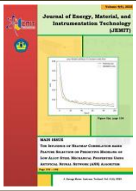
JOURNAL OF ENERGY, MATERIAL, AND INSTRUMENTATION TECHNOLOGY

Journal Webpage https://jemit.fmipa.unila.ac.id/



Analysis of the Effects of CO_2, H_2S Composition, and Temperature on Steam Towards Corrosion Rate in Geothermal Power Plants

Muhammad Rafsya Firdaus, Noor Hidayati*, and Arifia Ekayuliana

Department of Mechanical Engineering, Jakarta State Polytechnic, Prof. G. A. Siwabessy Street, Kampus UI, Depok, Indonesian, 16425

Article Information

Article history:
Received August 23, 2023
Received in revised form November 1, 2023
Accepted November 10, 2023

Keywords: *Aspen HYSYS, CO_2, Corrosion Rate, H_2S, Pipe Steam Line*

Abstract

The corrosion in the steam line pipes at the Geothermal Power Plant is caused by acidic substances present in the steam, especially H_2S and CO_2, originating from the geothermal reservoir. During operation, this leads to thinning of the pipe walls, affecting the pipe's thickness. The purpose of this research is to calculate the corrosion rate and compare the CO_2 and H_2S composition in each header using Aspen HYSYS software to determine their influence on the corrosion rate. The research findings indicate that the CO2 and H2S composition in the steam significantly affects the corrosion rate in the steam line pipes. Higher concentrations of CO2 and H2S result in a higher corrosion rate, and the higher the temperature, the corrosion rate will increase.

Informasi Artikel

Proses artikel:
Diterima 3 Agustus 2023
Diterima dan direvisi dari 1 November 2023
Accepted 10 November 2023

Kata kunci: *Aspen HYSYS, CO_2, H_2S, Pipa Steam Line*

Abstrak

Korosi yang terjadi pada pipa steam line di Pembangkit Listrik Tenaga Panas Bumi disebabkan oleh zat pengasam didalam steam terutama H_2S dan CO_2 yang berasal dari reservoar panas bumi sehingga penggunaan selama operasi terjadi penipisan didalam pipa yang dapat memengaruhi ketebalan pada pipa. Penelitian ini bertujuan untuk memperoleh hasil perhitungan laju korosi dan membandingkan hasil perhitungan komposisi CO_2 dan H_2S pada setiap header menggunakan software Aspen HYSYS terhadap hasil laju korosi. Dari hasil penelitian ini didapatkan bahwa komposisi CO_2 dan H_2S yang terkandung didalam steam memengaruhi laju korosi pada pipa steam line yang dimana semakin tinggi komposisi CO_2 dan H_2S maka laju korosi menjadi tinggi dan semakin tinggi temperatur maka laju korosi akan semakin meningkat,

1. Introduction

Indonesia holds 40% of the world's geothermal reserves due to its location in the Ring of Fire. The geothermal energy potential of Indonesia is estimated to reach 23.7 GW according to data from the Geological Agency of the Ministry of Energy and Mineral Resources since December 2020(ESDM, 2020).

Corrosion is a process in which metals undergo damage due to redox reactions with substances in their surroundings, leading to the formation of new compounds (McCafferty, 2010). Corrosion occurs due to electrochemical reactions between metals and their environment, leading to a deterioration in the quality of the metal. For example, the metal can become brittle, rough, and prone to disintegration. Metal corrosion is caused by water vapor, acids, salts, and high environmental temperatures (Utomo, 2015). The impacts of corrosion can manifest as damage to equipment, machinery, or building structures, disruption of production activities due to the need for replacement of corroded equipment, and other significant losses such as increased maintenance costs(Sam, 2009).

Hydrogen Sulfide (H_2S) is a colorless chemical gas compound, heavier than air, flammable, prone to explosions, and can induce corrosion. H_2S gas is commonly found in volcanoes, sulfur springs, and oil/gas deposits(Gibbons,

----
* Corresponding author.
E-mail address: (a)muhammad.rafsyafirdaus.tm19@mhsw.pnj.ac.id; (b)noor.hidayati@mesin.pnj.ac.id

1980). H_2S gas within pipelines is corrosive and can disrupt process equipment(Ningsih et al., 2018). Hydrogen sulfide (H_2S) gas has a higher solubility rate compared to CO_2, which can accelerate the corrosion rate and lead to damage in casings and piping systems(Ana,H.M., 2003). CO_2 is a dissolved corrosion agent in water, creating an acidic environment (Kermani et al., 2005). In the absence of water, CO_2 is non-corrosive. However, when water is present, CO_2 dissolves and forms carbonic acid. Carbonic acid, being a weak acid, leads to a decrease in pH and becomes highly corrosive to steel(Roberge, 2008). CO_2 is one of the primary causes of internal corrosion, alongside H_2S. Carbon dioxide is more soluble in water compared to oxygen, resulting in the formation of carbonic acid with a pH below 6, where the acidic environment becomes dominant(Kermani et al., 2005; Nordsveen et al., 2003).

Corrosion in the steam line pipes at the Geothermal Power Plant can occur due to the composition within the steam and continuous operational use, leading to thinning of the pipe walls. The corrosion rate can be evaluated by simulations using Aspen HYSYS to calculate the CO_2 and H_2S composition in each steam line header. This simulation can then compare the concentrations of acidic substances such as CO_2 and H_2S, as well as the temperature, against the corrosion rate.

This research aims to get the corrosion rate range in geothermal steam headers and to analyze which corrosion factor influenced the steam header's corrosion. To achieve the goal, the researcher used manual calculation and Aspen HYSYS software. Many papers have already analyzed the corrosion rate.

Sam (2009) calculated the corrosion rate in the iron pipe using manual calculation from iron's weight loss due to corrosion. Alternatively, the paper from Soeputra *et al.* (2015) calculates the destilation using HYSYS. However, none of those papers used Aspen HYSYS software to analyze the corrosion rate in the geothermal industry. That statement makes this paper different from others and worth applying.

2. Research Methods

This research employs a descriptive method, which aims to explain the phenomenon of corrosion rate occurring in the steam line pipes of a geothermal power plant. The purpose of this study is to analyze the corrosion rate and compare the corrosion rate results between CO_2 and H_2S on the steam line pipes. Wall thickness data can be obtained through measurements taken at various testing points within the pipe. The composition data of CO_2 and H_2S can be acquired by collecting steam data using tracer flow tests. These measurements and data sources can be utilized to assess and analyze the corrosion rate and potential damage to the pipes in the geothermal power plant steam line. The research flowchart can be seen in **Figure 1.**

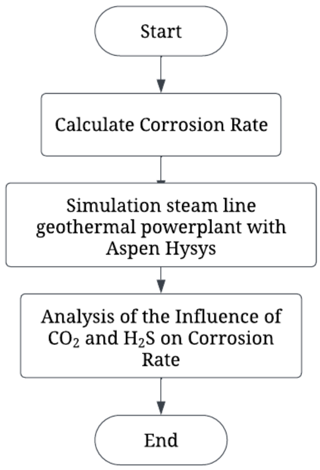


Figure 1. Research Flowchart

Corrosion rate is the amount of metal corroded or lost from a specific surface per unit of time (Utoyo, 2000). The corrosion rate is typically expressed in mils per year (mpy). One mil is equal to 0.001 inches. The corrosion rate can be determined through various methods, primarily by extrapolating the Table's curve. It can be observed in, which represents the relationship between corrosion rate and corrosion resistance (relative), as presented in the book "Corrosion Engineering" by Fontana (1986), as can be seen in **Table 1**.

Table 1. Level of corrosion rate resistance

Relative Corrosion Resistance	Corrosion Rate				
	mpy	mm/yr	µm/yr	nm/hr	pm/s
Outstanding	< 1	< 0.02	< 25	< 2	< 1
Excellent	1 – 5	0,02 – 0,1	25 – 100	2 - 10	1 - 5
Good	5 – 20	0,1 – 0,5	100- 500	10 - 50	20 – 50
Fair	20 – 50	0,5 - 1	500 – 1000	50 – 150	20 – 50
Poor	50 - 200	1 - 5	1000 – 5000	150 – 500	50 - 200

Based on the standards established by API 570 for the Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems(API, 2010), the following is the formula for corrosion rate in units of mm/year. **Equation 1** where = thickness, in inches (millimeters), at the exact location as tactual measured at initial installation ($t_{initial}$), = actual thickness, in inches (millimeters), measured at the time of inspection for a given location or component (t_{last}).:

$$Corrosion\ Rate = \frac{t_{initial} - t_{last}}{Time\ Period} \quad (1)$$

HYSYS is a software developed by Aspen Technologies Inc. that is highly useful in process sizing and simulation, enabling the detailed modeling of a process system(Soputra et al., 2015). HYSYS performs calculations and provides calculation results in real time. Whenever there is a change in data, HYSYS will respond and automatically recalculate. The utilization of Aspen HYSYS software involves the initial use of the "stream" feature, which is employed to input fluid data such as mass flow, mass fraction of CO_2 and H_2S, temperature, and pressure. The second feature is the "mixer," which combines multiple inlet streams into a single outlet stream. As seen in **Figure 2**, it represents a simple model for a mixer in HYSYS.

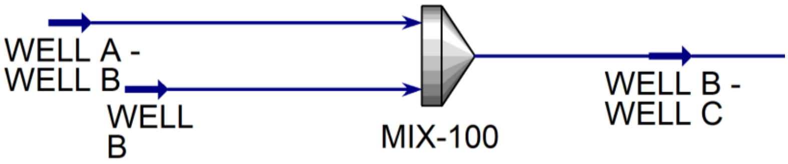


Figure 2. Simple Mixing Modeling in HYSYS

3. Results and Discussions

The results and discussions describe the data obtained from the research. Research data must be processed and, where possible, can be presented as tables or figures/graphs. Every data presented must be equipped with a complete and easy-to-understand description. The data of the research results are presented and associated with solving problems in the research. Discussion must be equipped with references (can be the results of related research) to show the privileges or uniqueness obtained from this research compared to the study. Discussion must also clarify the concept of background with the data obtained and then associate it with hypotheses. Each topic discussed is integrated into a unified research result as a new theory or modification of an existing theory.

The corrosion rate value is obtained by knowing the pipe thickness value during measurement using an ultrasonic thickness gauge. After obtaining the thickness value during measurement, the corrosion rate calculation is performed, where the initial pipe thickness is obtained by knowing the pipe thickness from **Table 1** in ASME B36.10.M, 2015. Below is **Table 1**, which contains corrosion rates and conditions for each steam line header.

Table 2. Corrosion Rate in the Header

No.	Header WELL East	Diameter (inch)	Schedule	Corrosion Rate (mm/yr)	Corrosion Resistance
1.	WELL A – WELL B	20	STD	0.089114583	Baik
2.	WELL B – WELL C	20	STD	0.02125	Baik
3.	WELL C – WELL D	36	XS	0.030738636	Baik
4.	WELL D - Demister	42	XS	0.03828125	Baik

No.	Header WELL West	Diameter (inch)	Schedule	Corrosion Rate (mm/yr)	Corrosion Resistance
1	WELL F – Demister	22	XS	0.065833333	Baik
2	WELL E – WELL F	10	STD	0.097137784	Baik

Based on the corrosion rate calculation results as shown in **Table 2**, the lowest corrosion rate is observed in header WELL B – WELL C at 0.02125 mm/yr, while the highest corrosion rate is in header WELL E – WELL F at 0.097137784 mm/yr. All headers in the geothermal power plant have values within the range of 0.02 – 0.1 mm/yr, which, according to **Table 1**, indicates a corrosion resistance level classified as excellent.

The CO_2 and H_2S composition values within the steam are obtained from each well by conducting measurements through tracer flow tests. After obtaining the CO_2 and H_2S composition values from each well, the CO_2 and H_2S composition calculations for each header will be conducted using Aspen HYSYS, inputting the acquired data. **Figure 3** provides a view of the simulation in the PLTP steam line, including the CO_2 and H_2S compositions for each header, and **Table 3** represents the CO_2 and H_2S compositions in each header.

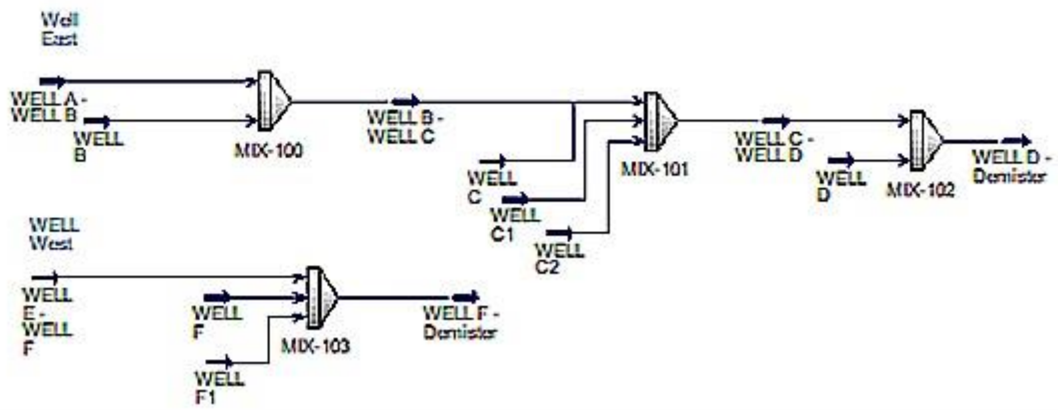


Figure 3. Simulation of the geothermal power plant steam line.

Table 3. Composition of CO_2, H_2S, and temperature for each header.

No.	*Header WELL East*	H_2S (PPM)	CO_2 (PPM)	Temperature
1.	WELL A – WELL B	150	4800	179.7
2.	WELL B – WELL C	149	4500	177.8
3.	WELL C – WELL D	183	5700	176.1
4.	WELL D - Demister	215	6700	175.6

No.	*Header WELL West*	H_2S (PPM)	CO_2 (PPM)	Temperature
1	WELL F – Demister	370	11400	174.9
2	WELL E – WELL F	640	37200	176

The influence of CO_2, H_2S, and temperature on the corrosion rate. Based on comparing corrosion rates with CO_2, H_2S, and temperature, the results can be observed in **Figure 4**, and **Figure 5** demonstrates that as the CO_2 and H_2S compositions increase, the corrosion rate also increases. There is a curve increase in the WELL East with CO_2 and H_2S compositions of 4800 PPM and 150 PPM, respectively. It is due to the elevated temperature, which can impact the corrosion rate—higher temperatures lead to increased corrosion rates.

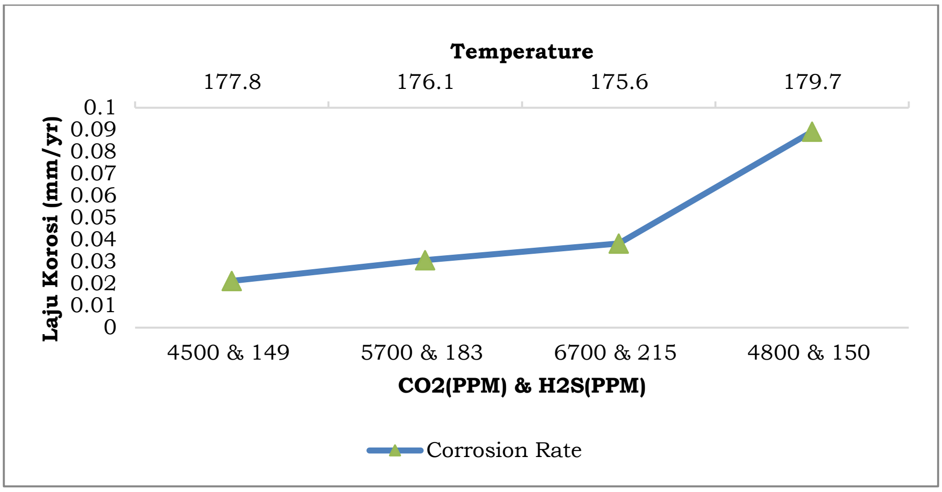


Figure 4. The influence of CO_2, H_2S, and temperature on the corrosion rate in WELL East

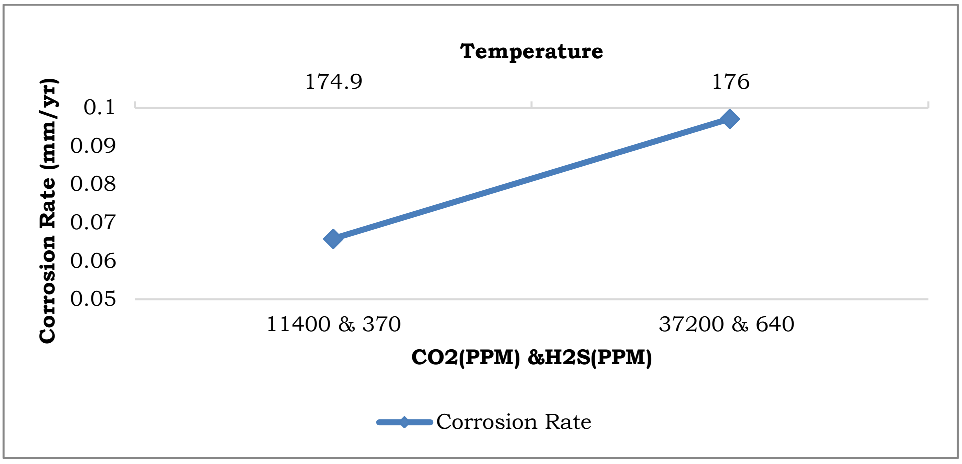


Figure 5. The influence of CO_2, H_2S, and temperature on the corrosion rate in WELL West

4. Conclusions

Based on the above research findings, the conclusion is that the corrosion rate for each header in the geothermal power plant falls within the range of 0.02 – 0.1 mm/yr, indicating an excellent corrosion resistance level for the headers. The influence of CO_2 and H_2S on the corrosion rate in the steam line headers is that higher CO_2 and H_2S compositions flowing through the pipes result in an increased corrosion rate due to the corrosive nature of CO_2 and H_2S. There is a curve increase in the WELL East with CO_2 and H_2S compositions of 4800 PPM and 150 PPM, respectively. It is attributed to higher temperatures compared to the other headers, as higher temperatures lead to an increased corrosion rate.

5. Bibliography

Ana, H. M. (2003). *Pencegahan Korosi Dan Scale Pada Proses Produksi Minyak Bumi.*

API, T. (2010). *API 570, Piping Inspection Code : In-service Inspection, Rating, Repair, and Alteration of Piping Systems. November 2009.*

ESDM, K. (2020). *Potensi Pengembangan Energi Panas Bumi di Indonesia.* https://ebtke.esdm.go.id/lintas/id/investasi-ebtke/sektor-panas-bumi/potensi#:~:text=Berada di kawasan ring of,diperkirakan mencapai 23%2C7 GW.

Fontana, M. G. (1986). *Corrosion Engineering.* McGraw-Hill. https://books.google.co.id/books?id=N95EAAAACAAJ

Gibbons, J. H. (1980). *Energy from Biological Processes.*

Kermani, B., Gonzales, J. C., Turconi, G. L., Perez, T. E., & Morales, C. (2005). Materials optimisation in hydrocarbon production. *Corrosion 2005.*

McCafferty, E. (2010). *Introduction to corrosion science.* Springer Science & Business Media.

Ningsih, E., Pudjiastuti, L., Wulansari, D., Anggraheny, N., Altway, A., & Budhikarjono, K. K. (2018). Simulasi absorpsi multikomponen gas dalam larutan K2 CO3 dengan promoter MDEA pada packed column. *Jurnal Teknik Kimia Indonesia*, *11*(1), 17–25.

Nordsveen, M., Nyborg, S. N. R., & Stangeland, A. (2003). A mechanistic model for carbon dioxide corrosion of mild steel in the presence of protective iron carbonate filmspart 1: theory and verification. *Corrosion*, *59*(05).

Roberge, P. (2008). *Corrosion Engineering : Principles and Practice: Principles and Practice.* Mcgraw-hill. https://books.google.co.id/books?id=PF6ZjjSHcn4C

Sam, A. (2009). Analisa kecepatan korosi pipa galvanis pada tanah dengan tingkat kehalusan yang berbeda. *Jurnal Jurusan D3 Teknik Mesin Fakultas Teknik Universitas Tadulako, Palu.*

Soputra, A., Siregar, P., & Ekawati, E. (2015). Perancangan sistem simulasi HYSYS & integrasi dengan programmable logic controller-human machine interface: studi kasus pada plant kolom distilasi etanol-air. *Jurnal Otomasi, Kontrol & Instrumentasi*, *6*(1), 1.

Utomo, S. (2015). Pengaruh Konsentrasi Larutan NaNO2 sebagai Inhibitor terhadap Laju Korosi Besi dalam Media

Air Laut. *Jurnal Teknologi*, *7*(2), 93–103.

Utoyo, W. (2000). Gas Production Operation. *House Training Gulf Indonesia Resources*.