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MODELLING CORROSION RATES IN OIL PRODUCTION TUBING

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Abstract

Data related to tubing corrosion in an oil field have been compiled and analysed in terms of angle of well tubing deviation, watercut and fluid velocity. Using a semi-empirical formula for CO_2 corrosion prediction, it was possible to model the effect on corrosion of the light crude oil produced from a field in the Middle East by means of a multiplier for the corrosion rate, the oil factor. A good level of correlation was achieved between field measured corrosion rates and calculated values using the model established for this specific field. The model was incorporated in a user-friendly computer programme suitable for analysing ongoing corrosion risks and anticipating future field developments.

Keywords

corrosion, modelling, tubing, computer programme, angle of deviation, fluid velocity

1 Introduction

During 1999 and 2000, a review was made of corrosion data obtained from carbon steel (L80) well tubing in a large (~400 wells) offshore oil field operation in the Middle East. From calliper surveys carried out over a 10 year period, and some corrosion monitoring data, an 80 well database was constructed, incorporating operational details such as temperatures, pressures, production rates, water cuts and concentrations of dissolved solids.

The wells were around 7000 ft deep, with typical bottomhole pressures and temperatures of 3000psi (207bar) and 210°F (98ºC), respectively. A very light crude was produced (API gravity of 49), together with varying amounts of water, and a negligibly small amount of gas. The gas-to-oil ratio (GOR) was approximately 300 scf/bbl and the CO_2 content of the produced gas was about 1.5Mol%.

The data from the original database of 80 wells were evaluated on the basis of the availability of all parameters necessary for their interpretation and the consistency of inspection and operational data, ruling out tubing where corrosion inhibitors had been used. This reduced the database to 25 wells, which was further analysed and used for the development of a predictive model for the CO_2 corrosion rate of the carbon steel tubing.

2 Analysis of field corrosion rates

The type of corrosion normally experienced in the downhole tubing was pitting attack. Observed corrosion rates were derived from the calliper readings using the reported depth of maximum corrosion. The corrosion rates were calculated by either dividing this maximum depth of attack by the total time of exposure based on the tubing age, or by dividing the change in depth of attack by the time interval between calliper surveys.

Examination of casing deviation profiles enabled the determination of the angle of deviation with the vertical at the location of maximum corrosion. All environmental parameters such as watercut, flowrate, etc., were established, taking average values for this specific location in the tubing string.

Temperatures, T, and pressures, P, at the location of maximum corrosion attack on the tubing were calculated from linear interpolation over the tubing length. Attempts to use more refined methods to calculate P and T did not give any significant improvement for the fit between the model and the field data.

Table 1 lists the data that were used to model the corrosion rates.

Table 1. Environmental conditions and observed corrosion rates in 25 different uninhibited carbon steel tubings producing oil and water.

Pressure at tubing depth of location of max corrosion, bar	Temp. at tubing depth of location of max corrosion, °C	Flowrate m/s	Average Water %	Depth of Max. Corr location Ft	HCO3 mg/l	calculated pH at location of max. corrosion	deviation angle at location of max. corrosion	observed corrosion rate mm/y
156	88	0.24	0.1	6540	263.5	5.70	42	0.65
156	88	0.06	0.3	6540	263.5	5.70	42	0.30
71	79	0.67	0.1	2850	546.6	6.16	24	0.18
77	73	0.97	2.3	2190	353.8	5.95	1	0.19
178	99	0.93	1.6	7920	353.8	5.86	1	0.31
244	96	0.23	30	9270	254.2	5.61	44	0.23
130	93	1.74	0.1	5640	409.9	5.99	59	1.78
189	96	1.63	0.7	6900	658.8	6.10	1	0.38
193	97	0.81	7	8880	546.6	6.01	47	1.24
75	86	1.80	1.3	2400	741.8	6.39	23	0.66
68	73	0.34	4.9	2580	363.9	6.07	36	0.75
10	80	0.77	1.3	-	442.9	6.98	46	0.00
107	89	0.34	19.2	5220	224.5	5.82	54	1.13
42	81	0.71	15.5	1830	793	6.66	22	0.99
151	85	0.87	1.8	4980	746.6	6.14	31	1.16
168	95	0.02	5	8730	23.7	4.65	41	0.29
161	93	0.01	4	8490	110	5.30	39	0.22
79	88	1.42	0.9	4680	629.5	6.31	49	0.76
86	82	0.30	0.5	4320	915	6.40	40	0.38
36	69	0.27	0.6	1710	180.6	5.97	26	0.56
187	94	0.68	1.1	7470	316	5.82	45	0.88
52	79	1.85	0.2	2310	724.7	6.46	39	1.04
37	70	1.17	2.7	1590	339.4	6.19	29	1.15
104	83	0.71	13.7	3720	356.2	5.99	41	3.02
41	70	0.63	1.9	1080	642.9	6.37	0.5	0.08

For the interpretation of the data, use was made of a semi-empirical model[1] for CO_2 corrosion, with the following formula for the corrosion rate V_{cor}:

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

where V_r and V_m represent the maximum kinetic reaction and mass transfer rates;

$$\log(V_r) = 5.07 - \frac{1119}{T + 273} + 0.58\log(pCO_2) - 0.34(pH_{actual} - pH_{CO_2}) \tag{2}$$

and

$$V_m = 2.7\frac{U_{liq}^{0.8}}{D^{0.2}} pCO_2 \tag{3}$$

for quenched and tempered steels[1]. Here, pCO_2 is the partial pressure(bar) of the CO_2 multiplied with the fugacity coefficient[2], T is the temperature in °C, and U_{liq} is the flow velocity in m/s. The term D is the internal tubing diameter in meters.

pH calculations were based on measured bicarbonate concentrations, CO_2 solubilities and carbonic acid dissociation constants[3 4], and on best fit equations for their temperature dependence. Comparison was made with the measured pH values but, in general, the calculated pH values were used for the interpretation of the data.

At temperatures in the order of 80 °C and higher, protective iron carbonate scale will form, and the corrosion rate will be lowered with a scale factor[2], F_{scale}, where $F_{scale} < 1$:

$$\log(F_{scale}) = \frac{2400}{T + 273} - 0.6\log(pCO_2) - 6.7 \tag{4}$$

which results in a base corrosion rate, V_{base}:

$$V_{base} = V_{cor} \times F_{scale} \tag{5}$$

These base corrosion rates do not correlate well with the observed field data, as can be seen in Figure 1.

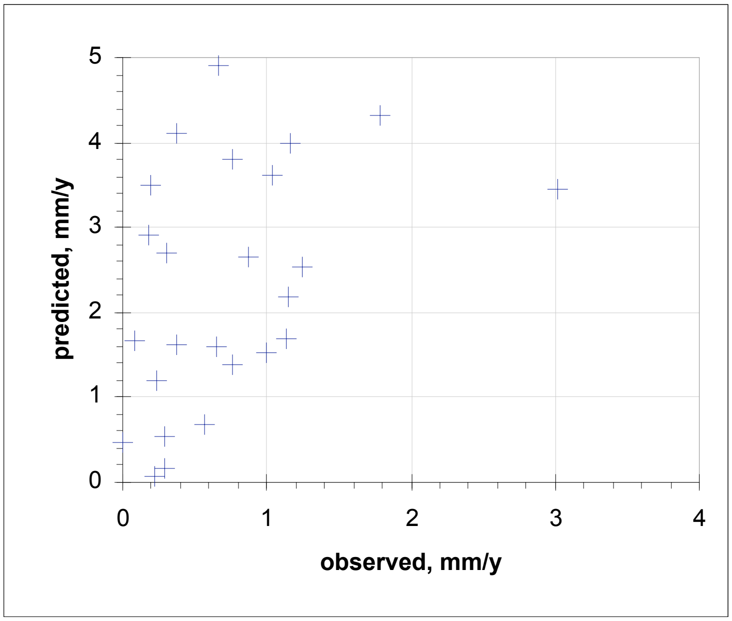

Figure 1. Lack of correlation between observed and calculated base corrosion rates, calculated with Eq. 5

Plots of observed corrosion rates versus various environmental parameters produced scatter diagrams with zero correlation. However, there was some indication of slight positive correlation of observed corrosion rates with the angle of deviation of the tubing at the location of observed corrosion, as shown in Figure 2 (a), and with the average water cut, as shown in Figure 2 (b).

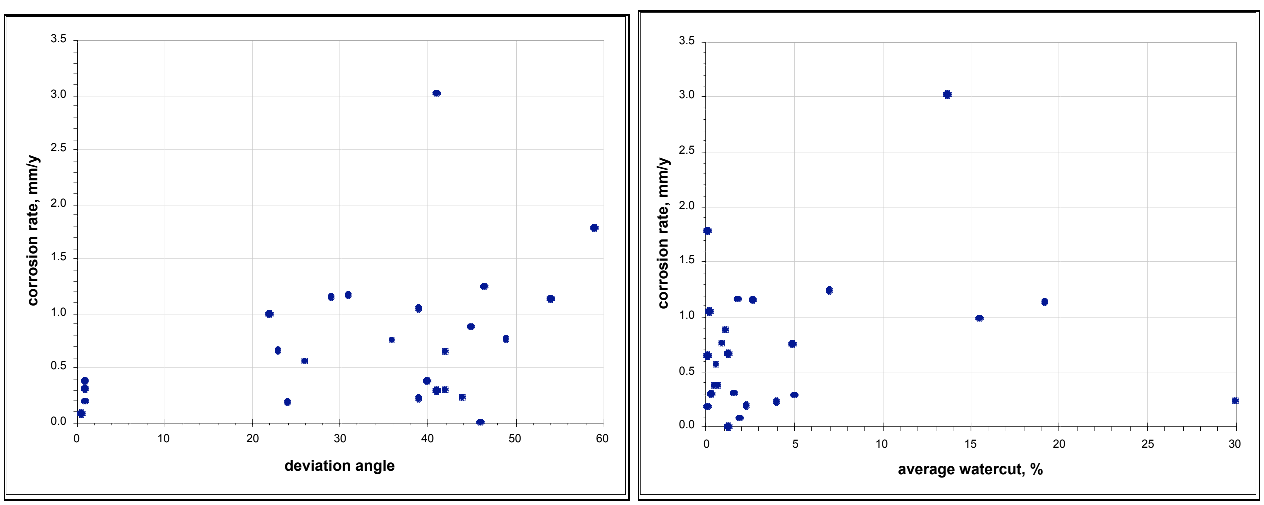

Figure 2. Plots of observed field corrosion rate vs. (a) angle of deviation of tubing and (b) average watercut %.

Various formulae were tried to combine these two parameters in the form of a multiplier, F_{oil}. Using various fitting and modelling techniques, the following formula gave the best fit to the data of all formulae tried:

$$F_{oil} = 0.545\frac{\alpha}{90} + 4.3WU_{liq}\left(1 + \frac{\alpha}{90}\right) \quad (6)$$

where W is the average water fraction of the liquid measured at the wellhead, and α is the angle of deviation (in degrees) of the tubing from the vertical.

With this oil factor, only two constants were needed to obtain an good fit between predicted corrosion rates and field data, as shown in Figure 3, which provided a correlation coefficient R^2=0.80.

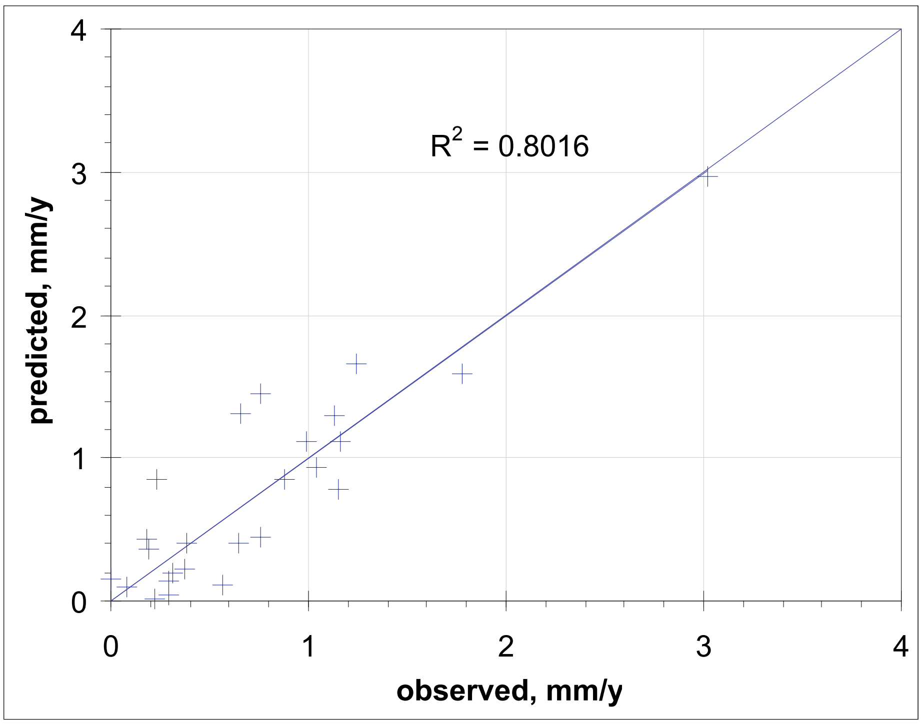

Figure 3. Correlation between observed and calculated base corrosion rates after multiplying the base corrosion rate (Eq. 5) by the oilfactor, Eq. 6.

3 Discussion

The good level of correlation obtained was remarkable, especially considering that the influence of such light crude on the corrosivity has generally been ignored in publications to date. There has been a tendency to regard light crude oils as incapable of carrying water and therefore offering no reduction of corrosion rate compared to full water wetting[5]. This work has demonstrated that some reduction in corrosion rate can be expected, even with such a light crude oil.

The Model shows that F_{oil} becomes smaller with decreasing angle of deviation, and is smallest for a completely vertical well. It has indeed been observed by Gunaltun[6] that the vertical (top) part of a well suffers less corrosion or no corrosion at all.

It should be noted that Equation (6) does not go to zero for zero average watercut. This reflects the findings of the specific field investigated. Several wells showed almost zero 'average' watercut values over long periods of time, but careful examination of the records would indicate occasional high watercut figures. Such wells still had corrosion indications, often associated with the position in the tubing below the section that had the highest deviation angle. The implication is that, in these wells, the production conditions were such that the water was tending to settle within the tubing at the start of the deviated zone. Here, it can cause some corrosion damage that is moderated by the low flow velocity of the corrosive medium.

It has also been pointed out by Gunaltun[6] that such an accumulation of water can sometimes form at very low watercuts. In such cases, no water is detected at the surface most of the time, with just occasional high values being measured if the timing of the measurement coincided with the sudden production of a "slug" of water. The passage of such a "slug" of water can also cause some corrosion in the upper, vertical part of the well, the extent of this corrosion being dependent on the frequency of this event.

For the field presently studied, it is reasonable to state that, even when the well appeared to be dry, there would be a risk of corrosion in the tubing, particularly if the angle of deviation, α, was high, since water would tend to accumulate at this position.

Equation (6) indicates that the protection offered by the oil decreases with increasing velocity. According to Gunaltun[6] the corrosion rate can decrease again at higher flow velocities, since then the water may be entrained in the oil as a water-in-oil emulsion, which is probably less corrosive because of its effect on the total duration of water wetting on the tubing wall. This effect was not found in the present study, probably because velocities were not high enough to emulsify the water in this field.

The results of this modelling exercise were incorporated into a user-friendly computer model, appropriate for the field investigated based on its past history, and geared to the anticipated developments in production conditions. This model could be used to evaluate the corrosivity of wells which had not yet been inspected and could prioritise workovers, as well as identifying those wells which could be safely left in production without intervention, thus resulting in substantial cost savings.

4 Conclusions

Utilising field data collected from a ten-year period of tubing inspections, it was possible to establish a reliable database of well corrosion information from which a corrosion model could be developed.

These field observations of tubing corrosion rates could be modelled by means of a model based on previously published CO_2 corrosion rate formulas, combined with an empirical modifier containing only two adjustable constants, which describes the effect of the crude oil-water mixture on corrosion.

Corrosion rates in oil well tubing depend on the angle of deviation of the tubing with the vertical. A higher deviation angle is conducive to higher corrosion rates. Data analysis identified a relationship between the angle of deviation of the tubing, the water cut and the fluid flow velocity, which resulted in good correlation of predicted corrosion rates with observed values.

The model developed, relevant to these specific field conditions, was incorporated into a user-friendly computer model providing guidance in the decision-making process regarding which wells should be inspected or worked over.

5 Glossary

α	angle of deviation, ^{o} from the vertical
D	diameter, m
F_{oil}	oil wetting factor
F_{scale}	scaling factor
pCO_2	partial pressure of $_{CO2}$ multiplied by fugacity coefficient, bar
pH_{actual}	actual pH
pH_{CO2}	pH derived from dissolved CO_2 only
T	temperature, ^oC
V_{base}	$=V_{cor} \times F_{scale}$, mm/y
V_{cor}	corrosion rate, mm/y
U_{liq}	liquid velocity, m/s
V_m	mass transfer rate, mm/y
V_r	kinetic reaction rate, mm/y
W	average water fraction of the liquid

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