CORROSION STUDY ON THE EFFECTS OF FLOWBACK WATER IN SHALE GAS RESERVOIR

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Dissertion submitted in partial fulfillment of the requirements for the Bachelor of Engineering (Hons) Petroleum Engineering

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the Petroleum Engineering Programme
Universiti Teknologi PETRONAS
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Approved by,

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SEPTEMBER 2014

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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Abstract

Shale gas is found within the shale formation which is a tight formation. Hence, to improve the low permeability of this formation hydraulic fracturing technique is used in extracting the shale gas. The injection of fracturing fluid into the wellbore is to cause the formation rock to crack and allowed the flowing of gas into the well. When production of shale gas starts, some of fracturing fluid known as flowback water will flow back to the surface and this flowback water cause corrosion to happen on the production casing. This study has been conducted to investigate the effects of reservoir conditions and flowback water toward downhole equipment; and to identify a suitable material for downhole equipment during the production of shale gas. The scopes of this study are focusing on the corrosion problems that could occur on the downhole equipment, efficiently select the materials to maintain the integrity of the equipment and the effect of reservoir condition such as presence of reservoir impurities to the corrosion or degradation rate. The methods used for corrosion mitigation is by using corrosion resistant alloy (CRA) as the downhole equipment material for shale gas production. Software called Electronic Corrosion Engineer (ECE) is used to calculate the corrosion rate of tubing in some specific condition of shale gas well and to select the most suitable tubing material for that condition.

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ABBREVIATIONS

Acronym	Definition
BCF	Billion Cubic Feet
CO_2	Carbon Dioxide
$FeCO_3$	Iron Carbonate
H_2CO_3	Carbonic Acid
H_2	Hydrogen Gas
H_2O	Water
H_2S	Hydrogen Sulphide
HCO_3^-	Bicarbonate
CO_3^-	Carbonate
FeS	Iron Sulphide
CRA	Corrosion Resistant Alloy
CLAS	Carbon Low Alloy Steel
ECE	Electronic Corrosion Engineer
HIC	Hydrogen Induced Corrosion
SSC	Sulphide Stress Cracking
SCC	Stress Cracking Corrosion

CHAPTER ONE

INTRODUCTION

1.1 Background of Study

The rises of natural gas in some of the countries around the globe especially in the North America region as new source of energy had caused the amount of producing and consuming of natural gas had annually increased. Referring to the analysis by U.S Energy Information Administration (EIA), world natural gas production had increase from 90,562 Billion Cubic Feet (BCF) in year 2002 to 118,866 BCF in year 2012 which is about 23.8% (Stevens and Paul, 2012). Shale gas is an unconventional reservoir with permeability less than one mD and normally cannot be extracted using the same methods as conventional reservoirs. Therefore, special technique called hydraulic fracturing must be used to extract the shale gas for commercial production.

Hydraulic fracturing technique involves injecting a mixture of acids, water, gases, and additives (Agbaji et al. 2009) known as fracturing fluids into the well to create fractures in the shale formation and this technique consumes large water quantity. Typical water volume used for hydraulic fracturing treatment is 6000 bbl per stage with 6 to 10 stage for horizontal well (Blow et al., 2009). After hydraulic fracturing technique is accomplished, some amount of fracturing fluid is recovered through a process known as flowback. The flowback water then will cause corrosion to occur at downhole equipment. The flowback water is contaminated by metals such as zinc and iron, corrosive elements such carbon dioxide and hydrogen sulphide, salt and solids such iron carbonate (Blow et al., 2009). All these contaminants in flowback water can give unfavourable effects to the well which it could lead to souring of the well (Blow et al., 2009).

The downhole equipment such as production casing is the production facilities that bring the produced shale gas from the reservoir to the surface. Mostly, corrosion occurs when steel interact with an aqueous environment then rusts (Corbin and Willson, 2007). Corrosion during the shale gas production can be one of the major problems as it can cause great impact to the operators such as losses of profit. Core problem that has been confirmed is corrosion had caused the pipeline to rapture.

1.2 Problem Statement

The fracturing fluid which is used for hydraulic fracturing technique during shale gas production has given rise to concerns around the effect to the integrity of downhole equipment. Since the hydraulic fracturing technique is using fracturing fluid which mostly contains water to crack the shale, a portion of the fluid known as flowback water will return back during the production of shale gas. This will create a favourable condition for corrosion to occur on the downhole equipment.

Moreover, natural gas extraction also contains some corrosive impurities which highly corrosive such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S). These types of impurities can react with water to form corrosion. Hence, continuous extraction of shale gas with these impurities can cause degradation of downhole equipment materials. Degradation of the downhole equipment means a loss of its mechanical properties such as strength and ductility (Papoola et. al, 2013). Hence, the needs on selecting the suitable materials are essential as the carbon steels that are currently used in the industry are seems to easily corrode.

1.3 Objectives of Study

The key objectives of the study are:

- To investigate the effects of reservoir conditions and flowback water toward downhole equipment for shale gas reservoir.
- To identify a suitable material for shale gas downhole equipment.
- To analyse the economical values of selected material.

1.4 Scope of Study

This study is focusing on the corrosion problems that could occur in shale gas reservoir especially on the downhole equipment such as production casing due to the effects of flowback water and reservoir impurities during shale gas extraction. This is because corrosion philosophies must be clearly recognized in order to obtain the corrosion characteristics during shale gas production. This study will be focusing on corrosion mitigation methods by efficiently select the materials that can maintain the integrity of the equipment thus prevent failure to occur. Moreover, corrosion mitigation can help in significantly reduced the corrosion rate per year which then dramatically increases component's life.

Furthermore, the scope of study will be focusing on the effects of reservoir condition such as the temperature and pressure to the rate of corrosion that could occur at the downhole equipment. The corrosion controls or mitigation methods during the production phase of the shale gas are main scope of study as accordance to the objective.

CHAPTER 2

LITERATURE REVIEW

2.1 Shale Gas

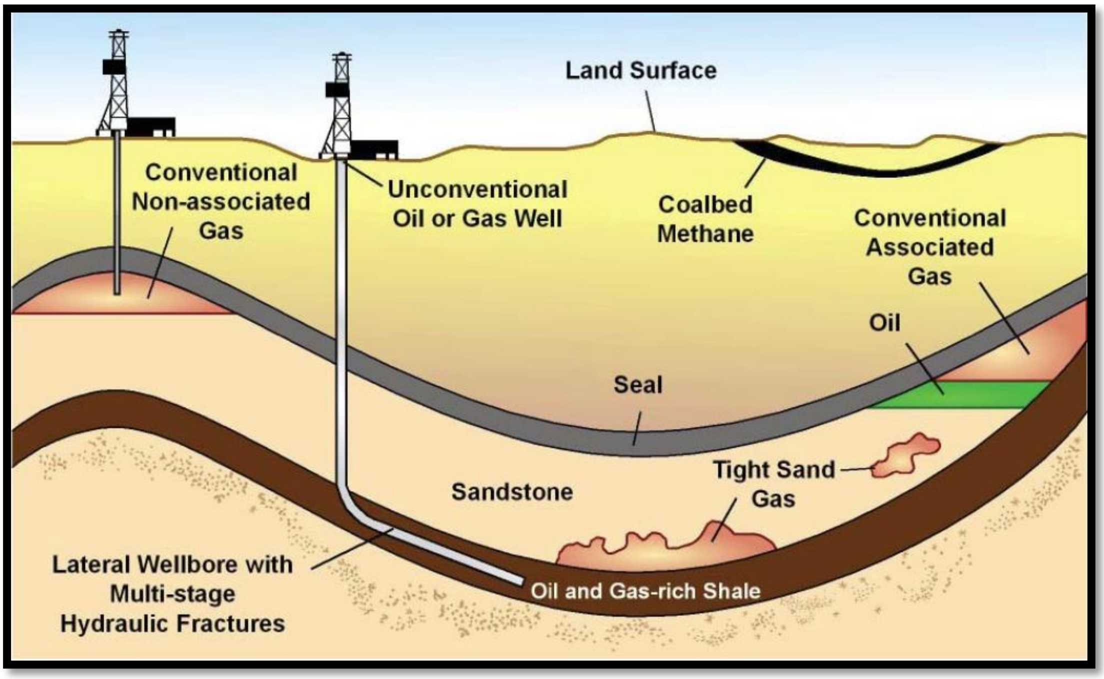


FIGURE 1: The Conventional and Unconventional Reservoir Geology

(Source: U.S EIA, 2013)

Shale gas is the natural gas that extracted from unconventional reservoir which is trapped in fine-grained sedimentary rocks that mostly fill by shale containing clay and minerals like calcite and quartz. In recent years, there is an increasing in the production of natural gas from the shale formations. The development of natural gas production from the unconventional reservoirs especially from shale formations has been a new-fangled target as the development of natural gas extraction from conventional reservoirs is decreasing and has caused the industry to change their focus to the exploration of unconventional reservoir. The development of conventional reservoir as the resources for natural gas extraction in Canada has declining in recent years and it is predicted to continue to decline for the next few years (National Energy Board, 2009). Also, by the year of 2035 the United States EIA predicted that shale gas will be supplying about 46% of natural gas in United States (Paul and Stevens, 2012).

Shale is the sedimentary rocks which are normally combination of silica, carbonate, clay and some percentage of organic materials deposited as mud which is clay and silt (Blatt and Tracy, 2000). Laminae of sandstone, limestone or dolostone may also be contained in shale. The interconnected pores in the shale formations are very low as it is 1000 times smaller than the permeability in the conventional reservoirs and compared to methane single molecule, it is just 20 times larger (Kent, 2007). However, the permeability of shale formations can be increased by the existence of natural fractures in the shale that will act as the pathway of fluid movements (Shurr and Ridgley, 2002).

FIGURE 2: Shale (Dark bed) and Limestone (Light bed).
(Source: The National Energy Board, 2009)

2.2 Hydraulic Fracturing

In the way of producing high flowrate of shale gas, generating additional permeability is needed to allow the movements of the gas for collection or producing commercially. This can be done by stimulate the reservoir mechanically using hydraulic fracturing technique and horizontal drilling for increasing the percentage of wellbore exposing to the reservoir as illustrated in Figure 3.

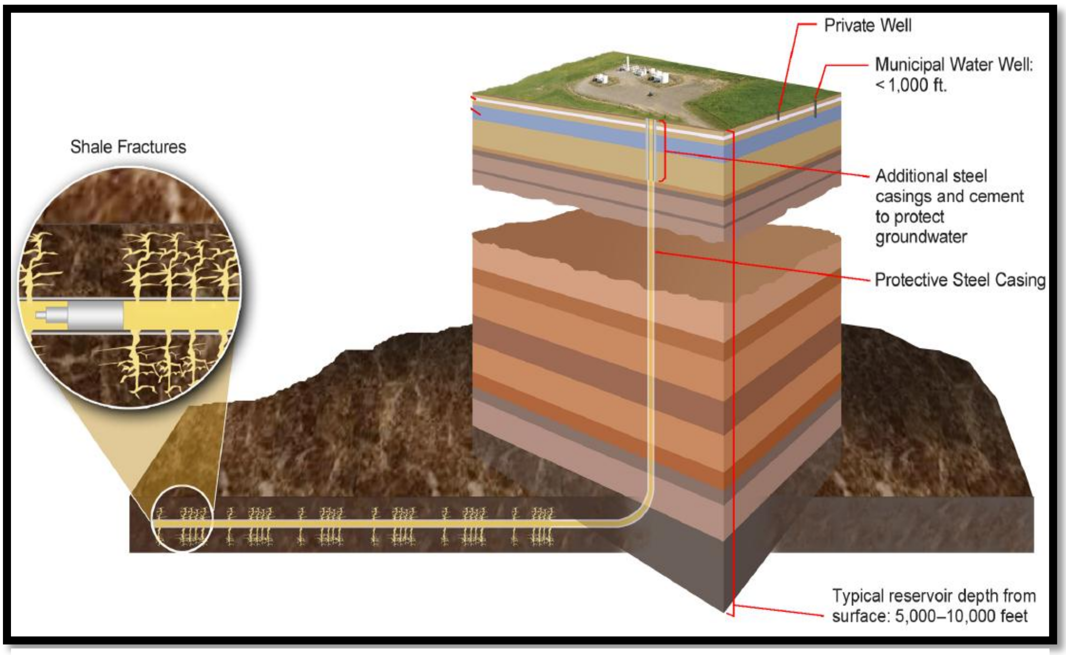


FIGURE 3: Illustration of Shale Fractures in Horizontal Well
(Source: Eawag Aquatic Research, 2013)

Hydraulic fracturing is a preferred technique for extracting shale gas and helps to raise the rates of production and the total recovered amount of shale gas (Perry, 2010 and Legs Resources, 2011). Hydraulic fracturing is a technique of injecting the pressurized fluids that generally contain of water and sand to create the fractures in shale formations. The purpose of sand injected with the fluids is to hold the fractures open. The injection of fracturing fluids needed to reached production zone and the injection is continuous until the pressure inside the well exceeds the rock strength and leads the fractures of the shale (Shurr and Ridgley, 2002). The hydraulic fracturing technique typically required high amount of water which is about 3–4 million gallons or equals to 71,000–95,000bbl per shale gas well (Arthur et. al, 2008).

By referring to the specific geologic formation and structure, pressure of formation and the well target, the fracturing fluids composition, volume and types are chosen (Perry, 2010). Broderick et. al, (2011) mentioned many factors will influence the fracturing fluid to be used including the sensitivity of the reservoir's clay to water and the way reservoir respond to certain fluids.

2.2.1 Flowback water

After performing hydraulic fracturing technique, shale gas production is started. When production started, there will be fluids that will flow back to the surface which is called as flowback water. The flowback water that returns from shale gas wells is consist of produced water and some percentage of fracturing fluids that are mix together (Eawag Equatic Research, 2013). (Broderick et. al, 2011 and Perry, 2010) notes that the percentage of flowback water from fracturing fluids is reported in the range between 9% and 35%. The existences of this flowback water can lead to the occurring of corrosion of the downhole equipment especially the production casing by react with the impurities such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S).

2.2.2 Reservoir Impurities

Impurities such as CO_2 and H_2S that exists in the shale well are contributed from the reservoir itself and often produce together with the shale gas. For examples, in the Horn River Basin, the shale gas contains around 12% of CO_2 (Environment Canada's Greenhouse Gas Division, 2008) and in the Horton Bluff Group of Nova Scotia, the CO_2 contents is around 5% (US Department of Energy, 2008). Actually, the presence of these impurities in the reservoir derived from the natural gases it selves such as methane and propane due to the high temperature and pressure or known as thermogenic system in the reservoir (National Board Energy, 2008). In addition, reported by Hamblin (2006), this exposure has also caused some percentage of minerals and organic matter converted to CO_2.

2.3 Corrosion

Corrosion happens when a material is reacting with its corrosive environment that leads to the damaging attack (Roberge, 2000). It is also known as a natural threat that linked to the transportation and production in industry of oil and gas (Kermani and Smith, 1997). Jones (1988) said that corrosion means the deterioration of material properties at every stage in oil and gas. Corrosion can be promoted when there is a presence of aqueous environment which could happen under many conditions during the hydrocarbon production, processing, and also in the pipeline systems (Champion Technologies, 2012).

During the production of shale gas, there will be the presence of flowback water which consists of water that produced from reservoir and return fracturing fluid. Many impurity products which are corrosive carried during oil and gas production (Lusk et. al, 2008). The presence of liquid water phase containing acidic gases which are CO_2 and H_2S can be the basis for occurring of harsh corrosion problem in gas production pipelines (Rendon and Alejendre, 2008). Basically, the types of corrosions that may threaten the production casing of shale gas well are CO_2 corrosion and H_2S corrosion.

CO_2 corrosion happens when CO_2 dissolves in water and carbonic acid (H_2CO_3) formed. Thus, the acid formed will cause the pH to be low and general corrosion or pitting corrosion of carbon steel will be promoted (American Petroleum Institute, 2011). General corrosion or also known as uniform corrosion is a type of corrosion damage in which the metal surface is attacked evenly over a large portion of the total area or it also can attack the entire surface area (Roberge, 2000). Thinning of general corrosion will take place until failures occur but this type of corrosion damage is easy to be predicted and measured. Pitting corrosion is a type of corrosion damage which the metal surface will severely be attacked at only small areas that cause deep pits to form. This corrosion damage is a process of stochastic which is quite hard to predict and it is often related to failures of pipeline.

Sulphide Stress Cracking (SSC), Stress Corrosion Cracking (SCC), Hydrogen Induced Corrosion (HIC) are the several types of damage that result due to the presence of wet H_2S environments. Sulphide Stress Cracking (SSC) is known as cracking of metal in the presence of water and H_2S, and SSC usually happen when there is combination action of corrosion and tensile stress. SSC results from absorption of atomic hydrogen that is produced by the sulphide corrosion process on the metal surface and SSC is actually a form of hydrogen stress cracking (American Petroleum Institute, 2011).

Stress Corrosion Cracking (SCC) is defined as the growth of crack formation in a corrosive environment. Cracking of metal involves anodic processes of localized corrosion and tensile stress in the presence of water and H_2S. At high temperature environment, unexpected sudden failure subjected to a tensile stress could happen due to SCC especially for ductile metals (ASM International, 1997). Hydrogen induced cracking (HIC) known as the internal cracks in which hydrogen atom diffuses into a metallic structure. Hydrogen atom is the smallest atom, so it is easily can be diffuse into the metal structure especially at elevated temperature in which the solubility of hydrogen is increased. When hydrogen atom is dispersed into the metal, internal pressure is created it will further elevate up to the period in which makes the metal lose its mechanical properties such as tensile strength and ductility. Finally, it will reach to the point of cracking, or HIC (Corrosionpedia, 2010).

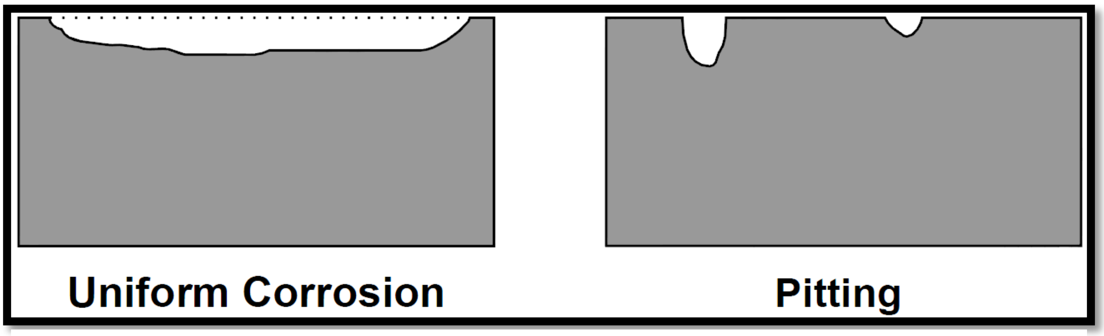


Figure 4: Visual illustration of Uniform and Pitting Corrosion
(Sources: Roberge, 2009)

Figure 5: Leak due to Pitting Corrosion in a pipe line
(Sources: Roberge, 2009)

Figure 6: Pitting Corrosion
(Sources: Roberge, 2009)

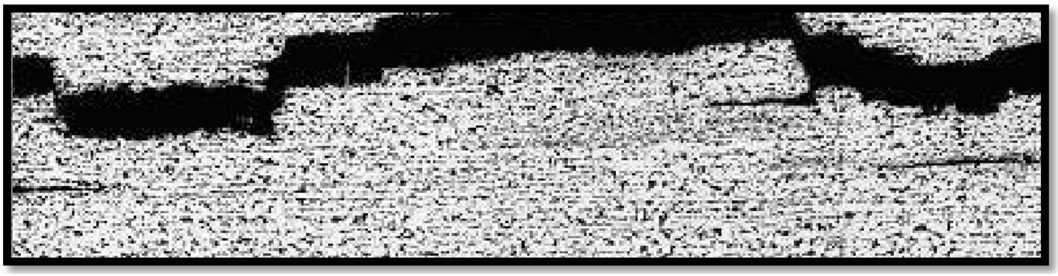


Figure 7: Hydrogen Sulphide Cracking (HIC)
(Sources: Roberge, 2009)

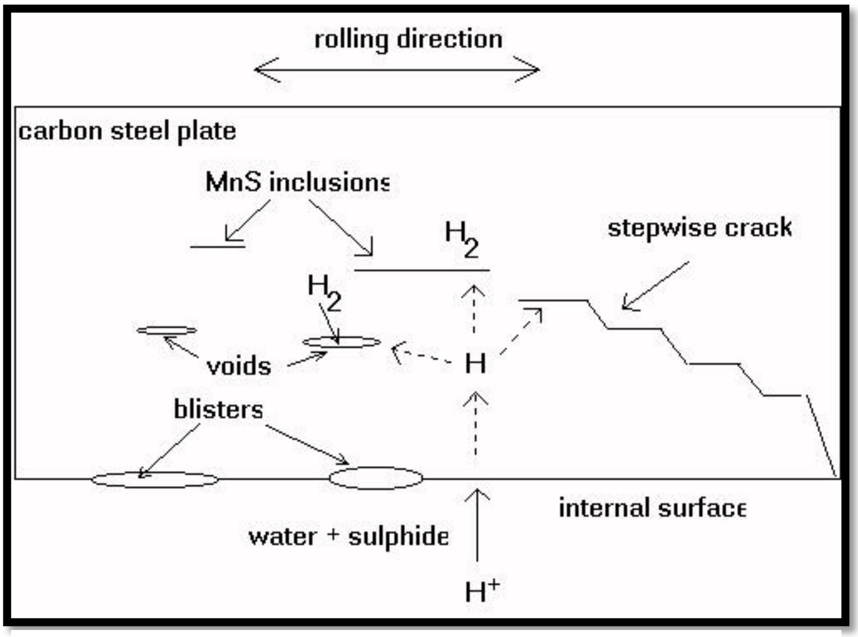


Figure 8: Hydrogen Sulphide Cracking (HIC) mechanism
(Sources: American Petroleum Institute, 2011)

2.3.1 CO_2 Corrosion

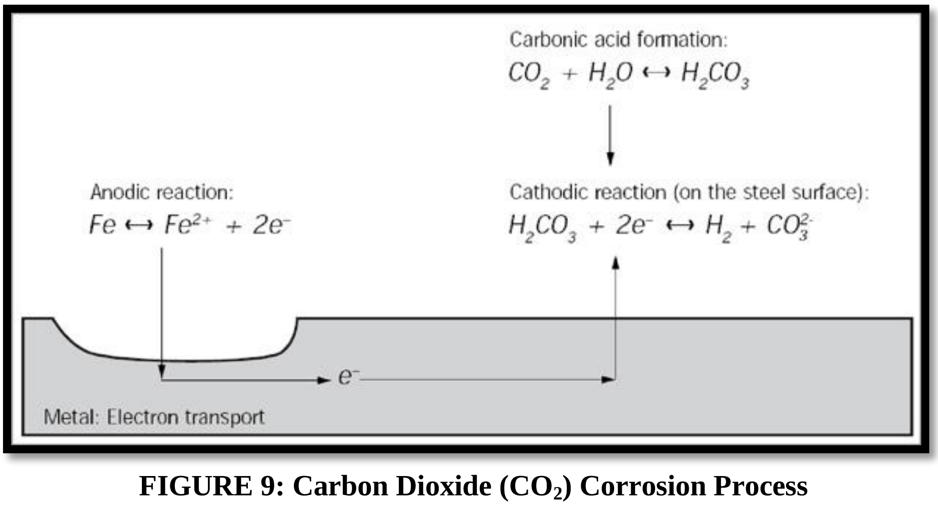


FIGURE 9: Carbon Dioxide (CO_2) Corrosion Process
(Source: IEA Greenhouse Gas R&D Programme, 2009)

CO_2 corrosion is one of the main corrosion problem and the most analyse corrosion in the industry since many years before (Zhao et al., 2009). Basically, this is due to the fact that there are some amounts of CO_2 produced from hydrocarbon reservoir (Koteeswaran, 2010). As CO_2 is one of the key agents for the occurrence of corrosion, the anxiety with this type of corrosion is it can disrupt the production of oil and gas including the shale gas production by causing failure on the downhole equipment such as production tubing (Gray et al., 1990). CO_2 at the dry condition is not corrosive unless it is in an aqueous environment as shown in equation 1 known as dissolution:

$$CO_{2(g)} \rightarrow CO_{2(aq)} \text{ [1]}$$

During the extraction shale gas, this aqueous environment is created due to the presence of flowback water. When the content of the flowback water is mixed with contaminants such as carbon dioxide (CO_2), this could results in the occurring of internal corrosion. The main reactions for CO_2 and water to form CO_2 corrosion is the reaction of dissolution and hydration. Hydration is a process of CO_2 mix with the water to form carbonic acid (H_2CO_3) as shown in equations 2 (Hunnik et. al, 1996):

$$H_2O + CO_2 \rightarrow H_2CO_3 \text{ [2]}$$

After the formation of carbonic acid (H_2CO_3), dissociation processes will take place which will disassociate the H_2CO_3 into bicarbonate and carbonate as in equations 3 and 4:

$$H_2CO_3 \rightarrow H^+ + HCO_3{}^- \text{ [3]}$$

$$HCO_3{}^- \rightarrow H^+ + CO_3{}^{2-} \text{ [4]}$$

Dissociation processes are produce the hydrogen ions (H+) as shown in equation 3 and 4 that act as oxidation agents that will induced the steel or iron (Fe) to release its electron (Hudlický and Miloš, 1996) as shown in equation [5]:

$$Fe \rightarrow Fe^{2+} + 2e^- \text{ [5]}$$

This oxidation process or known as electrochemical reaction is process of degradation of the material which happens when the metal state of the iron changes its form into ions and thus has cause depletion of the material thickness and this is called as the CO_2 corrosion. This is not only could result in internal corrosion of the pipeline due to CO_2, but this can have an adverse effect on pipeline integrity system. Thus, it needs to be addressed. The electrons that release by the iron will then gain by hydrogen ions as the cathodic reaction to form hydrogen gas (H_2) as shown in equation [6]:

$$2H^+ + 2e^- \rightarrow H_2 \quad [6]$$

The overall reaction of CO_2 corrosion is given as:

$$Fe + H_2O + CO_2 \rightarrow FeCO_3 + H_2 \quad [7]$$

From equation 7, CO_2 corrosion caused the corrosion product to formed known as iron carbonate (FeCO3) (Srinivasan and Kane, 1995). The H_2CO_3 direct reduction is as in equations 8:

$$2H_2CO_3 + 2e^- \rightarrow H_2 + 2HCO_3^- \quad [8]$$

Even though the studied about CO_2 corrosion have been done in many years, until now, it is still not recognized yet between equations 7 or 8 is the actually reaction takes place at the surface of the material. As suggested by (Sun and Nesic, 2006) at higher pH, equation 8 can be considered to be important.

2.3.2 H_2S Corrosion

Hydrogen sulfide (H_2S) gas in one of the major causes that lead to the severe corrosion of downhole equipment especially in production casing. H_2S corrosion is normally electrochemical in nature (Shahid and Faisal, 2009). The H_2S gas dissociation products can catalyse the electrochemical reactions because of its aggressiveness, especially when it comes to the dissolution of Fe. Formation of iron sulphide (FeS) film is generated as the corrosion product due to the reaction between H_2S and Fe in the downhole equipment:

$$Fe + H_2S \rightarrow FeS + H_2$$

The uniform characteristic of H_2S corrosion of steel has been studied by Sun and Nesic (2006) in the way to predict the corrosion rate over time at pH 5.0–5.5. Based on their report, an increase in H_2S gas concentration will cause corrosion rate to increase but after 24 hours the rate is lower compared to 1 hour because of the protective FeS film has been formed. Also reported by Shahid and Faisal (2009), increasing in gas concentration lead to an increase in corrosion rate.

During shale gas production, the presence of H_2S define vital problem to the shale gas production facilities such as the casing as it can cause the H_2S corrosion. The acid that forms by dissociation of H_2S gas is approximately 3 times weaker than carbonic acid. It is because H_2S gas is less soluble than CO_2 gas (Ma et al, 1999). Hence, the H_2S which in dissolved state do not needed to go through the slow hydration process (Shoesmith et al., 1980). During the occurrence of H_2S corrosion, hydrogen ions are also act as the oxiding agents to promote the iron to undergo the anodic reaction release the electron and become Fe^{2+}.

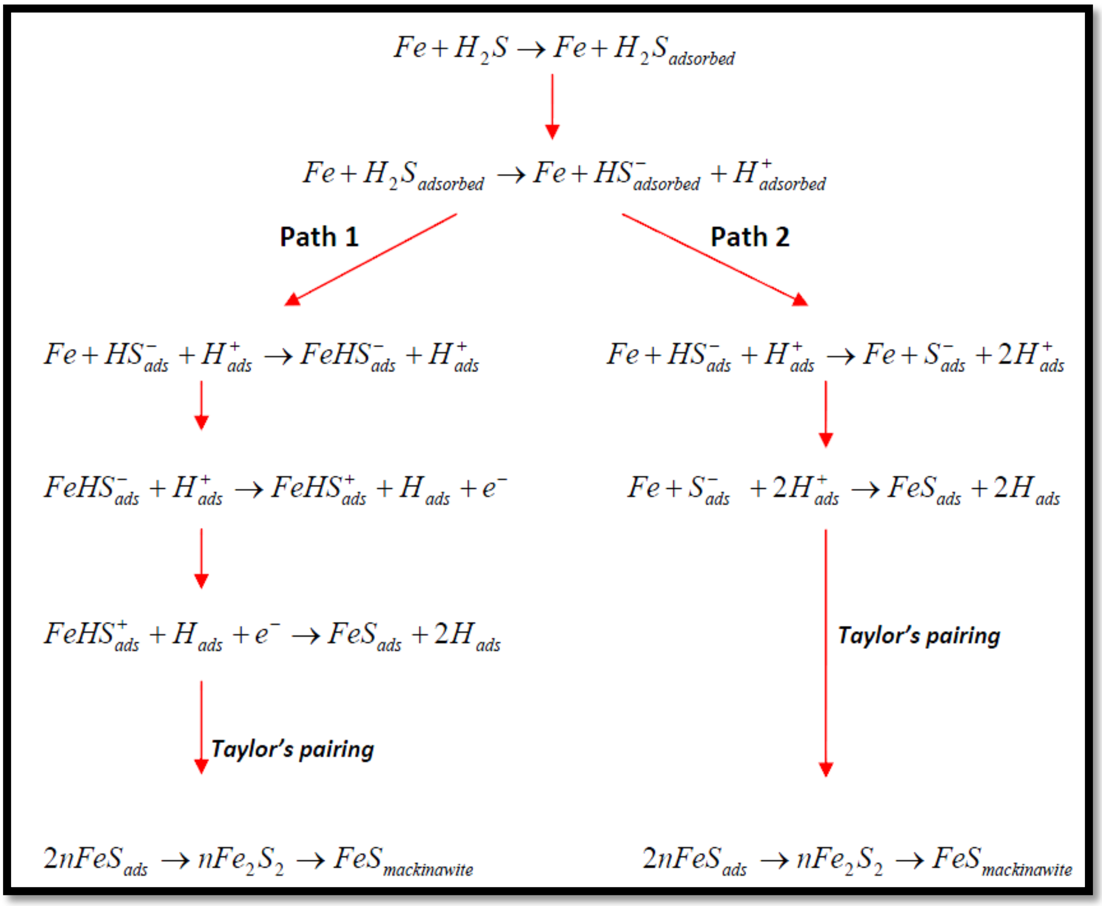


FIGURE 10: Mechanism of H_2S corrosion on Iron (Fe)
(Sources: Koteeswaran, 2010)

2.3.3 Factors affecting the corrosion rate

Reservoir conditions are the main factors that affecting the rates of corrosion inside the production casing during the production shale gas. These factors that can affect the rate of corrosion are such as temperatures and pressures. As the depth of reservoir increase, the temperature and pressure is also increase.

1) Effect of Temperature

In CO_2 corrosion, the chemical reaction will accelerate as the temperature increases. In addition, the rate of precipitation is proportional to the temperature. In precipitating the iron carbonate (FeCO3), some literature has stated that the high pH or temperature will accelerate rate of carbonate precipitates (Koteeswaran, 2010). Temperature effect on corrosion rate is depends on the solubility of protective films.

For example, protective films of $FeCO_3$ is not form at low pH, so as the temperature increases corrosion rate is also increase. This is because there is no barrier to protect the material surface from corrosion attack. However at high pH, increases in temperature will cause the corrosion rate to decrease due to the form of iron carbonate ($FeCO_3$) which acts as the barrier to prevent the corrosion to take place at the material surface (Hunnik et. al, 1996).

Meanwhile, the effect of temperature on H_2S corrosion has less influence the rate of corrosion. H_2S corrosion rate dependency on the temperature is very low. It also does not expect to have an effect at longer exposure times. Sun and Nesic (2007) has proposed that the presence of iron sulphide (FeS) scale is significant as it mainly controlled the H_2S corrosion rate.

2) Effect of Pressure

A high pressure will cause the partial pressure to be high. As the pressure inside the reservoir increases, it will cause the partial pressure of CO_2 and H_2S to increase. Internal corrosion are also significantly affected by the system pressure inside the well as the solubility or the partial pressure of corrosive acid gases such as H_2S and CO_2 increase as the system pressure is increase (Kritzer et. al, 1999).

So, basically pressure is not directly affect the corrosion rate but it will affect the partial pressure of those impurities. Then due to the increasing of the partial pressure, it will affect the rates of corrosion inside in the tubing.

At particular temperature, the partial pressure of the gas will determine the amount of gas dissolves (Dugstad et. al, 1994). Since the partial pressure of CO_2 is determined by the amount of CO_2, thus the lower CO_2 partial pressure the higher the corrosion resistance. At the conditions without the presence of protective film such as at high temperature and low pH, increasing the partial pressure of acid gases will lead to the increasing of the concentration of acidic condition which is could results in increasing the rate of corrosion. For example, when CO_2 partial pressure increase, it would cause concentration of H_2CO_3 in solution to increase thus helps in the increasing of the corrosion rate of carbon steel. However, at conditions of favourable forming of protective film which is at high temperature and pH, it gives an opposite effect which is by increasing the rate of $FeCO_3$ precipitation helps in reducing the rate of corrosion.

2.3.4 Corrosion Mitigation Methods

In order to mitigate corrosion of pipelines and due to safety reasons, impurities products that are classified as acid gases such as H_2S and CO_2 need to be detached from the gas flowline (Environment Canada's Greenhouse Gas Division, 2008). The mitigation method of corrosion can be done by using several methods such as select appropriate material of production casing and choose suitable corrosion inhibitor to be injected into the well.

2.4 Selection of Piping Materials

To control the corrosion in shale gas well, selecting the suitable material for the downhole equipment especially the casing is vital as the types of material are also the reason why corrosion is occurred. Usually, the type of pipeline materials is selected at the design stage. As the Carbon and Low Alloy Steel (CLAS) or known as the carbon steel is easily attacked by corrosion especially corrosion with the presence of CO_2, selecting Corrosion Resistant Alloy (CRA) as the casing material to produce the shale gas is seems to be a solution for mitigating the internal corrosion of the casing. In order to prevent the corrosion for a long period of time, CRAs are necessary for various types of components that exposed to corrosive environments during production (Treseder and Tuttle, 1993).

Example of CRA that can be used for this purpose is Stainless Steel. The contents of stainless steel must consist of chromium with percentage of 10.5% and iron with percentage of 50%. The 10.5% chromium content will helps to form a passive film on material surface to act as the corrosion barrier and stop the iron from any corrosion reaction (Kolts and Ciaraldi, 1996). This passive layer is composed mainly of chromium oxide and it acts to prevents oxidation of the base metal which is the iron (Craig and Smith, 2011). In extraction of natural gas applications, selecting suitable CRAs as the pipeline materials is based on corrosiveness of environment.

Applicable CRAs proposed in the oil and gas industries are:

- 13-Cr stainless steels
- Super 13-Cr stainless steels
- 22-Cr duplex stainless steels
- 25-Cr duplex stainless steels
- 28-Cr stainless steels

The resistance level of CRA to corrosion can be determined using equation of pitting resistant equivalent (PRE). The larger the PRE number, the more resistant the CRA to pitting corrosion.

Equation of Pitting Resistant Equivalent (PRE) number:

$$PRE = (\%Cr) + (3.3 * \%Mo) + (16 * \%N)$$

The compositions of chemical of the recommended CRAs and and its PRE number are show in Table 2 and Table 3.

TABLE 1: Chemical Composition of Recommended Corrosion Resistant Alloy
(Source: Craig B., & Smith L., 2011)

Alloys	Nominal Chemical Composition (%)						
	Cr	Ni	Mo	Mn	C	N	Fe
13Cr	13	0.15	0.02	0.8	0.2	-	Balance
S13Cr	13	5	2	0.5	0.025	-	Balance
22Cr Duplex	22	5	3	1	0.02	0.15	Balance
25Cr Duplex	25	7	4	1	0.02	0.28	Balance
Alloy 28Cr	27	31	3.5	1	0.01	-	Balance

TABLE 2: PRE Number of Recommended Corrosion Resistant Alloy

Alloys	Chemical Composition (%)			Pitting Resistant Equivalent (PRE) Number
	Cr	Mo	N	
13Cr	13	0.02	-	13
S13Cr	13	2	-	19.6
22Cr Duplex	22	3	0.15	34.3
25Cr Duplex	25	4	0.28	42.7
Alloy 28Cr	27	3.5	-	38.55

2.5 Economic Analysis

Optimizing the selection of material for downhole equipment can helps in reducing the life cycle cost of the materials used and this can be done by matching the characteristic of the environment with the characteristics of the materials (Hill et. al, 1989). Using corrosion resistant alloy or carbon steels materials for the downhole equipment such as production casing, a comprehensive and complete economic analysis is needed. The economic analysis is involving the process of evaluating material cost, installation cost, maintenance cost which including the labor cost and replacement cost (Parker Hannifin Corporation, 2008). The replacement cost is the cost of replacing the material of the downhole equipment after several years hydrocarbon has been produced from the well and it is subjected to the materials that have the life expectancy shorter than the well production life time (Redmond et. al, 1987).

For initial installation, selecting a more expensive material for the downhole equipment of shale gas well is actually a good investment as this selection can be a low-cost and trouble free solution especially for the well with medium and long life expectancy. Also, low cost material should be avoided because this type of material need to be replaced after sometimes and this will involve the consideration of the replacement cost of the equipment, new systems re-qualification, depreciation, low production rates during replacement period, and environmental loss. Other benefits of using an excellent construction material of the downhole equipment are lessening the probability of downtime due to the material corrosion and also improved the reliability of that equipment (Redmond et. al, 1987). Compared to carbon steels, the initial cost of the downhole equipment of shale gas well constructed of corrosion resistant alloy are usually higher but in terms of life cycle cost analysis, the use of corrosion resistant alloy is frequently appear to be substantially less than the life cycle cost of the carbon steels especially for longer shale gas well as the carbon steels materials have a shorter life expectancy in corrosive environment compared to the corrosion resistant alloy materials (Redmond et. al, 1987).

From this, the practicality of using high corrosion resistant alloy as the material of the downhole equipment for corrosion control appeared to be reasonable. To assist with the feasibility of lifecycle cost analysis of pipeline studies incorporating the use of corrosion resistant alloys, table 3 shows the example of comparison between two types of the materials. From Table 3, it shows that rather investing in a cheap material, investing in an expensive material today could be cheaper in a medium and long period of time as the more expensive material saved up to 40% life-cycle cost compared to the cheaper one.

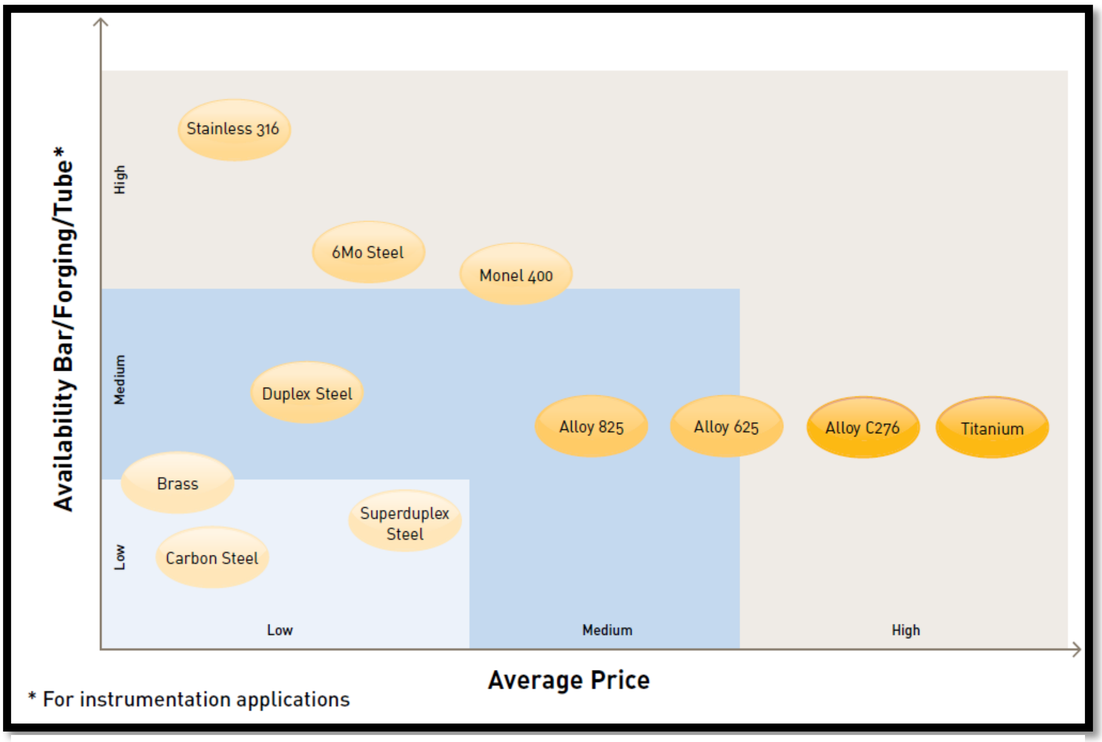


Figure 11: Materials average price comparison
(Sources: Parker Hannifin Corporation, 2008)

Table 3: Example of a typical installation and associated life cycle cost of CRA
(Sources: Parker Hannifin Corporation, 2008)

		Materials Selection A: Stainless Steel 316	Materials Selection B: Superaustenitic 6Mo
After 10 Years	8,000 meters of 1/2" x 0.065" tubing	$7/m	$23/m
	1,500 Fittings 1/2" x straight shapes	$15/unit	$40/unit
	Design Parameter	5 Years Life	15 Years Life
Initial Installation	Tubing & Fitting Replacement**	Tube: $7/m Fitting: $15/unit	$0
	MHR Labour Cost	40 MHR per 300 meters	$0
		$80 labour/hour	$0
After 5 Years	Tubing & Fitting Replacement**	Tube: $7/ft Fitting: $15/unit	$0
	MHR Labour Cost	40 MHR per 300 meters	$0
		$80 labour/hour	$0
TOTAL		$406,380	$244,000

CHAPTER 3

RESEARCH METHODOLOGY AND PROJECT ACTIVITIES

3.1 Research Methodology

In this project, Electronic Corrosion Engineer (ECE) software is used for the assessment of corrosion and material selection for the downhole equipment of shale gas reservoir. ECE software is generally used to predict the rates of corrosion quantitatively and to select the suitable materials for oil and gas production and processing facilities including downhole segment. Model used for corrosion analysis and material selection in ECE software is definitely based on laboratory data and field calibration studies both downhole tubing and surface facilities. In details for this project, the software will be used to:

- **Predict corrosion rates** in both sour and sweet corrosive conditions.
- **Predict failure risk** of carbon steel as the downhole equipment.
- **Evaluate Corrosion-resistant alloy (CRA)** by selecting the most appropriate alloys to be used as the downhole equipment for the specific conditions of shale gas reservoir which involving the risks of corrosion.
- **Calculate life cycle cost** of carbon steel and corrosion-resistant-alloys (CRA) based on net present value by evaluate and compare the cost of these types of material.

The results obtained from the software can be used in order to know the severity of the corrosion based on the corrosion rate and to show which material is the most suitable to be used in to mitigate corrosion in production casing during the production of shale gas. The required field data or operating data that is need to be put in the software is based on the general characteristics of Horn River Basin and Deep Basin of Western Canada which is a shale gas region. In obtaining the rates of corrosion, the input parameter of temperature, pressure, crude oil/condensate flowrate and API gravity, gas and water flowrate, steel size must be constant and for manipulated input parameter will be the gas composition of CO_2 and H_2S.

The data that to be put in the ECE software is as following:

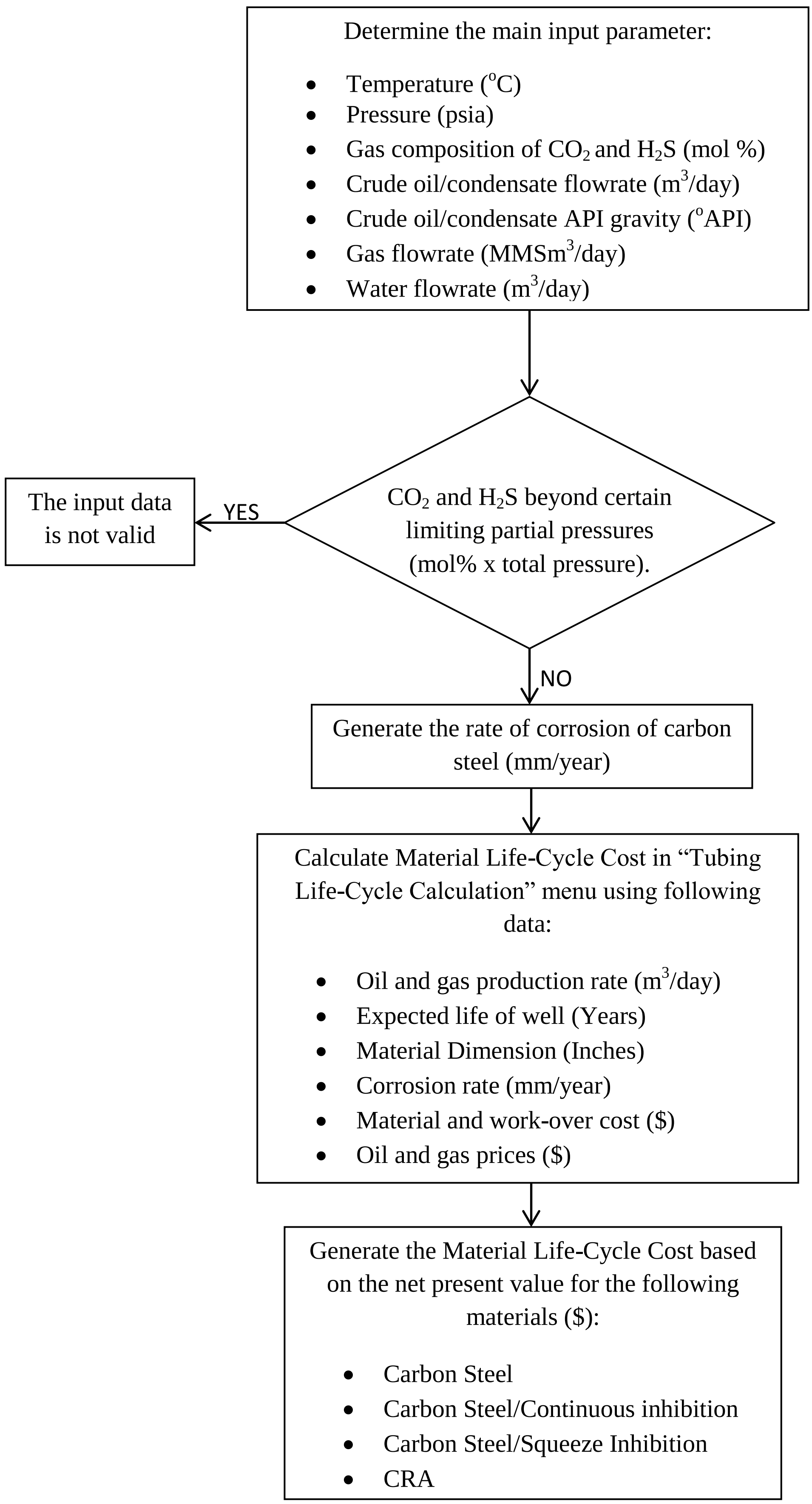
- Temperature (^oC)
- Pressure (bar)
- Gas composition of CO_2 and H_2S (mol %)
- Crude oil/condensate flowrate (m^3/d)
- Crude oil/condensate API gravity (^oAPI)
- Gas flowrate ($MMSm^3/d$)
- Water flowrate (m^3/d)

Table below are the input data of shale gas reservoir conditions taken from field data of Horn River Basin and Deep Basin of Western Canada which used in the Electronic Corrosion Engineer (ECE) software.

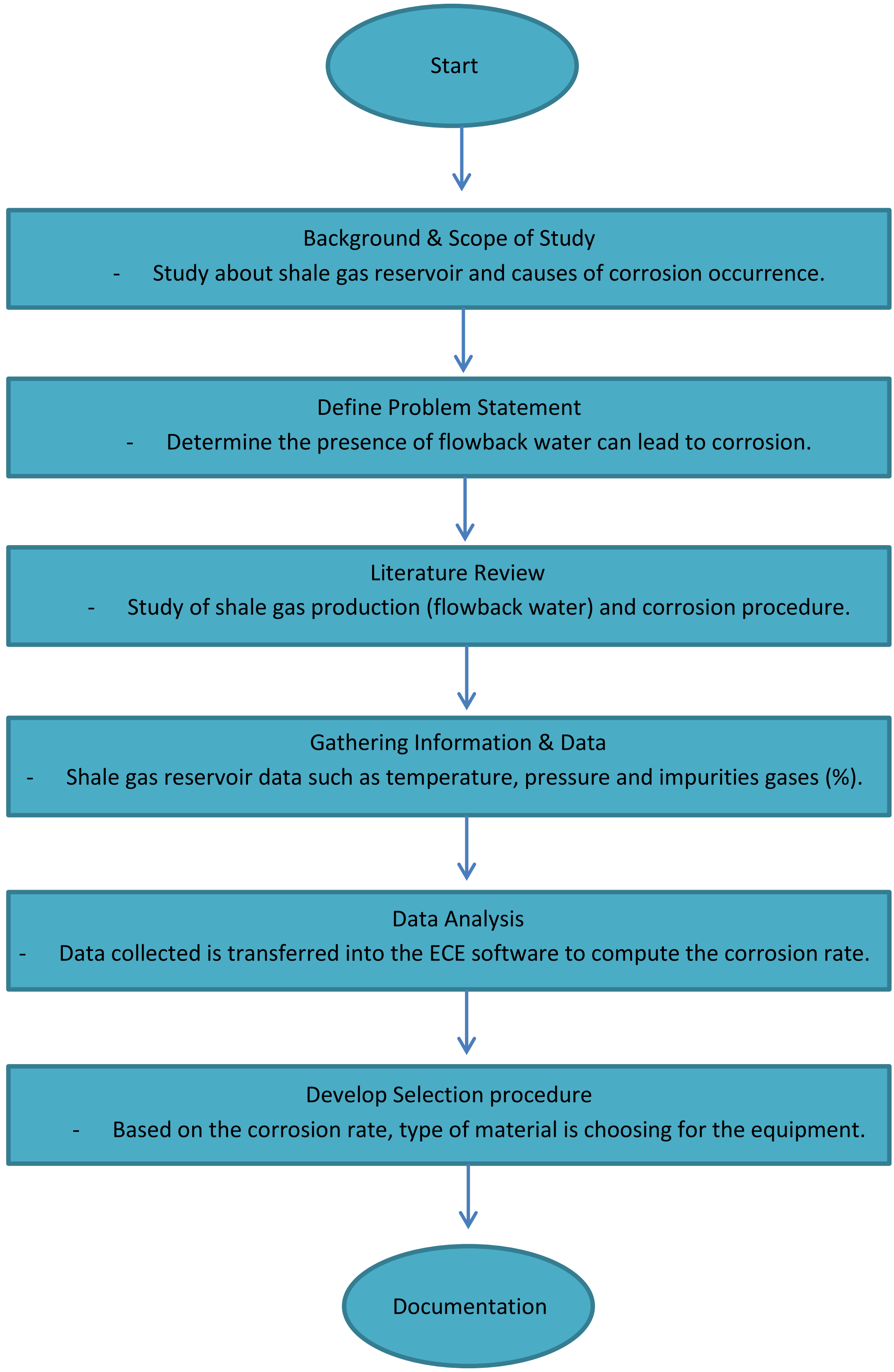
Table 4: General Characteristics of Horn River Basin and Deep Basin

Gas (e^3m^3/day)	Water (m^3/day)	Condensate (m^3/day)	H_2S (ppm)	CO (%)	Chloride (ppm)	Temperature (°C)	Pressure (kPa)
DEEP BASIN							
1-500	1-3	0	≤ 2500	≤ 21	100-25,000	50-120	2,000-28,000
HORN RIVER BASIN							
40 - 226	0.3 - 103	0	≤ 128	≤ 21	10 – 21,000	35 – 175	2,000 - 44,000

Electronic Corrosion Engineer (ECE) Software Procedure



3.2 Project Activities



3.3 Gantt Chart

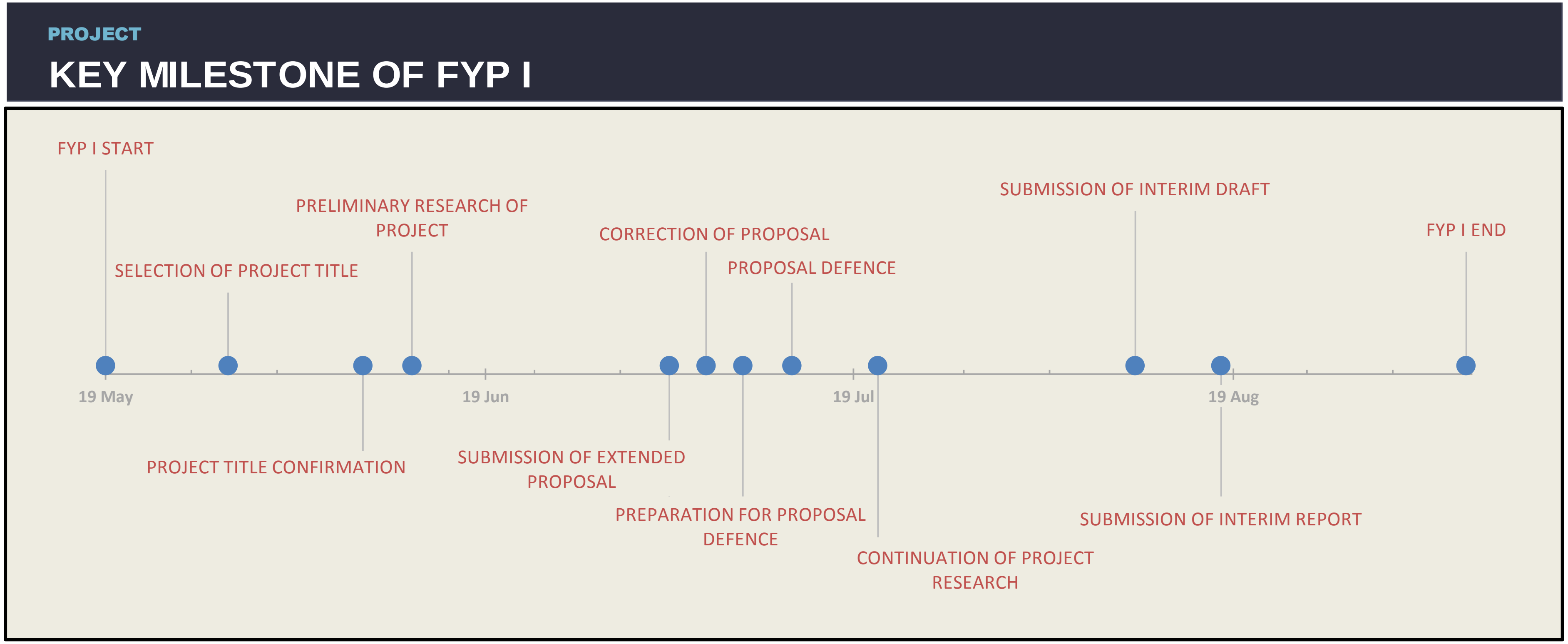
Table 5: Gantt chart of Final Year Project I

No.	Description	Week													
		1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Selection of Project - Choosing the topic of Final Year Project.														
2	Preliminary Research Work - Start finding some reference paper that related to the topic.														
3	Submission of Extended Proposal - Submit report that consists of introduction, literature review, and research methodology.														
4	Proposal Defence - Presentation of project progress.														
5	Project Work Continues - Finding method for project research.														
6	Submission of Interim Draft														
7	Submission of Interim Report - Report consists of introduction, literature review, research methodology and summary of project progress.														

Table 6: Gantt chart of Final Year Project II

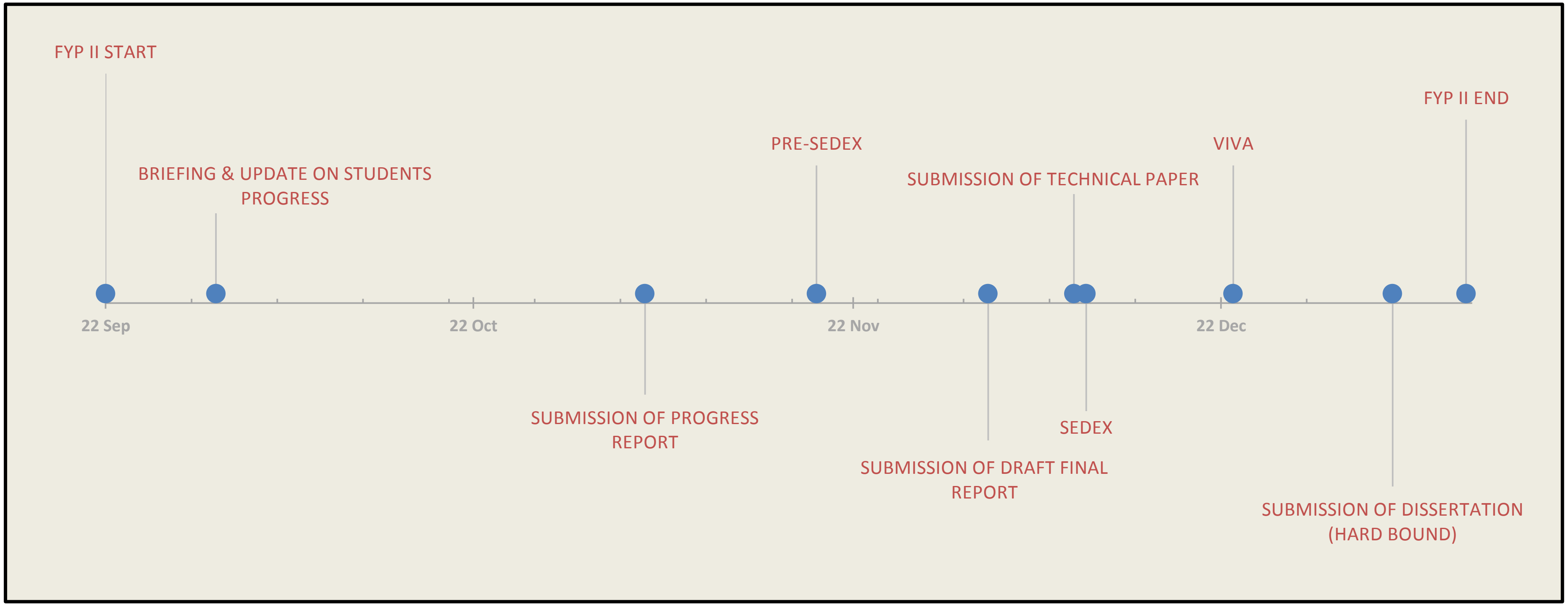
No.	Description	Week															
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
1	Project Work Continues - Start finding the software to be used for the project.																
2	Submission of Progress Report - Report consists of abstract, introduction, literature review, research methodology, result and discussion, and conclusion and recommendation.																
3	Project Work Continues - Continue to use ECE software for the project.																
4	Pre-SEDEX - Poster presentation based on results obtained.																
5	Submission of Draft Final Report - Report consists of abstract, introduction, literature review, research methodology, full results and discussion, and conclusion and recommendation.																
6	Submission of Technical Paper - Journal paper.																
7	Viva - Final presentation about project results.																
8	Submission of Project Dissertation (Hard Bound)																

3.4 Key Milestone



PROJECT

KEY MILESTONE OF FYP II



CHAPTER 4

RESULTS AND DISCUSSION

4.1 Corrosion Rate

The results of corrosion rate of Deep Basin are presented in Figure 12 and 13 while results of corrosion rate of and Horn River Basin are presented in Figure 14 and 15. The condition of Deep Basin is sweet condition and condition of Horn River Basin is sour condition. Sweet condition is an environmental condition without the presence of H_2S gas while sour condition is an environmental condition with the presence of significance amount of H_2S gas. The summaries of corrosion rate analyses for both samples were performed. The analysis was conducted with an assumption of 9800 feet of tubing length, 3.504 inches of tubing outer diameter and the type of material used is carbon steel with 0% and 1.2% of chromium content. The expected life of well is also assumed which is 15 years.

For Deep Basin that used carbon steel with 0% of chromium content as the production tubing material, it can be seen that with the presence of 21% mole of CO_2 and 0% mole of H_2S, the corrosion rate increased as the tubing length is increased. This indicate that the deeper the tubing, the higher the corrosion rate. The corrosion rates increased from 1.32 mm/year at 0 feet tubing up to 3.55 mm/year at 9800 feet tubing. Meanwhile for Deep Basin that used carbon steel with 1.2% of chromium content as the production tubing material, the corrosion rate also increased as the tubing length is increased with the same amount of CO_2 and H_2S presence during the production which are 21% mole and 0% mole respectively. This also proved that the deeper the tubing, the higher the corrosion rate. The corrosion rates increased from 0.37 mm/year at 0 feet tubing up to 0.97 mm/year at 9800 feet tubing which is less than the corrosion rates of carbon steel without chromium content.

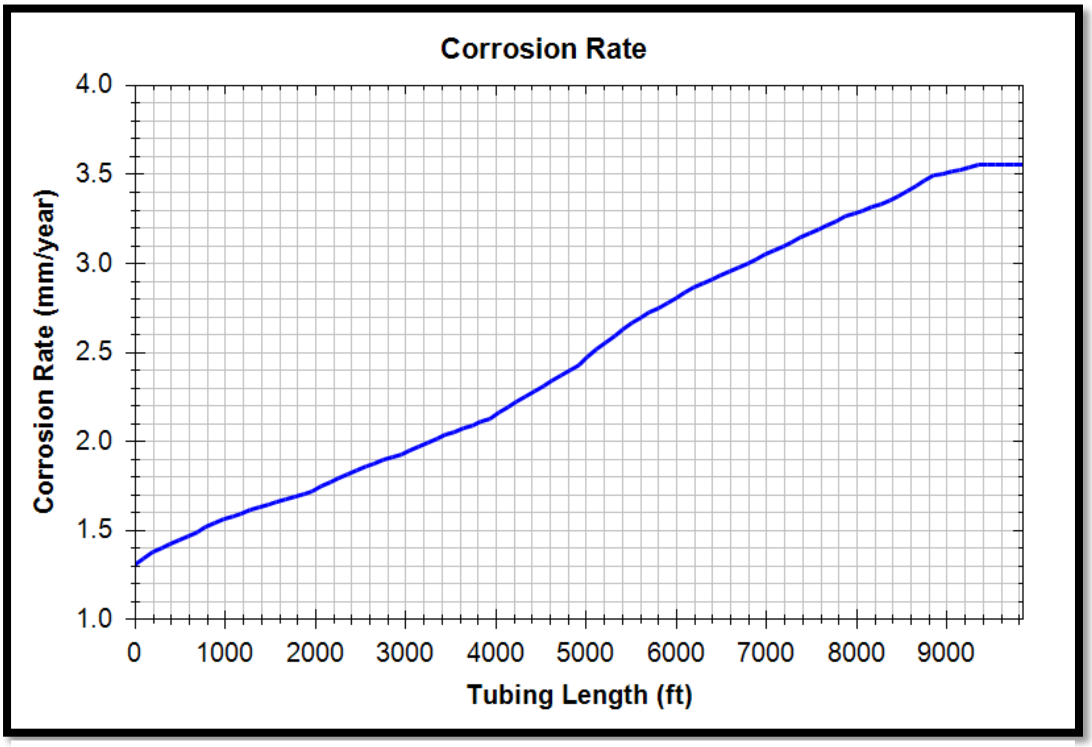


Figure 12: Corrosion rate of carbon steel with 0% chromium content of Deep Basin shale gas well

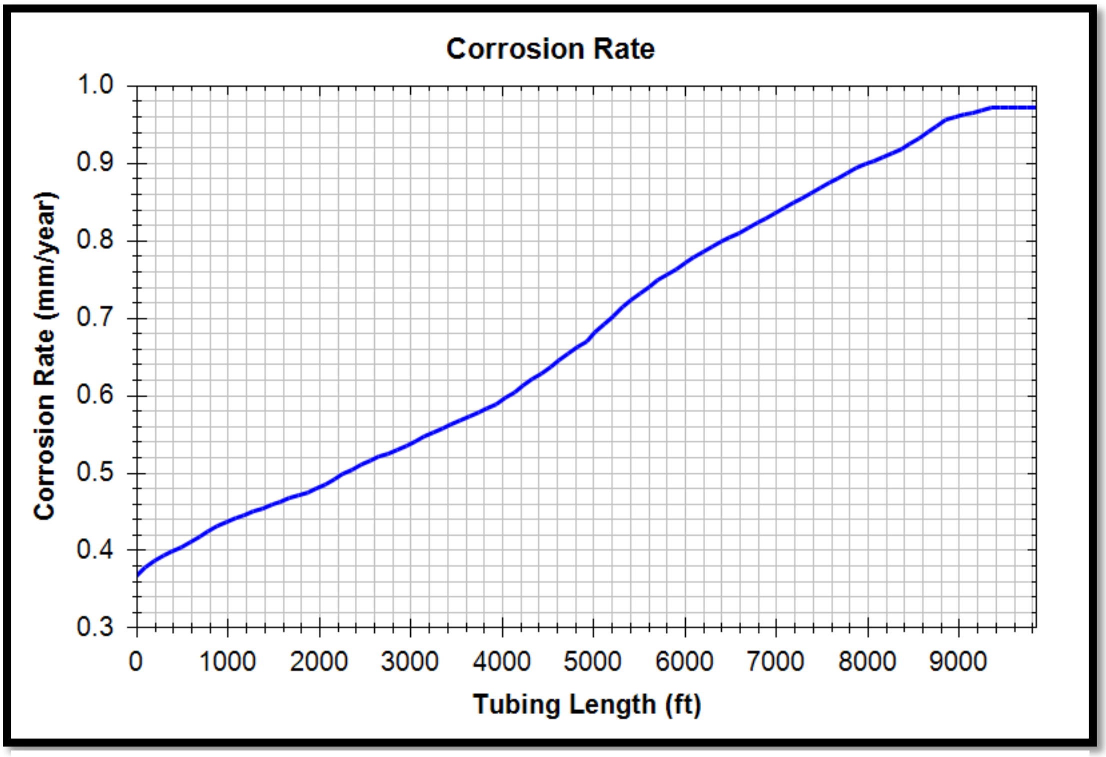


Figure 13: Corrosion rate of carbon steel with 1.2% chromium content of Deep Basin shale gas well

Generally, the type of corrosion that occurs in the shale gas well of Deep Basin is CO_2 corrosion and the CO_2 corrosion rate in this environment is taken as a possible rate of general corrosion and pitting corrosion as shown in the graph. This is because the rate of pitting attack is typically reported to be similar to the rate of CO_2 corrosion and when there is no presence of sulfide films or the films is break down, then the form of corrosion which takes place is pitting corrosion.

For Horn River Basin, significant amount of H_2S gas is presence during the production of the shale gas which is 0.25% mole. For corrosion rate analysis using carbon steel with 0% of chromium content as the production tubing material, it can be seen that the corrosion rate increased as the tubing length is increased which is the similar behavior as the corrosion rates in the shale gas well of Deep Basin. This also indicate that the deeper the tubing, the higher the corrosion rate. The corrosion rates increased from 2.21 mm/year at 0 feet tubing up to 4.8 mm/year at 9800 feet tubing.

Meanwhile for Horn River Basin that used carbon steel with 1.2% of chromium content as the tubing material, the corrosion rate also increased as the tubing length increased and the amount of CO_2 presence is the still the same during production of shale gas which is 21% mole. The corrosion rates increased from 0.38 mm/year at 0 feet tubing up to 1.00 mm/year at 9800 feet tubing which is less than the corrosion rates of carbon steel without chromium content. From both corrosion rates analysis of Horn River Basin, this also proved that corrosion rate will be higher as the depth of the well is deeper. The types of corrosion that occurs in the shale gas well of Horn River Basin are CO_2 corrosion and H_2S corrosion due to the presence of both impurities gases during the shale gas production. The graph also shows that general and localized pitting corrosion are occurred.

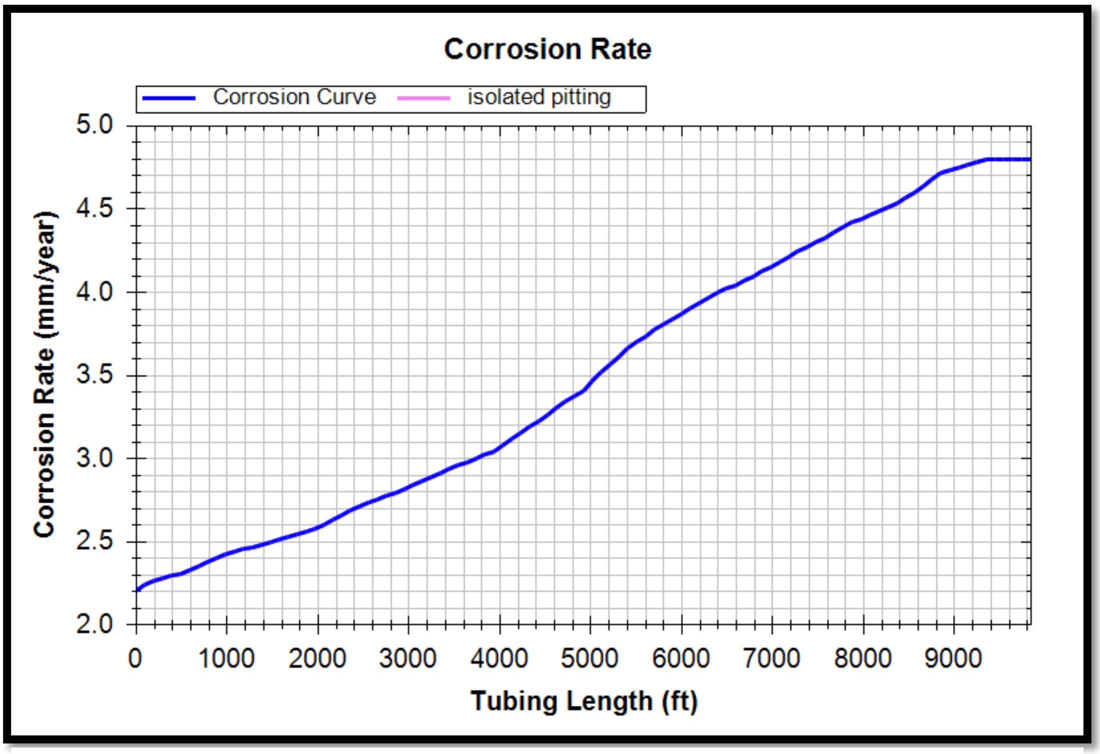


Figure 14: Corrosion rate of carbon steel with 0% chromium content of Horn River Basin shale gas well

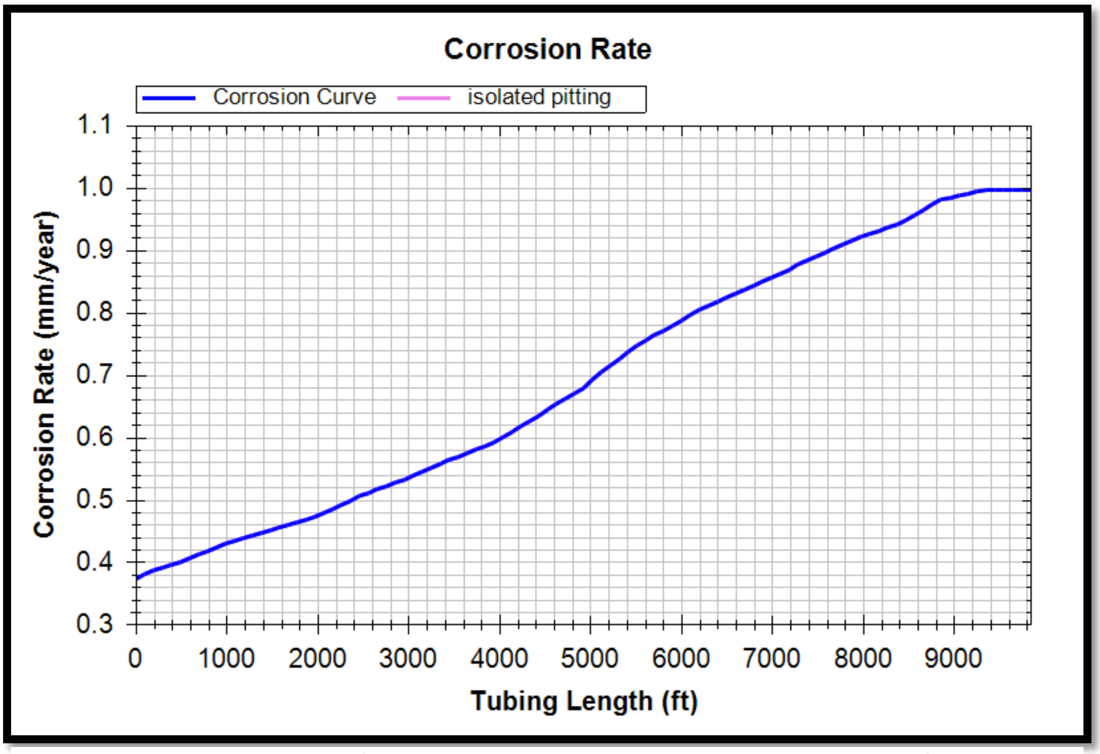


Figure 15: Corrosion rate of carbon steel with 1.2% chromium content of Horn River Basin shale gas well

The results obtained based the graph presented above for both wells are summaries in the table below:

Table 7: Corrosion rate of Deep Basin

Chromium content (%)	Corrosion Rate (mm/year)	
	Minimum	Maximum
0	1.32	3.55
1.2	0.37	0.97

Table 8: Corrosion rate of Horn River Basin

Chromium content (%)	Corrosion Rate (mm/year)	
	Minimum	Maximum
0	2.21	4.8
1.2	0.38	1.00

Based on the results obtain from both wells, it can be seen that the corrosion rate of the tubing that used carbon steel with 1.2% chromium content as the tubing material is normally less compared to corrosion rate of tubing that used carbon steel with 0% chromium content. This is because according to the research, the presence of chromium element in the carbon steel will helps in preventing the base metal which is the iron from reacting with the environment and hence corrosion reaction will not perform. The chromium element will form a passive film on top of the iron to act as the barrier between the iron and the environment. This passive layer is composed mainly of chromium oxide and it acts to prevents oxidation of the base metal. So, for this case, the some carbonic acid that forms from the reaction between flowback water and carbon dioxide were block by the chromium oxide layer from reacting with the iron and hence the process of oxidation of the base metal were not perform vigorously which then resulting in less corrosion rate of the tubing.

The severities of these corrosion rates shows that the downhole environments of Deep Basin and Horn River Basin are really corrosive and suitable material such as corrosion resistant alloy (CRA) is necessary to be used as the material of the downhole production tubing in order to mitigate the CO_2 and H_2S corrosion. The reason for the corrosion rates to increase over the length of the tubing is due to the increasing of pressure and temperature. This is because the temperature and pressure inside the well is increase with the depth of the tubing as shown in Figure 16 and 17 respectively. The effect of temperature and pressure to the rate of corrosion can be explained through the basic equation that used in the ECE software to calculate the CO_2 corrosion:

$$V_{cor} = \frac{1}{\frac{1}{V_r} + \frac{1}{V_m}}$$

Where:

$$* \log(V_r) = 4.84 - \frac{1119}{t + 273} + 0.58 \log\left(f_{CO_2}\right) - 0.34\ (pH_{actual} - pH_{CO_2})$$

$$* V_m = 2.8\ \frac{U^{0.8}}{d^{0.2}} f_{CO_2}$$

$$* \log\left(f_{CO_2}\right) = \log(pCO_2) + \left(0.0031 - \frac{1.4}{t + 273}\right) P$$

$t =$ Temperature (^{o}C)

$f_{CO_2} =$ Fugacity of CO_2 (bar); it is similar to partial pressure of CO_2

$P =$ Pressure (bar)

The rate of corrosion in the presence of H_2S is higher than without the presence of H_2S is because there are two effects of the presence of H_2S on corrosion in the ECE software model which are:

- It increases the acidity of the water
- It scavenges the dissolved Fe ions by forming Fe- sulphide precipitates, which decrease the pH and increase the corrosion rate.

These factors can slightly increase the corrosion rate under certain conditions but except at very low concentrations of H_2S, these effects are usually outweighed by significant reductions in corrosion rate due to sulphide scaling because of the presence of sulfide films. Moreover, when the dissolved iron is precipitated as FeS, this H_2S-containing environment is more acid than without the FeS film because there is no dissolved iron carbonate.

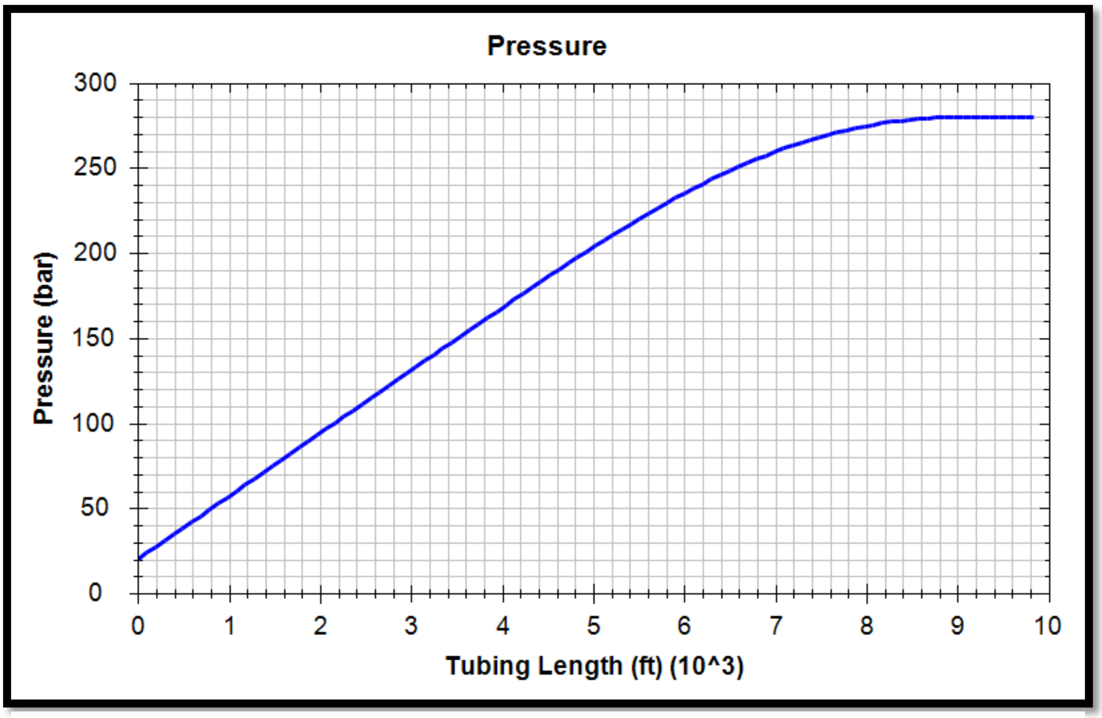


Figure 16: Pressure graph as a function of tubing length of Deep Basin and Horn River Basin shale gas well

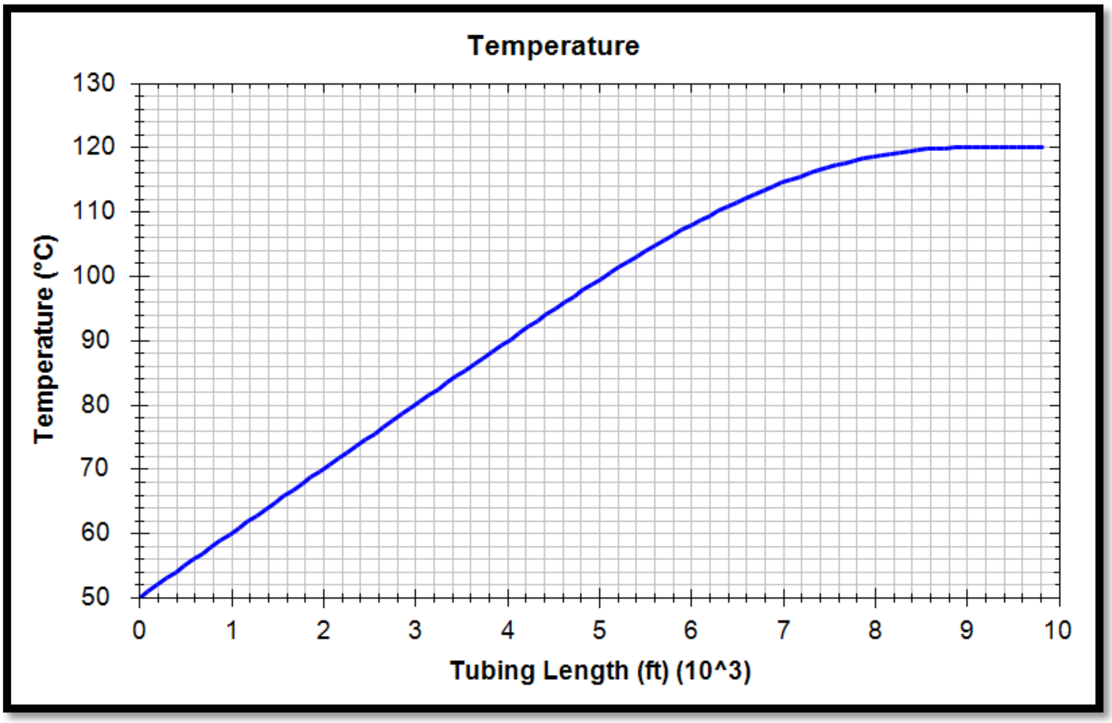


Figure 17: Temperature graph as a function of tubing length of Deep Basin and Horn River Basin shale gas well

4.2 Risk of Failure

Risk Analysis shows a graph of accumulated risk of failure vs. time (years). For its construction, it is assumed that the calculated corrosion rates have a normal distribution with a standard deviation of 25%. ECE software calculates a normal distribution curve around the maximum corrosion rate and converts this to an accumulated risk of failure by dividing into the wall thickness and integrating over time. In the presence of H_2S, the arbitrary assumption has been made that there is a 25% risk that the protective sulfide layer fails. Risk of Failure can be described as the probability of a component to fail due to the loss of mechanical properties of its material. Risk of failure is very important as it could be the technical information to measure the safety life of aging tubing and it can be assessed on the basis of the degradation of the tubing or pipelines. In other words, risk of failure is related to the resistance of the component to its loading.

With sufficient data for this project, it can be presented through the graph of risk of failure, on the average, the production tubing fails after a certain period of time. For Deep Basin that used carbon steel with 0% of chromium content as the production tubing material, it can be seen that with the presence of 21% mole of CO_2 and 0% mole of H_2S, the risk of tubing failure increased after a certain period of time usage. The risk of failure of the tubing increased up to 100% after 4 years of usage (Figure 19). Hence, the time limit of using this type of production tubing is only 4 years. For Deep Basin that used carbon steel with 1.2% of chromium content as the production tubing material, it can be seen that the risk of failure of the tubing increased up to 100% after 6 years of usage (Figure 20). Hence, the time limit of using this type of production tubing is only 6 years. At this failure risk of 100%, the production tubing must completely be removed and replace by a new production tubing in order to safely produce the shale gas.

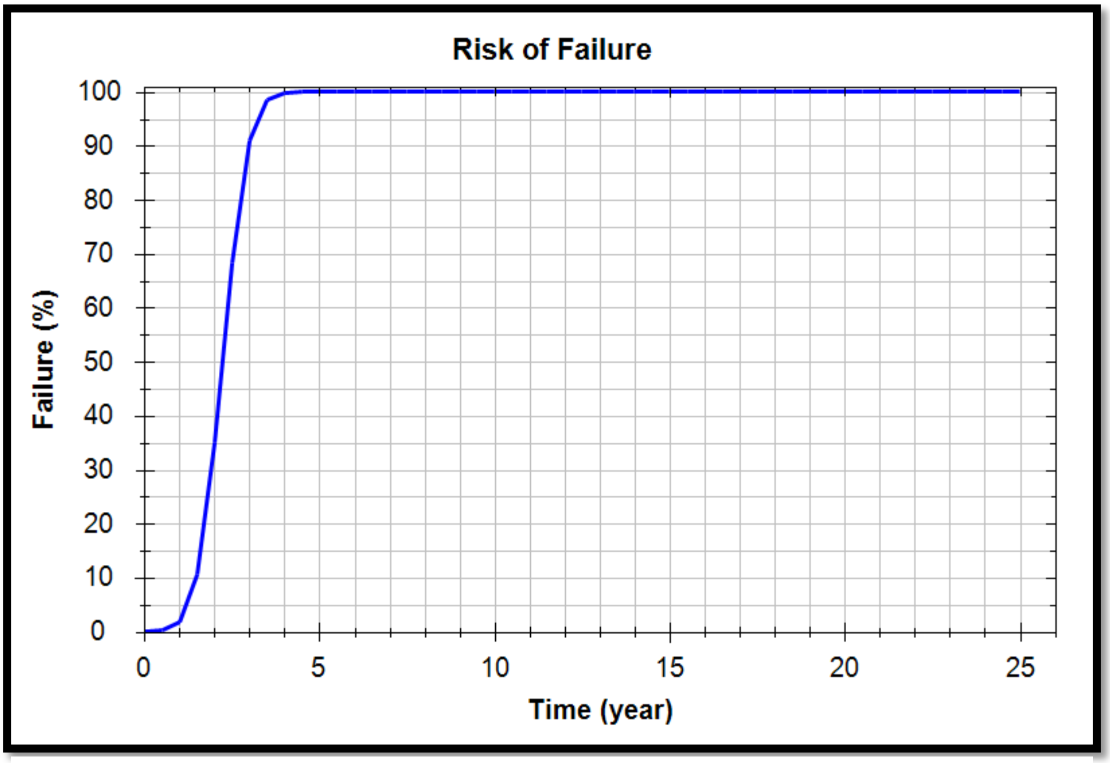


Figure 18: Risk of failure of carbon steel with 0% chromium content of Deep Basin shale gas well

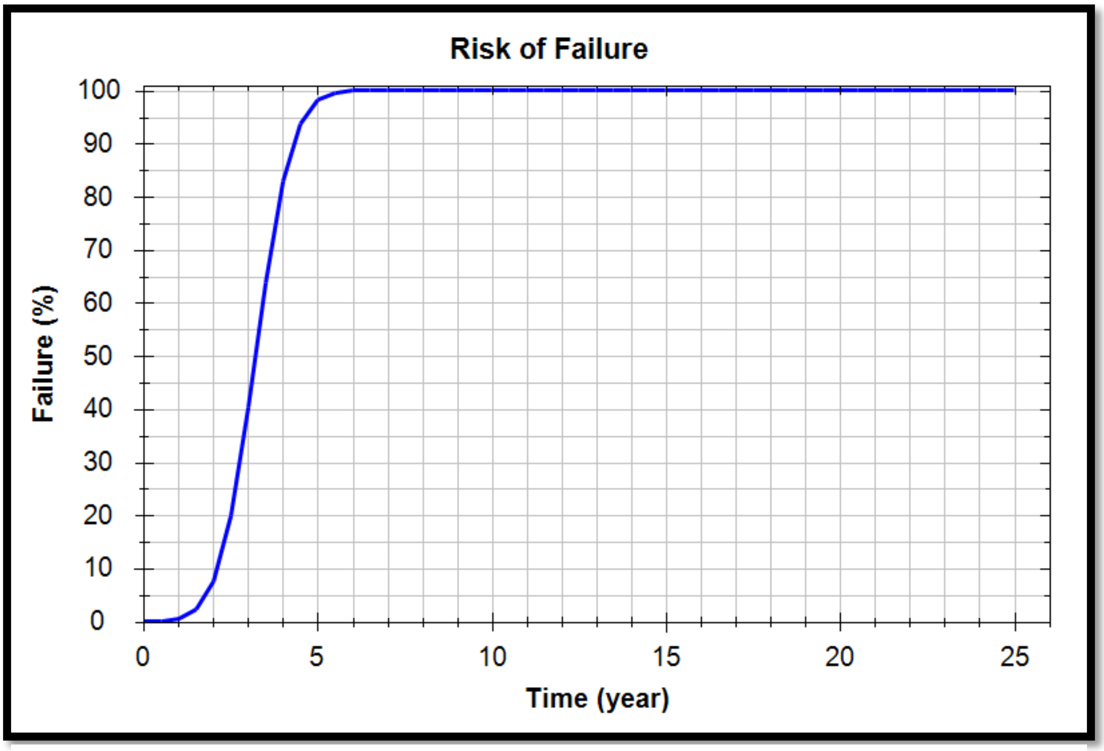


Figure 19: Risk of failure of carbon steel with 1.2% chromium content of Deep Basin shale gas well

For Horn River Basin that used carbon steel with 0% of chromium content as the production tubing material, the risk of failure of the production tubing increased up to 100% after 3 years of usage (Figure 21) with the presence of 21% mole of CO_2 and 0.25% mole of H_2S. Hence, the time limit of using this type of production tubing is only 3 years.

For shale gas well of Horn River Basin that used carbon steel with 1.2% of chromium content as the production tubing material, it shows that the risk of failure of the tubing increased up to 100% after 5.5 years of usage (Figure 22). Therefore, the time limit of using this type of production tubing is only 5.5 years. The reason for the usage time limit of carbon steel with 0% chromium content is shorter than carbon steel with 1.2% chromium content for both of Deep Basin and Horn River Basin is once again because of chromium content. Chromium in the carbon steel helps to reduce the corrosion rate. The function of chromium element is that it helps in forming a passive film to act as the corrosion barrier and prevent the iron from any corrosion reaction. Hence, tubing without chromium content will have shorter time limit of usage or high risk of failure.

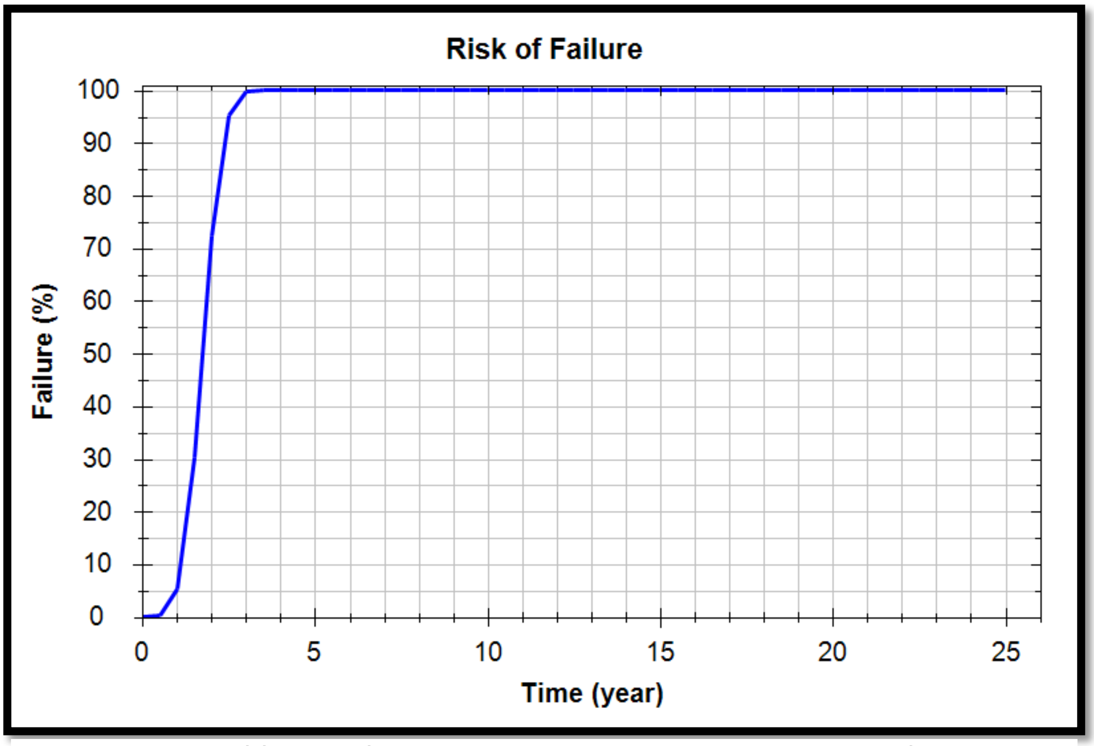


Figure 18: Risk of failure of carbon steel with 0% chromium content of Horn River Basin shale gas well

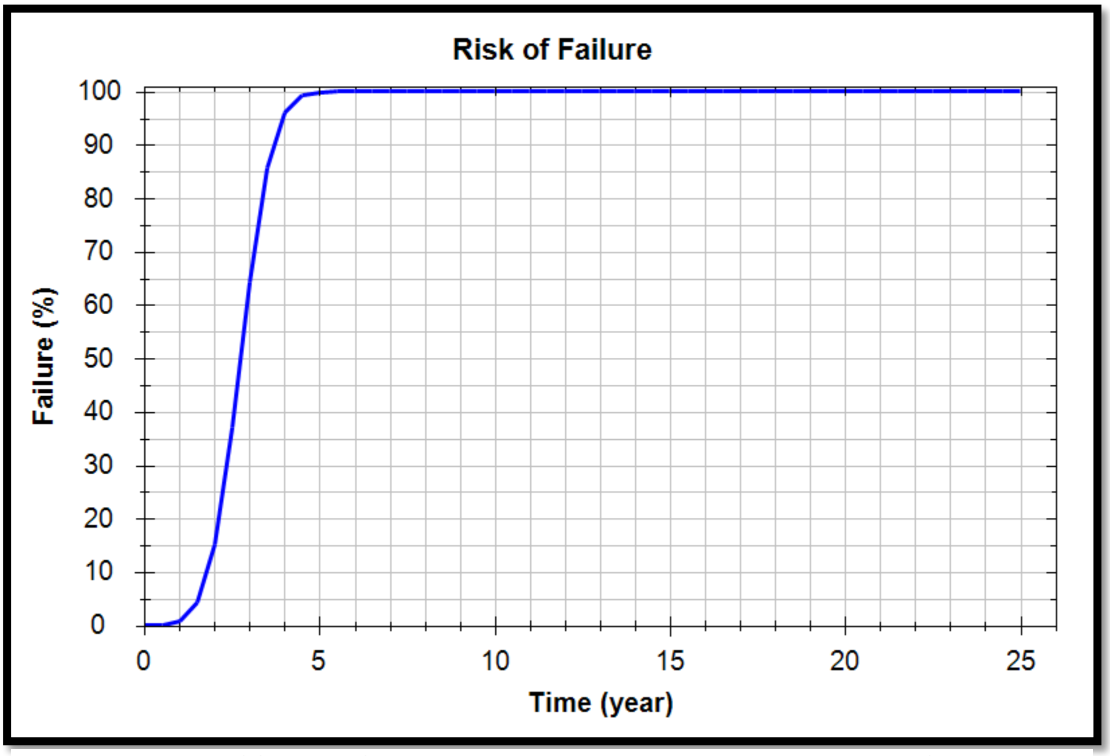


Figure 19: Risk of failure of carbon steel with 1.2% chromium content of Horn River Basin shale gas well

The results obtained based the graph presented above for both wells are summaries in the table below:

Table 9: Risk of tubing failure of Deep Basin

	Risk of Failure (year)	
	50%	**100%**
0% Chromium	**2.25**	**4**
1.2% Chromium	**3.25**	**6**

Table 10: Risk of tubing failure of Horn River

	Risk of Failure (year)	
	50%	**100%**
0% Chromium	**1.75**	**3**
1.2% Chromium	**2.75**	**5.5**

Also, based on the results obtained it can be seen that the risk of failure of tubing in Horn River Basin is higher compared to the risk of failure of tubing in Deep Basin. The reason is because in Horn River Basin there is 0.25% mole of H_2S presence in the reservoir. This amount of H_2S is significant as it turns the condition in the well into sour condition. In the presence of H_2S, additional chemical reactions occurring in the bulk of the solution include dissociation of dissolved H_2S which generating the hydrogen ions and bisulfide. This has caused extra amounts of hydrogen ions presence in the condition. These hydrogen ions produced will act as oxidation agents that will induced the steel or iron to release its electron which cause the degradation of the metal surface or known as the corrosion. Another reason is because of the effect of H_2S gas formed a weak acid and had causing the solution pH to decrease. This acid also increases the corrosion rate by providing an extra cathodic reaction in which H_2S will receive an electron and produced hydrogen atom and bisulfide. This hydrogen atom is the smallest atom, so it is easily can be diffuse into the metal structure especially at elevated temperature in which the solubility of hydrogen is increased. When it diffused, it can cause HIC to happen. These are the reasons that cause the risk of tubing failure in the Horn River Basin is higher than in Deep Basin.

When the risk of failure reach 100%, the production tubing must completely be removed and replace by new production tubing in order to safely produce the shale gas. The reason why there is a risk of failure of the production tubing of shale gas well is evidently because of the mechanical damage due to corrosion. Generally, it is identified that the existence of corrosion due to the presence of CO_2 and H_2S in the tubing reduces the strength of tubing material. The reliability of a component can be used as the way to represent the risk of failure of a component. The technique that used to predict failure of tubing due to corrosion damage is by determines the corrosion rate of the tubing to know how much the defected length to be compared with the corrosion allowance or tolerance of tubing design.

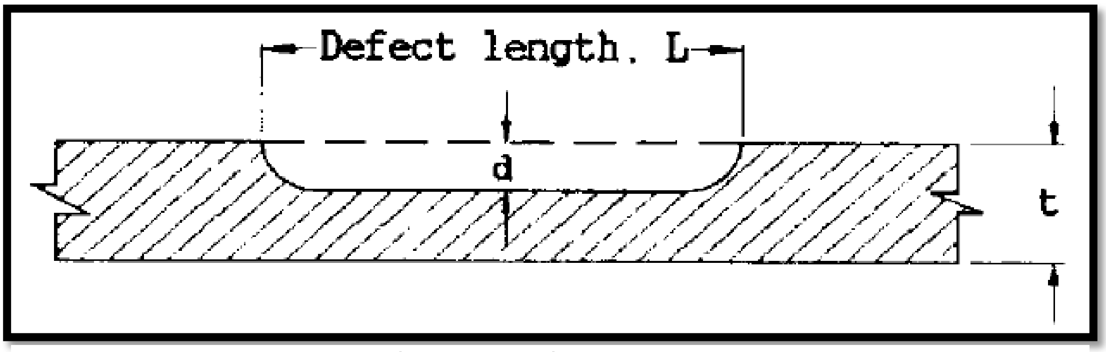


Figure 22: Defect length of material due to corrosion

4.3 Tubing CRA Evaluation

The limits of use of the different alloys are defined in terms of their resistance to corrosion in ‘sweet’ conditions and in terms of their resistance to corrosion or cracking in ‘sour’ environments. There is no minimum value partial pressure of H_2S which has to be exceeded for the environment to be referred to as ‘sour’, the performance of CRAs is checked against limits defined for each alloy individually as soon as any level of H_2S is present.

The suitable CRA are assessed based upon the following input data:

- Temperature = 90°C
- Pressure = 70 bara
- CO_2 = 21 mol%
- H_2S = 0 mol% (Deep Basin) / 0.25 mol% (Horn River Basin)
- Chloride Content = 1000 ppmw Cl^-

The assessment of the suitability of all CRAs is considered for each set of input data entered. This assessment of CRAs is independent of any data entered in other tools within the ECE, for example the Corrosion Predictor. The range of conditions which can be evaluated is wider, since CRAs may be utilized in conditions where carbon steels would not be applicable. The suitability of the alloys in a given environment is indicated by "traffic light" indicators on the right hand side of the window:

Green: The assessment indicates that an alloy will not suffer general or localized corrosion or sulfide stress corrosion cracking.

Red: the assessment indicates that there is a high risk of corrosion or cracking and the alloy should not be applied.

Amber: A ‘safety margin’ is established in some cases to indicate that the alloy is close to its application limit. When the alloy is judged to be close to a limit where there may be a risk of corrosion or of cracking then an amber light will show.

The available CRA listed in ECE software that can be used as the tubing materials are:

- 13Cr Martensitic Stainless Steel
- S13Cr Martensitic Stainless Steel
- 22Cr Duplex
- 25Cr Duplex
- Alloy 28
- Alloy 825
- Alloy 2550
- Alloy C276

For shale gas well of Deep Basin, with the presence of 21% mole of CO_2 and 0% mole of H_2S, all of the CRA listed by ECE are suitable and can be used in this specific shale gas well condition (Figure 23). This indicate that this condition will not cause the CRA to suffer general, localized and sulfide stress cracking (SSC) and all of the CRA are safe to be used as the tubing materials in this type of shale gas well environment. For Horn River Basin, with 0.25% mole of H_2S presence in the well during production of shale gas, it shows that all of the CRA are suitable to be used as the tubing material except for two types of CRA which are 13Cr Martensitic Stainless Steel and S13Cr Martensitic Stainless Steel (Figure 24). This point out that the two types of CRA should not be apply as the tubing material for this specific well condition because there is a high risk for the CRA to suffer cracking and corrosion either general or localized.

The reason why the 13Cr and S13Cr Martensitic Stainless Steel cannot survive in the condition of Horn River Basin is because of the presence of H_2S. These materials have the limits of application in environments containing H_2S which occurrence of sulfide stress cracking (SSC) is possibly high. With the presence of 0.25% mole of H_2S which is equal to 0.175 bar partial pressure of H_2S, the possibility of 13Cr and S13Cr Martensitic Stainless Steel to suffer cracking during production of shale gas is high which fall in the red area of safe range graph of 13Cr and S13Cr in sour service as expressed in the Figure 25 and Figure 26. The pH assume by ECE is about 3.3 to 3.4.

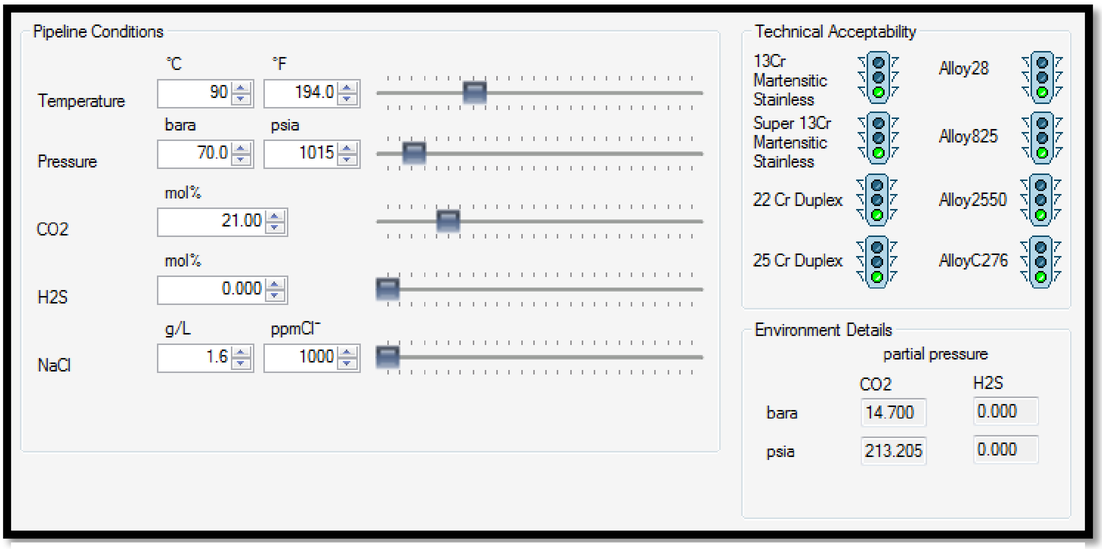


Figure 20: Tubing CRA evaluation for Deep Basin shale gas well

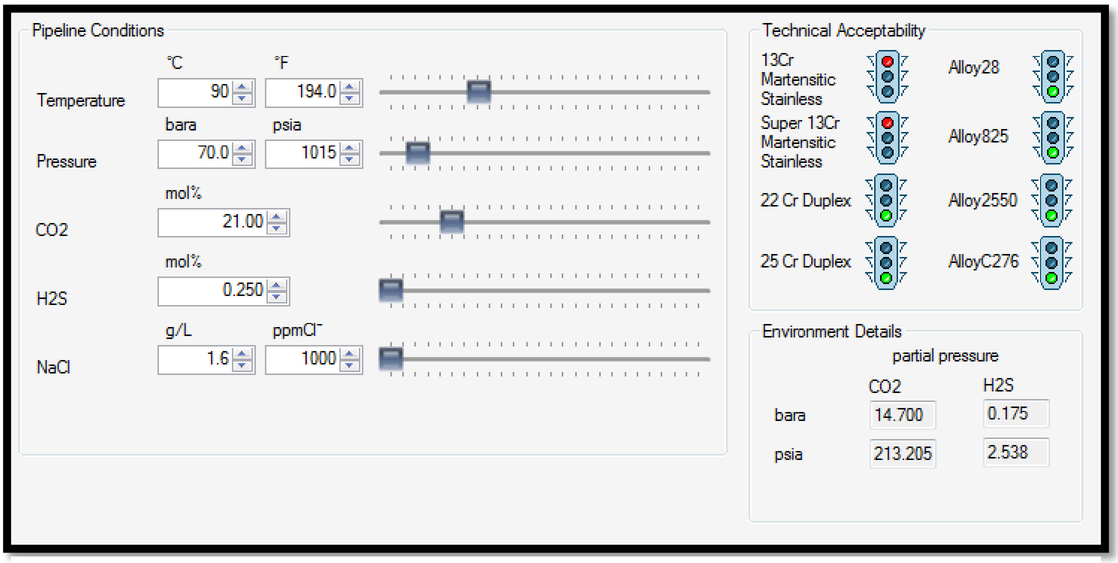


Figure 21: Tubing CRA evaluation for Horn River Basin shale gas well

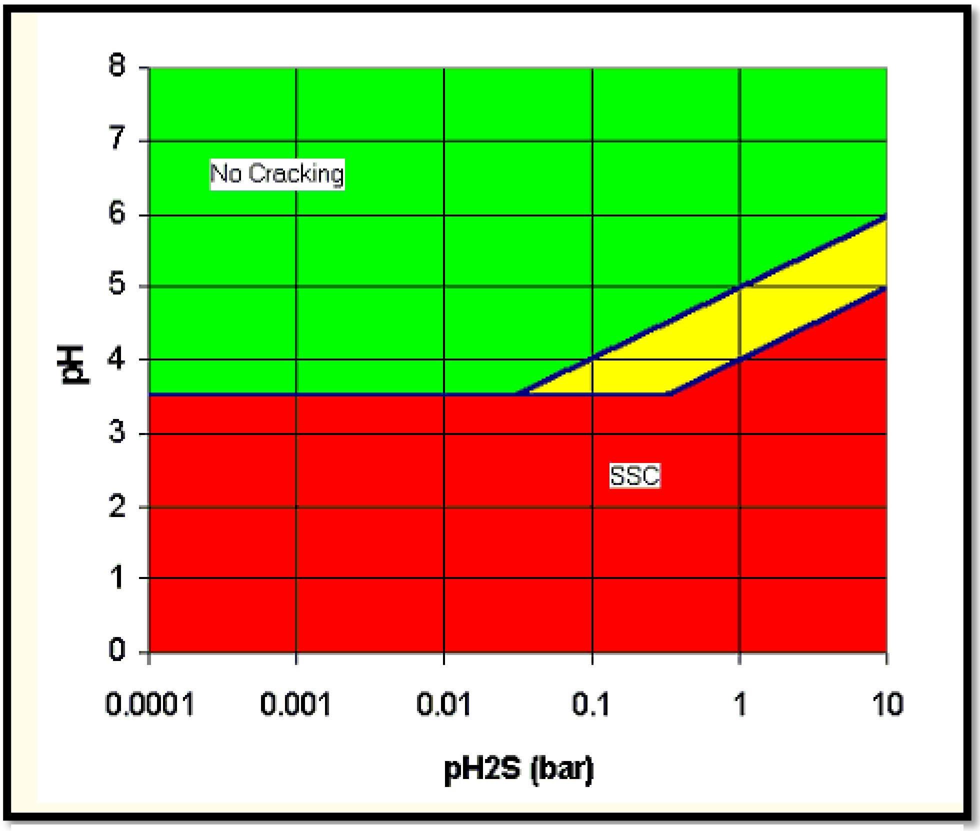


Figure 22: Safe Range Graph of 13Cr in sour service

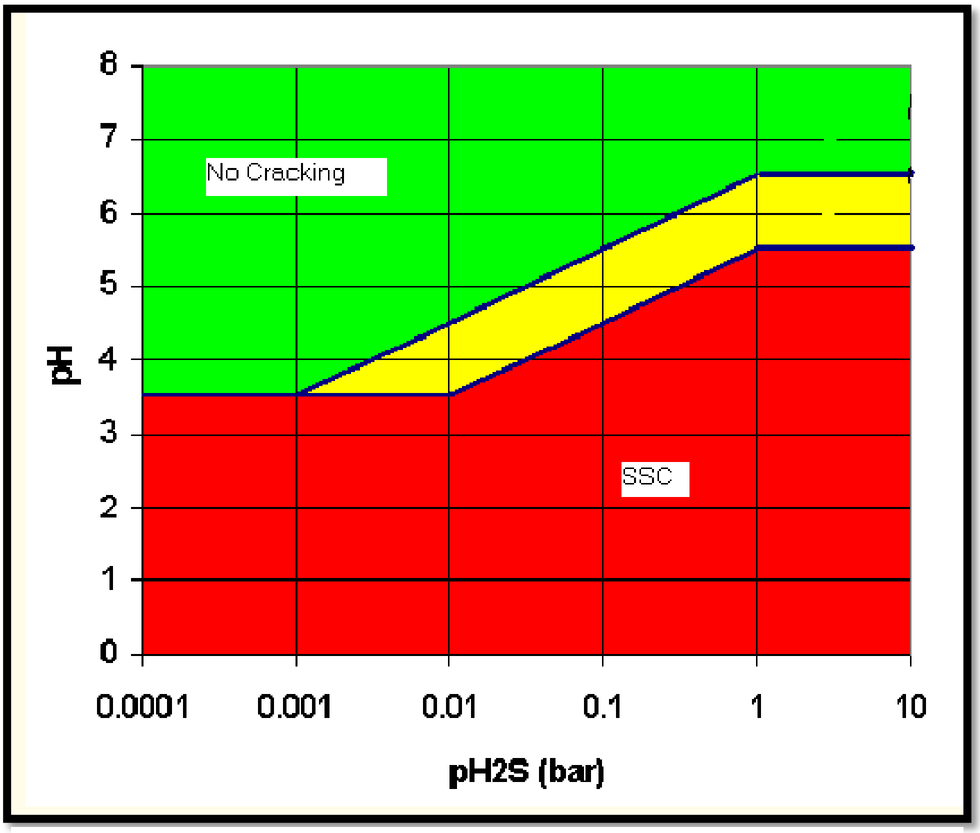


Figure 23: Safe Range Graph of S13Cr in sour service

4.4 Tubing Life Cycle Cost (LCC)

The LCC calculation used to carry out a cost comparison on completion of a corrosion analysis and CRA material selection, or it can be used totally independently by overwriting all the input field data with new information for any case being investigated. The LCC evaluation compares the cost of certain options of costing exercise especially in terms of material selection but do not estimating the actual costs of the projects. Many significant costs which are basically the same regardless of the corrosion control option chosen. Net Present Value graph (NPV) shows the changing cost of the CRA and carbon steel options as a function of time, up to the given life of the project.

The ECE lifecycle cost calculator for tubing is used to make an economic comparison of various corrosion control options for tubing:

- Carbon steel
- Corrosion resistant alloy
- Carbon steel with continuous inhibition
- Carbon steel with squeeze inhibition

For carbon steel tubing without injection of inhibitor, the life cycle cost seems to be the lowest as the net present value for each year until the end of project life is the same which is 3.02$ Million. For carbon steel tubing with squeeze inhibition, the life cycle cost seems to be the second highest as the net present value for each operating year increase until the end of project life. Squeeze inhibition means inhibitor is injected into the well at certain period of time not continuously injected. The net present value starts with 3.028$ Million at the first year of operation and end with 3.106$ Million at the final year of operation which increased 0.078$ Million throughout the 15 years of operation period. For carbon steels tubing with continuous inhibition, the life cycle cost seems to be the highest as the net present value at the end of project life is the highest compare to other material. The net present value starts with 3.03$ Million at the first year of operation and end with 3.116$ Million at the final year of operation which increased 0.086$ Million throughout the 15 years of operation period.

For CRA, the graph shows a straight line which means it has same net present value from the first year until the end of project life which is 3.069$ Million. The result of LCC is shown in Figure 27. Based on the result of LCC obtained, the most economic material option is carbon steel without injection of inhibitor because it is the one that is lowest in cost (the lowest line) at the end of the required project life. But, when it comes to the consideration of environmental factor which is corrosive condition, the best material should be used in as the tubing material of shale gas well is CRA. This is because CRA has the lowest cost compared to the carbon steel with squeeze or continuous inhibitor and CRA has better resistant to corrosion compared to carbon steel. Other than that, CRA also has longer expected life than carbon steel, so workover operation may not be needed.

The reason why the graph shows the CRA option as a straight line is because there are no operating costs calculated for this material option, as there is no need for inhibitor injection. The carbon steel without inhibitor also has no annual operating cost, in this model, so there is no increase in the costs including workover and tubing replacement cost on annual basis. Hence the graph is horizontal, unless a workover and tubing replacement is required, which shows as a step in the NPV graph. The graph of carbon steel with squeeze and continuous inhibitor show an annual increase because of the operating costs. At this point the costs arise for the tubing replacement, workover and deferred production. Costs later in the future are less than costs today, so the slope of the lines gradually becomes less steep at the end of project life. Again, if tubing replacement is expected more, there will be a jump in the graph for the workover costs. Note that with very high corrosion rate values the tubing replacements may be so frequent that the graph may appear to be a continuously rising line.

Naturally, in practice there would be some annual costs arising from operations, inspection and monitoring, but these are assumes by ECE to be roughly equivalent for the different tubing options. The mathematical definition of the Life Cycle Cost is given by the following formula:

$$LCC = AC + IC + \sum_{n=1}^{N} \frac{OC}{(1+i)^n} + \sum_{n=1}^{N} \frac{LP}{(1+i)^n} + \sum_{n=1}^{N} \frac{(RC - SC)}{(1+i)^n}$$

Where:

- LCC = Life Cycle Cost
- AC = Initial acquisition cost of materials
- IC = Initial installation costs (including fabrication)
- OC = Operating +/or maintenance costs
- LP = Lost production costs during downtime
- RC = Replacement materials costs
- SC = Residual value of replaced materials
- N = Desired life time (years)
- i = Discount rate
- n = year of the event

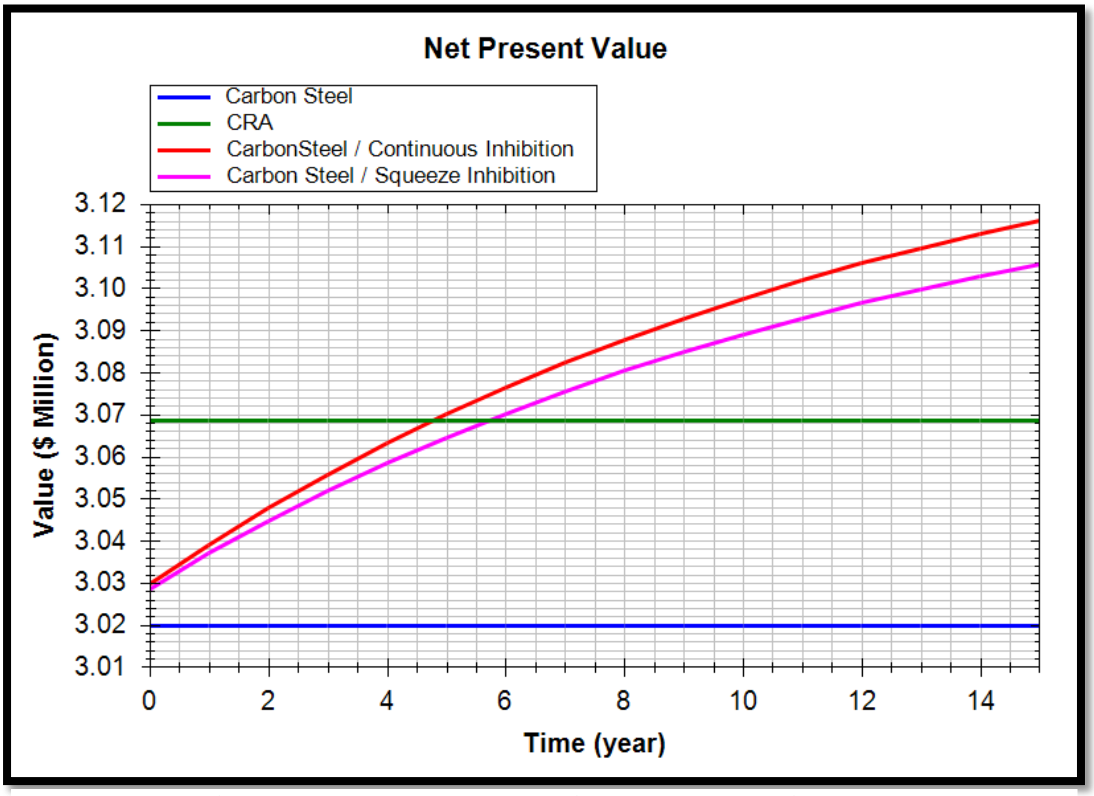


Figure 24: Life Cycle Cost (LCC) graph of material option for downhole tubing

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

In order to mitigate the corrosion that may happen to the downhole equipment due to the effect of flowback water, the method of selecting the most suitable materials of downhole equipment is choose. Using ECE software, it really helps in achieving this objective as ECE can assist in selecting the best CRA that can be used for the specific environmental condition of shale gas well and it also assist in calculating corrosion rate of tubing made up of carbon steel. The implementation of this strategy in mitigating the corrosion helps in protecting the integrity and longevity of the equipment. Hence, shale gas can be produce without undergo the production downtime. In selecting materials, the suitable CRA used can helps to prevent the corrosion activities happen at the surface of the equipment especially the production tubing as this equipment is exposed to the flowback water most of the time during shale gas production. The types of CRA that can used such as 13-Cr Stainless Steels, S13-Cr Stainless Steels, 22-Cr Duplex Stainless Steels, 25-Cr Duplex Stainless Steels and Alloy 28-Cr Stainless Steels are resist to corrosion as they contain the chromium (Cr) element. Therefore, for example the production tubing is made up of CRA such as 22 Duplex Stainless Steels, corrosion will not occur on the surface of the tubing. Thus, cracking that usually happens because of corrosion will not happen and no downtime for shale gas production.

5.2 Recommendation

Some significant recommendation are further study on H_2S and CO_2 corrosion for some other effects in shale gas reservoir such as erosional factors, as the erosional factors are also affects the corrosion behavior. Furthermore, the effect of high temperature and pressure should also be considered in selecting the best CRA as these two parameters are also affecting the corrosiveness of the environment. Effects of higher pH level on the acidity of the environment is also need to be investigate as this effects is also influence the corrosion rate on the carbon steel material.

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