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CRITICAL FACTORS IN INJECTOR WELL DESIGN FOR CARBON CAPTURE AND STORAGE CAMPAIGN IN FIELD "X"

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ABSTRACT

Indonesia's total energy supply increased nearly 60% from 2000 to 2021. However, the total energy sector emissions have grown faster than energy demand, more than doubling over the last two decades. In 2021, energy sector emissions were around 600 million tonnes of carbon dioxide (Mt CO_2) – making Indonesia the world's ninth-largest emitter. Indonesia faces a big challenge with the target to reach net zero emissions by 2060. Carbon capture and storage (CCS) is considered as a potential solution. However, CO_2 injection wells face well integrity issues that may lead to leakage. One of the most common problems in CO_2 injection wells is corrosion. Corrosion may cause damage on the downhole equipment which leads to degradation of the well integrity. Therefore, a thorough material selection should be considered. This study examines critical factors in designing CO_2 injector wells for a CCS campaign in Field "X", a major offshore gas condensate field with a planned injection rate of 160.2 MMSCFD. This study aims to determine suitable casing schemes, tubular material selection, and corrosion analysis for CO_2 injector wells, while evaluating leakage potential based on well barrier concepts. The drilling of "X" field CO_2 injection wells is planned to be executed with an estimated five casing sections consists of 30" conductor casing, 20" surface casing, 13-3/8" intermediate casing, 9-5/8" intermediate liner and 7" production liner. Based on the analysis using ECE (Electronic Corrosion Engineer) software, ISO 15156-3 standard, and the Nippon steel chart, the most suitable tubular materials for the CO_2 injector well is Duplex Stainless Steel SM22Cr or SM25CR.

Keywords: corrosion, CO2 injection, material selection, well barrier, well design

I. INTRODUCTION

Indonesia is one of the largest CO_2 emitters of greenhouse gases in the world (Sari et al., 2007). According to the Presidential Decree number 61 in 2011, the Indonesian government is committed to reduce the CO_2 emissions by 40% by 2020. To reduce emissions, carbon, capture, and storage in considered a solution to fulfill this target. However, CO_2 injection wells have well integrity issues that may lead to leakage of CO_2 to the surroundings. The most common problems of CO_2 injection wells are corrosion and erosion that may damage the downhole equipment. Therefore, a CO_2 resistant design should be considered when designing a CO_2 injection well. "X" field is a major gas condensate field in Indonesia with CO_2 injection rate of 160.2 MMSCFD. This study aims to determine the casing scheme of CO_2 injector well, determine the suitable tubular material selection and corrosion analysis for CO_2 injector well, and evaluate leakage potential of the CO_2 injected based on well barrier concept.

II. METHODS

Data collection is conducted to identify the field characteristics and several assumptions that will be used in simulation process. flowchart that explains the methodology of this study as a whole can be seen in Figure 6. It comprised of six main procedures.

Data preparation begins by inputting the acquired data and making several adjustments in the software. Several data that are used in this study consists of pore pressure and fracture gradient data, well depth, hole geometry analog data from existing wells, bottomhole pressure and 4 temperature, wellhead pressure and temperature, and CO_2 (Carbon dioxide) injection rate.

The hole geometry is not selected based on casing and bit size selection chart. Instead, the hole geometry is selected based on analog data from existing wells, which subsequently verified by using CasingSeat feature on Landmark software. Then, stress analysis is conducted to determine the most suitable casing grade by considering the burst, collapse, and tension loads as well as tubular availability. These loads are calculated by using StressCheck feature on Landmark software.

The tubing sensitivity analysis is conducted using PROSPER software to determine the most suitable tubing size based on injectivity. Another purpose of this analysis is to determine the maximum injectivity and wellhead pressure, which subsequently will determine the number of wells needed.

The final material selection for this tubing is considered based on ISO 15156-3 standard or ECE results and Nippon Steel chart, including CO_2 and H_2S partial pressure also tubing temperature. Corrosion and erosion model prediction is conducted using Electronic Corrosion Engineer (ECE) software. The input parameters for corrosion and erosion rate prediction consists of wellhead and bottomhole condition, flowrate, gas composition and wellbore angles. This will result in damage rate and alloy evaluator for the tubing.

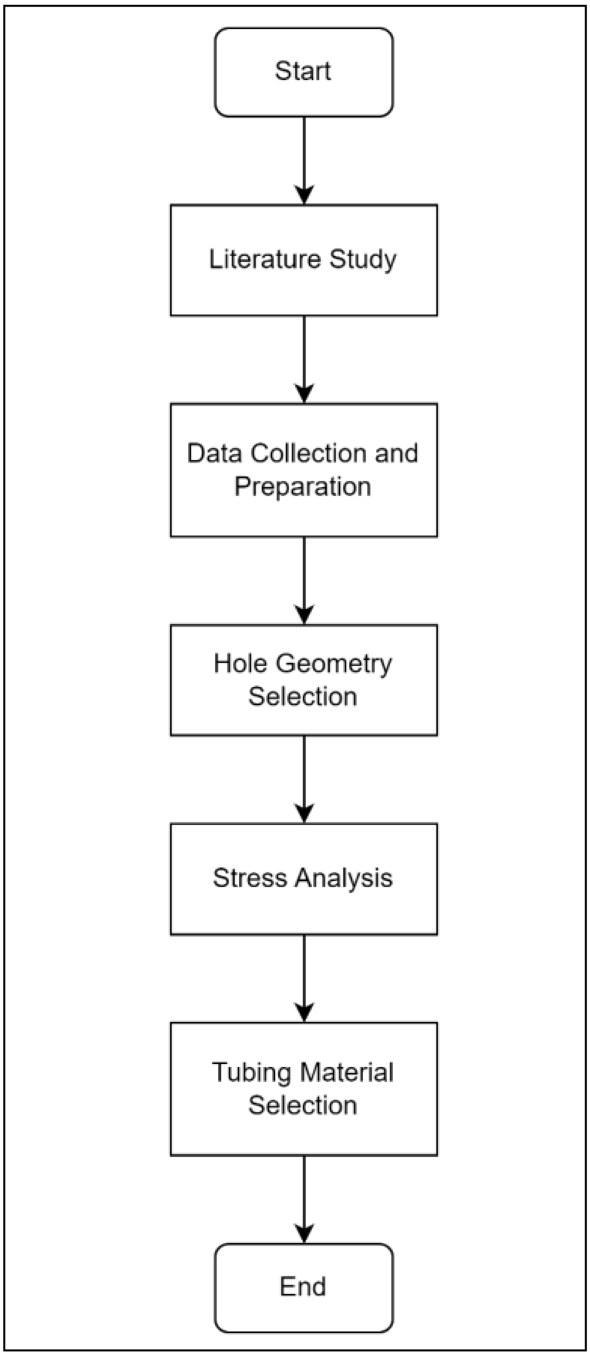

Figure 1. Workflow Guideline

III. RESULTS AND DISCUSSION

3.1. Hole Geometry Selection

The first step is to create the well trajectory by using the COMPASS feature on the software. Since the well is vertical, the inclination can be assumed as zero with depth of 3990 m. The drilling target of this well is at 3800 m TVD on the Plover formation. On the CasingSeat feature, pore pressure and fracture gradient data were inputted on the software to determine the hole geometry selection. Instead of using the conventional method by using the casing and bit size selection chart, the hole geometry is selected by using analog data from the existing wells. The final hole geometry selection can be seen in Table 1.

Table 1. Proposed Casing Scheme

OD (in)	Hole Size (in)	Measured Depth (m)			Mud at Shoe (ppg)
		Hanger	Shoe	TOC	
30	36	0	700	620	8.80
20	26	0	1100	620	8.80
13 3/8	17.5	0	2550	620	9.20
9 5/8	12.25	2400	3700	2400	11.80
7	8.5	3550	3900	3550	9.20

3.2. Stress Analysis

After the hole geometry is selected, stress analysis is conducted to determine the most suitable casing grade and material. Burst, collapse, and tension loads are calculated by using StressCheck feature on Landmark software. The design factors for this well can be seen in Table 2.

Table 2. Design Factor for CO_2 Injector Well

Design Factors	Value
Burst	1.100
Tension	1.800
Compression	1.300
Collapse	1.125
Triaxial	1.250

Safety factors based on API standards for casing loading are: burst = 1.1, collapse = 0.85 – 1.125 and tension = 1.6 - 1.8. (Rubiandini, 2012). The casing grade and weight are chosen by considering the design limits that can be seen in Table 1 and 3.

Table 3. CO_2 Injector Well Summary

String	OD/ Weight/ Grade	Connection	MD Interval (m)	Drift Diameter (in)	Minimum Safety Factor (Abs)			
					Burst	Collapse	Axial	Triaxial
Conductor Casing	30”, 309.700 ppf, X-60	N/A	0 – 700	27.813	3.48	9.87	4.25	3.49
Surface Casing	20”, 169.000 ppf, K-55	BTC, L-80	0 – 1100	18.189	1.26	2.38	3.57	2.61
Intermediate Casing	13 3/8”, 72.000 ppf, Q-125	BTC, Q-125	0 – 2550	12.250	2.13	1.33	3.42	3.61
Intermediate Liner	9 5/8”, 61.100 ppf, T-95	BTC, T-95	2400 – 3700	8.219	2.72	2.16	4.00	2.64
Production Liner	7”, 29.000 ppf, L-80	BTC, L-80	3550 – 3900	6.80	6.80	17.85	2.96	2.45

Based on Figure 2-6, it shows that the parameters on the graph are inside of the eclipse, which means that the casing grade and materials that are chosen are safe to use and does not exceed the minimum safety factors. Poor casing design selection will result in casing failure. The proposed CO_2 injector well schematic can be seen in Figure 8.

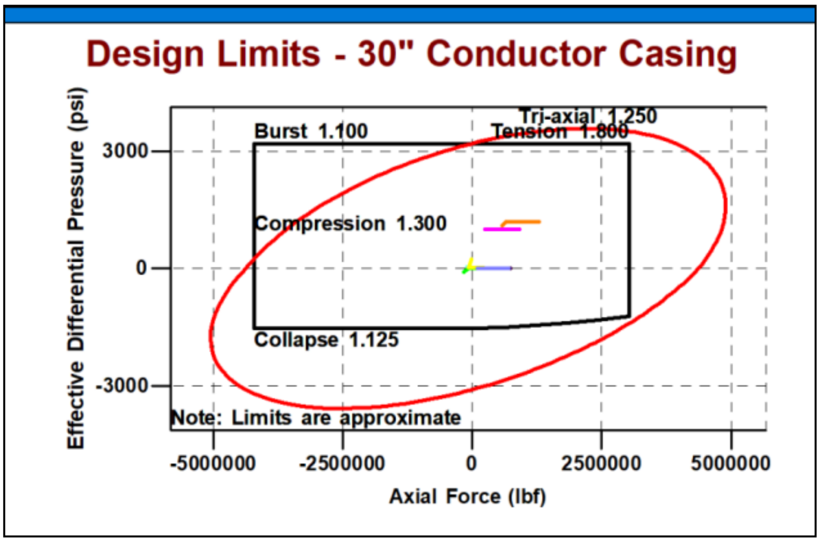

Figure 2. Design Limits for 30" Conductor Casing

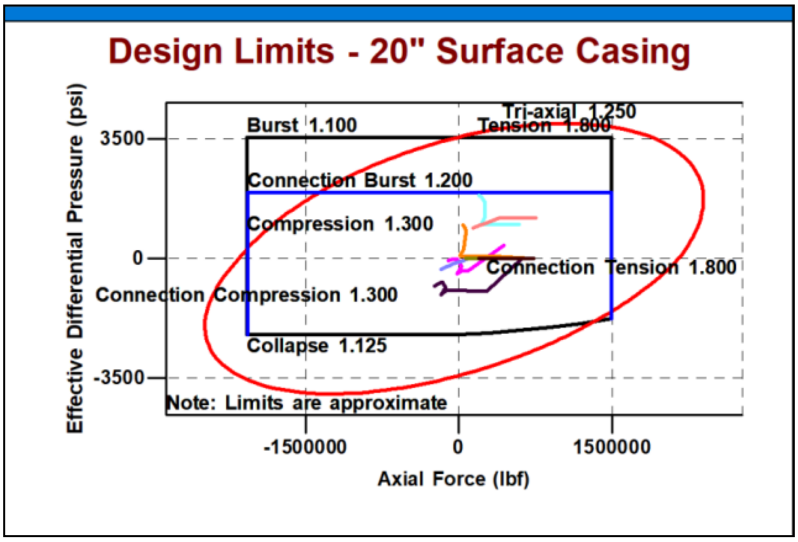

Figure 3. Design Limits for 20" Surface Casing

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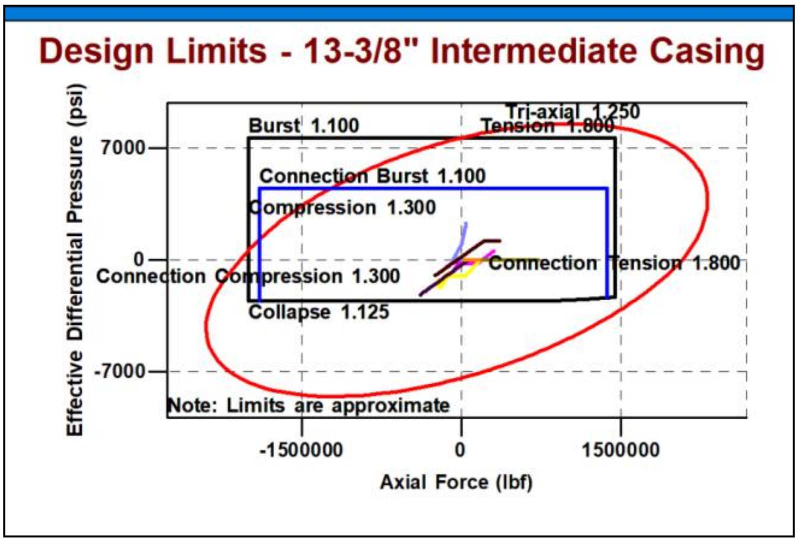

Figure 4. Design Limits for 13-3/8" Intermediate Casing

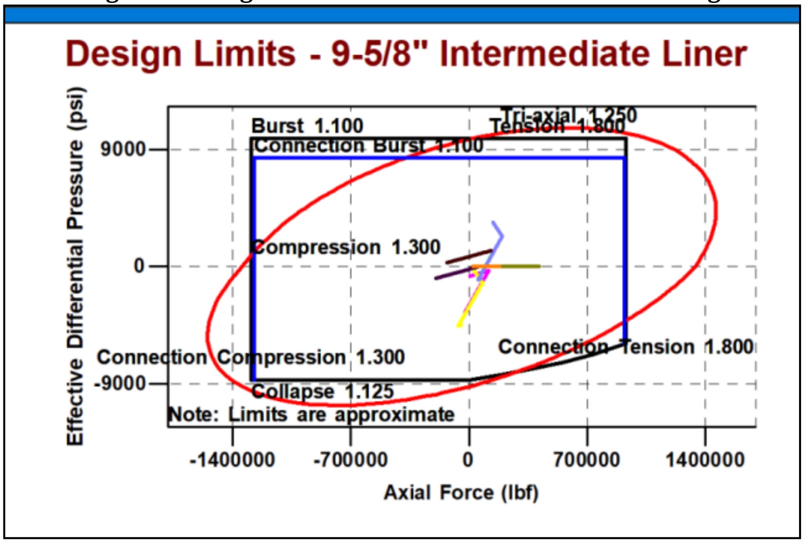

Figure 5. Design Limits for 9-5/8" Intermediate Liner

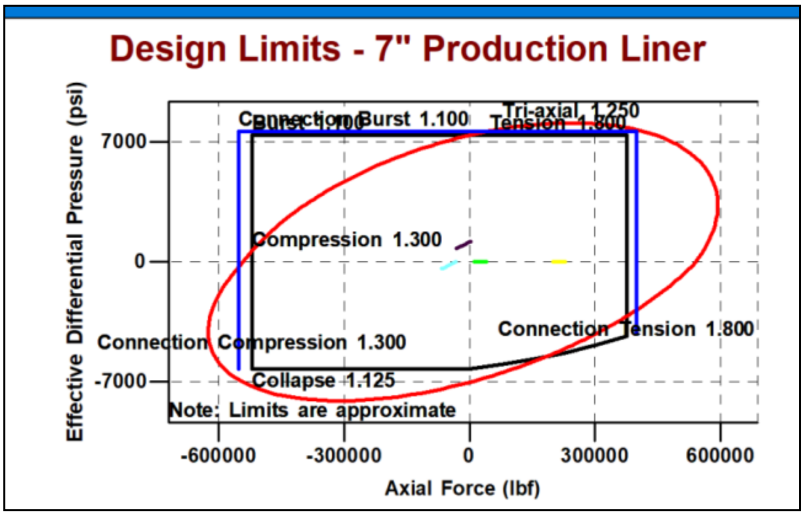

Figure 6. Design Limits for 7" Production Liner

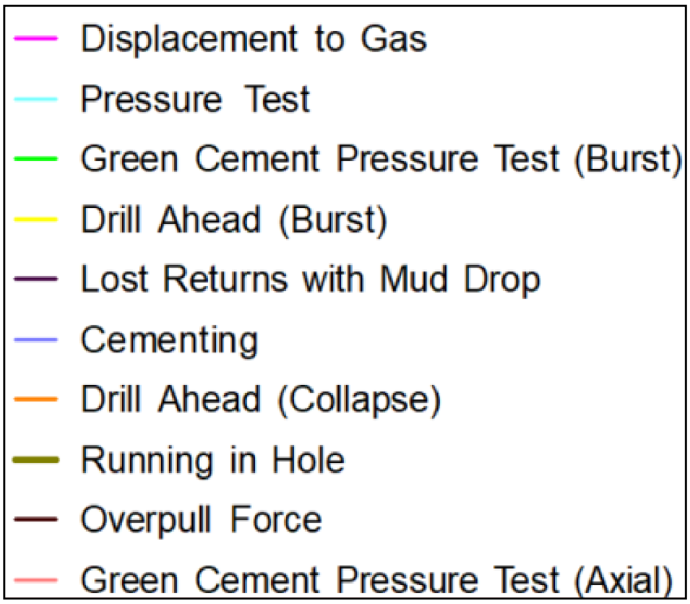

Figure 7. Design Limits Graph Legends

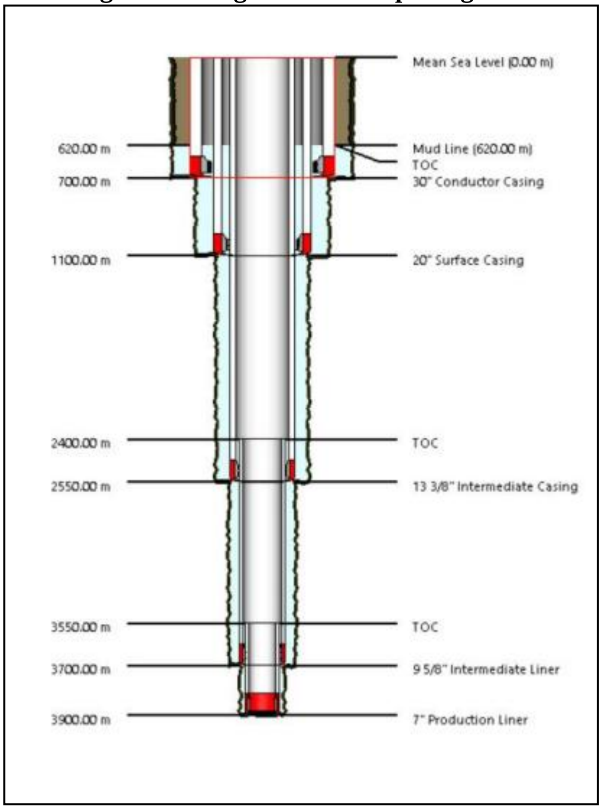

Figure 8. Proposed CO_2 Injector Well Schematic

3.3. Tubing Sensitivity Analysis

Tubing sensitivity analysis is conducted in order to determine the number of wells that will be utilized for this project. This analysis considered various tubing sizes and their impact on injectivity and wellhead pressure. Based on Figure 9-13, it shows that the most suitable tubing size is 4 inches with injection rate of 90 MMscf/day at 5600 psi.

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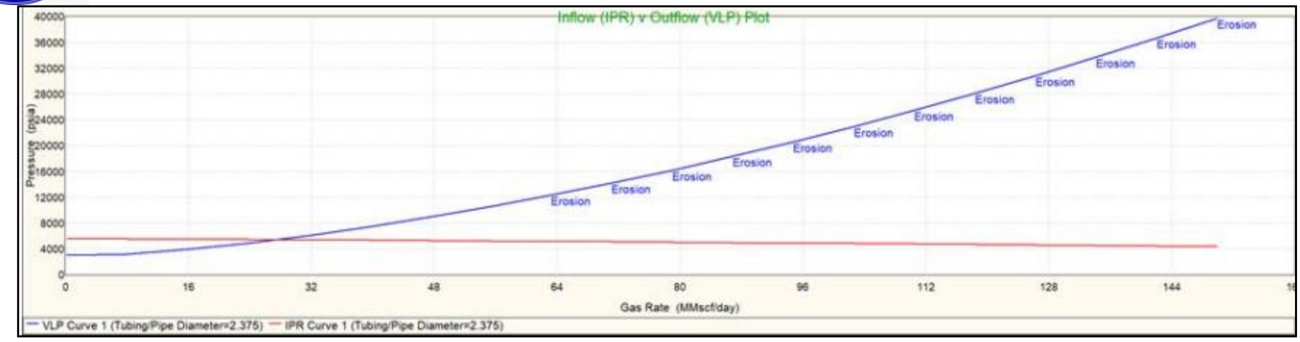

Figure 9. IPR vs. VLP Curve for Tubing 2.375 in

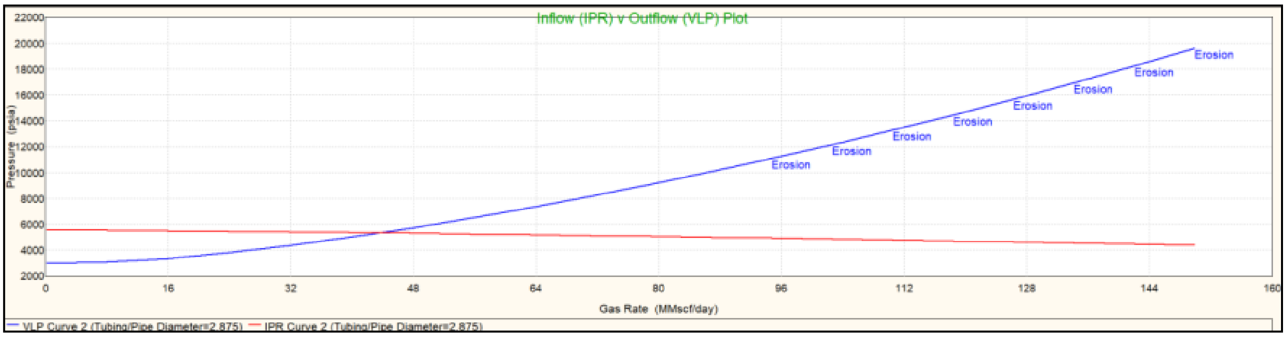

Figure 10. IPR vs. VLP Curve for Tubing 2.875 in

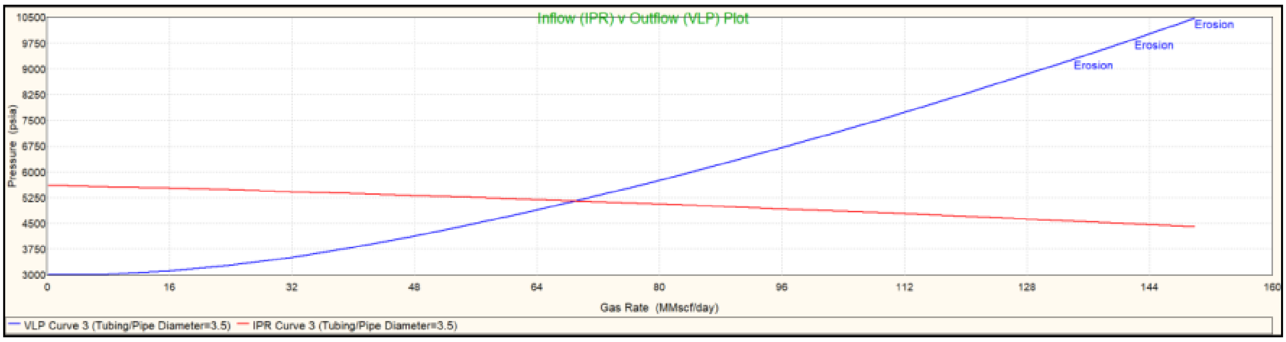

Figure 11. IPR vs VLP Curve for Tubing 3.5 in

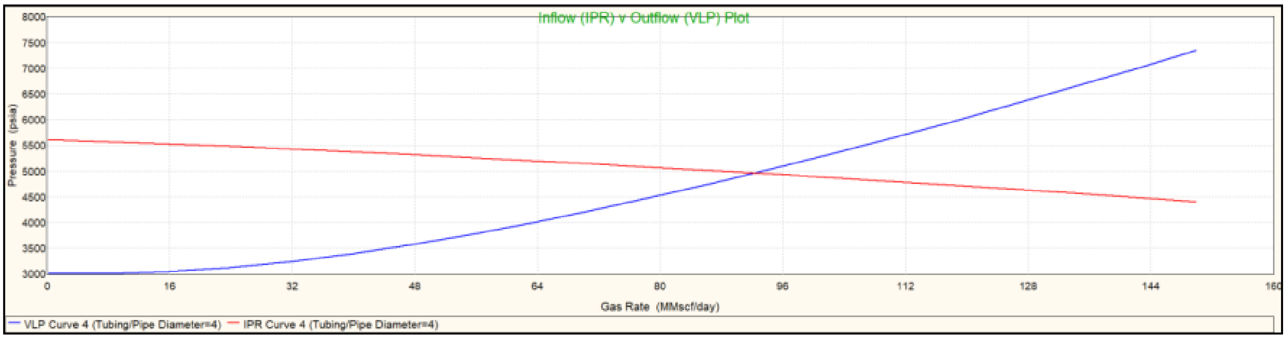

Figure 12. IPR vs VLP Curve for Tubing 4 in

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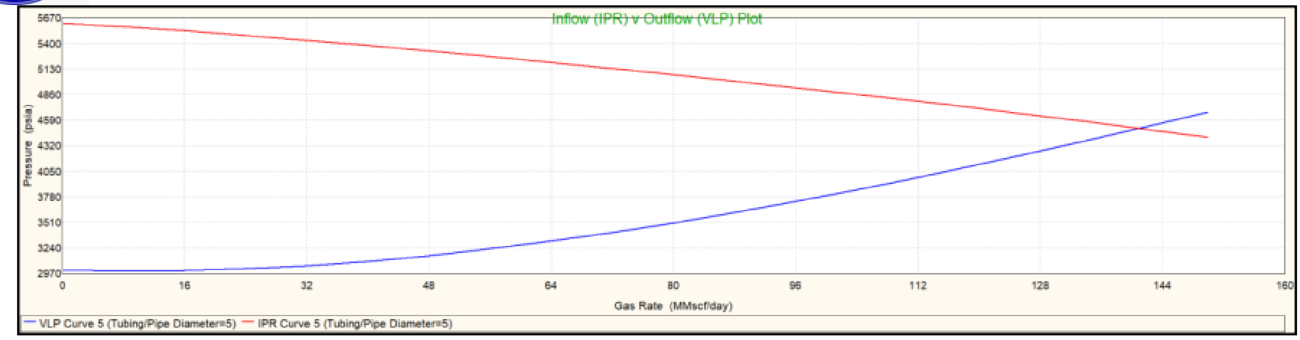

Figure 13. IPR vs VLP Curve for Tubing 5 in

Since the CO_2 injection rate is around 160.2 MMscfd, it can be concluded that there are two wells needed for the CO_2 injection process. The comparison of the well injectivity and wellhead pressure can be seen in Table 4.

Table 4. Tubing Sensitivity Analysis Results

Tubing Size (in)	Injection Rate (MMscf/day)	Wellhead Pressure (psia)
2.375	27.5	5254.2
2.875	43.8	5305.1
3	68.9	5129.2
4	92.5	4970.3
5	140.9	4514.5

3.4. Tubular Material Selection

From the tubing material selection using several evaluation rules for material specification (ECE results, ISO 15156-3 and Nippon steel chart), the material type results is obtained in Figure 14-18. From the summary of the selection results, it can be 5 concluded that the Duplex Stainless Steel SM22Cr or SM25Cr is the most appropriate choice of tubing material to be used. This is because there are possibilities of damage on the part of facilities, which cause a decrease in the purity of CO_2 and increase of H2S compositions.

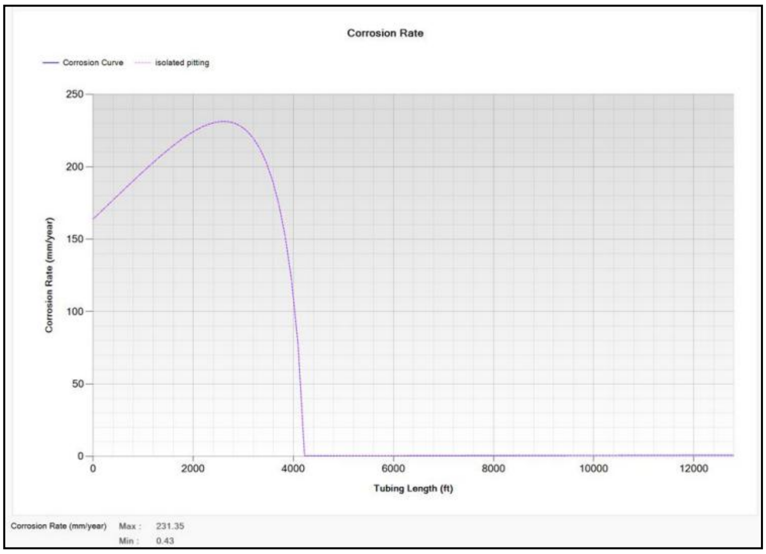

Figure 14. Corrosion Rate Prediction

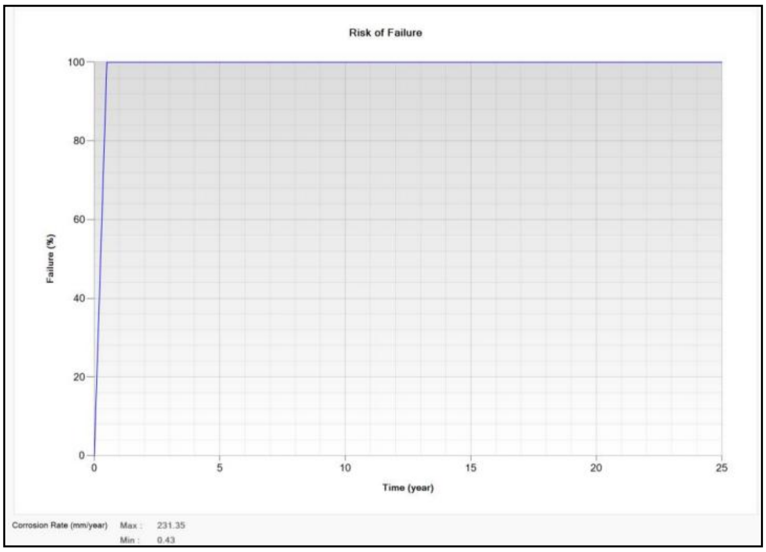

Figure 15. Risk of Failure Prediction

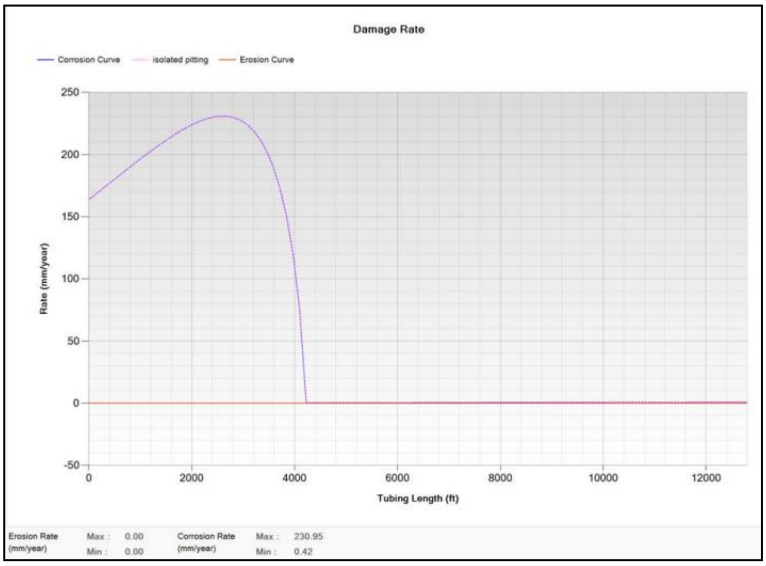

Figure 16. Damage rate prediction

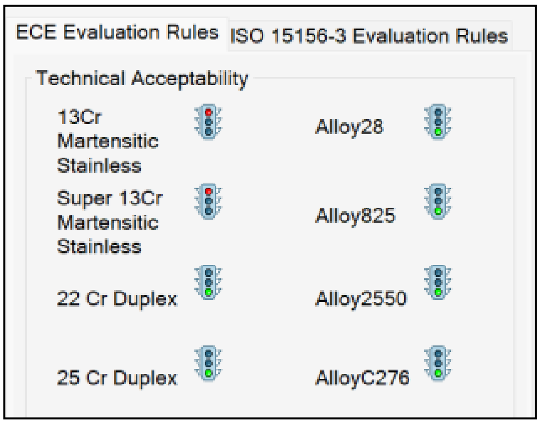

Figure 17. Alloy Evaluator for Tubing (ECE rules)

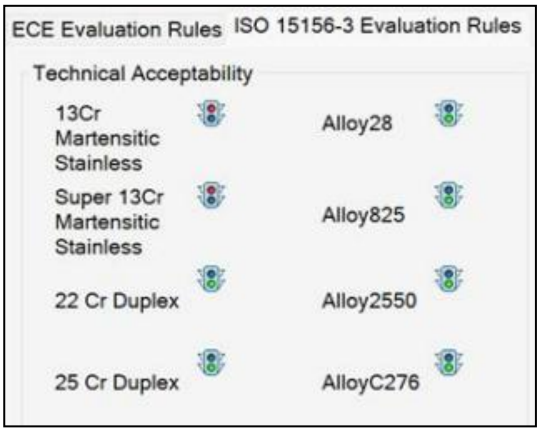

Figure 18. Alloy Evaluator for Tubing (ISO 15156-3 rules)

However, if there are no damage on the facility, the Martensitic-Ferritic Stainless Steel SM17CRS or SM13CRS is suitable to use based on Nippon steel chart as shown in Figure 19. The Nippon steel material selection chart divides several materials into certain parameter values (partial pressure of CO_2 and H2S also temperature). The CO_2 partial pressure is around 370.654 bar and the H2S partial pressure is 0.006 bar.

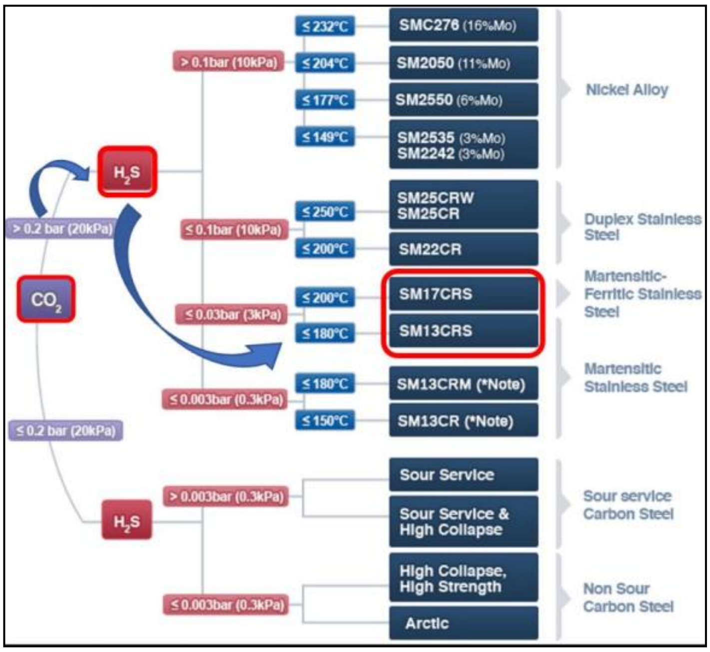

Figure 19. Nippon Steel Material Selection Chart

IV. CONCLUSION

Based on this research and analysis, it can be concluded that:

1. The casing scheme for the CO_2 injector well is presented in Table 2. And Table 3. It consists of 30" conductor casing, 20" surface casing, 13-3/8" intermediate casing, 9-5/8" intermediate liner and 7" production liner.
2. Based on the analysis using ECE software, ISO 15156-3 standard, and the nippon steel chart, the most suitable tubular materials for the CO_2 injector well is Duplex Stainless Steel SM22Cr or SM25CR.
3. The selected casing scheme and tubular materials contribute to maintaining well integrity and minimizing leakage risks by using well barrier concept. However, further cementing analysis, drill string design and completion design must be done in order to complete the well barrier elements.

To further enhance this research, the author recommends that seismic surveys must be done to present the structural integrity and the surveillance of how CO_2 medium distributes within the CO_2 injected reservoir, cementing calculation should be further done to evaluate potential leakage, and CO_2 distributions should be monitored since there are uncertainties related to how to CO_2 medium is spread within the reservoir which may lead to degradation of the well integrity.

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