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# Conflicting Views: $CO_2$ Corrosion Models, Corrosion Inhibitor Availability Philosophies, and the Effect on Subsea Systems and Pipeline Design

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## Abstract

This publication examines the influence of different corrosion models, corrosion availability philosophies, corrosion control philosophies and standards on materials selection and corrosion allowance design criteria for subsea systems and pipelines. These differ enormously from operator to operator and national authority to national authority. The result is that for the same nominal environmental conditions, pipeline and subsea systems designs can vary enormously, depending on who is the client and where the facility will be situated. Also, it results in designs that would be deemed as entirely acceptable for operation in one area of the world, but which would be considered as unsafe for operation in another.

This publication discusses the nature of these influences, and the effect on subsea system materials selection and corrosion allowance. It also discusses the conceptual conflict between what can be designed for in theory, and what experience tells us has actually been achieved in practice. Finally, it discusses the approach that Ionik Consulting would take in formulating solutions to these issues.

## Introduction

In terms of materials selection and corrosion allowance for subsea systems and pipelines, two of the dominating criteria are corrosion modelling and corrosion inhibitor availability. Different operators and subsea systems designers have different philosophies, both in terms of corrosion inhibitor availability and corrosion modelling. This can lead to a wide variance in terms of recommended corrosion control methodology, materials selection and corrosion allowance calculations.

Different national authorities also have varying approaches to these issues. This results in designs that would be deemed as entirely acceptable for operation in one area of the world, but which would be considered as unsafe for operation in another. One comparison that can be made is the effect on developments within the UK and Norwegian sectors of the North Sea, and will be discussed later.

This publication discusses the nature of these influences, and the effect on subsea system materials selection and corrosion allowance. It also discusses the conceptual conflict between what can be designed for in theory, and what experience tells us has actually been achieved in practice. Finally, it discusses the approach that Ionik Consulting would take in formulating solutions to these issues.

## Corrosion Modelling

Many corrosion modelling packages now exist. These range from in house operator developed models such as Hydrocorr (Shell) and Cassandra (BP, with other non BP variants), to industrial commercial packages such as the Honeywell/Intercorr Predict 4.0 software, university developed models such as Multicorp (University of Ohio), and corrosion models presented in the form of national standards such as NORSOK standard M-506.

A number of these models are conceptually based around the semi-empirical work of DeWaard, Milliams and others (1-3), with modifications to a lesser or greater extent. This would include models such as Cassandra and Hydrocorr.

Some models are based around empirical research and testing other than the references discussed above. This would include the NORSOK M-506 corrosion model.

Others are mechanistically based models, with testing and research used as confirmation of the model rather than as the basis for the model itself. The primary example of this type of model would be the University of Ohio Multicorp model.

A number of these corrosion models have been examined as part of a recent joint industry project (JSP) carried out at the

Institute for Energy Technology (IFE) in Norway. Further discussion can be found in papers published by Nyborg (4).

Because of the varying calculation criteria for the different models, these can give very different corrosion rate predictions for the same data input. This is especially true under conditions where the formation of protective films may occur, such as at elevated temperatures.

Of the models available, the two most commonly used are the BP Cassandra model (or non BP variants thereof) and the NORSOK M-506 model, as these are regarded as freeware (5,6).

## Corrosion Inhibitor Availability Philosophy

Two concepts have historically been used to describe corrosion inhibitor performance in the field. These are corrosion inhibitor efficiency and corrosion inhibitor availability.

Corrosion inhibitor efficiency is based on the formula given below:

Inhibitor Efficiency (%) = 100x (CR uninhibited – CR inhibited)/ CR uninhibited

This essentially examines the ratio of the inhibited and uninhibited corrosion rates and expresses this as a percentage. An inhibitor that reduced corrosion rates by a factor of 10 would be 90% efficient.

The problem with this approach is that while inhibitor efficiencies of perhaps 98+% can be achieved in laboratory testing, long term field monitoring often indicates efficiencies of 90% or less. One of the primary reasons is that in the field there will be periods when corrosion inhibitor is not injected due to pump failures, logistics problems and other issues.

This lead to the development of the concept of corrosion inhibitor availability. In this concept, field performance is determined based on the summation of total metal loss over field life, assuming periods of inhibited corrosion and uninhibited corrosion. Total metal loss over field life based on 95% corrosion inhibitor availability would thus use an inhibited corrosion rate for 95% of the total exposure time and an uninhibited corrosion rate, from modeling, for 5% of the time.

The concept of corrosion availability is presently supplanting the concept of inhibitor efficiency with respect to use in corrosion inhibition concepts for systems design.

Although most operators employ a corrosion inhibitor availability philosophy, these have not been presented into the public domain. Two exceptions to this can be found in public domain papers published by personnel working for 1) Shell and 2) BP. These papers are very useful in comparison. The BP approach lies at the ‘conservative’ end of the spectrum of philosophies, while the Shell approach could be considered an example of a more ‘liberal’ philosophy.

On the conservative side, two papers published by Hedges, Paisley and Woollam (7,8), describe the philosophy from the BP perspective. For a “medium” risk system, with modelled uninhibited corrosion rates of up to 3mm/yr, a target of 90% corrosion inhibitor availability is recommended. This is often used by corrosion engineers and oil field chemical companies as a target value that should be achievable with standard corrosion inhibitor injection equipment and corrosion monitoring technologies such as corrosion coupons and electrical resistance probes. This concept is reinforced by the NORSOK M-001 materials selection standard (9), developed by the Norwegian Oil Industry Association (OLF) and Federation of Norwegian Manufacturing Industries (TBL), and applied by the Norwegian authorities as the definitive document for oil and gas developments in the Norwegian sector of the North Sea. With respect to corrosivity calculations, and in lieu of additional information, an inhibitor availability of 90% is recommended as the standard design default.

The papers by Hedges *et al* (7,8) describe the maximum recommended corrosion inhibitor availability as 95%. They state explicitly that this is not strictly defined in terms of injection pump availability, which can exceed 98%, but takes into account many other factors that can influence corrosion inhibitor availability. They do not specifically exclude the use of inhibitor availabilities above 95%, but do state that this is outside BP recommended practice.

Within the BP guideline document for the use of the Cassandra program (10), it states that “even a >99% pump availability should not be used as a basis for assuming > 95% inhibitor availability. Carbon steel and corrosion allowance with corrosion inhibition is unlikely to provide integrity for the full field life, thereby requiring repairs or replacements. It should only be considered once environmental and economic analyses have shown this to be more cost effective than using corrosion resistant materials - an option of last resort”. It also states that this level of corrosion risk is beyond BP’s recommended practice.

The NORSOK M-001 standard is more explicit. It states specifically that inhibitor availabilities above 95% should not be used, and that corrosion resistant alloys should be selected if corrosion inhibitor availability requirements are found to exceed 95%.

Both the BP and NORSOK philosophies state that, for design and corrosion allowance calculation purposes, an inhibited corrosion rate of 0.1mm/yr should be assumed.

On the more liberal side, the paper by Rippon (11) describes the Shell perspective on corrosion inhibitor availability. There are a large number of philosophical differences. The base case for inhibitor availability, with typical injection equipment and corrosion monitoring, is set at 95%, not 90% as described by NORSOK M-001 and the BP associated authors. The upper limit for inhibitor availability is set to 99% (with the possibility of systems in excess of 99% examined), not 95%.

As well as differences in corrosion availabilities, there are differences with respect to the baseline inhibited corrosion rates to be applied during the design phase. The paper by Rippon describes a graded baseline, dependent on temperature, with 0.05mm/yr recommended for temperatures less than 70$^{o}$C, 0.1mm for 70$^{o}$C to 120$^{o}$C, and 0.2mm for temperatures above 120oC. Both the BP and NORSOK philosophies state that, for design and corrosion allowance calculation purposes, an inhibited corrosion rate of 0.1mm/yr should be assumed.

## Corrosion Inhibitor Availability - Experience in the UK Sector of the North Sea

As part of a recent project for an international oil major, Ionik Consulting were asked to give an assessment of experience with respect to achievement of corrosion inhibitor availability in the UK sector of North Sea. There is little or no useful data present within the public domain. Ionik Consulting examined the experience of its own employees, and also informally, and anonymously, canvassed a number of field corrosion engineers and chemical company personnel.

Generally experience to date with respect to multiphase oil production would not be described as promising, with respect to attainment of high corrosion inhibitor availabilities. Where systems have been designed to 90%, availability, 85-90% can often be achieved in practice, as a longer term goal. However, where systems have been designed to high levels of availability (95% or higher), this has typically not been achieved. With respect to multiphase oil production in the UK sector of the North Sea, Ionik Consulting have yet to come across a positive example, either from in house experience or from third party discussion, where a 95% target has been consistently met throughout a field and over the longer term. In fact, for multiphase oil production, as opposed to gas, Ionik Consulting experience indicates that for systems designed to high levels of inhibitor availability, what is typically achieved in practice is 85-90% availability, as found with lower specification designs. This would indicate that the limiting factors are operations and logistics related, rather than being limited by the system design.

As will be discussed in more detail later in this document, one of the primary causes of this is likely to be the operator conflict between corrosion inhibition and production, when problems arise. Given that a loss of production will have an immediate financial effect on an operator, whereas a corrosion problem will be most likely to have an effect after months or years, the temptation to keep producing when inhibitor availability issues arise may be highly tempting.

This ties to some extent with the general experience of Shell, as described by Rippon (11). He states that Shell have achieved 99%+ inhibitor availability in some fields (believed to be onshore). However, they have also seen inhibitor availabilities as low as 50% over field life, and presumably every number in between.

This raises a fundamental question. As pipeline and subsea system designers, should we design systems to what can be theoretically achieved, or should we design systems in accordance with what we know is typically achieved? The Ionik Consulting philosophy on this point will be described later in this document.

For gas producing systems the situation is more optimistic. More highly oil soluble corrosion inhibitors with greater persistency can be used, improving inhibitor availability on the pipeline wall even where pump availability may not be as effective as desired. Also, other alternatives to high levels of corrosion inhibition availability as defined by injection pump operability exist, in addition to the corrosion resistant alloy option. These alternatives will now be discussed.

## Alternatives to Pump Availability for Inhibition of Corrosion in Gas Production

The non corrosion resistant alloy (CRA) alternatives to high pump injection availability can be listed as follows:

- Combine corrosion inhibitor availability with hydrate control
- Use pH stabilization as an alternative to corrosion inhibition
- Use pH stabilization in addition to corrosion inhibition

### Combined Corrosion Inhibition and Hydrate Control

This concept can be effective for ensuring high levels of inhibition as it combines corrosion inhibition with methanol or MEG (monoethylene glycol) injection, when these are used for hydrate control on a continuous injection basis. Corrosion inhibitors can be dosed into the MEG or methanol at the level required for corrosion inhibition. Corrosion inhibition is then dependent on methanol injection.

Because hydrate formation can result in a pipeline blockage on a rapid time scale, many operators will give a high priority to detecting loss of methanol/MEG injection. They will also commit to a cessation of production if MEG/methanol injection failure occurs, to avoid the risk of hydrate formation. As the temptation to keep producing is strongly reduced, this can be an effective methodology for successfully achieving very high levels of corrosion inhibitor availability. There are a number of gas production facilities operating with this concept in the UK sector of the North Sea and around the world, although specific information is usually not in the public domain.

However, this concept alone would not meet the requirements of the NORSOK M-001 standard and would be unlikely to be permitted as a corrosion inhibition methodology in the Norwegian sector of the North Sea.

**pH Stabilization**

One methodology that is allowed under the NORSOK M-001 standard as an alternative to corrosion inhibition, in sweet gas production with condensed water and little or no produced water, is pH stabilization. The NORSOK standard specifically permits this methodology when combined with continuous MEG injection. Instead of the corrosion inhibitor availability formula, a flat corrosion rate of 0.1mm/yr is permitted for use in the design phase. Control of pH is usually achieved by potassium hydroxide dosing of the MEG, although amines could also be used.

**Combined pH Stabilization and Corrosion Inhibition**

Although pH stabilization can be effective in condensed water gas production systems, there is always the possibility of some produced water formation occurring in later life. The most recent developments in corrosion control for gas production have concentrated on the concept of combining pH stabilization and corrosion inhibition with MEG injection. After extensive research, this has now been chosen as the corrosion control methodology for the Norske Hydro Ormen Lange development (12). The research and methodology are described in detail. Between the options of corrosion inhibition, full pH stabilization and combined partial pH stabilization and corrosion inhibition, the combined methodology was found to be potentially the most effective.

## Corrosion Allowance

These differences in both corrosion modelling and corrosion inhibitor availability philosophies can lead to very different corrosion allowance predictions from the same basic data.

As an example, the corrosion allowance for a theoretical pipeline can be calculated using the Cassandra and NORSOK models, and the BP and Shell aligned inhibitor availability philosophies, based on the parameters described below.

100,000ppm sodium chloride brine with 500ppm of bicarbonate ions, 100bara, 1% $CO_2$ (gas phase), 65°C and 100°C, No significant flow effects considered, 20 year design life.

| | |
|---|---|
| Model 1 | Cassandra |
| Model 2 | NORSOK M-506 |
| Philosophy A | 95% availability upper limit, inhibited corrosion rate 0.1mm/yr (conservative) |
| Philosophy B | 99% availability upper limit, inhibited corrosion rate 0.05/0.1 mm/yr (65°C/100°C) (liberal) |

The worst case uninhibited corrosion rates and corrosion allowances are described in Tables 1 and 2 for 65°C and 100°C respectively, below.

Table 1 Corrosion Rate and Allowance Calculations for 1% $CO_2$ and 65°C.

| Model /Philosophy | Uninhibited Corrosion Rate (mm/yr) | Corrosion Allowance (mm) |
|---|---|---|
| 1/A | 2.5 | 4.4 |
| 1/B | 2.5 | 1.5 |
| 2/A | 1.5 | 3.4 |
| 2/B | 1.5 | 1.3 |

Table 2 Corrosion Rate and Allowance Calculations for 1% $CO_2$ and 100°C.

| Model /Philosophy | Uninhibited Corrosion Rate (mm/yr) | Corrosion Allowance (mm) |
|---|---|---|
| 1/A | 4.8 | 6.7 |
| 1/B | 4.8 | 2.9 |
| 2/A | 0.4 | 2.3 |
| 2/B | 0.4 | 2.1 |

If we take the same 100°C conditions and move to 5% $CO_2$, then the differences become more extreme as can be seen in Table 3 below.

Table 3 Corrosion Rate and Allowance Calculations for 5% $CO_2$ and 100°C.

| Model /Philosophy | Uninhibited Corrosion Rate (mm/yr) | Corrosion Allowance (mm) |
|---|---|---|
| 1/A | 10.9 | 12.8* |
| 1/B | 10.9 | 4.2 |
| 2/A | 2.3 | 4.2 |
| 2/B | 2.3 | 2.5 |

The result marked with a * would be considered as excessive for the use of carbon steel with a corrosion allowance. Ionik Consulting use the limit of 10mm, as recommended by the NORSOK M-001 standard and the DNV-OS-F101 documentation (13). In accordance with DNV-OS-F101, Ionik consulting would also recommend a minimum corrosion allowance of 3mm for any upstream pipeline carrying wet hydrocarbons.

In this specific case, model/philosophy 1/A would lead to a recommendation for corrosion resistant alloy, while 2/B would lead to carbon steel with 3mm corrosion allowance, both from the same data source.

## Design Conflicts

As has been described, because of differing design concepts with respect to corrosion models, availability philosophies, corrosion control methodologies and national standards, a huge variation in design concepts can be found with respect to fields with very similar conditions.

**Operator Variations**

Many of the choices in terms of corrosion allowance and materials selection can be tied to the relative conservatism of the operator in question.

Towards the conservative end of the spectrum lie companies such as Statoil and BP. In aggressive environments, these companies are most likely to favour a design based on a corrosion resistant alloy solution. Examples from Ionik Consulting experience include recommendations for CRA clad pipelines and weldable 13 Cr super Martensitic stainless steel on two recent BP gas projects. However, given the present situation with respect to CRA materials costs and lead times, this can, potentially, have a serious effect of the viability of new developments.

Towards the more liberal side lie companies such as Shell and Chevron. Here a carbon steel solution is far more likely to be the chosen option. Again in a recent project involving Ionik Consulting, for a Chevron gas development, the recommendation was for carbon steel and corrosion inhibition tied to the MEG injection for hydrate control.

**National Variations**

One useful comparison that can be made with respect to variations between different national agencies is a comparison of the UK and Norwegian sectors of the North Sea.

With respect to the UK sector, the Health and Safety Executive (HSE) provides guidelines and evaluates development proposals in terms of corrosion and materials. However, there are no rules or specific guidance with respect to corrosion availability concepts, with justification left to operators and designers. This has lead to the authorization of developments requiring very high levels of corrosion inhibitor availability, with values of up to 98-99% in some cases. As has been discussed previously, experience has indicated that this level of availability has proven difficult to achieve in practice offshore UK.

In the Norwegian sector, where developments are limited by compliance with the NORSOK M-001 standard, a maximum limit of 95% availability has been imposed with respect to new systems design. There are thus a number of assets operating in the UK sector of the North Sea that would not be deemed as acceptable designs for facilities operating in the Norwegian sector.

## Ionik Consulting Philosophy

The Ionik Consulting philosophy on the various issues described in these discussion areas is given below.

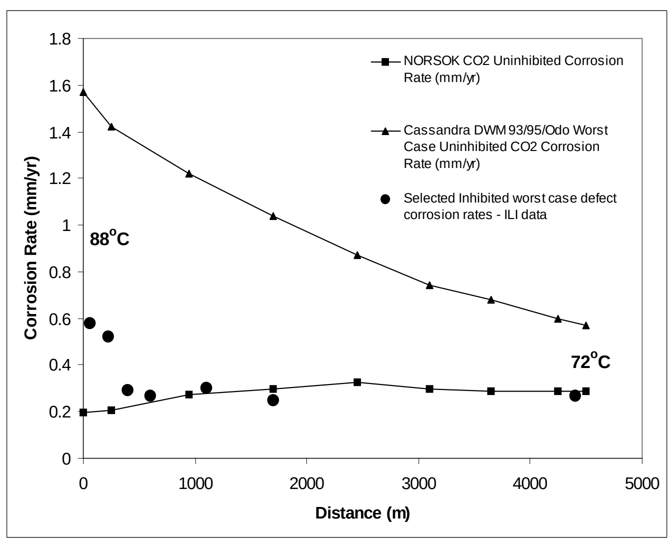
**Corrosion Modelling**

The typical corrosion models used by Ionik Consulting are an in house modified variant of the Cassandra model, and the NORSOK M-506 model. The in house variant of the Cassandra model is based on the public domain concepts behind the BP Cassandra model, and will generate corrosion results very similar to those that would be obtained from the older variants of the BP Cassandra model, prior to incorporation of multiphase modeling post 1998. Ionik Consulting will also use other software packages when provided and licenced by specific clients, such as the latest versions of the BP Cassandra model, and the Shell Hydrocorr model.

Ionik Consulting consider that the NORSOK M-506 model is optimistic with respect to worst case defect corrosion rate at elevated temperatures (>60°C), and the results from the more conservative Cassandra model are recommended as the basis of design under these conditions.

An example from recent Ionik Consulting experience is provided in Figure 1. The data is from a section of a 12" multiphase oil/gas /water line and compares the worst case defect corrosion rate (in the presence of corrosion inhibitor), as established by ILI data, with the uninhibited corrosion rate predictions from the Cassandra and NORSOK M-506 corrosion models.

Figure 1 12" Multiphase Oil Gas Water Flowline Section Uninhibited predicted Cassandra and NORSOK M-506 Corrosion Rates Against Inhibited Worst Case Corrosion Rates From ILI Data.




The main point of note is that the inhibited worst case defect corrosion rates are similar to the uninhibited rates predicted by the NORSOK model, until local temperatures begin to approach 90°C. At this point, the corrosion rate of the worst case defects significantly exceeds the prediction of the NORSOK model, even in the presence of corrosion inhibitor.

Under elevated temperature conditions, Ionik Consulting regard the NORSOK M-506 model as being probably a good indication of the expected uninhibited general corrosion rate, with Cassandra indicating the worst case isolated defect corrosion rate.

**Corrosion Allowance**

The general philosophy of JPKenny/Ionik Consulting is to work within the recommendations of the NORSOK M-001 and DVN-OS-F101 standards and recommended practices. This leads to a corrosion allowance for hydrocarbon carrying lines of minimum 3mm and maximum 10mm.

**Corrosion Inhibitor Availability**

Ionik Consulting have prepared corrosion inhibitor injection and monitoring recommendations for systems with inhibitor availabilities of up to 99% for oil production and >99% for gas production, in line with the recommendations described by Rippon (11), where this has been specifically required by the clients involved and does not exceed the limits imposed by relevant national standards. However, any design requiring greater than 95% inhibitor availability will come with a health warning detailing the potential pitfalls involved, and a strong recommendation that corrosion resistant alloys area examined as an alternative. Where Ionik consulting are asked for recommendations on corrosion inhibitor availability, then a value of 90% to 95% would be proposed, depending on the corrosion monitoring systems and corrosion inhibitor injection equipment to be deployed.

This has been raised to 96% for oil producing systems (slightly in excess of the upper 95% usually recommended) on occasion, with the following additional recommendations:

- A top grade logistics supply and management structure will have to be set up well in advance.
- A strategic reserve of corrosion inhibitor and spare parts for the corrosion inhibitor injection system should be created on the production facility.
- A corrosion management system must be in place and ready to operate from day one of production, and this must operate in a proactive and not a reactive manner.
- The organisation, management, skills and training of personnel will need to be of the highest quality.
- The operator will need to commit to maintaining these capabilities throughout the lifetime of the field.
- The operator must be willing to give preference to maintaining corrosion inhibition over production where conflicts arise.

The latter recommendation will be one of the keys to success in systems where high corrosion inhibitor availabilities. From experience, it is also the recommendation that is least likely to be complied with in practice. Given that a loss of production will have an immediate financial effect on an operator, whereas a corrosion problem will be most likely to have an effect after months to years, the temptation to keep producing may be almost irresistible.

For gas producing systems, other alternatives to high levels of corrosion inhibition availability exist, in addition to the corrosion resistant alloy option. This has been discussed previously.

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