Remaining Life and Corrosion Rate Prediction of Well Casing Material in the CO₂ Environment

Muhamad Yudi Masduky Sholihin¹*, Hendry Saputra Kusyanto², Roni Hadi Wijaya², Wahyu Haryadi³
¹ Department of Mechanical Engineering, Universitas Pancasila, Jl. Srengseng Sawah, Lenteng Agung, Jakarta 12640, Indonesia
² Material Science Study, Department of Physic, Universitas Indonesia, Depok 16424, West Java, Indonesia
³ y.masduky@ui.ac.id

Abstract. Prediction of CO₂ corrosion is required for predicting remaining life and determination of the required material selection. This paper give prediction of corrosion rate and remaining life of casing in the North Aceh well which is operated almost 14 years. Simulation method application is appropriate with the condition of North Aceh field since the well fluids contain high CO₂ gas (35 – 37%) and small amount of H₂S gas (0.016%). Based on historical data North Aceh well’s after production almost 14 years, it is possible that production packer leaks and degradation of cement could cause formation gas migrate through micro channeling inside cement. The CO₂ gas which is accumulate in casing could cause CO₂ corrosion. The corrosion rate calculation based on temperature 141°C, pressure 103.4 Barg and CO₂ contain 37% is 0.871 mm/year. After calculating the thickness loss, we found thickness loss of casing K55 is 12.741 mm. Meanwhile thickness of K55 casing 10.92 mm, it means the casing already leak before year 14th. Based on simulation and calculation the North Aceh well is assumed to have tubing and packer leaks in annulus #0 and channeling on annulus #1 so that the well is not recommended for re-production because of the communication between the annulus and the loss of the well barrier that can cause wellhead leakage. This condition is very dangerous because the well fluid is flammable and can cause pollution in the sea.

Keywords : Remaining life, prediction, corrosion

1. Introduction
Since the 40s, oil and gas industry has always faced corrosion problems. Corrosion can affect the main important equipment which is design in metal. Because of this deterioration, the carbon steel corrosion mechanism has been studied to reduce the contamination in the oil industry. Many documents associated to carbon steel corrosion have been published, to relate the carbon steel contamination mechanisms and different interpretation to resolve the problem of corrosion have been reported. Several research and studies has shown the cause of corrosion in petroleum industry to be the existence of hydrogen sulphide, carbon dioxide, oxygen and water in the reservoir. Another material that is affected by corrosion is the surface facility and wells material. Corrosion damage can be internal or external. Factors that can influence internal corrosion in pipelines and wells can be the surface of the steel, temperature, flow velocity, water chemistry, oil or water wetting, hydrogen sulphide (H₂S) and carbon dioxide (CO₂) content.
Well structure consists of conductor, surface casing, tubing, casing shore and liner head with varying diameters according to the design as shown in Figure 1. The well is drilled with differently sized drill bits that get smaller as the well gets deeper. Each point when a casing diameter changes, the joint need to be sealed, cements is pushed between casings and bedrock. It protects the metal wall from gas pressure and from gas leaking up the outside of well pipe.

In this study, the well that located in the offshore of the North Sumatra Basin in the Straits of Malacca, covering an area of 77 Km² and 6287 ft depth with directional well type. The well has been shut in since 2004 due to production facility problem.

Based on historical data the well after production almost 14 years, it produced gas and oil that contains 37% CO₂ and 0.016% H₂S. In order to reproduce, the integrity of the well need to be assess because high amount of CO₂ in fluid can cause CO₂ corrosion in tubing and casing of the well [1-3]. It is also possible that the production packer leaks and degradation of cement caused the formation gas to migrate through micro channeling inside cement that can cause cracking [4,5].

In this paper we study the corrosion that occurs in old wells in the North Sumatra Basin using Norshok method which will be used as recommendation if it will be operated again for production.

![Figure 1. Operational Well Structure [6].](image)

2. Experimental Method
Studied the different corrosion prediction models to evaluate field data by running different corrosion prediction models for a set of cases taken from the corrosion field database. It varied considerably from case to case which models were most successful in their prediction, and it was not possible to declare one or two models as better than the others. An evaluation of any model against field data can be strongly dependent on the selection of field data used for the evaluation or validation and the validity and accuracy of the field data. It is important to understand the limitations and uncertainties in the corrosion prediction models [6]. The Norsok M-506 model is an empirical model developed by the Norwegian oil companies Statoil, Norsk Hydro and Saga Petroleum for prediction of CO₂ corrosion. The model is fitted to a large amount of laboratory data. The model takes larger account for the effect of protective. In order to be able to run the different corrosion prediction models the following data
from the field cases were specified as a minimum: Temperature inlet and outlet, Pressure inlet and outlet, CO$_2$ mole %, Bicarbonate, acetate and calcium content in the water (preferably full ionic water composition), production rates (Gas, water, and oil), Pipe inner diameter. Bubble point pressure or pressure in last separator stage for full liquid systems Corrosion films at higher temperature and higher pH than several of the other models, as it is fitted to high temperature data up to 150 °C [7].

Provide the main limitations for Norsok M-506 model are the following: The model cannot be used for ratio between CO$_2$ and H$_2$S partial pressure less than 20 and when the H$_2$S partial pressure is above 0.5 bars. The model cannot be used for total organic acid content above 100 ppm when the partial pressure of CO$_2$ is less than 0.5 bars. The model cannot be used for prediction of corrosion rates for pH-stabilised systems. The model cannot be used for prediction of top-of-line corrosion. The model is a point model and change in pH along a pipeline due to corrosion has to be determined separately

Corrosion in pipeline, casing, and tubing can always be modelled, but the corrosion model should consider the limitation when modelling corrosion. The model should be part of an overall corrosion risk assessment methodology, consider existing corrosion rate data and experience with similar production fluids when it is available to backup corrosion modelling. When there is uncertainty, consider accelerated corrosion testing to support corrosion assessment [8]. This simulation is focusing to predict corrosion rate and remaining life of well tubing and casing using Norsok M-506 method as shown in Figure 2 and the basic input parameter in Table 1.

![Figure 2. Experimental And Prediction Method Using Norsok M-506.](image-url)
Table 1. Basic Input Parameter Norsok M-506.

| Parameter                        | Units     | Range     | Comments                                                                 |
|---------------------------------|-----------|-----------|---------------------------------------------------------------------------|
| Temperature                     | ° C       | 20 to 150 |                                                                           |
|                                 | ° F       | 68 to 302 |                                                                           |
| Total pressure                  | bar       | 1 to 1000 |                                                                           |
|                                 | psi       | 14.5 to 14500 | Only relevant when CO₂ is given in kmol/h                               |
| Total mass flow                 | kmol/h    | 10³ to 10⁶|                                                                           |
| CO₂ Fugacity in the gas phase   | bar       | 0.1 to 10 | The CO₂ partial pressure shall be ≤ the total pressure. The allowed ranges of mole % and kmol/h |
|                                 | Psi       | 1.45 to 145 |                                                                          |
|                                 | Mole %    | Variable  |                                                                          |
|                                 | Kmole/h   | Variable  | CO₂ are dependent on the total pressure.                                  |
| Wall shear stress               | Pa        | 1 to 150  | Can be calculated by use of other input parameters.                      |
| pH                              |           | 3.5 to 6.5| Can be calculated by use of other input parameters.                      |
| Glycol concentration            | Weight %  | 0 to 100  |                                                                           |
| Inhibitor efficiency            | %         | 0 to 100  | See NORSOK M-001                                                         |

3. Result and discussion

Based on the available data, the casing material used for the well are 25Cr, K55 and L80 which can be seen in API 5 CT as a standard suitable for casing tubing. The wells produce with a flow pressure at an average wellhead of 1500 Psig and temperature of 286 °F. The well fluid also contains 37% CO₂ gas and 0.016% H₂S gas which cause of corrosion in the well casing. The degradation of cement in the annulus allows the gas coming from the reservoir of the migrating well to enter the annulus and accumulate so that corrosion may occur in the annulus.

The most fundamental in casing corrosion mechanism is that there must be liquid water in contact with the casing surface. This allows aqueous corrosion attack to take place. If the cement sheath is intact and well-bonded to the casing surface then there is little chance for water to reach the steel surface. Cement sheath quality is rarely so reliably perfect. In some cases well designs have not required cementing of the casing over critical geological intervals. More typically, cementing operations face significant losses in certain intervals so cementing has to be stopped without filling the annulus completely, or to the planned top of cement depth. Well operations, including thermal and pressure cycles, may also deteriorate the cement sheath quality with time. Under these circumstances ground water or subsurface aquifers may contact the casing. If the water has a composition which is aggressive to steel, including one or more constituent which can support a corrosive reaction, then corrosion of the casing may then take place. These are varying factor of corrosion at casing: water contact with the casing surface, temperature of the water, temperature of the casing, concentration of cathodic species in the water (particularly dissolved oxygen or carbon dioxide), concentration of chloride ions in the water, ease of replenishment of the water [9].

Poor mud displacement during cementing was high-lighted as being a major cause of poor sheath integrity and loss of zonal isolation as shown in Figure 3. Water channeling along a bad cement job with potential for corrosion at the casing surface.
When CO$_2$ is dissolved in water, it forms carbonic acid (HCO$_3^-$) which reacts with compounds in hydrated Portland cement matrix such as calcium silicate gel (C–S–H) and calcium hydroxyl (Ca(OH)$_2$) [6]. The major reaction products are calcium carbonate and amorphous silica gel. Leaching of the resulting CaCO$_3$ and Ca (HCO$_3$)$_2$, leads to rapid reduction in strength, varied permeability, and corrosion on the casing [11]. The process can be described with the following reactions:

\[
\begin{align*}
\text{CO}_2 + \text{H}_2\text{O} & \leftrightarrow \text{H}_2\text{CO}_3 \quad (1) \\
\text{H}_2\text{CO}_3 + \text{Ca(OH)} & \rightarrow \text{CaCO}_3 + 2\text{H}_2\text{O} \quad (2) \\
\text{C–S–H} + \text{H}_2\text{CO}_3 & \rightarrow \text{CaCO}_3 + \text{amorphous silica} \quad (3) \\
\text{CaCO}_3 + \text{H}_2\text{CO}_3 & \rightarrow \text{Ca(}\text{HCO}_3\text{)}_2 \quad (4) \\
\text{Ca(}\text{HCO}_3\text{)}_2 + \text{Ca(OH)}_2 & \rightarrow 2\text{CaCO}_3 + 2\text{H}_2\text{O} \quad (5)
\end{align*}
\]

In the initial reaction, carbonic acid is built out of dissolved carbon dioxide and water. Then the acid reacts with calcium hydroxide and the calcium–silicate–hydrate gels and forms calcium carbonate. The calcium carbonate continues to react with the carbonic acid and builds water-soluble calcium bicarbonate. The last reaction is very critical, because the formation of water allows dissolution of more CO$_2$. Micro annulus further indicated that CO$_2$ migrated along the cement/cap rock and cement/casing interfaces, in the latter case speculating that CO$_2$ infiltration may have occurred due to migration up the casing wall, through casing threads or at particular points of corrosion. Figure 4 shows CO$_2$ corrosion caused by micro annulus and channeling. Microannulus further indicated that CO$_2$ migrated along the cement/cap rock and cement/casing interfaces, in the latter case speculating that CO$_2$ infiltration may have occurred due to migration up the casing wall, through casing threads or at particular points of corrosion.

Based on data well parameter in Table 2, Kt factor in Table 3 and f(pH) could be determined. A constant Kt has been generated, is found by a linear extrapolation between the calculated corrosion rate at the temperature above and below the desired temperature. Kt factor based on temperature table is shown below in Table 4. Kt is a temperature dependant constant. It increases corrosion rate from 5$^\circ$ to 60$^\circ$ C and then decreased up to 150 $^\circ$C.
Figure 4. CO₂ Corrosion Process By Microannulus and Channelling [9].

Table 2. Well Parameter for Calculating Corrosion Rate.

| Well Parameter | Value | Units | Range          | Comments       |
|----------------|-------|-------|----------------|----------------|
| Temperature    | 286   | °F    | 68 to 302      |                |
|                | 141.1 | °C    | 20 to 150      |                |
| Pressure       | 1500  | Psi   | 14.5 to 14500  |                |
|                | 103.4 | Bar   | 1 to 1000      |                |
| % mole CO₂     | 37    | %     |                |                |
| pH             | 5     |       | 3.5 to 6.5     |                |
| Glycol Concentration | % | 0 – 100 | Not available |
| Inhibitor efficiency | % | 0 – 100 | Not available |

Table 3. Kt factor Based on Temperature.

| Temperature (°C) | Kt   |
|------------------|------|
| 5                | 0.42 |
| 15               | 1.59 |
| 20               | 4.762|
| 40               | 8.927|
| 60               | 10.695|
| 80               | 9.949|
| 90               | 6.250|
| 120              | 7.770|
| 150              | 5.203|

Temperature of the well is 1410 °C. Kt factor based on extrapolated between 1200 °C and 1500 °C is 5.973. Determine f(pH) based on is f(pH) 0.037. The effect of temperature, which is well 1500 °C is 5.973. Determine f(pH) based on Table 4 is f(pH) 0.037. The effect of temperature, which is well known to accelerate all processes involved in CO₂ corrosion, has been clarified. At low pH when
protective scales do not form, temperature accelerates corrosion and vice versa when conditions are favorable for iron carbonate to form, temperature leads to faster precipitation and often to lower corrosion rates. The effect of pH on CO$_2$ corrosion is well established and successfully modelled, at low pH typical for condensed water will accelerate corrosion rate. In almost all cases higher pH leads to lower corrosion rates.

Table 4. f(pH) based on temperature and pH range.

| Temperature (°C) | pH          | F(pH)                                      |
|-----------------|-------------|--------------------------------------------|
| 5               | 3.5 ≤ pH ≤ 4.6 | f(pH) = 2.0676 – (0.2309 x pH)             |
| 5               | 4.6 ≤ pH ≤ 6.5 | f(pH) = 4.342 – (1.051 x pH) + (0.0706 x pH$^2$) |
| 15              | 3.5 ≤ pH ≤ 4.6 | f(pH) = 2.0676 – (0.2309 x pH)             |
| 15              | 4.6 ≤ pH ≤ 6.5 | f(pH) = 4.986 – (1.191 x pH) + (0.0706 x pH$^2$) |
| 20              | 3.5 ≤ pH ≤ 4.6 | f(pH) = 2.0676 – (0.2309 x pH)             |
| 20              | 4.6 ≤ pH ≤ 6.5 | f(pH) = 5.1885 – (1.235 x pH) + (0.0706 x pH$^2$) |
| 40              | 3.5 ≤ pH ≤ 4.6 | f(pH) = 2.0676 – (0.2309 x pH)             |
| 40              | 4.6 ≤ pH ≤ 6.5 | f(pH) = 5.1885 – (1.235 x pH) + (0.0706 x pH$^2$) |
| 60              | 3.5 ≤ pH ≤ 4.6 | f(pH) = 2.0676 – (0.2309 x pH)             |
| 60              | 4.6 ≤ pH ≤ 6.5 | f(pH) = 15.444 – (6.1291 x pH) + (0.8204 x pH$^2$) – (0.0371 x pH$^3$) |
| 80              | 3.5 ≤ pH ≤ 4.6 | f(pH) = 2.6727 – (0.3636 x pH)             |
| 80              | 4.6 ≤ pH ≤ 6.5 | f(pH) = 331.68 x e$^{(-1.2618 x pH)}$     |
| 90              | 3.5 ≤ pH ≤ 4.57| f(pH) = 3.1355 – (0.4673 x pH)            |
| 90              | 4.57 ≤ pH ≤ 5.62| f(pH) = 21254 x e$^{(-2.1811 x pH)}$    |
| 90              | 5.62 ≤ pH ≤ 6.5| f(pH) = 0.4014 – (0.0538 x pH)            |
| 120             | 3.5 ≤ pH ≤ 4.3 | f(pH) = 1.5375 – (0.125 x pH)             |
| 120             | 4.3 ≤ pH ≤ 5  | f(pH) = 5.9757 – (1.157 x pH)             |
| 120             | 5 ≤ pH ≤ 6.5  | f(pH) = 0.546125 – (0.071225 x pH)        |
| 150             | 3.5 ≤ pH ≤ 3.8 | f(pH) = 1                                 |
| 150             | 3.8 ≤ pH ≤ 5  | f(pH) = 17.634 – (7.0945 x pH) + (0.715 x pH$^2$) |
| 150             | 5 ≤ pH ≤ 6.5  | f(pH) = 0.037                             |

The value of f(CO$_2$) based on formula:

$$a = 10^{P(0.0031-1.4/T)} \quad P \leq 250 \text{ Bar} \quad (6)$$

where: $a$ is fugacity coefficient, $P$ = Pressure (Bar), $T$ = Temperature (°C).

The CO$_2$ partial pressure is found by

$$PCO_2 = (\text{mole} \% \text{ CO}_2 \text{ in the gas phase}/100\% \times P) \quad (7)$$

Where mole % CO$_2$ is 37% and $P = 103.4$ B, the result is 38.26.

The real CO$_2$ pressure can then be expressed as:

$$fCO_2 = a \times PCO_2 \quad (8)$$

where fCO$_2$ is CO$_2$ pressure, $a$ is fugacity coefficient and PCO$_2$ is CO$_2$ partial pressure.

With $a = 0.936$ and PCO$_2$ = 38.26, the result of fCO$_2$ is 35.802.

Fugacity of CO$_2$ decreases with increasing temperature. It decrease with distance due to stronger dependency on system pressure (P) which decreases along the pipeline with assuming partial pressure (PCO$_2$) is constant. In the case of scale-free CO$_2$ corrosion, an increase of CO$_2$ partial pressure PCO$_2$.
typically leads to an increase in the corrosion rate. At a high pH, higher PCO$_2$ leads to an increase in bicarbonate and carbonate ion concentration and a higher supersaturation, which accelerates precipitation and scale formation [12]. Mean wall shear stress in straight pipe sections is used. Shear stress formula is:

\[
S = 0.5 \times \rho_m \times f \times U_m^2
\]

(9)

\[
\lambda = \frac{Q_L}{(Q_L + Q_G)}
\]

(10)

\[
\mu_m = \mu_L \times \lambda \times \mu_G \times (1 - \lambda)
\]

(11)

\[
U_m = U_L + U_G
\]

(12)

\[
\rho_m = \rho_L \times \lambda + \rho_G \times (1 - \lambda)
\]

(13)

\[
f = 0.001375 \left[ 1 + \left( 2000 \times \left( \frac{k}{D} \right) \right) + 10^{6} \times \left( \frac{\mu_m}{(\rho_m \mu_m D)} \right)^{0.33} \right]
\]

(14)

The result of shear stress is $S = 0.55$ with $Q_{\text{gas}}$: 4.2906 MMSCFD and $Q_{\text{oil}}$: 4227 BBLD. Wall shear stress increases with increasing of viscosity and density which in turn decrease with increasing of temperature [13]. Wall shear stress can be calculated from production rates and pipe diameter. The effect of flow on CO$_2$ corrosion still remains a contentious area in the predictive processes. The flow parameter currently favored for determining the effect of velocity on corrosion rate and scale and inhibitor film formation/stability is liquid shear stress at the pipe wall [14]. The tangential force produced by the higher velocity flow of the liquid may hinder the formation of the protective film on the surface of the metal, in that case, the corrosion rate intensified [15]. The corrosion rate based on temperature 141 °C, pressure 103.4 Barg and CO$_2$ contain 37% by Norsok M-506 is 0.871 mm/year.

\[
\text{CR}_{t} = K_t \times f_{\text{CO}_2}^{0.62} \times (S/19)^{0.146} + 0.0324 \ \log \left( f_{\text{CO}_2} \right) \times f(pH)t
\]

(15)

Well has production casing K55 type. The thickness is 10.92 mm. The well had been produced since 8 November 2004. Based on calculation we found that corrosion rate is 0.871 mm/year so the thickness loss after 14 years is 12.741 mm, meanwhile thickness of K55 casing 10.92 mm, it means he casing already leak before year 14th.

The complex interaction of multiple factors that may cause production casing leaks is most likely: cement sealing performance, age of well, production casing thickness, CO$_2$ content in the indigenous aquifer. Assessment of well integrity for both operational and abandoned wells can be performed in different ways. For operational wells, different tests can be implemented with varyin accuracy. However, no logging tool is available which can explicitly detect the presence and extent of corrosion in cement. A commonly used one is CBL complimented with Variable Density Log (VDL) to identify different defects such as channeling, micro-annulus and deboning.

4. Conclusion

Norsok M-506 method application is appropriate with the condition of the well since the well fluids contain high CO$_2$ gas (35 – 37%) and small amount of H$_2$S gas (0.016%). Based on historical data well after Shut in almost 14 years it is possible that production packer leaks and degradation of cement could cause formation gas to migrate through micro channeling inside cement. The CO$_2$ gas which is accumulate in casing could cause CO$_2$ corrosion. The corrosion rate based on temperature 141°C, pressure 103.4 Barg and CO$_2$ contain 37% by Norsok M-506 is 0.871 mm/year. After calculating the thickness loss, we found thickness loss of casing K55 is 12.741 mm, meanwhile thickness of K55 casing 10.92 mm, it means the casing already leak before year 14th. Based on simulation and calculation the North Aceh well is assumed to have tubing and packer leaks in annulus #0 and channeling on annulus #1 so that the well is not recommended for re-production because of the communication between the annulus and the loss of the well barrier that can cause wellhead leakage.
This condition is very dangerous because the well fluid is flammable and can cause pollution in the sea. Assessment of well integrity for both operational and abandoned wells can be performed in different ways. For operational wells, different tests can be implemented with varying accuracy. However, no logging tool is available which can explicitly detect the presence and extent of corrosion in cement. A commonly used one is CBL complimented with Variable Density Log (VDL) to identify different defects such as channeling, micro-annulus and deboning.

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