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APPLICATION OF INTERNAL CORROSION MODELING IN THE RISK ASSESSMENT OF PIPELINES

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ABSTRACT

A unique model for prediction of corrosion profiles in oil and gas pipelines has been created. The model is based on multiphase flow modeling, water wetting predictions, pH calculations and models of CO_2 and H_2S corrosion. The input data are typically the pipeline profile, fluid composition data, production rates and data on injected chemicals. It is possible to combine the model with inspection or monitoring data. Based on the uncertainty related to the model and the available data, a probability distribution for the corrosion predictions is established. The result is combined with existing codes for the allowable corrosion attack in pressurized pipes and used to assess the need for pipeline inspection based on the risk of pipeline failure. Detailed examples are given for a gas/oil multiphase pipeline, a crude oil pipeline and a pipeline carrying dried gas under upset conditions.

Key words: Oil and gas production, pipelines, internal corrosion, modeling, risk assessment, risk based inspection (RBI).

INTRODUCTION

Pipelines carrying oil and gas may suffer from internal corrosion if there is water present. The corrosivity will vary in dependence of many factors such as the temperature, total pressure, CO_2 and H_2S content in the gas, pH of the water, flow conditions, use of inhibiting chemicals etc. The wall thickness of the pipe is normally selected from design considerations, in which one assumes a certain design pressure and corrosion allowance. The corrosion allowance is based on assumptions of the corrosivity during the production period. In order to maintain integrity, many pipelines are subject to intelligent pig inspection at certain time intervals. Corrosion monitoring at fixed locations is sometimes used to verify the efficiency of inhibiting chemicals.

For many pipelines considerably cost savings can be obtained if the intelligent pig inspection planning is based on the Risk Based Inspection (RBI) principle. This implies that a risk assessment is carried out for the actual pipeline or pipelines, and that the time to next pig inspection is determined from the risk assessment. An RBI procedure for pipelines requires a means to assess the corrosivity and the corresponding risk of corrosion related failures. The corrosivity can be assessed from previous inspections, from monitoring or from corrosion models based on the process data. In the present paper we will highlight the use of corrosion modeling in the RBI process. The model is described in some detail, and examples of its application on various pipeline cases are given.

THE PIPELINE CORROSION MODEL

General

The pipeline corrosion model has been developed at CorrOcean under the name CorPos(1). The model is composed of several modules, as shown in Figure 1. The model is applicable to a wide variety of internal fluids such as dried gas, wet gas and multiphase oil, gas and water. The modules handling the various steps in the model calculation are described below.

Multiphase flow module

The multiphase flow module is based on the OLGAS 2000(2) and PVTSim(3) simulators. The module provides information on the temperature profile, the pressure profile, the velocity profiles of each phase, phase holdups, shear stresses and flow regimes. Typical input data required are the pipeline profile, production rates of each phase, the chemical composition of the phases, heat transfer conditions and temperatures/pressures at the inlet.

Water phase module

The purpose of the water module is to come up with values for the water wetting factor F_w. This is a factor to be multiplied with the corrosion rate (CR) value for a 100 % water system:

$$\text{CR(actual water wetting)} = \text{CR(100 \% water)}*F_w \quad (1)$$

In a system with wet gas or oil, the water may exist as a separate phase flowing at the bottom of the pipe, or it may be mixed with the oil/condensate to form a dispersion or an emulsion. Separation of water depends on the flow regime, the water fraction and the liquid velocity. The outcome of the multiphase flow simulation is the main basis for the calculation of F_w, but correlations presented and discussed in published papers are also taken into account[1-2]. Many of the published data indicate that the wetting probability can become extremely small for certain oils, especially oils with a high acid number or a high nitrogen content[1]. Without the knowledge of such properties of the oil, some conservatism has to be adopted. In the present model of F_w this is reflected in a minimum value of 0.1, i.e. the value of F_w is allowed to vary from 0.1 to 1.0 in dependence of the flow conditions and the water content.

pH and water chemistry module

The pH is calculated by the XLpH-module, which has been developed for BP's CASSANDRA CO_2 corrosion prediction program[3]. XLpH is applicable to pure water as well as brines with a wide variety of ion concentrations.

When the water phase is dominated by the reservoir water (brine), there is normally no significant variation of the ion concentrations along the pipeline. In wet gas systems the situation is different. The water phase will here be dominated by the water condensing from the gas as the temperature drops along the pipeline. This water has no salts dissolved, and the ions accumulating in the water phase have to come from the dissolution of gases (CO_2 and H_2S) and the corrosion process. Dissolution of CO_2 will cause formation of ions like bicarbonate (HCO_3^-). During corrosion, Fe^{2+}

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(2) Tradename of Scandpower A/S

(3) Tradename of Calsep A/S

and HCO_3^- ions are released as a result of the electrochemical reactions. For wet gas systems, therefore, it is necessary to adjust the Fe^{2+} and HCO_3^- concentrations along the pipeline due to the corrosion process. This may have a significant impact on the pH-profile along the pipeline.

Point corrosion module

For pure CO_2 corrosion the pipeline corrosion model applies the point corrosion module known as the NORSOK-model[4], with minor modifications.

The corrosion rates are calculated from a general formula:

$$CR_t = K_t (fCO2)^{0.62}\left(\frac{S}{19}\right)^{0.146+0.0324\log(fCO2)} f(pH)_t \qquad (2)$$

where

CR_t = Corrosion rate at temperature t [mm/y]
t = temperatures 20, 40, 60, 80, 90, 120 or 150 ºC.
K_t = constant for a given temperature t
f_{CO2} = fugacity of CO_2 [bar]
S = wall shear stress [Pa]
$f(pH)_t$ = the pH factor at temperature t

The values of the K_t and the formulas for $f(pH)_t$ are obtained from the NORSOK M-506 document[4].

The experimental corrosion rates on which the NORSOK M-506 formula is based are largely weight loss data. Thus, the corrosion rates in the deepest pits may be larger. In our pipeline corrosion model we wish to distinguish between failures caused by pipe rupture and leakage. Pipe rupture may take place when the pipe wall is weakened over a certain length. In the model we assume this length to be infinite. The corrosion attack is then named longitudinal grooving. The average corrosion rate of longitudinal grooving is assumed to be identical to the NORSOK-506 corrosion rate.

Inhibitors

When inhibitors are applied the CR value from the point corrosion model has to be modified. There are two ways of doing this, through the use of an inhibitor efficiency (IE), eq. 3, and the use of the concept inhibitor availability (IA), eq. 4.

$$CR = CR_{unmit} * (100 - IE)/100 \qquad [mm/year] \qquad (3)$$

Equation 4 is based on the assumed existence of corrosion inhibitors that are able to protect the steel to a maximum mitigated corrosion rate (CR_{mit}) (typically 0.1 mm/year) regardless of the uninhibited corrosion rate (CR_{unmit}), taking into consideration the percentage of time IA the inhibitor is available at the water wetted surface.

$$CR = (CR_{mit} * IA/100) + (CR_{unmit} * (100-IA)/100) \quad [mm/year] \qquad (4)$$

Model verification

In the period 1999-2001 a Joint Industry Project (JIP) was run by Institute of Energy Technology (IFE) in Norway. The goal for this JIP was to compare different calculation tools for CO_2 corrosion with field data. A total of 12 different models were included in the project. The results from the project showed that our prediction model was one of the models that correlated best with the field data.

COMBINING CORROSION MODEL WITH DATA FROM INSPECTION AND MONITORING

When inspection data (ip) and monitoring data (mon) are available one may combine measurements and model predictions (mod). This can be done as follows:

$$CR_{ave} = w_{\mathrm{mod}} CR_{\mathrm{mod}} + w_{ip} CR_{ip} + w_{mon} CR_{mon} \qquad (5)$$

where w_{mod}, w_{ip} and w_{mon} are the weight factors that can take the values between 0 and 1 depending on an evaluation of the data available, but such that $w_{mod} + w_{ip} + w_{mon} = 1$. The main problem with this procedure is that corrosion rates are not always available from inspection data, and that monitoring data are limited to one or a few locations. With inspection data available one may predict the future development of observed corrosion features as follows:

$$d(T) = d(T_0) + CR_{ave}\Delta T \qquad (6)$$

$$L(T) = L(T_0) * d(T)/d(T_0) \qquad (7)$$

where

$d(T_0)$ = depth of a corrosion feature as determined from inspection at time T_0
$d(T)$ = depth of a corrosion feature as predicted at time T
$L(T_0)$ = length of a corrosion feature as determined from inspection at time T_0
$L(T)$ = length of a corrosion feature as predicted at time T_0
$T = T_0 + \Delta T$

RISK ANALYSIS

General

The definition of risk is:

Risk = Probability of failure x Consequence

For a subsea pipeline the consequence of a failure is large and assumed not to be very variable along the pipeline. Risk analysis of pipelines is therefore concentrated on the probability of failure. The acceptable annual failure probability is, however, dependent on the safety class, which again is a reflection of the consequence. According to DnV F-101 the probabilities given in Table 1 should be obeyed[5].

Oil and gas pipelines, where no frequent human activity is anticipated, will normally be classified as Safety class Normal. Safety Class High is used for risers and the part of the pipeline close to the platform, or in areas with frequent human activity.

Based on the requirements of Table 1 DnV has developed formulas for calculation of the "Allowable Pipe Pressure" (P_{corr}) for pipelines with various types of defects as determined from relative measurements (magnetic pigs) or absolute measurements (acoustic pigs). For a single, longitudinal corrosion defect, the formula for relative measurements is:

$$P_{corr} = g_m \frac{2tSMTS}{(D-t)} \frac{(1 - g_d (d/t)^*)}{(1 - \frac{g_d (d/t)^*}{Q})}$$

$$Q = \sqrt{1 + 0.31 (\frac{l}{\sqrt{Dt}})^2} \tag{8}$$

$$(d/t)^* = (d/t)_{meas} + e_d StD(d/t)$$

where

t = nominal wall thickness (mm)
SMTS = Specified Minimum Tensile Strength (N/mm^2)
d = depth of the defect (mm)
l = length of the defect (mm)
D = nominal outside diameter (mm)
$?_d$ = partial safety factor for corrosion depth
$?_m$ = partial safety factor for model
$?_d$ = factor for defining a fractile value for the corrosion depth
StD(d/t)= Standard Deviation of the instrument reading d/t

When the above formula is used to calculate P_{corr}, values of the safety factors are obtained from tables in the DnV document. The acceptance criterion for operation of the pipeline is then:

$$P_{corr} > P_{mao} \tag{9}$$

where P_{mao} = Maximum Allowable Operating Pressure (MAOP).

The DnV F-101 document also advises on assessment of interacting defects.

Formulas like eq. 8 are frequently used to analyze inspection data to obtain the risk at the time of the inspection. The procedure is then simply to calculate the value of P_{corr} for all or the most important defects and to verify that the criterion 9 is obeyed.

With model predictions as the only basis for risk analysis we do not have information about actual defect observations in terms of depths and lengths. The approach is then to look at two limiting cases that may lead to two different modes of pipe failure:

1. Pipe rupture due to longitudinal corrosion at the bottom of the pipe

2. Leakage due to narrow pits

We shall here only consider longitudinal corrosion at the pipe bottom.

Longitudinal corrosion

The corrosion rate with longitudinal corrosion is obtained from the general corrosion rate predictions of the CO_2 model (CR), which is also the corrosion rate used for wide pits. With longitudinal corrosion the length of the defect becomes infinite. This means that also the factor Q goes to infinity.

StD(d/t) is originally defined to be the instrument standard deviation. In a model prediction we take this to be proportional to StD(CR). StD(CR) is obtained from Monte Carlo simulation taking into account the uncertainties in the input variables, the pH, the wetting factor, the point corrosion models, the inhibitor availability etc.. In the pipeline corrosion model this is handled by the Excel Add-In function Crystal Ball(4), which is a commercial program for any kind of probabilistic Monte Carlo simulations.

CASE STUDIES

Dry gas pipeline

The dry gas pipeline has been in operation for about 3.5 years. In this period the dew point instrument readings indicated that the water content of the gas has been close to the design value (T_{dew} = -18 °C) for about 1075 days, while in a period of 220 days the dew point temperature has been very high, about 3 °C. There were indications that the high dew point readings could be due to erroneous readings, but since the pipeline is not designed for “nearly wet gas operation”, a model study was carried out to investigate the influence of this possible “upset” on the risk of operating the pipeline.

The fluid flow in the pipeline is dominated by the gas phase. Since the temperature varies from about 50 °C at the inlet to about 5-7 °C after 10 km, there is no condensed water phase even in the upset period. The liquid phase present is a thin film of glycol running along the bottom of the pipe. This glycol phase will absorb water from the gas. When the gas is dry the water content is below 5 %, while in the upset period it may rise to about 30 %. This has an influence on the corrosivity. The corrosion and risk analysis of the pipeline as per today showed that the upset period had a negligible influence on the risk. The calculated accumulated corrosion depth after 3.5 years with upset to T_{dew} = +3 °C was only 0.1 mm, while the critical depth based on eqs. 8-9 is 2.0 mm. The nominal wall thickness is 17.3 mm for the first 500 m and 12.0 mm for the rest of the pipeline. Various scenarios up to the end of the lifetime (in 2030) were also considered. The result is shown in Figure 2. It is here evident that even if the upset time fraction of 17 % is continued all the way to the end of the lifetime, this will not lead to an accumulated corrosion depth beyond the critical depth of 2.0 mm. With upset 50 % of the time the corrosion risk will become unacceptable towards the end of the lifetime.

The relatively small influence on the risk from corrosion upsets is due to several factors:

- The corrosive phase is not pure water, but a glycol/water mixture with maximum 30 % water. The glycol is an efficient corrosion inhibitor.
- The gas has a relatively low content of CO_2.

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(4) Tradename of Decisioneering, Inc.

- The maximum in the corrosion rate profile is near the inlet under design operation and near the outlet during upsets. Thus, the integration over time tends to average out the maximum in the corrosion rates.
- The pipeline has been designed with a corrosion allowance of 1 mm.

Oil pipeline

The oil export pipeline has been in service since 1985. In the period 1996-98, the last half of the pipeline was replaced. A wax inihibitor is applied to the oil prior to export, but no corrosion inhibitor is applied.

An ER probe mounted topside showed corrosion rates in the period June to December –00 and January to August –01 to be approximately 0.05 and 0.1 mm/year, respectively. Two findings are reported from the magnetic pig inspections in 1987 and 1993, but these were located in the last end of the pipeline which has now been replaced, and were not likely to be due to internal corrosion.

A model study was performed to improve the basis for the evaluation of the need for a new pig inspection. The need for such a study was motivated from the fact that the production data show very large fluctuations, with flow rates varying from 10000 Sm^3/day to 18000 Sm^3/day and a water fraction varying from 1.5 % to 7 %. The inlet temperature and pressure is about 56 °C and 25 bar respectively. The pipe diameter is 0.5 m and the length 37 km.

Figure 3 shows some result from the flow analysis with minimum oil flow and 2 % water. We see here that the oil and the water flow at the same velocity in some pipe sections while they separate at others. This behavior is determined by the pipe profile; separation takes place when the pipe runs uphill. When the water velocity is low the probability of water wetting is quite high.

Corrosion rates profiles have been obtained for the different production scenarios and the integrated result is shown in Figure 4. The curve in Figure 4 reflects the variable water wetting as well as some effects of the temperature. In general the average corrosion rate varies between 0.05 and 0.09 mm/y. These values agree well with the monitoring data on the platform. For the risk analysis we have used the maximum value.

From equations 8 and 9, and the uncertainty analysis of the corrosion predictions, we obtain a critical depth of 4.0 mm for the actual pipe. The nominal wall thickness is 13.1 mm for the first 500 m and 10.6 mm for the rest of the pipeline. The corrosion related risk of operating the pipe in the future is summarized in Figure 5. This figure shows that if we use only the model predictions there will be an acceptable risk until 2030. As an alternative approach we have utilized the negative inspection results in 1993. Assuming the sensitivity of the pig instrument to be 2.1 mm we may conclude that in 1993 there were no corrosion features with a depth larger than 2.1 mm, but there might have been corrosion features with a depth up to this value without being detected. Thus, this alternative forecast starts with a maximum depth of 2.1 mm in 1993 and with a future growth based on the model alone. This approach yields a critical time around 2014. In both cases there is no immediate need to initiate a new inspection.

Multiphase flowline

The 12“ multiphase flowline has been in operation since 1990. The pipeline carries unprocessed oil/gas/water. The length of the pipeline is 13 km and the diameter about 0.3 m.

The pipeline was subject to inspection with magnetic flux intelligent pigs in 1993, 1994 and 1996. Serious corrosion attacks were detected with maximum depths of about 50 % of the nominal wall thickness (12.7 mm), but the correlation between the different inspections was not good. An ultrasonic pig was run in 1998, showing maximum 28 % reduction of the wall thickness. Further intelligent pigging has been made difficult due to the low production rate. In 2000 a thorough analysis was carried out with the purpose of evaluating the risk of pipeline failure before 2005.

Due to very variable production parameters the model study had to be divided into six different time sections, where the gas flow has varied from 50000 to 800000 Sm^3/d and the water content from 2 % to 12 %. The GOR-value is typically 150 – 200, the inlet pressure declining from 30 to 15 bar and the inlet temperature has been in the range 60 – 70 °C.

The flow analysis showed:

- Dominant slugging from 0 – 3 km
- Dominant stratified flow beyond 3 km

Significant flow effects on the corrosivity were thus to be expected near the inlet. This agreed qualitatively with the inspection data, showing that most of the corrosion attacks were concentrated near the inlet part of the pipeline.

Based on the procedure described above a model for the corrosion development of the pipeline was established. For the first part of the pipeline the result is shown in Figure 6, together with the four deepest pits at each inspection. The change from a high corrosion rate to a much lower corrosion rate in 1993 is due to the startup of inhibitor injection. Before 1993 no inhibition was applied. The model prediction in Figure 6 shows corrosion depths of 4-5 mm in the period 93-96, while the average of the deepest pits from pig inspection are in the range 5-6 mm. This is still within the uncertainty of the model predictions (30-40 % of the mean value). It indicates that the model gives a fairly good description of the development.

The inspection data are too scattered to be useful for a trend analysis giving a corrosion rate solely based on inspection. The variation among the three pig inspections is assumed to be due to a development of the equipment as well as the software used to analyze the data. The much shallower pits observed with the ultrasonic pig is assumed to be due to wax problems. Removal of wax in the deepest pits is difficult and remaining wax may give very low signal reflections. Thus, the deepest pits may not be detected.

In order to utilize both model and inspection data, the approach described by equations 6 and 7 was adopted, but with the model corrosion rate only. The ten deepest pits in the 1996 inspection were used as the starting point. The development of these corrosion features up to 2005, both in depth and length, is shown in Figure 7. Extension to 2010 is shown in Figure 8. The solid curve in these figures represent the critical curve for operation of the pipeline with respect to the MAOP-value. A reduction in the MAOP-value from 61 to 52 barg has no significant influence on the situation. We observe that the predicted development of the corrosion features from 1996 to 2005 does not lead to an unacceptable risk, even though some of the features get quite close to the critical curve. In 2010, however, 4-5 of the corrosion features are predicted to grow above the critical curve. This means that the probability of a corrosion failure due to rupture is larger than acceptable. The conclusion from this study was that if the pipeline is to be operated beyond 2005, one should start planning for a new inspection before 2005.

CONCLUSIONS

A unique model for prediction of corrosion profiles in oil and gas pipelines has been created. The model is based on multiphase flow modeling, water wetting predictions, pH calculations and models of CO_2 and H_2S corrosion. Based on the uncertainty related to the model and the available data, a probability distribution for the corrosion predictions is established. The result is combined with existing codes for the allowable corrosion attack in pressurized pipes and used to assess the need for pipeline inspection based on the risk of pipeline failure.

The aspects of the model is demonstrated with cases covering a dry gas pipeline, an oil pipeline and a multiphase flowline. For these particular cases the conclusions are as follows:

- The dry gas pipeline has not been inspected nor has it the facilities necessary for running a pig inspection. Modeling was therefore the only tool available for corrosion assessment. Over the first 3.5 years of operation there was a recorded upset period with a dew point temperature of about +3 °C covering 17 % of the time. The corrosion model predictions showed that this upset period had a negligible influence on the risk of failure.
- The oil pipeline had been inspected in 1996, but no internal corrosion features were found. This information was combined with the model predictions to establish a corrosion depth forecast that could be used to evaluate the need for a new inspection. It was shown that critical conditions were not likely until 2015, indicating that there was no immediate need to run an inspection pig.
- The multiphase flowline had been in operation since 1990, and inspected in 1993, 94, 96 and 98. Deep corrosion features were detected already in 1993, but their further development was obscured due to the lack of a clear trend in the data. The ten deepest pits in the 1996 inspection were used as the starting point for a development prediction, using the model corrosion rate to estimate the future growth. The development of these corrosion features was then observed to become critical soon after 2005. Operation of this pipeline beyond 2005 was therefore not recommended without a new inspection as soon as possible.

In general terms, one may conclude that modeling of internal corrosion of pipelines can be used to get a better basis for corrosivity assessment and risk analysis of pipelines, in particular when inspection data are lacking or when they do not provide a sufficiently good basis for determination of the corrosion rate.

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Table 1. Safety class and target annual failure probability according to DnV[6]

Safety class	**Annual failure probability**
High	$< 10^{-5}$
Medium	$< 10^{-4}$
Low	$< 10^{-3}$

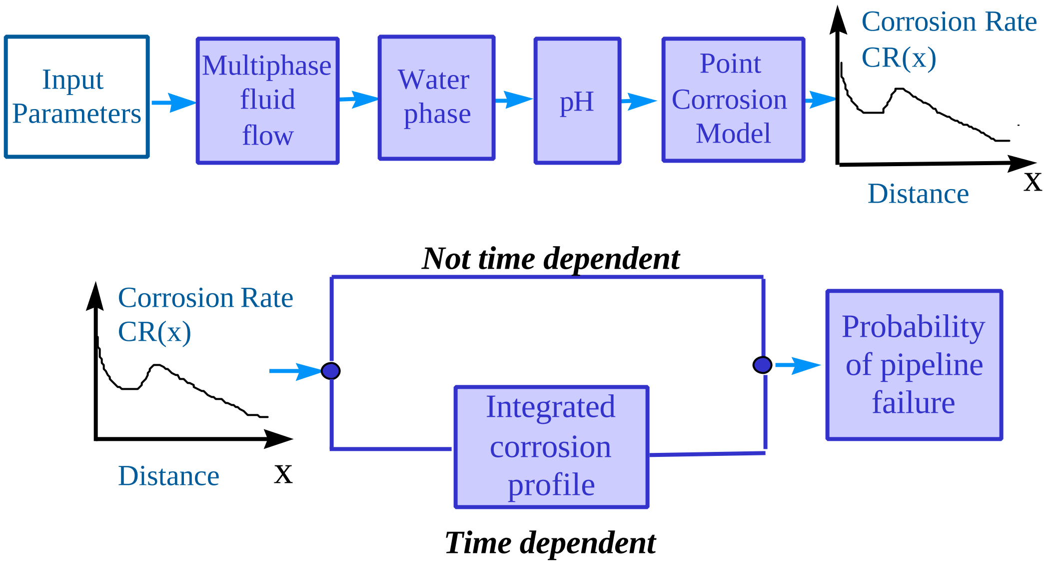

Figure 1. Flow chart of the pipeline corrosion model.

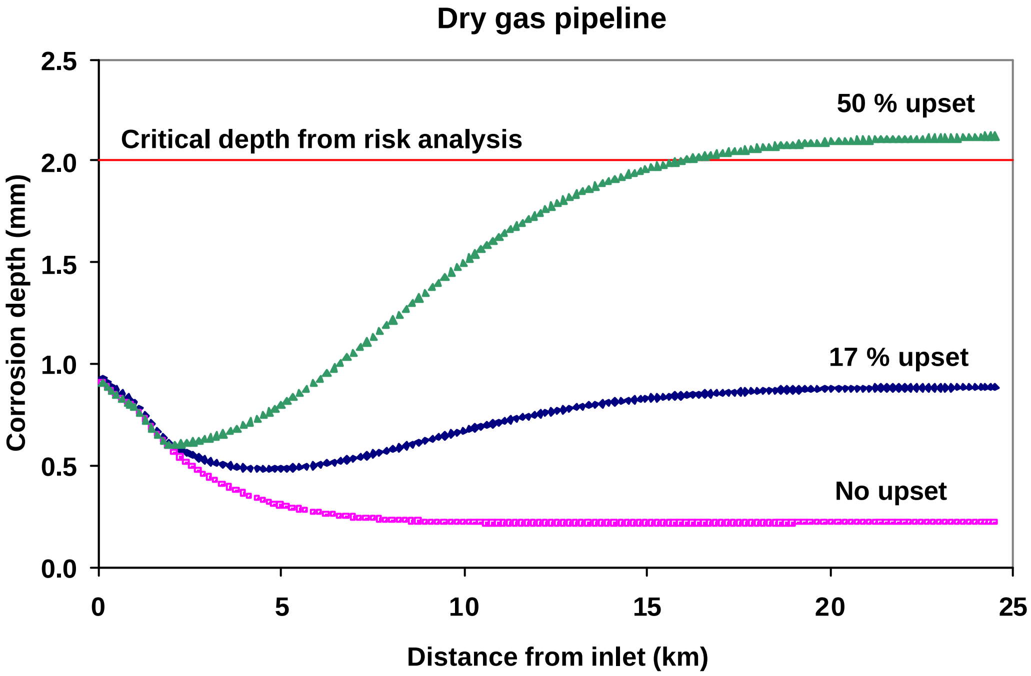

Figure 2. Accumulated corrosion depth profiles in 2030 for different scenarios of upset.

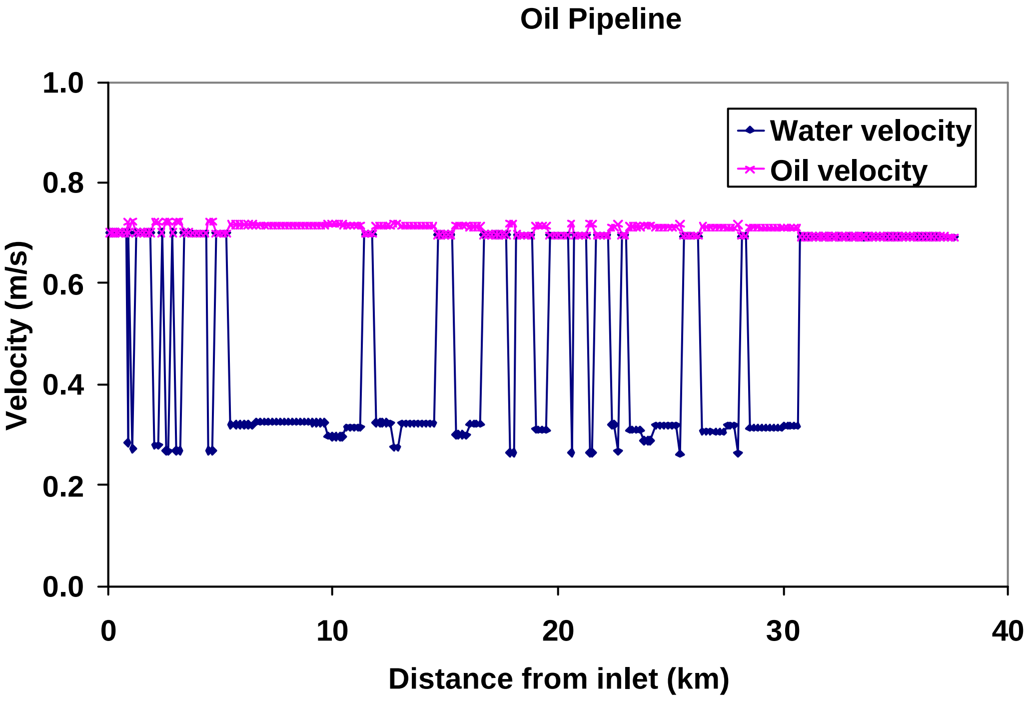

Figure 3. Oil and water velocity profiles for the oil pipeline at minimum production and a water content of 2 %. Results from the flow simulator.

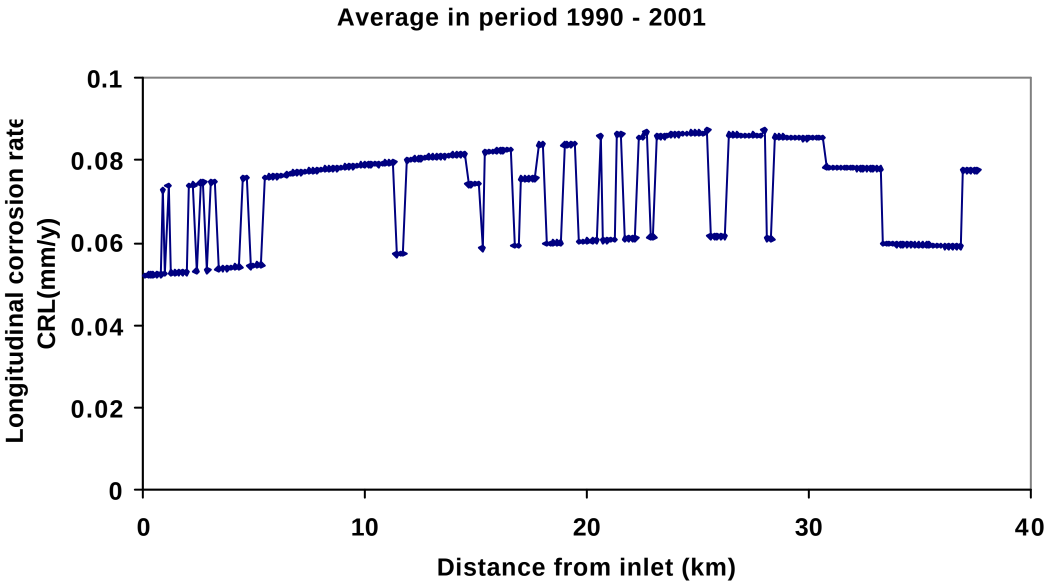

Figure 4. Average corrosion rate profile at the bottom of the oil pipeline as predicted by the pipeline corrosion model.

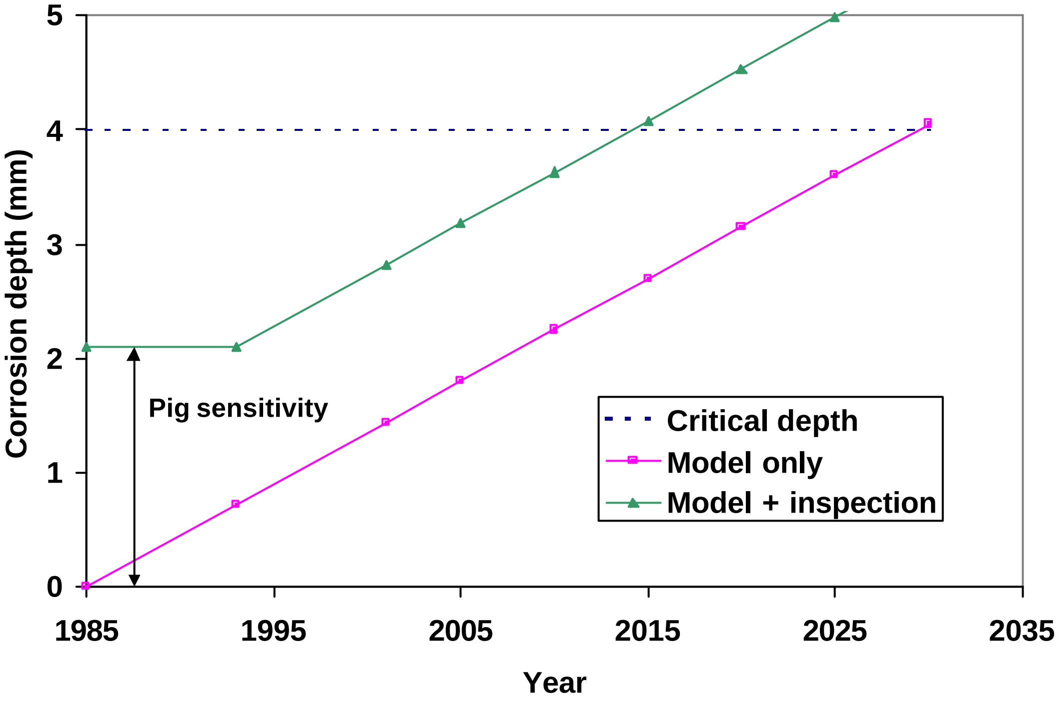

Figure 5. Accumulated maximum corrosion depth as function of the time for the oil pipeline, as predicted by the pipeline corrosion model alone or in combination with the negative findings in the 1993 pig inspection.

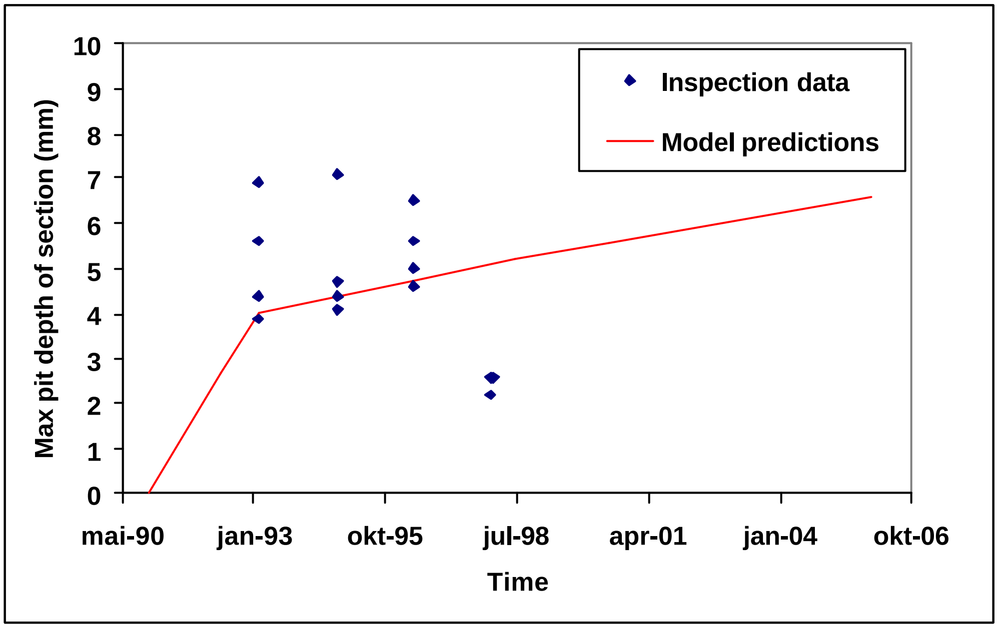

Figure 6. Time development of the deepest internal corrosion pits of the multiphase flowline as observed with pig inspection and the pipeline corrosion model.

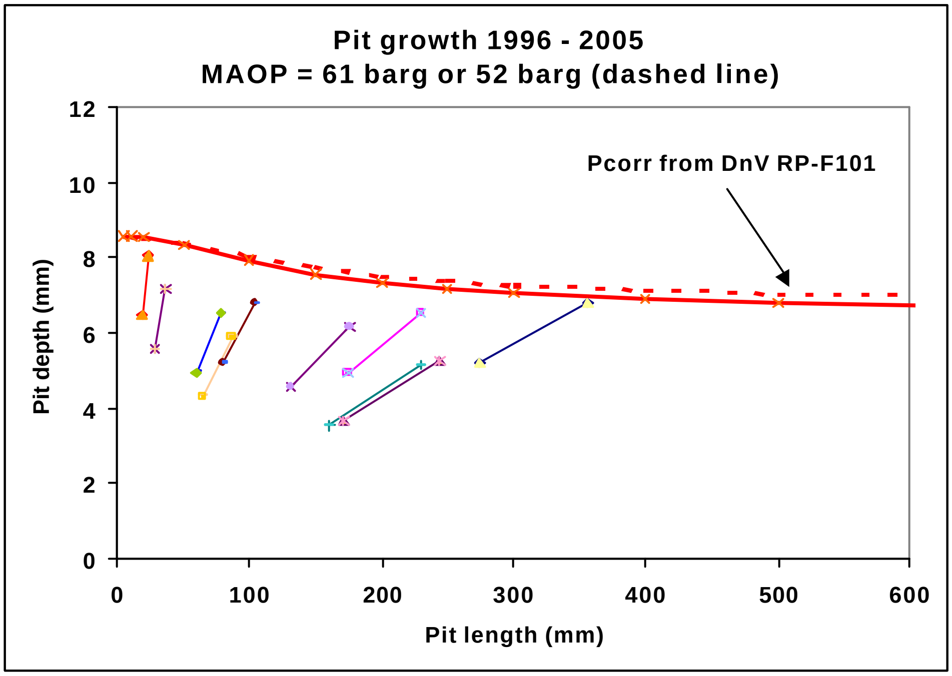

Figure 7. Predicted growth in the period 1996 – 2005 of the deepest pits in multiphase flowline in relation to the critical curve (P_{corr}), based on the inspection data in 1996 and the model predictions thereafter.

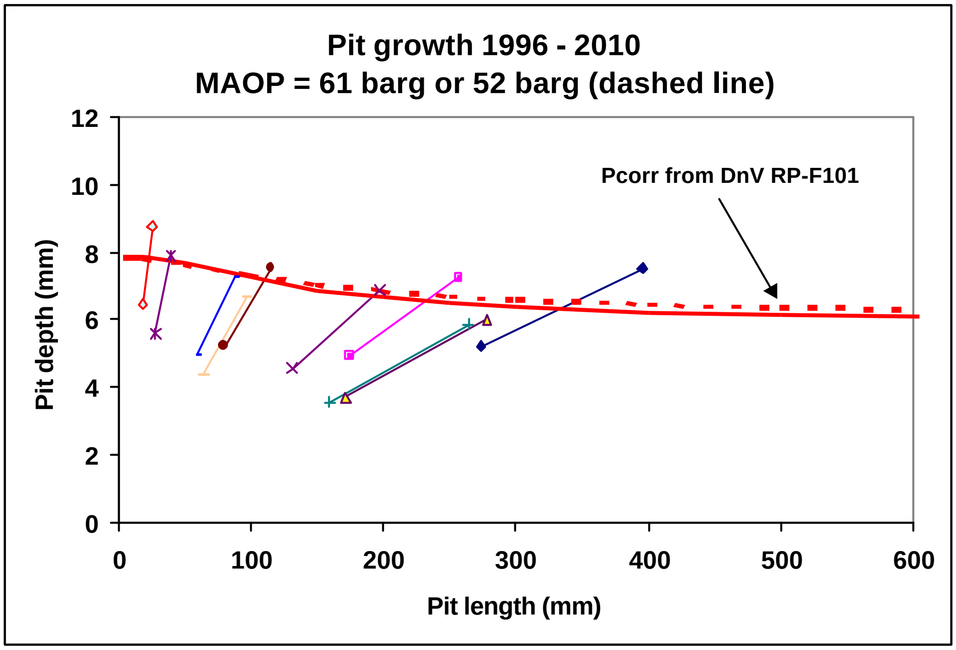

Figure 8. Predicted growth in the period 1996 – 2010 of the deepest pits in the multiphase flowline in relation to the critical curve (P_{corr}), based on the inspection data in 1996 and the model predictions thereafter.