program of Bandung Institute of Technology (ITB). Several terms related to the production process were considered in this model: the characteristics of the produced fluid, flow regimes, pressure and temperature conditions along the tubing, the trajectory of the well, the type of tubing material used, and the use of inhibitors. The model was developed from the model developed by C. de Waard, Liane Smith, and Mike Billingham. The corrosion rate calculation model was then validated using field data and the results were compared with the result from industrial commercial software, Electronic Corrosion Engineer (ECE®). The corrosion rate calculation model were able to predict the rate of corrosion in oil and gas wells accurately. A software-based system was created based on this integrated and accurate proven model. By using this software, the production system can be simulated and tested for various conditions, and then the result can be compared with each other to obtain the optimum fluid production rate with minimum corrosion rate. In addition, this software is capable to determine the most suitable tubing material which will be used in a given production environment and condition.

1. Introduction

1.1. Background
During the production life of an oil and gas well, tubing corrosion and deterioration cannot be avoided because of the presence of the corrosive material in hydrocarbon production \cite{1} \cite{2}. The corrosion problem leads to several failures such as tubing cracking, tubing leaks, or at worst tubing part-off. Activities that require high expenditure such as well intervention and workover, are required to deal with these kinds of failures.
An accurate corrosion rate prediction model is required to control the corrosion that considers not only the composition of the production fluid, but also other factors such as fluid properties, environmental condition, production rate profile, well deviation, tubing characteristics, and the use of inhibitor for the corrosion protection [1] [2] [3] [4].

1.2. Objectives
The objectives of this study were to:

1. develop a model of corrosion rate prediction (called tubular corrosion desktop or TCD) on tubing based on the model developed by C de Waard, Lianne Smith, and Mike Billingham [5] [3] [6] [4] [7] [1];
2. create a software interface for ease of use of the model. In principle, the TCD model considered the material selection for the downhole production tubing as one of the key capital expenditure items in oil and gas field development [8].

1.3. Study Methodology
The methodology used in this study was to develop the basic concept of the corrosion rate prediction model (TCD model) from the model developed by De Waard, Smith, and Billingham (Intetech’s corrosion model) [9] [10] [11]. Then, a software interface was created for the ease of use of the corrosion model. The corrosion model result of self-created software was called Tubular Corrosion Desktop (TCD). This corrosion rate prediction model was then compared with the commercial software, Electronic Corrosion Engineer (ECE®) that was based on Intetech’s Corrosion Model [11]. Finally, several improvements were made to overcome the drawback of Intetech’s model, and several recommendations were provided for the future development of the corrosion rate prediction model and the TCD software.

2. Result and Discussion
The corrosion model in ECE® software was based on de Waard-Lotz corrosion equations and further model developed by C. de Waard, Liane Smith, and Mike Billingham [11] [3] [4] [9] [10] [5] [7] [1] [9]. Table 1 shows the list of the input data for corrosion modeling.

| Parameter                  | Data                | Unit   |
|----------------------------|---------------------|--------|
| Fluids Properties          | CO₂ content         | % mole |
|                            | N₂ content          | % mole |
|                            | H₂S content         | % mole |
|                            | Dissolved Bicarbonate | ppmw   |
|                            | Gas Gravity         |        |
|                            | Equivalent NaCl     | ppmw   |
|                            | Water Density       | kg/m³  |
|                            | Liquid Density      | kg/m³  |
|                            | Oil API Gravity     | ° API  |
| Environmental Condition    | Wellhead temperature | °C     |
Further, the corrosion rate model was developed in this study based on the following equation [1] [3] [4] [7] [5] [9] [12] [13] [10]:

\[ \text{Corrosion rate} = V_{\text{cor}} x F_{\text{scale}} x F_{\text{H}_2\text{S}} x F_{\text{cond}} x F_{\text{oil}} x F_{\text{inhibit}} x F_{\text{glyc}} \] (1)

The above equations were adjusted for the presence of protective scale, H$_2$S, crude oil or condensate, glycol, and inhibitor using multiplier factors for the basis of CO$_2$ corrosion rate. However, in this study, $F_{\text{H}_2\text{S}}$, $F_{\text{cond}}$ and $F_{\text{glyc}}$ were not considered in the equation. Therefore, the corrected corrosion rate equation model used in this study was as follows:

\[ \text{Corrosion rate} = V_{\text{cor}} x F_{\text{scale}} x F_{\text{oil}} x F_{\text{inhibit}} \] (2)

where $V_{\text{cor}}, F_{\text{inhibit}}, F_{\text{oil}}, F_{\text{scale}}$ are the corrosion rate accounting the combination between mass-transfer controlled part and reaction controlled part (mm/year), the corrosion rate for mass-transfer controlled part (mm/year), the corrosion rate for reaction controlled part (mm/year), carbon compositional correction factor, chrome compositional correction factor, the correction factor for the presence of inhibitor, the correction factor for the presence of oil, and correction factor for the presence of protective scale, respectively.

Following factors were considered in TCD model development [14] [15] [6] [4] [16] [17] [18] [19] [20] [21] [22] [23] [24] [25] [26] [27] [28]:

1. Pressure and temperature
2. Fugacity of CO2
3. pH calculation
4. Gas compressibility factor (Z-factor)
5. Condensation of water
6. Flow profile and pattern
7. Mixture density
8. Erosion-corrosion
9. Influence of carbonate scales
10. Influence of crude oil
11. Influence of inhibitor
12. Compositional correction factor

The TCD software was created for the ease of use of the corrosion prediction model using C++ programming language and Qt and Qwt Wrapper. The algorithms were established based on the corrosion rate model for software development.

Figure 1. User interface of tubular corrosion desktop (TCD)

The TCD software accommodated more input data for a more comprehensive analysis and more accurate calculation of corrosion rate. Besides, there were additional parameters that were considered in the software, such as N₂ gas fraction, standard temperature and pressure used by the user, and dissolved NaCl. In TCD software, the Z-factor was calculated based on the condition at each tubing segment, providing better and more accurate gas effect and corrosion prediction calculation [20] [16] [19]. The Z-factor was calculated using Hall-Yarborough Correlation.

3. Conclusion
   1. TCD model was accurate for carbon/low alloy steel.
   2. TCD model accommodated additional data parameter.
   3. The model only considered corrosion rate prediction calculation for quenched and tempered steel, but it did not consider normalized steel.
   4. The TCD software accommodated user for both metric unit input data and field unit input data.

4. Further Study
Future development of the TCD model should include and consider: oil condensate formation correction factor, the compositional correction factor for chrome and carbon content, glycol correction
factor, normalized steel, squeeze inhibition system, more accurate density model, multiphase fluid flow in the tubing, more accurate pH calculation, dissolved Fe, H₂S and pitting, H₂S correction factor, acetic acid, gas gravity, more flow pattern profiles, smoothness of pipe in erosion calculation, top-line corrosion, high deviated and horizontal wellbore, high pressure and high temperature (HPHT).

5. Nomenclature and List of Abbreviations

API: Gravity of the oil in °API
F_{scale}: Correction factor for the presence of protective scale (the value between 0 – 1)
ECE®: Electronic Corrosion Engineer
HPHT: High pressure and high temperature
F_{cond}: Correction factor for the presence of condensate (the value between 0 – 1)
RP: Recommended practice
F_{glyc}: Correction factor for the presence of glycol (the value between 0 – 1)
V_{cor}: Corrosion rate accounting the combination between mass-transfer controlled part and reaction-controlled part (mm/year)
F_{H₂S}: Correction factor for the presence of H₂S (the value between 0 – 1)
TCD: Tubular corrosion desktop
F_{inhib}: Correction factor for the presence of inhibitor (the value between 0 – 1)
Z-factor: Gas compressibility factor
F_{oil}: Correction factor for the presence of oil (the value between 0 – 1)

Acknowledgements

The authors would like to acknowledge funding from the Institute for Research and Community Services (Lembaga Penelitian dan Pengabdian kepada Masyarakat) Institut Teknologi Bandung (ITB) through the 2020 Research, Community Service, and Innovation (P3MI) Program.

References

[1] Bellarby J 2009 Well Completion Design (Amsterdam: Elsevier Science)
[2] American Petroleum Institute (API) 2000 API RP 14E: Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems [Internet] (Washington D.C.: American Petroleum Institute) Available from: https://www.api.org/
[3] Waard C de, Lotz U 1994 Prediction of CO₂ Corrosion of Carbon Steel. Working Party Report on Predicting CO₂ Corrosion in the Oil and Gas Industry European Federation of Corrosion
[4] de Waard C, Lotz U, Milliams DE 1991 Predictive Model for CO₂ Corrosion Engineering in Wet Natural Gas Pipelines Corrosion 47(12) 976–85
[5] Billingham MA, King B, Murray A 2012 Maximising the Life of Corroding Tubing by Combining Accurate MultiFinger Caliper Data with Corrosion Modelling. In: Abu Dhabi International Petroleum Conference and Exhibition. Abu Dhabi: SPE
[6] Waard C de, Lotz U, Dugstad A 1995 Influence of Liquid Flow Velocity on CO₂ Corrosion: A Semi-Empirical Model. In: Corrosion 95. NACE
[7] Nyborg R 2010 CO₂ Corrosion Models For Oil And Gas Production Systems. In: Corrosion [Internet]. San Antonio, Texas: NACE Available from: https://onepetro.org/NACECORR/proceedings-abstract/CORR10/All-CORR10/NACE-10371/127015
[8] Tenaris University 2009 The Effect of Corrosion on Material Selection-Sweet Corrosion
[9] Smith L and De Waard C 2005 Corrosion Prediction and Materials Selection for Oil and Gas Producing Environments. In: Corrosion. Houston, Texas: NACE

[10] Smith L, Bartlett P, Cunningham H 2001 Modelling Corrosion Rates in Oil Production Tubing. In: Eurocorr

[11] Wood Group Intetech Ltd. 2019 Electronic Corrosion Engineer, ECE®

[12] Smith L, Craig B, Waard K de 2003 The Influence of Crude Oils on Well Tubing Corrosion Rates. In: Corrosion [Internet]. California: NACE Available from: https://onepetro.org/NACECORR/proceedings-abstract/CORR03/All-CORR03/NACE-03629/114463

[13] Van Hunnik E, Pots BFM, Hendriksen ELJA 1996 The Formation of Protective FeCO3 Corrosion Product Layers in CO2 Corrosion. In: Corrosion. NACE

[14] Brennen CE 2005 Fundamentals of Multiphase Flow (New York: Cambridge University Press)

[15] Craig B 1998 Predicting the Conductivity of Water-in-Oil Solutions as a Means to Estimate Corrosiveness Corrosion 54(8) 657–62

[16] Whitson CH, Brule MR 2000 Gas Gravity and Brine Correction. In: SPE Phase Behavior Monograph. Richardson: SPE

[17] Khaled AAF 2007 A Prediction of Water Content in Sour Natural Gas (Riyadh: King Saud University)

[18] IHS Markit. Pressure Loss Calculations [Internet]. Fekete Associates Inc. Available from: http://www.fekete.com/SAN/TheoryAndEquations/HarmonyTheoryEquations/Content/HTML_Files/Reference_Material/Reference_Materials.htm

[19] Gas Processors Suppliers Association (GPSA) 2004 GPSA Engineering Data Book, FPS Version [Internet] (Tulsa: Gas Processors Suppliers Association (GPSA)) Available from: www.gasprocessors.com

[20] Guo B 2005 Ghalambor A. Natural Gas Engineering Handbook (Houston: Gulf Publishing Company)

[21] Pots BFM, Hendriksen ELJA 2000 CO2 Corrosion Under Scaling Conditions – The Special Case of Top-of-Line Corrosion in Wet Gas Pipelines. In: Corrosion. NACE

[22] Russell R, Nguyen H, Sun K 2011 Choosing Better API RP 14E C Factors for Practical Oilfield Implementation. In: Corrosion. NACE

[23] Society of Petroleum Engineers 2012 Petrowiki [Internet]. Society of Petroleum Engineers (SPE) Available from: https://petrowiki.spe.org/ Temperature-depth_profiles

[24] Cai J, Nesic S, C. De Waard 2004 Modeling of Water Wetting in Oil-Water Pipe Flow. In New Orleans, Louisiana: NACE Available from: https://onepetro.org/NACECORR/proceedings-abstract/CORR04/All-CORR04/NACE-04663/115011

[25] Mcketta JJ, Wehe AH 1958 Use This Chart for Water Content of Natural Gases. Petroleum Refiner p 153

[26] George E. King Engineering. George King [Internet]. GEK Engineering. Available from: https://www.gekengineering.com/

[27] Sagar R, Doty DR, Schmidt Z 1991 Predicting Temperature Profiles in a Flowing Well SPE Prod Eng [Internet] 6(04) 441–8. Available from: https://onepetro.org/PO/article-abstract/6/04/441/53475/Predicting-Temperature-Profiles-in-a-Flowing-Well?redirectedFrom=fulltext

[28] Petalas N, Aziz K 2000 A Mechanistic Model for Multiphase Flow in Pipes J Can Pet Technol [Internet] 39(06) Available from: https://onepetro.org/JCPT/article-abstract/doi/10.2118/00-06-04/30038/A-Mechanistic-Model-for-Multiphase-Flow-in-Pipes?redirectedFrom=fulltext