Application of Corrosion Prediction Software to Optimize Material Selection in Offshore Pipelines and Tubing

by

Abd Azim Aizat Bin Ali

Dissertation submitted in partial fulfillment of
the requirements for the
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CERTIFICATION OF APPROVAL

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Approved by,

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January 2009

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 that the original work contained herein have not been undertaken or done by unspecified sources or persons.

ABD AZIM AIZAT B ALI

ABSTRACT

Corrosion prediction in upstream oil & gas industry is a very important process. Many prediction models have been developed for the Exploration & Production (E&P) business, varying from the empirical to mechanistic models. The fact that data are very limited in the design stage compared to operational stage. The uses of default values are common in design stage by which the design of the tubing and pipelines are decided. The question whether the utilization of default values is accurate can be checked with the modeling of operational data. This project will assess the corrosion predictions from two CO_2 prediction models mainly the ECE4 and MULTICORP. Comparison on the corrosion rates predicted and other driving features will be analyzed for a set of cases taken from corrosion field database. Evaluation of the models can strongly depends on the selection of field data used and the accuracy of the field data. The task is to perform modeling of field data by comparing the predictions on the design and operation stage of a project by using same field data. The accuracy of ECE4 predictions for the design stage is higher by more than 200% compared to the operation stage predictions. However, MULTICORP did come up with predictions that are within 30% difference of the design and operation stage. CO_2 partial pressures, H_2S, acetic acid, carbonate content, flow type and flow velocity are the crucial parameters that can highly stimulate corrosion process to occur. Therefore, it is essential that the user have the ability to accurately predict the default values if the data are not available. With less data available, ECE4 can provide satisfactory predictions. MULTICORP would be a better model for higher accuracy predictions if more data were available. Thus, regardless the amount of data available, it is crucial to understand the uncertainties and limitations of the corrosion prediction models and how the input could affect the corrosion prediction.

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CHAPTER 1
INTRODUCTION

1.1 Background of Study

Corrosion study is a critical step in any feasibility studies involving the Exploration & Production (E&P) business, and yet the amount of reliable corrosion field data is very limited. Currently, large numbers of CO_2 corrosion prediction models were developed. Several of the models are mainly based on empirical correlations with laboratory data. Some of the models are based on mechanistic modeling. Very different results can be obtained when the models are run for the same cases due to the different philosophies used in the development of the models. Predicted corrosion rates from the different models have great influence on material selection and hence total project cost. Credible prediction and proper control of corrosion is vital for safe design facilities and cost effectiveness. Attempt to use any of the models requires a certain degree of knowledge on the exact parameters required in order to produce accurate results and to avoid extra budget to engage the corrosion. The complexity in predicting CO_2 corrosion depends on many parameters like partial pressure of CO_2, H_2S content, high temperature, pH, iron and carbonate content and flow velocity besides other critical factors, since real hydrocarbon system is under multiphase flow. The task mainly is to evaluate on the differences between predictions of corrosion rates in the design and operation stage. These data are insufficient during the design stage. Many default values will be used instead. This would strongly affect the predictions accuracy when compared to the predictions of operation stage where abundance of real data is available. Thus it is very important to evaluate the critical parameters to produce right predictions. These predictions are important, as it will actuate to a substantial process, the material selection for the main components; pipelines and flowlines.

In PETRONAS, the ECE4 and HYDROCOR are two models that have been employed to predict the corrosion rate in any offshore projects. UTP employs ECE4 and MULTICORP. Below standards design can sacrifice a project’s integrity while over designing can affect its cost. People usually disregard the different philosophies behind the innovation of the corrosion prediction softwares. This leads to the selection of impertinent software that is well designed for specific applications and thus contributes to choosing the impropriate material that will certainly affect its cost and integrity.

Corrosion has great significance in causing pipeline ruptures that has led to loss of life, property, and contamination of the environment. Although periodic inspection of pipelines will ensure such failures are minimized, inspection of pipelines is expensive. These issues trigger the significance of modeling through the corrosion prediction software, to predict corrosion rate the locations along a pipelines. Therefore, it is decisive to analyze the suitability of the softwares' for economic feasibility and determining its design life since it is highly related to the overall project's life cycle.

The two models will be used to perform study on corrosion predictions. Further analysis will be done on the results to guide the material selection and other related processes behind its application.

1.2 Problem Statement

Due to the complexity and variability of the models and availability of data during design stage specifically, accuracy of predictions are usually questioned. Data are very limited in the design stage compared to operational stage. This will prompt the use of default values that are unreliable at times. Accuracy of the design stage predictions might be affected and this contributes to improper material selection process that can sacrifice a project's cost and integrity.

1.3 Objective & Scope of Study

Corrosion predictions from both ECE4 and MULTICORP for an offshore project and discuss on the important parameters that are crucial to come out with the best possible accuracy of predicted corrosion. Through this, proper material selection process can be performed and economical aspect of the offshore project can be maximized for profit optimization.

Based on the case studies with design data and actual operations data, the objectives would be to:

1) Evaluate two different models on the accuracy of corrosion rate predictions using the ECE4 and MULTICORP.
2) Compare the corrosion rate predictions during the design and operational stage of offshore projects.

CHAPTER 2
LITERATURE REVIEW AND THEORY

2.1 Models Background

The two models (ECE4 and MULTICORP) developed with aim to provide guidance on two key capital items of any project that is the production tubing, pipelines, and flowlines. They were ‘corrosion predictor’ which calculates corrosion rate of carbon steel from a given input data. The output of the models will be graph of corrosion rate with depth or distance along the line.

ECE4 was developed by Intetech and based on the de Waard 95 model. It includes new oil wetting correlation and effects of small amounts of H_2S and acetic acid. The oil-wetting factor is dependent on the oil density, the liquid flow velocity and the inclination of the flow. Small amounts of H_2S can give a considerable decrease in the predicted corrosion rate due to formation of protective film. But that also depends on the working temperature. Usually at high temperature, this film tends to dissolve in the fluid. The model also includes a module for calculation of pH from the water chemistry and bicarbonate produced by corrosion.

For ECE4, model includes features to measure CO_2 corrosion rate, effect of dissolved iron bicarbonate, effect of high temperature carbonate scaling, influence of H_2S, top-of-line corrosion, influence of crude oil or condensate, influence of acetic acid, inhibition, and effect of glycol. But not all of the features could be applied in the modeling since it depends on the availability of the field data.

Institute of Corrosion and Multiphase Technology (ICMT), Ohio University on the other hand developed MULTICORP. MULTICORP V4 has many advantages when compared to other related software. It is based on a mechanistic (theoretical) model in contrast with the other models, all of which are empirical or semi-empirical.

MULTICORP V4 also integrates a corrosion model with a multiphase flow effects on corrosion, which is related to water wetting and entrainment of water by the oil phase. Besides, it also includes the mechanistic model of sour corrosion (H_2S effect), which is fully integrated, with the CO_2 corrosion model. Add to that, the water chemistry model, which can predict speciation and pH of brine and the effect that these have on the corrosion rate.

MULTICORP V4 also put attention on the effect of organic acids that can accurately predict corrosion at very low temperatures (1°C) as well as high salinity brines (25% NaCl).

MULTICORP V4 is the only software or model that enables fundamentally correct and reliable prediction of conditions where protective iron carbonate and iron sulfide scales form which can help mild steel survive the corrosive conditions found in pipelines. Other models are either incapable of predicting protective scale formation or have arbitrary and dubious factors to account for this phenomena.

Both models will allow us to come towards the alloy selection process. Input data are used in a series of mathematical and logical relationship to consider the suitability of the corrosion alloys. Criteria for acceptability of the alloys are that they should not show generalized corrosion. Besides, the ECE4 can also perform Life-Cycle Cost Analysis and has its own Suppliers Database for both the tubing and flowlines. The life cycle cost evaluation tool can be used to give approximate cost between the CRA option and carbon steels. As a decision is made on the tubing and flowlines, manufacturer’s database can be addressed to determine the required dimensions and alloy type.

2.2 Models' Functionality and Uncertainties

CO_2 prediction is performed in the design phase to determine material selection for main components such as pipelines and flowlines. It is continuously done to determine the required corrosion allowance for the systems. Few samples from actual formation will be used in the modeling to produce production profiles over the lifetime of the field. Often the values will vary from the prediction from that of the operation.

Previous published papers have never come to study the comparison of predictions of the design and operational stage of any offshore projects. It is well aware that predictions during the design stage of a project could highly influence the total project cost as materials for pipelines and tubing were selected based on the design predictions. This makes it very significant to get the best possible accuracy in the predictions at the early stage of a project. By understanding the models and vital parameters that can affect the predictions, it is possible to get accurate predictions in design stage. This should assist in selecting the right material for pipelines and tubing and help optimize cost allocation of a project.

A study [1] was once done by collaboration of few oil companies and research institutions to study on the corrosion prediction models. Data were collected mostly from the failure cases. Some cases have detailed corrosion data along pipelines while the others only have data available at certain points of the pipeline.

As mentioned earlier, minimum required data to run the modeling of the different models were:

- Temperature at inlet and outlet
- Pressure at inlet and outlet
- CO_2 mole %
- Bicarbonate, acetate and calcium content in the water
- Gas, oil and water production rates
- Pipe diameter

Usually not all data are available at design stage. At this stage, data were attained from previous geological history of close by fields. Through the selection of available field data, only uninhibited systems cases (without glycol or methanol injection) were use in the modeling [1]. Three field data was used. They are the Oil line, Gas line and also Oil well. All showed high corrosion rates from 1 to 5 mm/yr.

Oil line case is a multiphase oil line operated for seven years and experiencing multiple leakages. Investigation done showed that the pipeline had a low CO_2 content with presence of acetate. For Gas line, there was 10% water cut and corrosion measured is highest at 4.1mm/yr. Oil well, leakage occur and water cut increased from 2% to 80% in 17 months. Calculated pH is around 5 to 5.5 indicating acidic condition and having a corrosion rate of 4.6mm/yr for its total production. In can be seen here, even at low CO_2 content, flow can become corrosive with the presence of water.

HYDROCOR and ECE4 have been mentioned previously. Here the paper [1] also includes modeling on other models such as Cassandra, Lipucor and Norsok. Brief description of these models is given below. They are labeled:

- A Norsok
- B HYDROCOR
- C Cassandra
- D de Waard model
- E Lipucor
- F ECE4

Cassandra is BP's implementation based on the de Waard model. Oil wetting effects are not considered and effect of protective films at high temperature is weaker than the de Waard model.

Lipucor model developed by Total relates a big amount of field data that considers oil-wetting effects. This makes it less conservative.

Statoil, Norsok Hydro and Saga Petroleum on the other hand developed Norsok. Is much the same as the de Waard model taking account the effect of protective corrosion films at high temperature and high pH.

When evaluating the models against field data, it is necessary to have reliable information for example the temperature and CO_2 partial pressure at the exact location where corrosion is measured.

Figure 2.2.1 below shows how corrosion prediction varies over the different depths of Oil well case. It plots the corrosion rate over the depth of all the models. This is the case of producing wells. Different forms of corrosion can be observed in wells and pipelines and different predictions will also be produced from different models, as they were design based on different theories and philosophies.

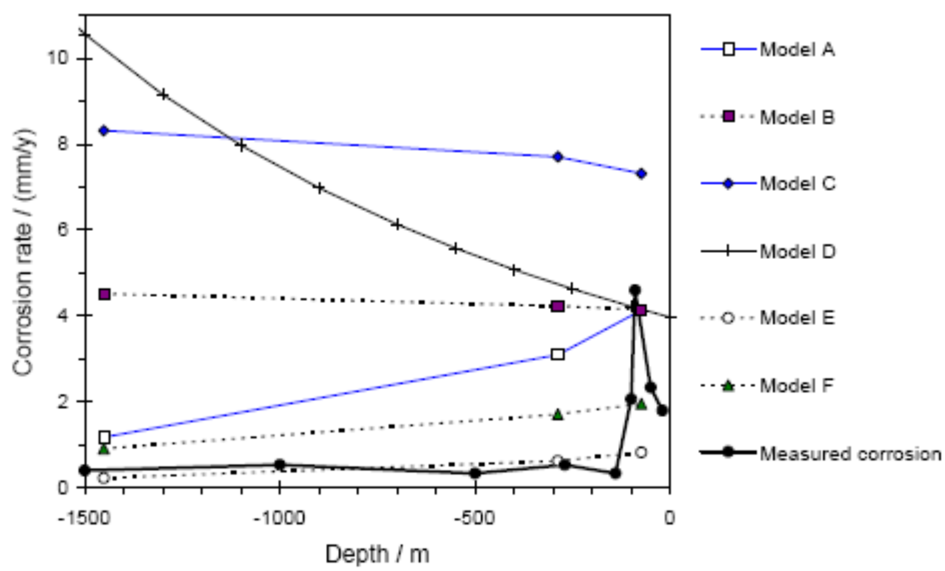

Figure 2.2.1: Predicted and measured corrosion rates at different depths in Oil well.

For the case of Oil well, it can be seen that model E is not able to predict the high severe corrosion condition at top of well. This is because the model takes into consideration large effects of protective corrosion films and oil wetting. Model F also considers large effect of oil wetting. But, model B, C and D are good in predicting the severe corrosion at top of well but not deep inside the well. This is due to not considering the effect of protective corrosion films, and so it predicts higher corrosion rate at bottom hole where temperature is higher. As for model A, both the corrosion rate at the top and lower parts of well were successfully predicted as the model the model takes larger effect of protective corrosion films at high temperature. This shows that at different locations, there are certain parameters that we should consider in order to obtain proper value of predictions that is as close as possible to the measured value. Here the effect of protective film was stressed out as the important factor.

Besides, the effects of protective corrosion films, oil-wetting can also highly influence the result of the corrosion between very high and very low corrosion prediction rates. However, there are limitations to the corrosion prediction models. In a case of prediction in the design phase of a project, input data might be limited. This led to uncertain predicted temperature, pressure and flow velocity as default values might be used.

It is important to estimate actual pH in water phase too as for cases with condensed water, increase in pH could happen due to bicarbonate produced by corrosion. CO_2/bicarbonate, H_2S/sulphide and acetic acid/acetate buffering system can be important in determining actual pH value. Presence of organic acids and acetic acid can have big impact on corrosion rates especially in low CO_2 partial pressures. These organic acids can give high values of carbonates and hence high value of pH. But most of the models does not account for that. At design stage, these data are usually insubstantial. However, it is important for the engineers to consider these parameters even in the design stage to avoid used of extra budget in choosing improper material or sacrificing projects integrity.

Other than that, most of the corrosion prediction models also did not take into consideration the specified water chemistry from water analysis. The water chemistry can also indicate super saturation of calcium carbonate. It is important to know either water or oil wets the steel surface since corrosion only occurs when water is present at the surface. Study shows that the degree of oil wetting depends on the flow conditions, water cut and also properties of the hydrocarbon. Flow conditions can be in term of its flow velocity or the type of flow either laminar or turbulence.

Models developed so far does not account so much on system with H_2S. There is a need for H_2S corrosion model that takes different iron sulfide films into consideration. Since a little presence of the H_2S could give large difference in predicted corrosion.

Another outcome from a study [2] of Electronic Corrosion Engineer (ECE) found that ECE is a very user-friendly software/model. It is specifically designed to predict corrosion rates of carbon steel flowlines and tubing in the presence of CO_2. The model considers parameters such as CO_2 content, pressure, temperature, flow velocity and pH. The corrosion rate is also corrected for the effects of presence of H_2S and acetic acid.

Study shows that the ECE consider in details a lot of important parameters that could contribute to corrosion such as the influence of H_2S, effect of high temperature carbonate scaling, influence of acetic acid, top-of-line corrosion, and effect of glycol.

H_2S factor accounts for the reduction of corrosion rate when protective FeS is formed. The precipitation of H_2S can reduce the pH of the system. This model can perform additional calculation of the corrosion rate without the filming effect. In H_2S containing environments, corrosion rate quickly reduces as the concentration of H_2S increases. This could give different result of predicted corrosion if a model does not account for this parameter. But in condition where water is present, H_2S can become sulphuric acid that is highly corrosive. Normal standard deviation for prediction of corrosion that includes H_2S is set at 30%. But the model has added an extra 25% chance that corrosion rate is based entirely upon the rate without H_2S presence.

Corrosion at top-of-line is controlled by the rate of condensation of water from gas and the composition of condensing phase. Rate is often lower at the bottom and usually dissolved bicarbonate salts are only present in the liquid at the bottom. This will result in top-of-line corrosion. So, considering this parameter is crucial in preventing corrosion at certain point.

The influence of acetic acid comes from the water carried inside any flowlines or pipelines. Water transports the acetic acids, HAc. The effect of acetic acid is measured both at the top and bottom. As a result, top-of-line corrosion is calculated. Next, in the case of glycol effects ECE calculates how much water is absorbed from the gas into the water/glycol liquid at each point in the pipeline.

Another outcome from a different study [4] of the model Norsok shows that the model is designed for high temperature range of 5°C to 150°C but it does not cater for H_2S dominated environment or system with high content of organic acids. Besides, the model cannot predict top-of-line corrosion and effect of oil wetting is not included. It is acknowledged that H_2S and acetic HAc have an impact on the corrosion rates. Norsok does not account for that. This could provide user with less accurate corrosion rate predictions.

Norsok model the effects of fluid flow rate since it proved that flow rate influences CO_2 corrosion. Flow effects are empirically modeled in terms of shear stress and shall not be used for critical flow cases. In the case of top-of-line corrosion, it is normally more severe in conditions with high content of organic acids than with CO_2 alone. Thus, top-of-line corrosion cannot be predicted, as the model does not account for the effect of acetic acids.

In terms of the functionality, (process system) say in unprocessed well stream e.g. piping/components between wellhead and inlet separator; the model should not be used to predict erosion corrosion or maximum allowed flow rate as the risk for loss of inhibitor is not included in the model. For oil stabilization process e.g. separators and piping that transport oil between separators; water content can vary from 50% to 0.5% at the last stage separator. It is applicable for the model to be applied in such system. In produced water environment, it is not recommended that the model be used since generally corrosion rate in such systems are much higher than predicted. The model cannot be use for gas treatment system also since free water can be expected.

Functionality (pipelines), if formation water as the major water phase, corrosion prediction can be done by use of the model using partial pressure of CO_2, total pressure and formation water content as input parameters. It is also applicable for liquid transport pipelines.

It is an advantage if a model can come up with a good corrosion prediction in produced water system. Since normally models assume 100% water wetting, this will lead to a conservative prediction. This can also drive the user to select higher corrosion resistance material that are more costly just to cater for the high corrosion rate predicted when in real operation case maybe only 10% water wetting occurs. Default values that are usually used in the design stage should have credibility in terms of precision. Still, reduction of predicted corrosion rate due to lack of water wetting could give risk to a project if in real cases the water wetting is higher.

However, there are uncertainties involved. They are mostly linked to unreliable input parameters, effect of water wetting and corrosion inhibitor. In the design phase, parameters like temperature, pressure, water composition and flow rate were defined by assuming production rate and pipe diameter. In the case of water analysis, uncertainty could happen when drill water is contaminated with drill fluid. These uncertainties in input parameters contribute to uncertainty in predictions. Water wetting also cannot be accurately predicted, but it is possible to identify the conditions for which wetting is unlikely such in oil pipelines with high velocity and low water cut.

Next, is modeling using Cassandra [5]. The model stresses value of pH as a major input. It performs more complex and detail calculations for determining the pH of pure water and brines with no restrictions. But there are limits to it where effect of solubility limits of brine is not considered.

Fugacity was used in the model. Fugacity represent the true activity of gases that includes CO_2 since in high total pressure condition, partial pressure would not be an accurate parameter to be used. Thus, here in the model pressure is converted to fugacity before being used in the calculations.

Cassandra does not include the effect of oil wetting since in the study of the model, some oil system tends to be corrosive but turn out the other way due to the nature of the hydrocarbon. Next is in terms of effects of scaling temperature, here Cassandra offers flexibility to the user. As known, CO_2 corrosion leads to formation of iron carbonate $FeCO_3$ scale. This is a protective layer that can reduce overall corrosion rate. At low temperatures the scale can be described as semi protective and becomes increasingly protective at high temperatures. So, the model chose middle course where at temperatures above the scaling temperature the corrosion rate is not allowed to increase but instead form a plateau. The model also includes the effect of acetates. This is important since acetates can increase the system pH and reduce corrosion rate.

In another study [8], it shows that the common underlying theme in all these studies is that localized attack in CO_2 corrosion of mild steel is always associated with the formation and breakdown of protective iron carbonate films. However, it should be stressed here that all these studies have been conducted in single-phase water flow. There are no studies on localized corrosion conducted under wet gas flow conditions. Hence, an extrapolation of these results achieved in single-phase flow to multiphase flows under field conditions is uncertain.

This next paper discussed on the MULTICORP model. MULTICORP provides immediate answers like the corrosion rate. Not just that, the model also allowed the users to get a deeper insight into the root causes behind the problem. Due to the strong theoretical background of the original model, the user could extrapolate the predictions outside the calibration domain. MULTICORP is a new model that considers most of the crucial parameters that could affect corrosion rates.

This mechanistic model is designed so that in future, further extensions could be done easily. This is in contrast with the extensions of semi empirical models that are complex and often difficult. It includes features such as:

- Prediction of CO_2 corrosion at low temperatures;
- Prediction of CO_2 corrosion in high salinity brines;
- Complete prediction of sour corrosion (pressure H_2S=0.001 bar - 10 bar).

2.3 Important Parameters That Could Affect Corrosion Rate

Low Temperature

Standard models are able to predict the uniform CO_2 corrosion rate at temperatures between 20ºC and 80ºC [10]. However, the corrosion rate is poorly predicted when used at lower temperatures. It is not easy to adjust an empirical model without doing a full recalibration or by introducing another questionable correction factor. However, a more straightforward answer can be found for the original mechanistic model of MULTICORP.

Somehow there are problems with mechanistic model at low temperatures. The activation energy, which applies between 20^oC and 80^oC, is increased as the water freezing point is approached. In other words, the rate of the various electrochemical reactions slows down much more rapidly than anticipated as the temperature approaches 0^oC [10]. Interestingly, the standard activation energies for the mass transfer and homogenous chemical reactions in the model worked well across the whole temperature range and did not display this inconsistency at very low temperature.

The only explanation for the observed behavior of the electrochemical reactions is a change of the reaction mechanism. Therefore, in order to obtain more accurate predictions at low temperatures, the activation energies for the four key electrochemical reactions underlying the CO_2 corrosion need to be adjusted at low temperature. The values were suggested for 5ºC and 1ºC. The predictions obtained with the new updated model, using adjusted activation energies for the four-electrochemical reactions, are shown in Figure 2.2.2. Clearly a much better agreement is obtained and the new updated model can be trusted at low temperature.

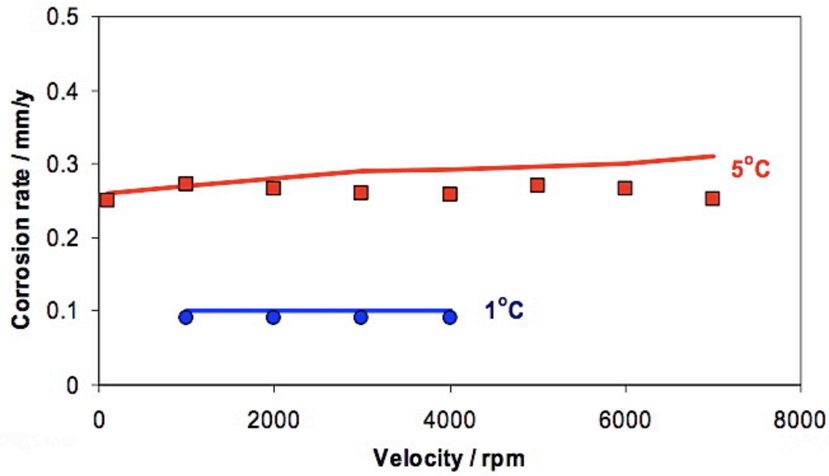

Figure 2.2.2: Comparison between experimental results (points) and predictions (line) for the new updated model at low temperature.

Effects of H_2S

Internal CO_2 corrosion of mild steels in the presence of hydrogen sulfide (H_2S) represents a significant problem for the oil and gas industry. In CO_2/H_2S corrosion of mild steel, both iron carbonate and iron sulfide layers can form on the steel surface. Studies have demonstrated that surface layer formation is one of the important factors governing the corrosion rate in H_2S corrosion [10].

The corrosion of mild steel in H_2S aqueous environments proceeds initially by a very fast direct heterogeneous chemical reaction at the steel surface to form a solid adherent mackinawite layer. The overall reaction can be written as:

$$Fe(s) + H_2S \rightarrow FeS(s) + H_2$$

As both the initial and final state of Fe is solid, this reaction is often referred to as the "solid state corrosion reaction". This film is very thin (<<1μm). The thin mackinawite film continuously goes through a cyclic process of growth, cracking and delamination generating the outer sulfide layer, which thickens over time (typically >1μm). This outer sulfide layer is very porous and rather loosely attached, over time it may crack, peel and spall, a process aggravated by the flow. Considering the flow type and velocity together with the effect of H_2S could provide the user with a better accuracy predictions. As it is realized that even with thick protective film available on the pipelines surface, with turbulence flow, the shear force can rip off the protective films away.

Effects of High Salinity

Many assumptions were made on the CO_2 corrosion effects of mild steel when having high salinity brines (>>1% by weight). Some suggested that it is detrimental to survival of mild steel in CO_2 saturated solutions; others suggested that it is beneficial.

It is found that with high salt concentrations across the whole temperature range the CO_2 corrosion rates of mild steel are severely retarded. This can be seen in Figure 2.2.3 that the plots deviate progressively as the concentration of salt increases. Corrosion rate is also higher at higher temperature.

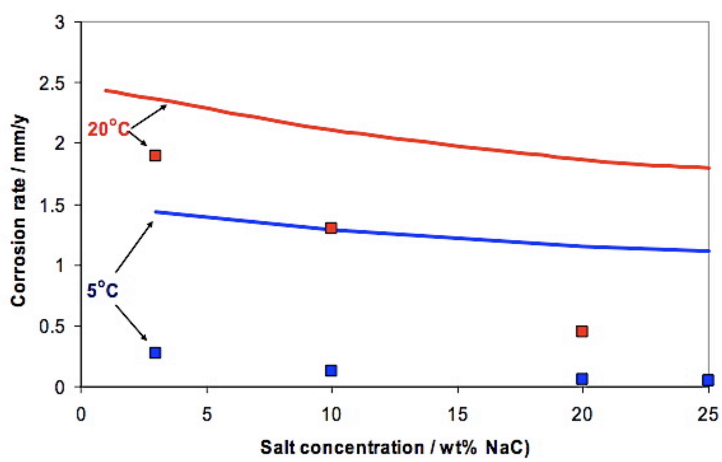

Figure 2.2.3: Comparison between experimental results (points) and predictions (lines) for the original model at various NaCl concentrations.

Higher salt concentration changes the brine physico-chemical properties comprehensively. The density and viscosity are increased. As the salt concentration increases well beyond a few percent, the brine becomes a non-ideal solution. This can be seen in Figure 2.2.4, where it is seen that high salt concentration affects mainly the activity coefficient of H+ ions in saturated CO_2 solutions. Consequently, the pH of a brine changes significantly with increasing salt concentration. Furthermore, high salt concentration will decrease the solubility of CO_2 in the corrosion solution.

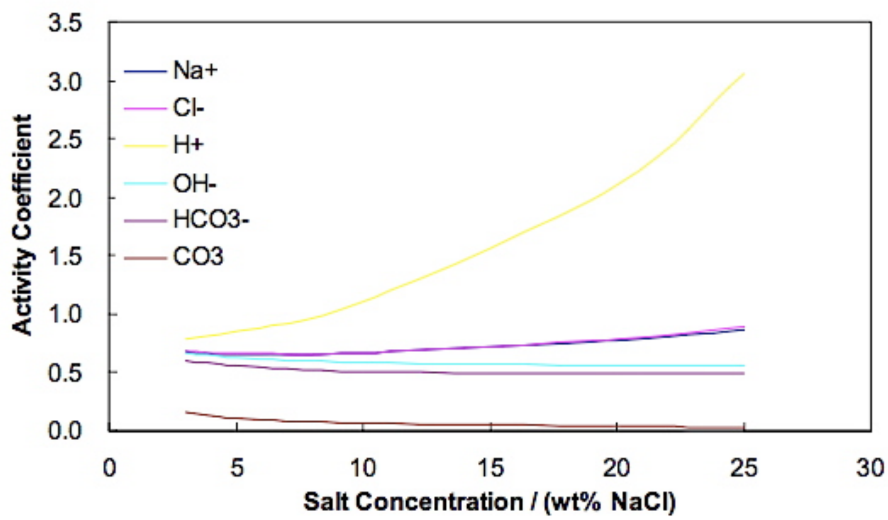

Figure 2.2.4: Calculated activity coefficient change with salt concentration at 20ºC at 1 bar total pressure.

Studies have discovered that many other processes underlying CO_2 corrosion are affected by salt concentration. The heterogeneous electrochemical reactions at the steel surface were affected in the first place by surface reaction retardation. Mass transfer coefficients were also changed for reasons beyond those related to the increased density and viscosity of the brine. When all these effects were accounted for by using the appropriate theories where available, and introduced into MULTICORP, a much-improved fit with the experimental results is obtained across the whole temperature and salinity range.

In a different case study, it is found that surface scale formation is one of the important factors governing the corrosion rate. The scale growth depends mainly on the kinetics of the scale formation. In an H_2S environment, many types of iron sulfides may form such as amorphous ferrous sulfide, mackinawite, cubic ferrous sulfide, smythite, greigite, pyrrhotite, troilite, and pyrite, among which mackinawite is considered to form first on the steel surface by a direct surface reaction.

In pure H_2S corrosion of mild steel there was no significant effect of dissolved Fe^{2+} concentration on neither the corrosion rate nor the iron sulfide scale retention rate. This was in contrast with pure CO_2 corrosion where the iron carbonate scale formation rate is a strong function of dissolved Fe^{2+} concentration. Iron sulfide films form even in solutions, which are at pH much lower than pH5.0-5.5. In addition, the structure and morphology of the iron sulfide films formed in H_2S corrosion (mackinawite) is different from the iron carbonate films formed in CO_2 corrosion. Therefore they concluded that iron sulfide films observed in the experiments form primarily by a direct heterogeneous chemical reaction between H_2S and iron at the steel surface (solid state reaction). But there are still possibilities that iron sulfide films forming by precipitation in supersaturated solutions over long periods of time. However, in the relatively short duration experiments, they inferred that the main mechanism of iron sulfide formation is the direct chemical reaction between H_2S and the steel surface. More importantly it is thought that the thin and tight iron sulfide films formed in this way are one of the most important controlling factors in H_2S corrosion.

Effect of H_2S Concentration

Analysis was performed to investigate the effect of H_2S gas concentration on the mackinawite scale formation in the solutions with H_2S/N_2 at the temperature of 80^oC. Figure 2.2.5 shows the comparison of corrosion rate and scale retention rates expressed in the same molar units vs. H_2S gas concentration after a 1-hour exposure [10]. The comparison indicates that both the corrosion rate and scale retention rate increase with the increase of H_2S gas concentration, however, the corrosion rate is always higher than the scale retention rate. The scaling tendency under the test conditions indicates that between 40% and 72% of the iron consumed by corrosion ended up as iron sulfide on the steel surface, with the balance lost to the solution [10].

The same kind of data is presented for a 24-hour exposure where a broader range of H_2S gas concentrations was used: 0.0075-vol% – 10-vol% [10]. The same conclusions apply as for the 1-hour exposure with the exception that the magnitude of both the corrosion rate and scale retention rate is almost an order of magnitude lower after 24 hours. The figure concludes that corrosion rate is higher at higher concentration and thus it must be considered to come into good predictions.

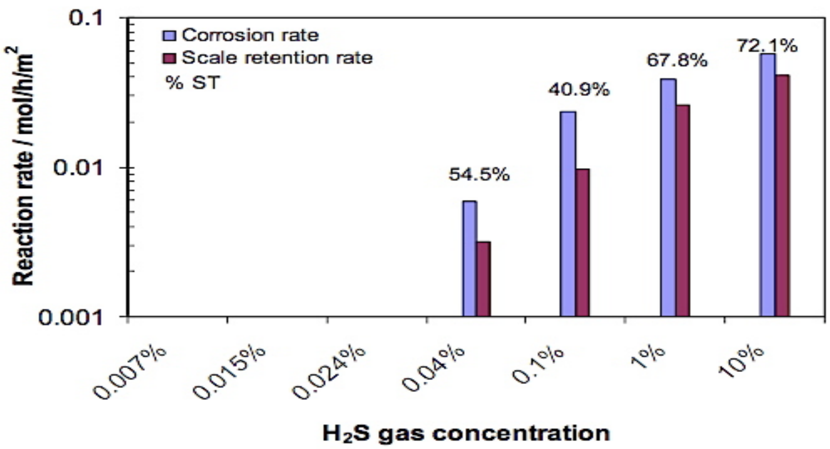

Figure 2.2.5: The comparison of corrosion rate (CR) and scale retention rate (SRR) in the same molar units as a function of H_2S gas concentration.

Effect of Temperature

The effect of temperature on both the corrosion rate and the scale retention rate is shown in Figure 2.2.6 for a 1-hour exposure at 1-vol % of H_2S gas concentration. Very weak temperature dependence is observed even for the short-term exposure, but disappears for the longer exposure times. The same is obtained in experiments at H_2S gas concentrations of 10-vol% [10]. This suggests that the corrosion rate is predominantly controlled by the presence of the iron sulfide scale, with the effect increasing over time. Naturally, any process or reactions tend to increase with increasing temperature.

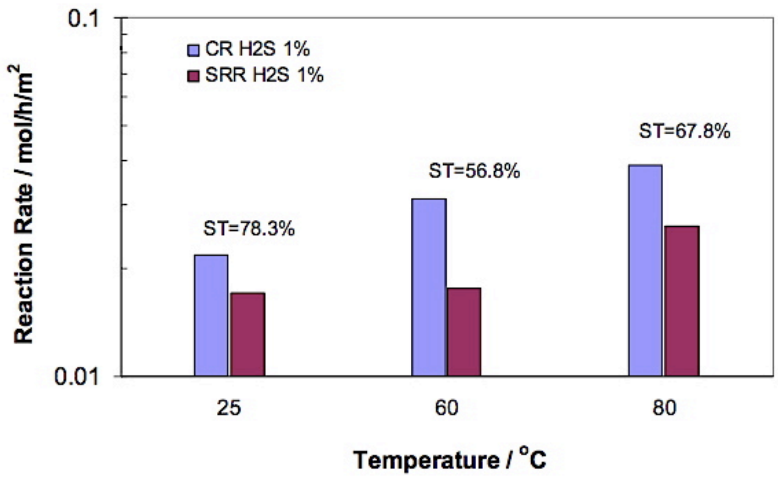

Figure 2.2.6: The corrosion rate (CR) and scale retention rate (SRR) vs. temperature.

Effect of Flow Rate

Besides the effect of H_2S concentration and temperature, the effect of flow rate has also been investigated at a velocity of approximately 4 m/s done with 0.04 vol% of H_2S in the gas phase [10]. The corrosion rate as a function of reaction time at different velocities is shown in Figure 2.2.7. The corrosion rate clearly increases with velocity and the effect is much more pronounced for shorter exposure times. For longer exposures in flowing conditions, the corrosion rates decrease significantly due to a buildup of a protective iron sulfide scale.

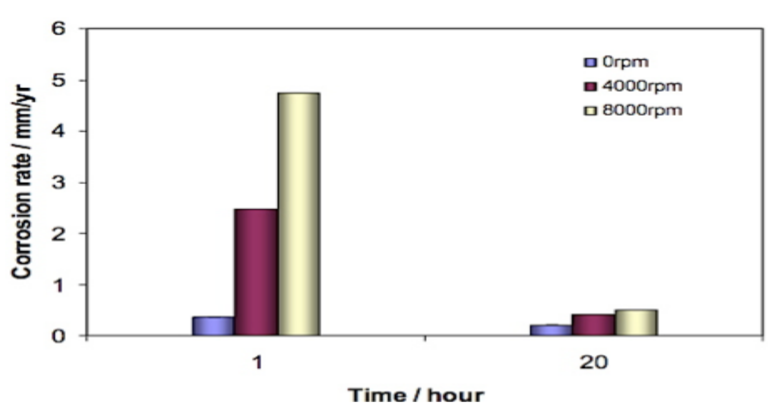

Figure 2.2.7: The corrosion rate vs. time for different rotational speeds.

From all the theories and findings of the studies, it can be concluded that corrosion rates were affected by many factors. These are like the partial pressure and temperature of the fluid flowing in the pipelines, CO_2 and H_2S content, presence of carbonates, fluid velocity, density and many other parameters. Not just that, different models also were design based on different ideology. Some were based on experimental study; some were fully mechanistic while the others were design from combinations of both. It is very important that we understand the corrosion process in order to analyze the parameters or factors that affects the corrosion predictions.

It is understand that crude does not emerge from the reservoir uncontaminated and is always accompanied by various amounts of water, carbon dioxide, hydrogen sulfide, and organic acids. These substances give rise to a very aggressive environment where the survival of mild steel is not guaranteed. The multiphase mixture can accelerate corrosion of mild steel by increasing the mass transfer rates of corrosive species and/or by damaging the protective films formed on the steel surface.

While corrosion prediction models were design from multiple backgrounds, it provides different forms of solutions. MULTICORP and ECE4 are good models since it considers most of the crucial parameters that will affect corrosion rates in pipelines or flow lines. However, the amount of data used also influence the accuracy of the predictions. It is useful to study these parameters to ensure every aspect of the project especially during the design stage is fully optimized. Understanding the models well and knowing the substantial parameters that should be considered can produce best predictions.

Through this, differences in predictions between design and operational stage can be cut down. Suitable material will be selected for selected field conditions without risking the integrity of the project and misspend expenditures.

CHAPTER 3
METHODOLOGY

Corrosion field data will be gathered and properly analyzed. The amount of available data might vary from one case to another. But it is typical that many of the cases, when corrosion problems are encountered, it is difficult to trace back the relevant information from the earlier stages of the field. Field data are usually very limited particularly design stage data. Two main tasks are to:

1) Compare corrosion predicted in design and operational stage using same field data.
2) Compare corrosion predicted from two different models (ECE4 & MULTICORP) by using same field data.

3.1 Offshore tubing and pipelines data

Field data will be secured from PCSB and data will be simulated in the models to come out with the CO_2 corrosion rate and the pH value of the fluid flowing inside the pipelines. These field data can be found in the Result & Discussion section. Few field data were attained but they were limited to a certain extent. This might result to slight uncertainties.

3.2 Corrosion Prediction Models

Both the ECE4 and MULTICORP will be used to come up with corrosion rate predictions. Comparing it with true corrosion rate value that is gained from offshore data will assess accuracy of the corrosion rate predicted from both models. Difference in the amount of input required in each model will give dissimilar results of corrosion rate.

3.3 Data interpretation

Corrosion rate predicted will be interpreted and the factors that contribute to such predictions will be analyzed. From here, it can be determined which parameters are crucial and can give significant impact to predictions of corrosion rate. Values from field data will be extrapolated to see the effects more clearly.

3.4 Process Flowchart

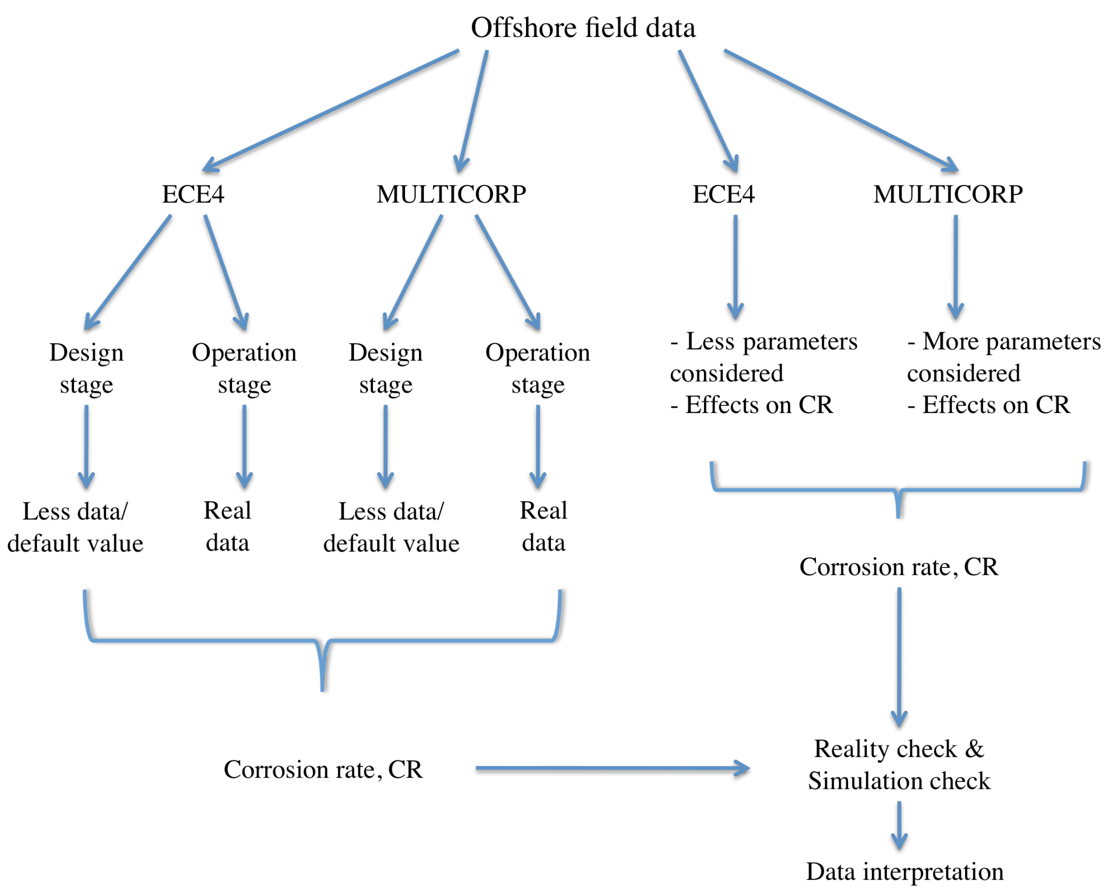

Figure 3.4.1: Process flowchart.

3.5 Data Gathering and Analysis

Available data varies from one case to another. Study was continuously done on reading paperwork and doing literature review of the different models, factors considered in evaluating the models and also what factors could best influence the result of the predicted corrosion. Evaluation of the models by using field data can strongly depend on the proper selection and the accuracy of the field data, as there are limitations and uncertainties in the corrosion prediction models.

Data shown below were attained from X North field, one of PETRONAS South East Asia project. Data includes the reservoir, structural and pipeline information. These data will be used to model corrosion rate using both the ECE4 and MULTICORP. Below in Table 3.5.1 showed some of the reservoir parameters like the pressure and temperature of the selected zone downhole.

Table 3.5.1: Down hole conditions.

Component	Sand
Reservoir Datum (TVD SS - meter)	1,622
Static bottomhole pressure, psia	2,303
Bottomhole temperature (^{o}C)	70
Bubble point pressure, psia	2,105

The maximum and minimum flowing tubing head pressure and temperature are indicated below in Table 3.5.2 and 3.5.3 respectively. They were design stage data for the year 2009 to 2012. Design stage data designate that there might be inaccuracy or uncertainties. Even so, closest figure can be used based on the previous history or geological data.

Table 3.5.2: Flowing Tubing Head Pressure for X North.

Year	FTHP (psia)
2009	306
2010	753
2011	525
2012	278

Table 3.5.3: Flowing Tubing Head Temperature for X North.

Year	Temperature (100% total production)
2009	44
2010	44
2011	44
2012	44

Below in Table 3.5.4 showed the flow tubing head pressure and temperature data and in Table 3.5.5 is the other properties of crude that are usually considered in predictions like the viscosity and API gravity of the crude. Table 3.5.6 shows the fluid compositions like the CO_2 and H_2S content inside the crude. Associated subsea pipeline was designed to handle production capacity as shown in Table 3.5.7 and Table 3.5.8 shows the forecast production profile data of X. That is the yearly forecasted production for the year 2009 to 2012.

Table 3.5.4: Wellhead Other Conditions for X North.

Description	Well X1
Normal Flowing tubing head pressure, psia	200
Normal flowing tubing head temperature, deg C	44.4
Maximum Flowing tubing head temperature, deg C	47.2
Minimum Flowing tubing head temperature, deg C	36.7

Table3.5.5: Crude Properties at Full Well Stream Conditions at Wellhead for X.

Description	Well X1
Solution GOR, scf/bbl	562
Field Producing GOR, scf/bbl	600
Cloud Point, deg C	30.5
Pour Point, deg C	27
Wax Content, wt %	18.45
Asphaltene content, wt%	1.94
Gel Strength	-
Viscosity, cP	0.79
API Gravity @ 60F	32.5

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Table 3.5.6: Well Stream Fluid Composition for X.

Well name	Well X1
Reservoir	**X**
Component	**Mol%**
H_2S	0.00
CO_2	0.05
N_2	0.41

Table 3.5.7: Design Capacity of X and Associated Pipelines.

Description	X1
Maximum oil, STB/day	8000
Maximum water, STB/day	500
Maximum gross fluid, STB/day	8500
Maximum gas, mmscfd	4.5
Maximum gas lift, mmscfd	3

Table 3.5.8: Yearly Forecast Production Profile for Oil.

Year	Oil (stb/d)	Gas (MMscfd)	Water (stb/d)
2009	2,301	1.2	0
2010	8,000	3.9	0
2011	7,981	3.7	96
2012	6,718	4.0	448

CHAPTER 4
RESULTS & DISCUSSION

4.1 Modeling of Field Data

As shown above, well data was collected from X North field. This data was simulated in both models. Besides, there are few other field data from field B and field J that were also used in the modeling to come up with the corrosion rate predictions. These are real field data, however differences in predictions should be observed since both models were design based on different backgrounds and philosophies.

4.1.1 ECE4 Modeling

Modeling was done on X North field. The simplified data that were used in ECE4 modeling is as shown in Table 4.1.1.1. Only some of the field data were used in the modeling due to limitations in the amount of parameters that can be substituted to produce the corrosion predictions. The result shows 0 mm/y of corrosion rate. The effect of certain parameters like the CO_2 partial pressure and H_2S content is shown in the discussion section. This was done by simply manipulating the value of CO_2 and H_2S in the model and sees the effect accompanying it shown on the plotted graph.

Table 4.1.1.1: Well data for X North field.

X North field	
Parameters	Value
Temperature, deg C	
Wellhead	44
Bottom hole	70
Pressure (psia)	
Wellhead	306
Bottom hole	2303
CO_2 mol %	0.05
H_2S mol %	0
Production flow rates	
Crude (bopd)	2301

Gas (MMscfd) Water (bpd)	1.2 0
API gravity	32.5
Tubing nominal diameter - in	10
Reservoir datum (TVD)	1622
Corrosion rate (mm/y)	0

All necessary data to be used inside ECE4 is available. These data were keyed into the model and the model produce graphical output on the corrosion rate predicted, pH and also the risk associated with the type of material chosen. ECE4 also comes with a tool called CRA (Corrosion Resistance Alloy) evaluation. This tool provides list of suitable material to be choose depending on the result produce. This helps the user to easily select the suitable materials that are safe for use in the stated conditions.

There are many factors that are crucial in predicting corrosion in offshore wells and pipelines. They are like the operating conditions; pressure, temperature and fluid velocity; dissolve gases like CO_2 and H_2S content, flow velocity, effect of acetic acid and also pH condition of the wells.

Like the other chemical reactions, increased in temperature, accelerates reaction rate. In oil production process, desalting usually performed in high temperature (between 90^oC to 120^oC related to oil API), so high temperature is an important factor in corrosion. Pressure also effects on chemical reactions but in oil production process its effect is more on dissolved gases value. Fluid velocity is another important parameter in corrosion rate. Fluid with low velocity causes low corrosion rate. If the flow velocity is high, it might not allow the dissolve metal ions to be precipitated as protective layers. Dead zone in piping and equipments is a proper site for bacteria; it is also a good place for accumulation of solid particles that lead to pitting corrosion. High velocity of fluid increases rate of corrosion especially in presence of solid particles.

Table 4.1.1.2 below shows field B data used in modeling on ECE4. Generally, more information was available in the operation stage. However here in ECE4, there are limitations to the amount of input that can be used. Value of each parameter also varies from the design and operation stage. However, same value of corrosion rates were produced from ECE4, that is 0 mm/y. This might be due to uncertainties in the design stage data or the limitation in terms of amount of input that were used in ECE4.

Table 4.1.1.2: Data from field B used for ECE4 modeling.

ECE4 - B Field		
Parameters	Value	
	Design	Operation
Temperature (deg C)		
Inlet	70	66
Outlet	30	50
Pressure (bar)		
Inlet	20	28
Outlet	7	27
CO_2 mol %	0.04	0.001
H_2S mol %	-	0
Production flow rates		
Crude (m^3/day)	435	1000
Gas (MMscfd)	0.2	0
Water (m^3/day)	2390	2660
API gravity	30	39
Alkalinity as bicarbonate (ppm)	-	2330
Water cut (%)	85	68
Corrosion rate (mm/y)	0	0

4.1.2 MULTICORP Modeling

Table 4.1.2.1 shows the modeling of data from field B using MULTICORP. Like the previous case, more information was available in the operation stage compared to design stage and the value also varies between the design and operation stage. Yet different sets of corrosion rates were produced. Both came up with two different values of corrosion rate at 0.13 mm/y and 0.02 mm/y for the design and operation stage respectively. Higher corrosion rate was predicted in the design stage as a lot of default values were used. This might be the reason to the big difference in the predicted corrosion rates. Even so, MULTICORP allows the user to input more parameters. This might in a way increase the accuracy of its predictions and makes it more reliable.

Table 4.1.2.1: Data from field B used for MULTICORP modeling.

MULTICORP – B Field		
Parameters	Value	
	Design	Operation
Temperature (deg C)	70	66
Pressure (bar)	20	28
CO_2 mol %	0.04	0.001
H_2S mol %	-	0
Production flow rates Crude (m^3/day) Gas (MMscfd) Water (m^3/day)	 435 0.2 2390	 2186.3 0 512
API gravity	30	39
Alkalinity as bicarbonate (ppm)	0	3600
Sulphates (ppm)	0	98
Chlorides (ppm)	0	13000
Water cut (%)	85	68
Oil density (kg/m^3)	780	793.7
Oil viscosity ($N.s/m^2$)	-	0.0013
Velocity (m/s)	-	1.158
Corrosion rate (mm/y)	0.13	0.02

As can be seen in Table 4.1.2.1 above, the effects of sulphates, chlorides and bicarbonate contents were not considered. This is the reason to why the model predicted a very high corrosion rate prediction at the early design stage. Even the velocity of fluid flowing was not considered. It is shown earlier in the literature review section that velocity of fluid is also an important factor that should be considered to come up with high accuracy predictions. User will attempt to use high CRA to cater for the high corrosion rate but in real situation, the corrosion rate is much less. This will give an impact on the total project cost.

4.2 Discussions

4.2.1 ECE4

Figure 4.2.1.1 to 4.2.1.4 are snapshots of the output of ECE4. The figures show the corrosion rates predicted and the risk of failure after 25 years for operational and design stage respectively. Detail discussions were discussed below. From Figure 4.2.1.1, at low temperature, with low CO_2 content and negligible H_2S content, ECE4 predicted 0 mm/y of corrosion rate. The stated condition was approximated to be at pH 6.25 that is close to neutral. Figure 4.2.1.2 shows the risk associated for the stated condition. ECE4 predicted zero percent failure even after 25 years of operation.

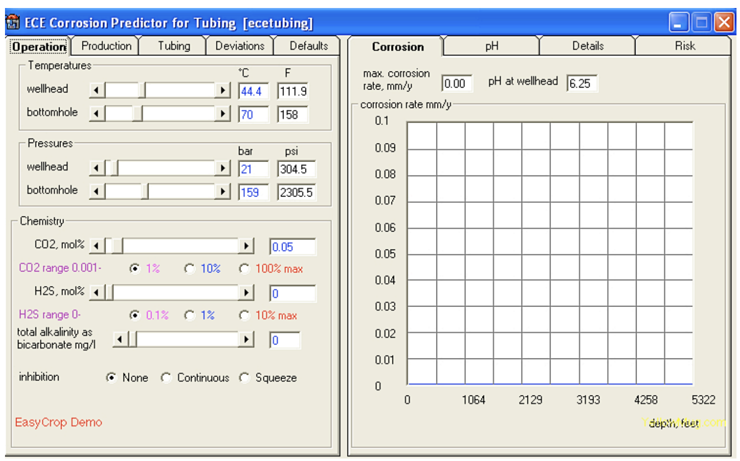

Figure 4.2.1.1: Corrosion rate predicted (operation).

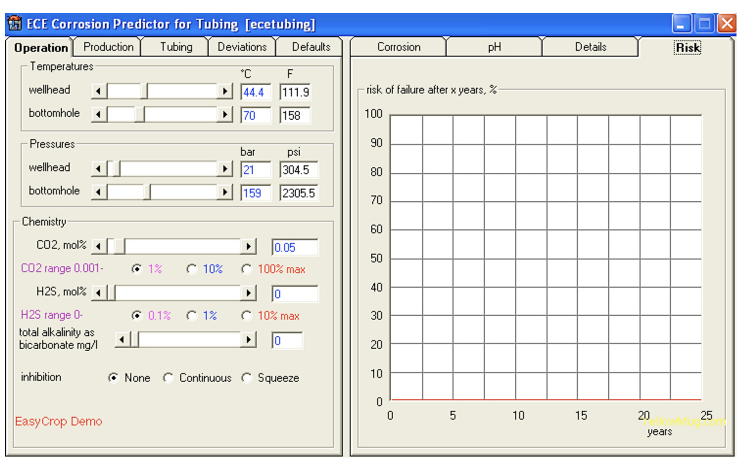

Figure 4.2.1.2: % failure risk for 25 years life period (operation).

Figure 4.2.1.3 shows the corrosion rate prediction for the same well data for design stage. Here, ECE4 predicted a 0 mm/y of corrosion rate similar to the operation stage. It should be useful when both the design and operation stage produce close or similar value, as consistent predictions are reliable. The risk associated in the design prediction is also similar to those predicted in the operation stage.

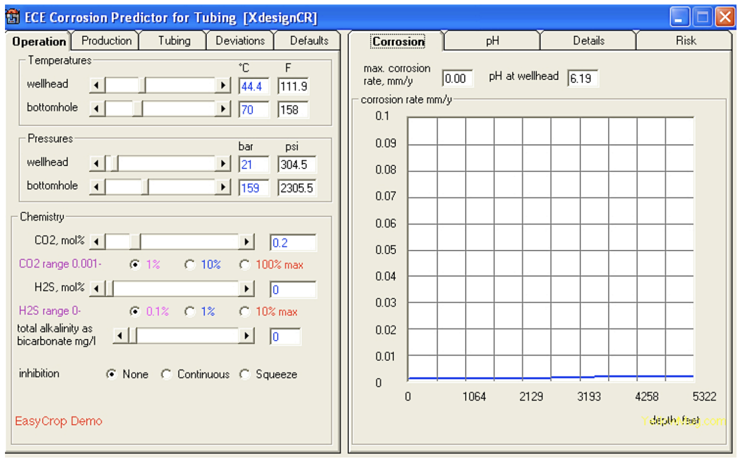

Figure 4.2.1.3: Corrosion rate predicted (design).

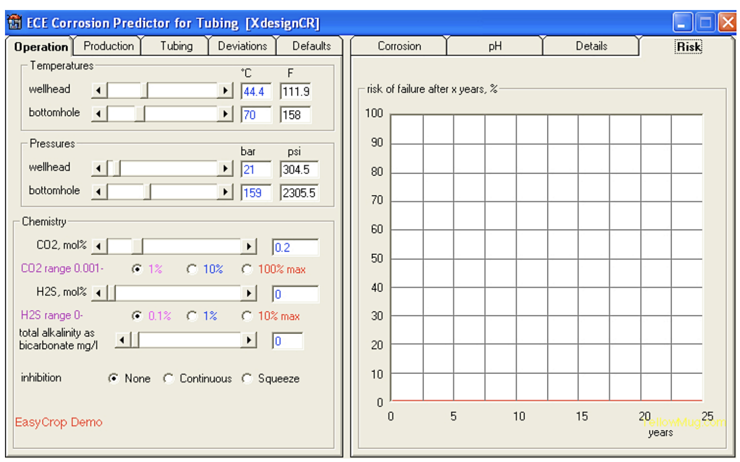

Figure 4.2.1.4: % failure risk for 25 years life period (design).

Referring to the four figures above, we can see that both the corrosion rate predicted and % failure risk for both the design and operational stage are within proper limits. According to the design parameters, the allowable corrosion limit is below 0.5-mm/y. Figure 4.2.1.1 and Figure 4.2.1.3; each shows that the corrosion rate predicted are very close to 0-mm/y that is far from reaching 0.5-mm/y. While Figure 4.2.1.2 and Figure

4.2.1.4 shows 0% risk of failure both in the design and operational stage respectively. According to the design life, it is targeted to have between 10 to 15 years of fatigue life. In the figures, even after 25 years, well is still under good shape.

Corrosion predictions can rely on many factors. Carbon dioxide (CO_2) content is one factor that could distinctly affect the predicted corrosion. The presence of CO_2, hydrogen sulphide (H_2S) and free water can cause severe corrosion problems in oil and gas tubing's and pipelines as shown in Figure 4.2.1.5. Internal corrosion in wells and pipelines is influenced by temperature, CO_2 and H_2S content, water chemistry, flow velocity, oil or water wetting and composition and surface condition of the steel. A small change in one of these parameters can change the corrosion rate considerably. This is due to changes in the properties of the thin layer of corrosion products that accumulates on the steel surface [6]. This can be shown be executing few simulation check.

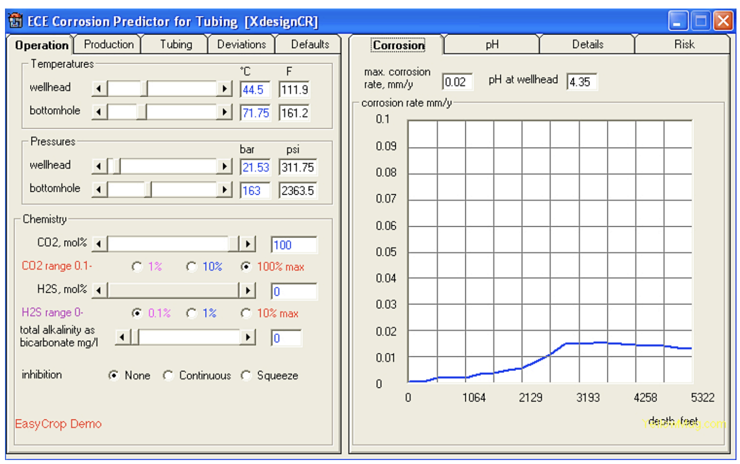

Figure 4.2.1.5: Corrosion rate monitoring at pure CO_2 condition.

This can be seen from the simulation in the ECE4. With the other parameters maintained, changing the CO_2 mole % to a maximum of 100-mole % (pure CO_2 condition) with pH 3.9, corrosion readings were in the range of 0-0.02-mm/y (see Figure 4.2.1.5). So, with only CO_2 present, the pH dependence of the corrosion rate was small. However, corrosion severity also generally increases with CO_2 partial pressure. CO_2 is an acid gas and the term acid refers to its ability to depress pH when it is dissolved in an aqueous solution.

An added effect of H_2S in CO_2/brine systems is a reduction in corrosion rate of steel when compared to corrosion rates under conditions without H_2S. This reduction in corrosion rate is primarily a low temperature effect and predominates system corrosivity at temperatures less than 80 deg C due to the formation of stable iron sulfide film. On top of that, at higher temperatures the combination of H_2S and chlorides will usually produce higher corrosion rates than just CO_2/brine systems, since stable iron carbonate films usually do not occur as readily in systems with H_2S as they do in systems without H_2S [8]. As can be seen in Figure 4.2.1.7, at low temperature (approximately 70 deg C) presence of H_2S effectively reduces corrosion rate to around 0.003-mm/y compared to Figure 4.2.1.6 when only CO_2 exist.

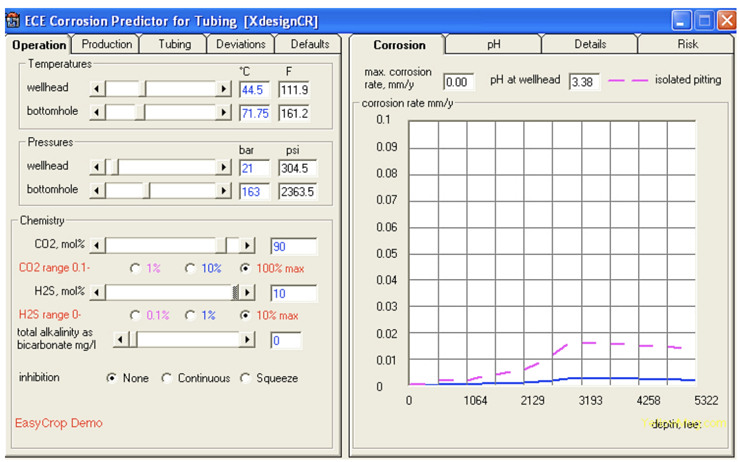

Figure 4.2.1.6: Presence of H_2S reduces corrosion rate.

When corrosion products are not deposited on the steel surface, very high corrosion rates of several millimeters per year can occur. The corrosion rate can be reduced substantially under conditions where iron carbonate ($FeCO_3$) can precipitate on the steel surface and form a dense and protective corrosion product film. This occurs more easily at high temperature or high pH in the water phase. When H_2S is present in addition to CO_2, iron sulphide (FeS) films are formed rather than $FeCO_3$, and protective films can be formed at lower temperature, since FeS precipitates much easier than $FeCO_3$. Thus, it is decisive that we consider the effect of H_2S content to come out with a better corrosion prediction.

Next, is when there is presence of both CO_2 and H_2S in free water or in the case where wells experience certain % of water cut. Investigation of the influence of solution with CO_2 and H_2S on the corrosion showed a significant increased in corrosion in switching from near neutral to very acidic with pH 3. At around 1% water cut, the failure risk is still at moderate level. At the stage where all three components exist, increasing the amount will increase risk of failure.

Looking at the graph produced in Figure 4.2.1.7, here is a technical explanation on how presence of solution containing H_2S could increase corrosion rate. Dissolving in water, hydrogen sulfide dissociates as a weak acid into ions:

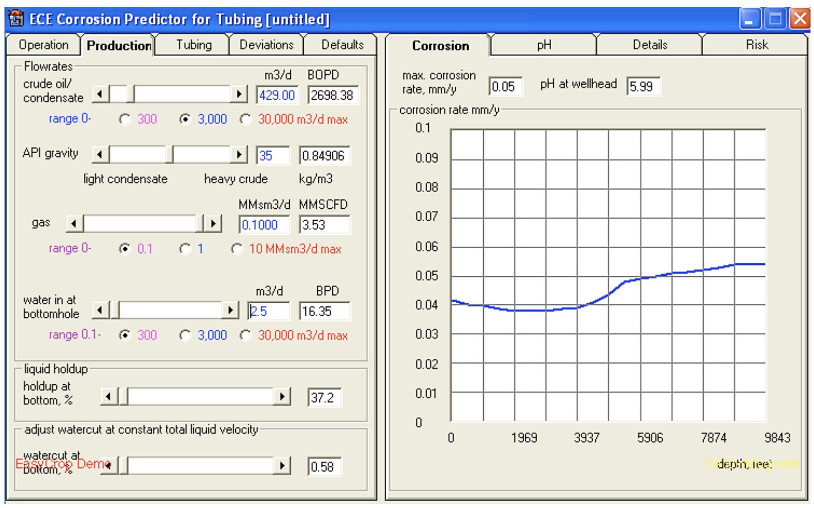

Figure 4.2.1.7: Effect of H_2S in free water.

$$H_2S \rightarrow HS + H^+ \rightarrow S^{2-} + 2H^+$$

In neutral and alkaline media more hydrosulfide ions are contained, in acid media those of molecular hydrogen sulfide, and in weakly alkaline electrolytes sulfide ions appear in small quantities. The significant hydrogen sulfide content in the aqueous phase leads to a decrease in pH (acidic) of the liquid phase of well production and the main portion of hydrogen sulfide is found not in ionic but in molecular form. Thus, hydrogen sulfide will accelerates the anodic reaction of ionization of iron. But it is different in the case of gas producing wells. H_2S combines with water to form sulfuric acid (H_2SO_4), a strongly corrosive acid.

Figure 4.2.1.8 shows graph on the risk of failure of the tubing downhole of wells. Changing only the gas flow rates value does not give serious consequence on the failure risk. But by increasing the water cut value in gas producing wells, increased of 50% failure risk after between 15-20 years of operation is observed. What can be clarified is that with only the presence of gas without free water, corrosion rates are still at its minimal. When high water cut occurs, the high levels of shear and turbulence at the bottom of the pipe will strip away the protective film of corrosion products formed on the pipe wall resulting in high rates of corrosion [9].

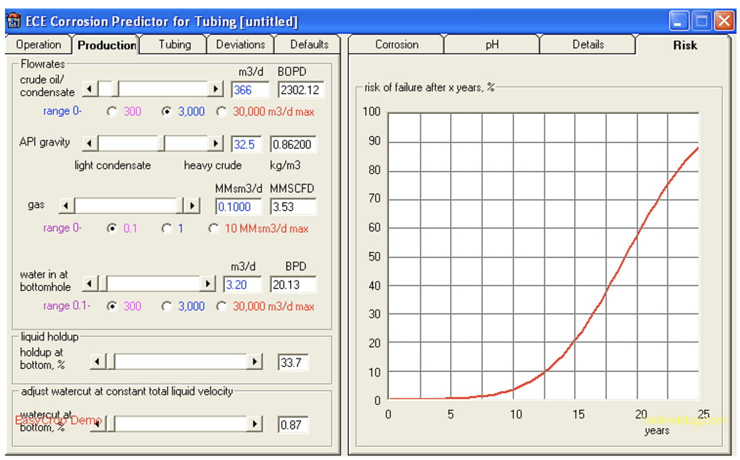

Figure 4.2.1.8: Failure risk increase with presence of water in gas producing wells.

Besides the presence of H_2S, CO_2 and free water, other factor that should be considered when predicting corrosion is the chloride content. Recent failures of corrosion resistant alloy (CRA) production tubing and sand control screens due to stress corrosion cracking (SCC) were also regularly reported. Investigation of these field failures revealed that calcium chloride completion brine or brine containing calcium chloride was a major component in most failures. Consequently, a growing perception is developing that calcium chloride or even calcium chloride/calcium bromide completion brine should not be considered for use in wells completed with high strength CRA tubular in high-temperature, high-pressure environments. The operation and design stage data from East Malaysia, field B were used and is discussed in detail next. Figure 4.2.1.9 and 4.2.1.10 show the result of design and operation stage predictions of ECE4. Here again ECE4 produce a consistent predictions for both the design and operation stage of 0 mm/y.

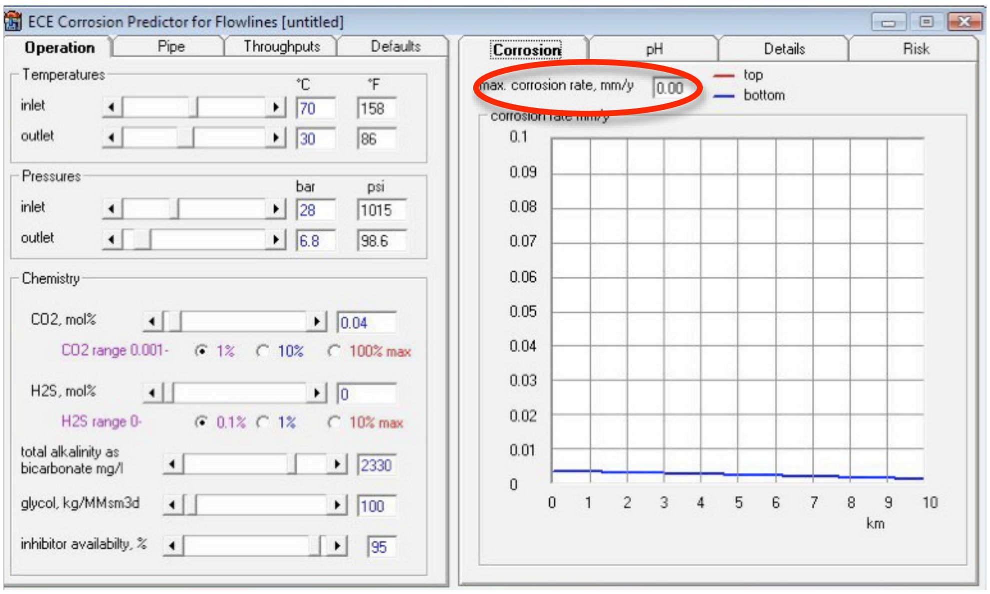

Figure 4.2.1.9: Design stage ECE4.

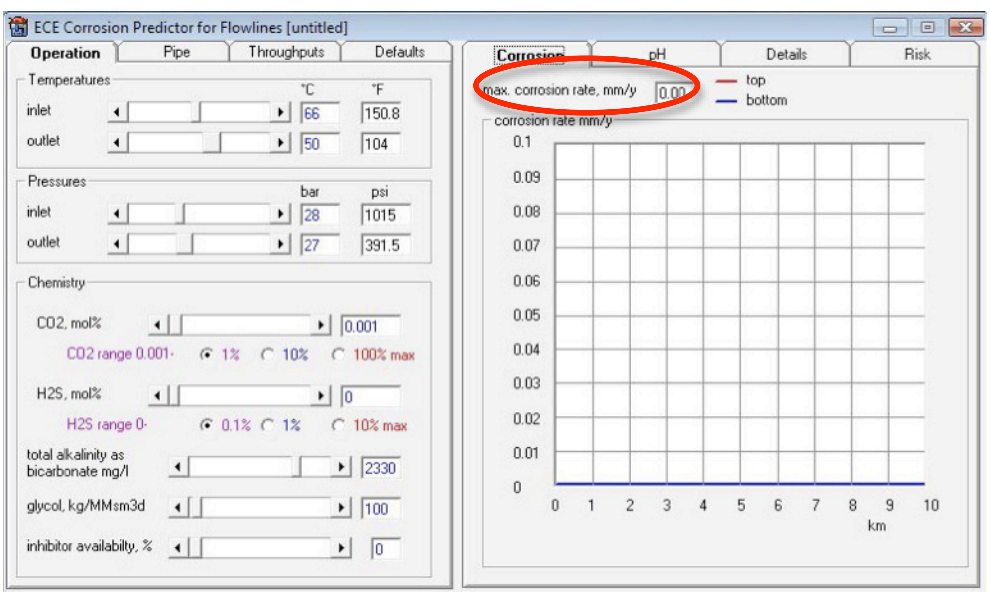

Figure 4.2.1.10: Operation stage ECE4.

SCC refers to cracking of metal involving anodic processes of localized corrosion and tensile stress in the presence of water and H_2S. However, it becomes necessary to further understand the SCC behavior of high strength CRA materials in brines containing calcium chloride and/or calcium bromide, the most widely used, economical completion brines and packer fluids. Thus, it is vital that we considered this parameter to get more precise predicted corrosion.

Here, study was also done on the material selection tools. It is understood that the tubing's and pipeline costs are a considerable part of the investment in subsea projects, and for long-distance, large-diameter pipelines, they can become prohibitively high if the corrosivity of the fluid necessitates the use of corrosion-resistant alloys instead of carbon steel. Better understanding and control of the corrosion of carbon steel can increase its application range and therefore have a large economic impact.

ECE4 provide good material selection tool as they have database on what material to be selected for safe conditions of well or pipelines. The life cycle cost evaluation tool also will give rough indication of the relative cost between the CRA option and carbon steel, and particularly show how the overall life-cycle costs is. Figure 4.2.1.11 shows the CRA evaluation tool in ECE4.

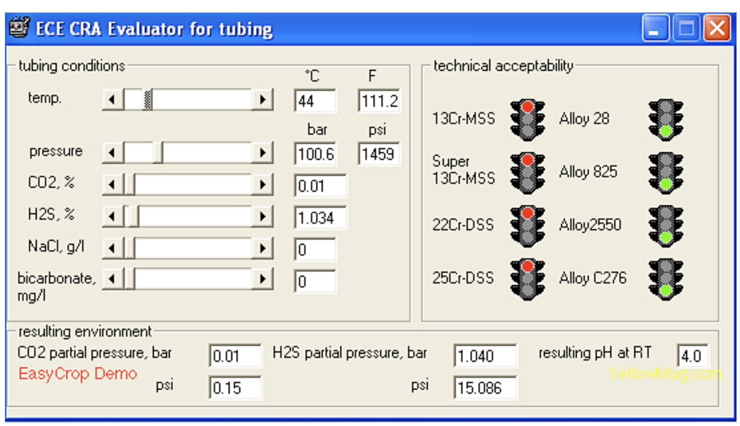

Figure 4.2.1.11: ECE4 CRA evaluation tool.

Manipulating around with the figure, output revealed that temperature and H_2S content influence the choice of material selection. At high temperature (above 170 deg C), one by one material starts to fail its technical acceptability. Starting with 13Cr-MSS to finally Alloy C276 that can stand temperature of up to 300 deg C. But in the case of H_2S presence, even small amounts of H2S (1%) appear at low temperature condition, it can fail all four chromes.

Table 4.2.1.1 show the comparison of corrosion rate predicted at design and operation stage for field B and field J. Results show that design stage and operation stage predictions are considerably alike. But higher prediction is usually obtained at design stage. Comparing it with real corrosion rate data obtained from offshore ultrasonic test can test accuracy of the field data. Both design and operation stage came up with predictions that are more than 100 percent deviation from the real corrosion rate value of 0.014 mm/y.

Table 4.2.1.1: Design and operation stage predicted corrosion rates (ECE4).

Field	**Corrosion rate, mm/year (ECE4)**	
	Design	**Operation**
Field B	0	0
Field J	0.250	0.160

This could be due to many factors. One of them is due to applying lots of default values in the design stage. Both design corrosion rates were predicted differently compared to the predictions obtain during the operation stage. Many parameters were not considered in ECE4. Important variable e.g. the effect of carbonate should have been considered and that should revise the corrosion rate to a more accurate value. When these critical parameters were retained from the modeling, project can be at risk by selecting low CRA steel or choosing high cost material that will sacrifice total project’s cost.

4.2.2 MULTICORP

Simulations have also been done on MULTICORP. This is to compare on the corrosion rate predicted as stated in the methodology.

1) To compare corrosion predicted in design and operational stage using same field data.
2) To compare corrosion predicted from two different models (ECE4 & MULTICORP) by using same well data.

So, now we have both results from the ECE4 and MULTICORP, collation of the output can be seen in terms of the (1) and (2) objectives.

These simulations were performed using different field data as used previously. The same operation and design stage data from East Malaysia field B were used in this section. The result of design and operation stage predictions of MULTICORP is shown in Figure 4.2.2.1 and 4.2.2.2. The difference is in terms of the amount of data that can be used for the modeling. MULTICORP allows the user to input more value when performing the simulation of data. Thus, it is evident that critical parameters like the effect of acetic acid content, carbonate and flow type and velocity were considered.

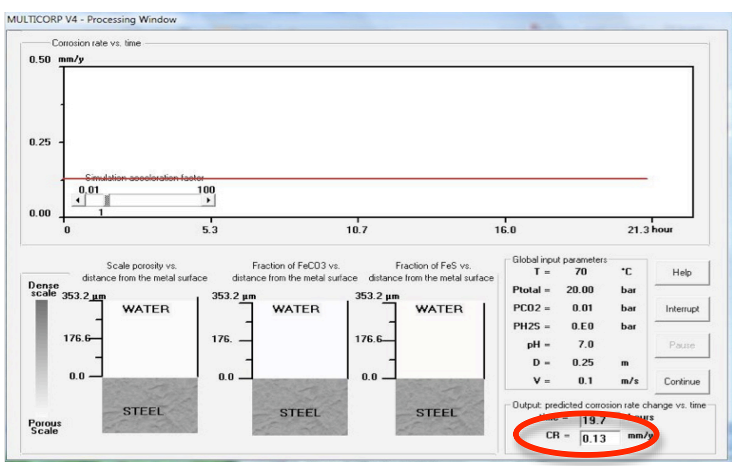

Figure 4.2.2.1: Design stage MULTICORP.

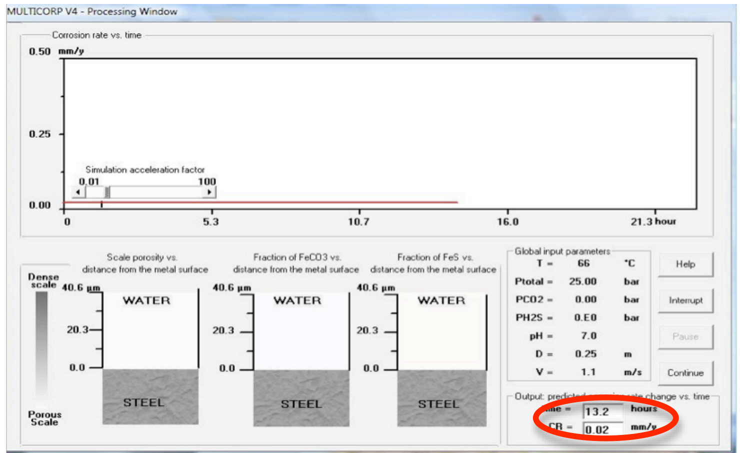

Figure 4.2.2.2: Operation stage MULTICORP.

Looking at the figures above, it can be seen that both the design and operation stage give a big difference of prediction when using MULTICORP. The big differences in the prediction between design and operational stage is due to the amount of parameters used during each stage. The more critical parameters considered the higher accuracy predictions could be achieved. This was proved in the explanation below. Predicted corrosion rates vary with the sets of field data used and what parameters are available.

It is a good identification if the design and operation predictions are closed to one another. Material selection, maintenance plan such as corrosion prevention measures and the risk associated with the project throughout its life cycle are highly dependent on the design stage predictions, thus it is very crucial that the early predictions at the design stage are precise. Low corrosion rate predicted at the design stage can also forfeit the risk of failure in the material chosen. Thus, the best possible state is to have accurate predictions at the design stage. Table 4.2.2.1 show the corrosion rate predicted from MULTICORP using data from two different fields respectively.

Table 4.2.2.1: Design and operation stage predicted corrosion rates (MULTICORP).

Field	**Corrosion rate, mm/year (MULTICORP)**	
	Design	**Operation**
Field B	0.130	0.020
Field J	0.080	0.018

Above shown the same field data used to figure the corrosion rate using MULTICORP. From the table above, having the value of the pipeline thickness (from the Ultrasonic test) for field J, we get to calculate the preciseness of the models. The initial pipeline thickness was 12 mm and reading attained from the ultrasonic test was 11.9 mm. The ultrasonic data was attained at the exact location where field J data was obtained. For a 7 years operating pipeline, the corrosion rate is calculated to be approximately 0.014 mm/year. Comparing this value with the predicted value in the operation stage (by MULTICORP), there is a 29 percent difference. This could be due to the inaccuracy of the model. Now comparing the design stage value of 0.08 mm/year of corrosion rate with the value from the ultrasonic test (0.014 mm/year), the difference is even bigger with 471 percent deviation.

Distinct value of predicted corrosion of the MULTICORP shows that when true field data value were used to predict, with certain parameters considered it will give more accurate value of predictions. A higher prediction value in the design stage (of MULTICORP) is due to the many default values used in the model. Here the effects of using default values can be seen. It gives high value of predicted corrosion. This can significantly affect the material selection. Even with MULTICORP, high deviations of prediction value can be attained (in design stage) if the default values are simply put as any value. Logical values should be used as default values to increase its credibility. High corrosion rate corresponds to high quality of CRA that is much more expensive. When actually the corrosion rate is much lower. Safety is secured in that case, but total project cost is relinquished.

This is important that it should be reduced or minimized. By having appropriate study on both models, we have come across to a position where we know that it is important that few critical parameters like stated below in Table 4.2.2.2 should be considered to come to accurate predictions.

Accuracy of the value predicted using the models could be determined by comparing it with the actual value of metal loss measured offshore. Equipment such as ultrasound was used in the Ultrasonic testing to measure he actual wall thickness of the pipeline by introducing a high frequency sound wave into the exterior side of a pipe, and reflecting the sound wave from its interior surface.

Table 4.2.2.2: Comparison of parameters used in both models.

Parameters	ECE4	MULTICORP
CO_2 mole %	✓	✓
H_2S mole %	✓	✓
O_2 in water	–	–
Acetic acid in water	–	✓
Pressure	✓	✓
Temperature	✓	✓
Gas flow rate	✓	✓
Oil flow rate	✓	✓
Water flow rate	✓	✓
Internal diameter	✓	✓
Pipe length	✓	✓
Bicarbonates	–	✓
Sulphates	–	✓
Chlorides	–	✓
Dissolved iron in water	–	✓
API gravity	✓	✓
Oil density	–	✓
Oil viscosity	–	✓
Water density	–	✓
Water viscosity	–	✓
pH	✓	✓
CO_2 partial pressure	–	–
Oil velocity	–	✓
Water velocity	–	✓
Water cut	✓	✓

Initial design stage consumes cost most crucially. Having a big divergent corrosion rate values could affect the total project life cycle. Predictions should be as accurate as possible in order to come up with the most economical material and processes to maximize the profit of the project. Material selection is a vital process in achieving the best quality and value for the project feasibility. Materials such as carbon steel, high strength low alloy steels, austenitic, martensitic (13 Cr) and duplex stainless steels, titanium alloys, clad and lined pipe and other corrosion resistant alloys comes with different specifications.

Type of materials to opt for depends on the conditions of the fluid e.g. its operating pressure, temperature, flow rate, velocity, pH etc. Having known these parameters, corrosion rate can be estimated. The result can then be used to evaluate on the proper material to be used for any specific well or pipeline operations. As mentioned before ECE4 comes with a CRA evaluation tool that can predict types of carbon steel suitable for any sweet and sour conditions. The tool is also able to come up with a life-cycle cost that evaluates the economics of the carbon steel corrosion control besides predicting early failure of the carbon steel.

Other than ultrasonic testing, intelligent pigging can also be used to measure the metal loss inside the pipelines due to corrosion. It is a device that travels inside a pipeline to clean or inspect. It is typically known as a "PIG". In our case here, the pig is used to inspect. A Magnetic Flux Leakage (MFL) tool contains electronics and collects data real-time while traveling through the pipeline. As the tool travels along the pipe, the sensors detect interruptions. These interruptions are typically caused by metal loss and which in most cases is corrosion. The value attained from the pig reading can also be used as a reference to that predicted from both the models.

CHAPTER 5
CONCLUSION & RECOMMENDATIONS

5.1 Conclusion

The accuracy of ECE4 predictions for the design stage is higher by ore than 200% compared to the operation stage predictions.

MULTICORP did come up with predictions that are within 30% difference of the design and operation stage.

CO_2 partial pressures, H_2S, acetic acid, carbonate content, flow type and flow velocity are the crucial parameters that can highly stimulate corrosion process to occur. Therefore, it is essential that the user have the ability to accurately predict the default values if the data are not available.

With less data available, ECE4 can provide satisfactory predictions. MULTICORP would be a better model for higher accuracy predictions if more data were available.

Both models were design based on different philosophies and they require different amount of input data. MULTICORP takes into account more critical parameters in their predictions compared to ECE4. However, not just the amount of data that should be considered but how reliable the data is can also be questioned.

5.2 Recommendations

The next step would be to study further on many other factors that can affect the corrosion prediction besides that were discussed above and to model on different field data using both ECE4 and MULTICORP considering more parameters. A well-constructed model will be very useful in providing the results and abundance of data will help to come up with a much better accuracy predictions. By understanding the proper functions of the models and knowing the vital input data required, PETRONAS could less rely on the consultant to perform the corrosion prediction and this could assist in producing outputs with a more accurate result in selecting materials. Proper material selection process could save a lot in total project cost life cycle.

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APPENDICES

Gantt Chart