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# Creep life assessment of an overheated 9Cr-1Mo steel tube

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ABSTRACT

Crude oil heater 9Cr–1Mo steel tubes from a refinery plant were studied, after 24 years of service at nominally 650 °C and 27 MPa, to predict their remanent lives. The investigation included dimensional, hardness and tensile measurements in addition to accelerated stress rupture tests between 650 °C and 700 °C and microstructural examination. Tube specimens were taken from two sections, the overheated side and the side which only saw the nominal operating temperature. The method employed involved the prediction of the increase in temperature with increasing sediment deposition during the operating life times using an FEM model. In addition the predicted temperatures are used to derive appropriate creep properties at relevant temperatures in a 3D pipe FEM creep analysis to predict the pipe deformation rate. All compare well with the actual service exposed pipe measurements and layer deposition. The overheated side revealed a small loss of creep strength in a stress rupture test. A layer of sediment (appr. 10 mm thickness) consisting basically of sintered carbon (coke) spread over the inside of the tube was acting as a thermal barrier causing the temperature to rise above 650 °C. Analysis for the overheated side predicted an upper bound temperature of ≈800 °C and a life of about 50 h suggesting that failure by creep rupture could occur rapidly in the sediment region.

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## 1. Introduction

Internally pressurized tubes are critical components in heat-exchanger applications, such as boiler water tubes, steam superheater elements and chemical plant reformer tubes [1,2]. Such tubes in power plants have a finite life because of prolonged exposure to high temperatures, stresses and aggressive environments. Remaining life assessment of aged power plant components in the present highly competitive industrial scene has become necessary both for economic and safety reasons as most of the power plants are over 25 years old. In real life situations both premature retirement and life extension in relation to the original design life can be encountered [2].

The consequences of failure of a component in-use can be tragic and expensive. There are many cases of engineering disasters resulting in loss of life and property. For boiler components, utmost attention is required to ensure that such incidents cannot take place. Carbon and Cr–Mo steels are extensively used in high temperature components in power plants. Even though most of these components have a specific design life of 20 years, past experience has shown that they can have significant remaining life beyond the original design specification [3].

One of the most widely used techniques for life assessment of components involves removal of service exposed alloy and conducting accelerated tests at temperatures above the service temperature [4]. The aim of the present work is to evaluate the remaining life of Crude oil heater 9Cr–1Mo steel tubes from a refinery plant, after 24 years of service, based on experimental and numerical analysis.

## 2. Experimental program

The material specification with service condition and history of operation of the exposed 9Cr–1Mo steel superheater and reheater tubes from a refinery furnace that heats crude oil at 450 °C are given in Table 1. Due to impurities in crude oil, basically sintered carbon (coke) has been deposited on the lower half of the tube section (Fig. 1). In this section, the rate of heat transfer from the tube to the crude oil would therefore decrease. In order to keep the temperature of the crude oil constant at 450 °C more heat is required and subsequently material at this section (Fig. 1) will experience a higher temperature in comparison to the other side. This increase of temperature leads to higher physical and metallurgical damage, hence leading to a shorter safe operating time. In this article an experimental comparison has been made between the overheated and not-overheated side.

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**Table 1**
Material specification, dimension and condition of the service exposed tubes (9Cr–1Mo steel).

| Material specification/grade of steel (ASTM) | A220-T9 |
|---|---|
| Design oil pressure (MPa) | 31 |
| Operating steam pressure (MPa) | 20 |
| Design inner surface temperature (°C) | 419.4 |
| Operating inner surface temperature (°C) | 450 |
| Operating outer surface temperature (°C) | 680 |
| Tube thickness (mm) | 6.35 |
| Inner diameter (mm) | 168 |
| Service exposed (h) | 217206 |

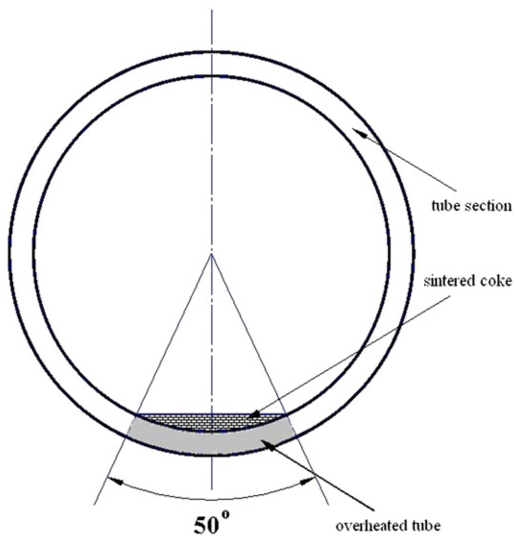


**Fig. 1.** Schematic section of tube showing the position of sintered impurities.

Visual inspection and chemical analysis of the service exposed tubes was first undertaken which was followed by light optical metallographic examination, where the samples were polished by standard metallographic techniques with a final polishing step of 0.1 μm diamond paste followed by etching with 2% nital. The average Vickers hardness values (VHN) of these tubes were measured at 30 kg load.

Chemical analysis with ASTM A200 T9 standard values for 9Cr-1Mo (Table 2) shows that the materials under the present investigation are basically 9Cr–1Mo steels conforming to the grades specified in Table 2. Optical metallographic examinations (Figs. 2 to 5) were carried out on the service exposed tubes from both sides (Fig. 6).

The TEM examination of extraction replicas showed the serviced exposed material to have widespread fine spherical precipitates of VC and (NbV)C together with larger randomly distributed precipitates of $M_7C_3$ and small amount of $M_6C$. These are illustrated in Fig. 5. The average hardness values (VHN) of these tubes are shown in Table 3.

Tensile and accelerated stress rupture tests have been performed in accordance with ASTM E8 and ASTM E8M respectively. The results are shown in Tables 4 and 5.

## 3. Results and discussion

### 3.1. Visual observation and metallography

The outer diameter of the service exposed tube was measured in three different locations along the pipe length and fifteen thickness readings on both side of pipe were taken along the tube length and in general no measurable change in outer diameter or thickness compared to the original dimensions was evident [11]. Examination of the overheated inner surface side showed a thick layer of sintered coke approximately 10 mm to exist, Fig. 6, and on the outer surface the colour of the material was darker than the other side. The thickness of the external oxide scale was normal. There was no evidence of any localised attack on the outer and inner surfaces of the tube. However, along the length of the pipe due to formation of sediment the outside temperature of the overheated side had increased with resulting creep strain and thermal stresses, which caused the pipe to bend. The height of the bend measured is ≈0.59 m [11]. Generally it appears that the tube, due to its relatively long length and large curvature, had not undergone any appreciable local deformation or thickness reduction during operation over 24 years.

Additionally, chemical analysis by the wet method [5] showed (Table 2) that the service exposed 9Cr–1Mo steel alloy still conformed to the ASTM specification, but in closer view, the percent of carbon in the overheated side is rather more than the other side and this could be a result of carbon penetration from the coke layer into the material.

The microstructure of the service exposed tube in the not-overheated side mainly consists of ferrite grains dispersed with carbides. Additionally, there is no evidence of decarburization or creep damage in the form of cavities in any of the service exposed tubes. But on the overheated side, the microstructure consists of mainly austenite grains; the austenite grains are dispersed with large amounts of chromium carbides, with an increase of carbides near the inner surface showing carburization of this section (Fig. 4a). Additionally, on the outer surface cavities with a maximum 1 mm depth exist (Fig. 4b).

It has been observed [7,8] that, for Cr–Mo steels, depending on the particular steel, carbides can precipitate in the matrix during high temperature service as stable final products or with intermediate stages involving the carbides $M_2C$, $M_3C$, $M_7C_3$, $M_{23}C_6$ and $M_6C$. For 9Cr-1Mo steel, Furtado et al. [9] showed that the sequence of evolution of carbides in the 9Cr–1Mo steel is as $M_7C_3 + MC \rightarrow M_7C_3 + M_6C + MC$. Fig. 5 shows carbides present and their morphology in the service exposed tube, large size $M_7C_3$ with fine spherical MC and small amounts of $M_6C$ were detected; these types of carbide are in agreement with those found by other authors [7–9] and show that the material in this side is in the final stages of its creep life.

### 3.2. Mechanical properties

Chemical analysis result (Table 2) showed that in both sides the alloy percent in metal is in the specific range defined by the ASTM standard but in the overheated side carbon percent is slightly more than for the other side and this could be due to penetration of carbon in base metal at higher temperature in this section.

**Table 2**
Chemical analysis of service exposed boiler tubes (Wt. %).

| | C | Si | S | P | Mn | Cr | Mo | Ni | V | Co |
|---|---|---|---|---|---|---|---|---|---|---|
| Not-overheated side specimen | 0.1 | 0.64 | 0.006 | 0.022 | 0.46 | 9.1 | 0.98 | 0.1 | 0.04 | 0.022 |
| Overheated side specimen | 0.14 | 0.68 | 0.008 | 0.025 | 0.45 | 8.9 | 0.96 | 0.1 | 0.04 | 0.022 |
| ASTM Standard A200 T9 | max 0.15 | 0.25–1 | max 0.01 | max 0.025 | 0.3 to 0.6 | 8 to 10 | 0.9 to 1.1 | – | – | – |

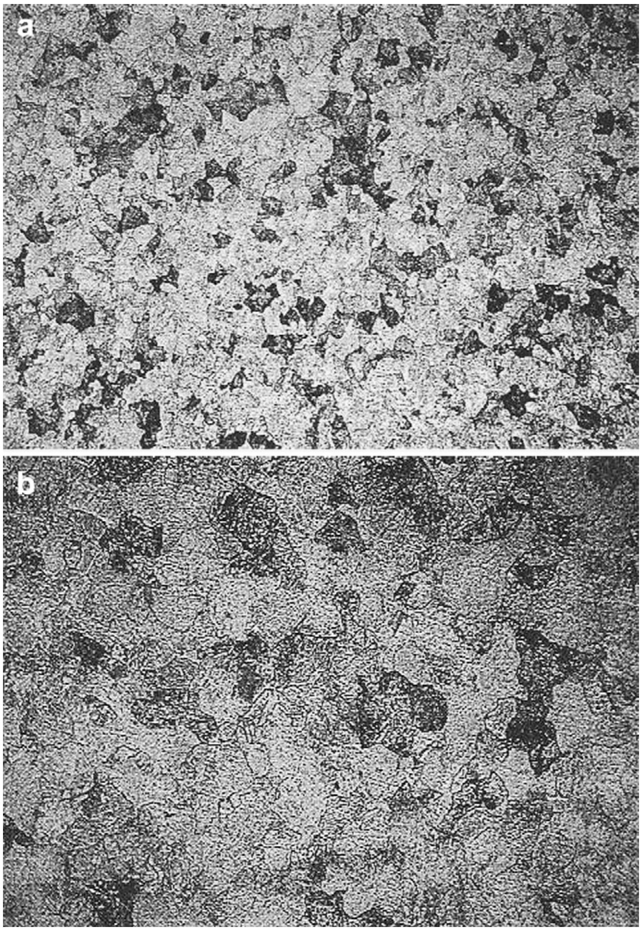


**Fig. 2.** Optical micrograph of the serviced exposed tube from not-overheated side at (a) ×200 and (b) ×500 revealed ferritic and bainitic structure with no evidence of creep cavitation damage after 24 years. The ferrite grains are dispersed with spherical carbides.

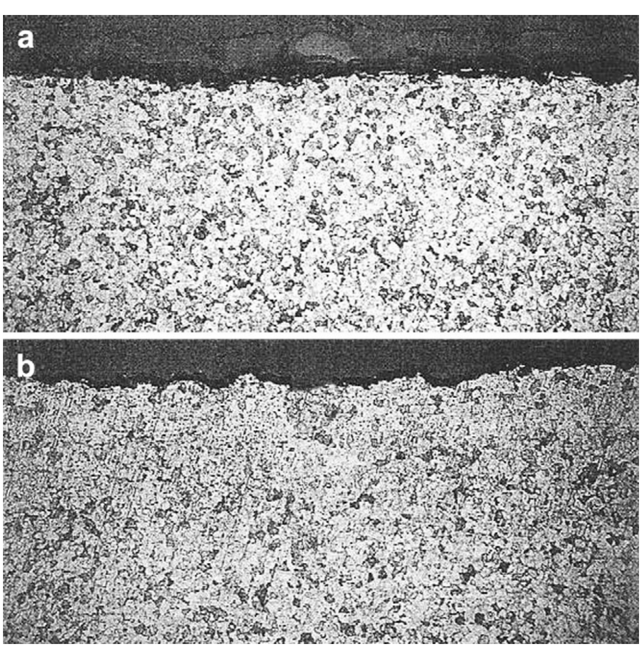


**Fig. 3.** Optical micrograph of the serviced exposed tube from not-overheated side at (a) inner surface and (b) outer surface at ×100 revealed some corrosion, with no cavities.

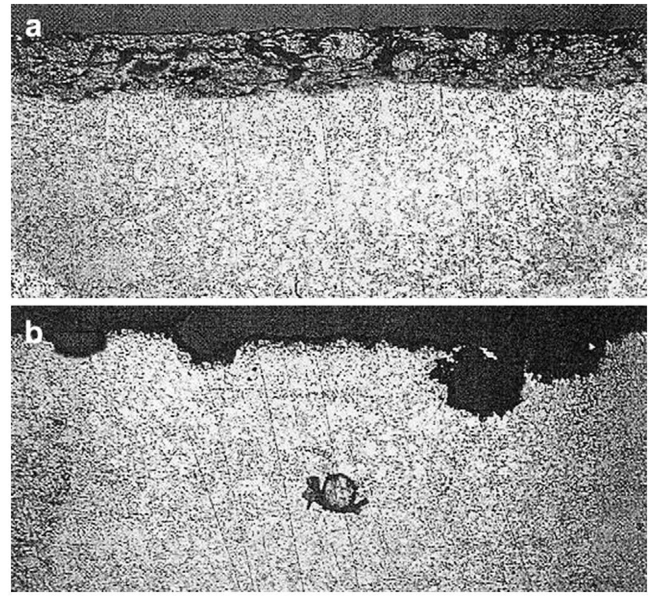


**Fig. 4.** Optical micrograph of the serviced exposed tube from overheated side at (a) inner surface and (b) outer surface at ×500 revealed austenite structure with chromium carbide in inner surface and cavities with maximum 1 mm depth in outer surface; in both carbides are larger than in the not-overheated side.

Room temperature hardness values for the exposed alloy are given in Table 3. Overheated side (83 RB = 154 BR) was slightly harder than the other side (78.6RB = 148 BR).

The stress rupture test results are given in Table 4. Results shows that in the not-overheated side, rupture times are clearly more than times predicted by API STD 530 standard [5], but in the overheated side, the specimen failed before the predicted time indicating a shorter creep life.

### 3.3. Finite element analysis

The FE analysis was performed in two parts. First a two dimensional model (Fig. 7) was set up and analysis was performed using ABAQUS/Standard to obtain the temperature and sediment thickness relationship (see Fig. 8). In the second phase a 3 D pipe section was meshed (see Fig. 9) to derive the stress analysis of the pipe. The details are described below.

#### 3.3.1. Sediment thickness and temperature

Originally when the tube was installed the crude oil temperature inside the tube and the external temperature of the tube were

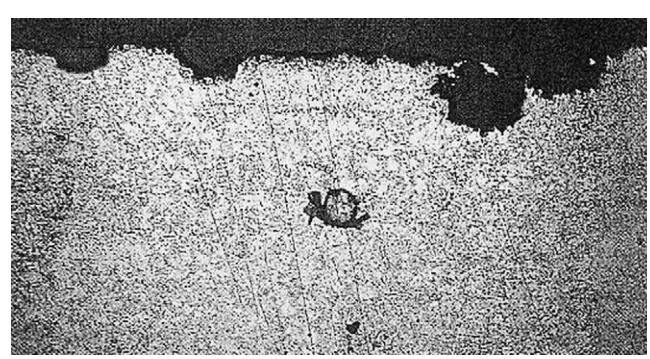

**Fig. 5.** TEM analysis showing carbides present and their morphology at service exposed tube; large size $M_7C_3$ with fine spherical MC and small amount of $M_6C$ were detected.

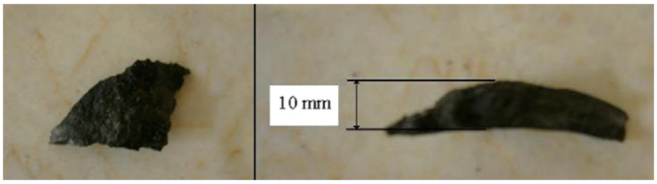


**Fig. 6.** Thick layer of sintered coke taken from the base of the tube.

**Table 3**
Hardness values of service exposed material.

| Type of specimen | mean hardness value (RB) | dispersion range of hardness value (RB) |
|---|---|---|
| Not-overheated side | 78.6 | 77.9–79.2 |
| Overheated side | 83 | 82–84 |

480 °C and 680 °C respectively (based on on-line control at refinery). Since there is only a temperature gradient in the radial direction, with no formation of sediment, the rate of heat transfer per unit area is $q_r$/Area = 1503032 W/m$^2$ [10]. After formation of sediment the surface in contact will experience lower heat transfer, suggesting that it will acquire a higher temperature in order to keep the crude oil temperature constant.

Experimental work was carried to obtain thermal conductivity of the incrementally increasing sediment and shown in Table 6. The initial temperature condition was set at 480 °C at the inner surface, 680 °C at the outer surface. Using steady state heat transfer and zero sediment layer thickness, a temperature analysis for steps of 0.1 mm increase in thickness of sediment was performed until the maximum measured thickness (10 mm) was obtained. The temperature at the end of this layer deposition analysis was ≈800 °C.

### 3.3.2. *Pipe bend due to creep*

A three dimensional elastic–creep FE analysis with a fixed internal pressure of 15 bar, under a fixed-end condition were performed using ABAQUS/Standard. Symmetry conditions were fully utilized in FE models to reduce the computing time. The pipe dimensions are outside diameter 628 mm, thickness 6.35 mm and 15 m length. To avoid problems associated with incompressibility, reduced integration elements (element type C3D20R within ABAQUS) were used. The pipe was pre-heated to the working temperature before installation so there is no thermal stress due to operation. Regarding pressure loading condition, internal pressure was applied as a distributed load to the inner surface of the FE model.

### 3.3.3. *Validation of the finite element results using metallurgical observations*

*3.3.3.1. sediment thickness and temperature.* From the numerical sediment thickness predictions shown in Fig. 8, it is clear that the increase in tube wall temperature is approximately proportional to sediment thickness imposed on the FEM analysis. The final measured temperature from the F.E. analysis is ≈800 °C which is in good agreement with the final temperature record of the actual pipe ≈785 °C [11]. Also, these results are in good agreement with experimental findings, because;

- Penetration of carbon in the base metal at higher temperature is faster and because the sediment near the overheated side is basically sintered carbon (coke), this justifies the higher percent of carbon in the overheated side (see Table 2);
- The overheated side metallography showed that in this section, unlike the other side, base phase is austenite, whereas base phase should be ferritic – bainitic [4], this transmutation can happen at about 800 °C which confirms the FE result predicted temperatures in Fig. 7 showing this range of temperature for the overheated region;
- Carbides present and their morphology in the service exposed tube showed large size of $M_7C_3$ with fine spherical MC and small amounts of $M_6C$. According to Furtado et al. [9], this sequence of evolution of carbides in the 9Cr–1Mo steel can be developed at an average temperature of 566 °C, and FE results showed such a range of temperature in the thickness of the tube during the sediment growth.

**Table 4**
Tensile properties of the service exposed boiler tubes.

| Specimen | Yield stress (MPa) | U.T.S. (MPa) | % Elongation | % reduction Area |
|---|---|---|---|---|
| Not-overheated side n.1 | 291.9 | 550.4 | 32.6 | 70.5 |
| Not-overheated side n.2 | 288.4 | 554.4 | 28.8 | 65.0 |
| Not-overheated side n.3 | 298.7 | 558.4 | 33.0 | 71.2 |
| ASTM A200 T9 | 172 min | 414 min | 28 min | |

**Table 5**
Stress rupture properties of the service exposed boiler tubes.

| Type of material | Test temperature (°C) | stress (MPa) | Predicted rupture time (h) Base on API STD 530 [6] | Rupture time (h) |
|---|---|---|---|---|
| Not-overheated side n.1 | 700 | 60 | 100 | 112.6 |
| Not-overheated side n.2 | 700 | 60 | 100 | 114.8 |
| Not-overheated side n.3 | 830 | 30 | 158 | 231.4 |
| Overheated side | 700 | 60 | 100 | 40 |

*3.3.3.2. Pipe bend due to creep.* The creep analysis of the pipe section using FEM also confirmed the experimental findings as follows. Using creep properties of the service exposed pipe material in Table 5, Fig. 9 shows the pipe bend due to creep deformation for fixed-end condition. For the overheated side the initial temperature condition was 480 °C at the inner surface, 680 °C at the outer surface. Formation of sediment causes the outside temperature to increase to 801 °C with resulting creep strain and thermal stresses which cause the pipe to bend shown in Figs. 10 and 11. The height of the bend measured from the F.E. analysis is 0.67 m at the maximum bend point of the pipe which is in good agreement with the measured bend height ≈0.59 m [11] of the actual pipe. The thermal stress due to formation of sediment for the not-overheated side is shown in Fig. 12. The maximum stresses on the overheated and not-overheated side are 35 MPa and 28.5 MPa respectively. The local thickness at the maximum pipe curvature was small reflecting the actual thickness measured in the service exposed pipe shown above. This can be attributed to the large curvature of the gross deformation (Fig. 12).

**Table 6**
Data for FE analysis of tube with sediment.

| | Density | specific heat | Thermal conductivity | coefficient of thermal expansion |
|---|---|---|---|---|
| | $\rho(\frac{kg}{m^3})$ | $C_p(j/kg.k)$ | $K\ (W/m.k)$ | $\alpha(^0Cx10^{-6})$ |
| 9Cr-1Mo (ASTM A200) | 7858 | 442 | 42.3 | 12.2 |
| Sediment (experimental) | 1350 | – | 0.26 | – |

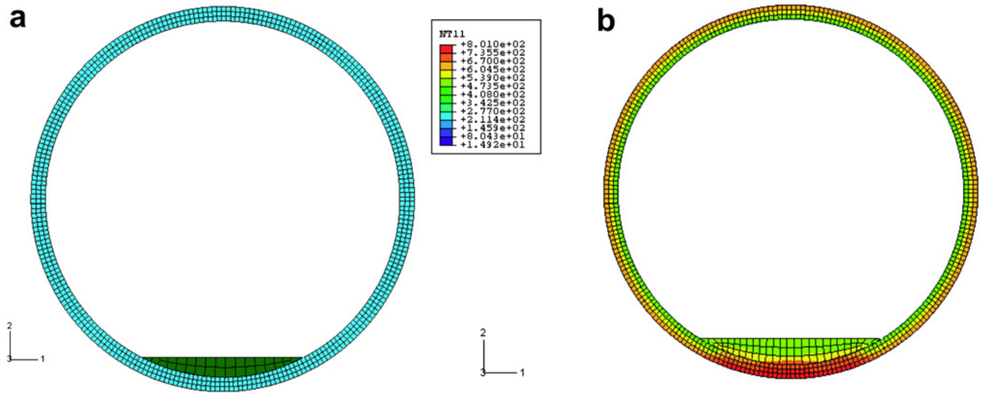


**Fig. 7.** (a) 2D model of tube with sediment (b) temperature analysis for max sediment thickness.

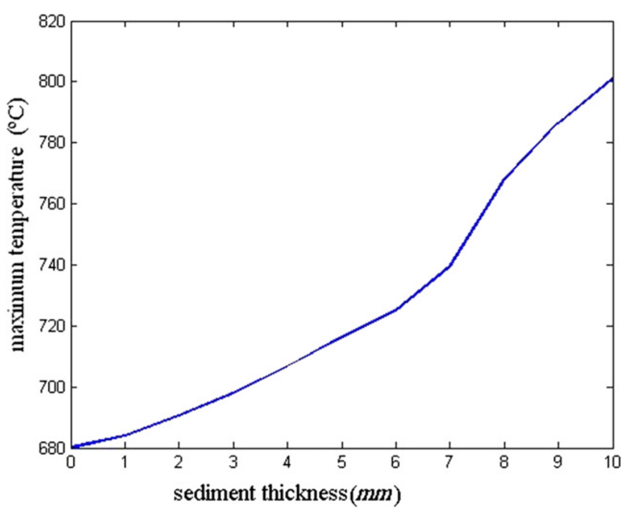


**Fig. 8.** Predicted increase in tube wall temperature with respect to sediment thickness.

### 3.4. Life estimation

Using the predicted temperature and stresses from the validated FE analysis and appropriate service exposed material properties in Table 5 the remaining life of the tube for the two sides with the normal and overheated condition was calculated according to API STANDARD 530 appendix E [6]. For this steel tube the start-of-run (680 °C) and end-of-run (800 °C) was chosen based on the FEM calculations. It is possible to define an equivalent tube metal temperature in which the tube operating at this temperature sustains the same creep damage as one that operates from the start-of-run to end-of-run temperatures [6]. For this work the analysis was based on maximum temperature. The Larson–Miller parameter was employed in the API 530 to derive the relevant life as explained below.

The Larson–Miller parameters (equation (1)) for normal and overheated sides are shown in Tables 7 and 8.

$$\mathrm{LMP} = T(C + \log t_r) \tag{1}$$

where T is temperature in degrees Kelvin, $C \approx 20$ [6] and $t_r$ is time to rupture in hours.

For the normal side, the rupture test performed on the sample at T = 700 °C = 973°K gave $t_r$ = 6/112 h (Table 5). Hence, the Larson–Miller parameter (LMP) = T(C + log $t_r$) = 973(20 + log 112.6) => $LMP_1$ = 21456. From the minimum rupture strength curves in Figure E.10 [6] of ASTM A 200 T9: for a stress of 60 MPa, the Larson–Miller value is $LMP_2$ = 36700 and for the F.E. stress and temperature on this side of $\sigma$ = 28.6 MPa and T = 680 °C, the Larson–Miller value is $LMP_3$ = 39000.

For the overheated side, the rupture test performed on the sample at T = 700 °C = 973°K gave $t_r$ = 40 h. Hence, the Larson–Miller parameter (LMP) = T(C + log $t_r$) = 973(20 + log 40) = $LMP_1$ = 21018. From the minimum rupture strength curves in Figure E.10 [6] for ASTM A 200 T9: for a stress of 60 MPa, the Larson–Miller value is $LMP_2$ = 36700 and at the F.E. stress and temperature on this side of $\sigma$ = 35 MPa and T = 680 °C, the Larson–Miller value is $LMP_3$ = 38400.

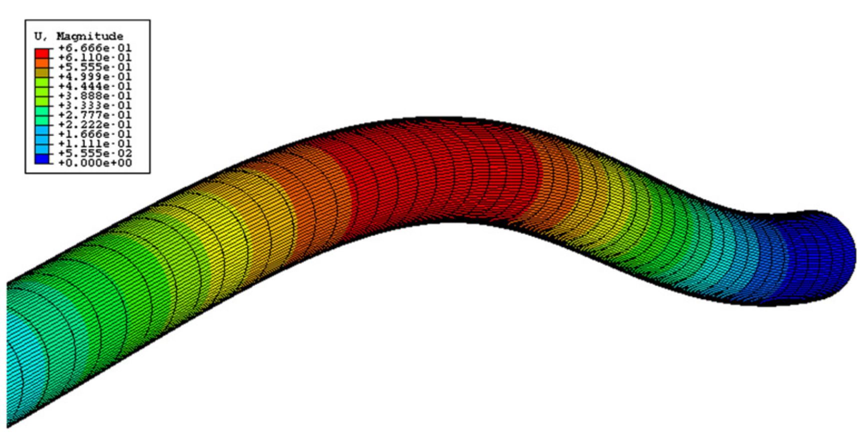


**Fig. 9.** Predicted bend height due to temperature rise in the overheated side (0.67m).

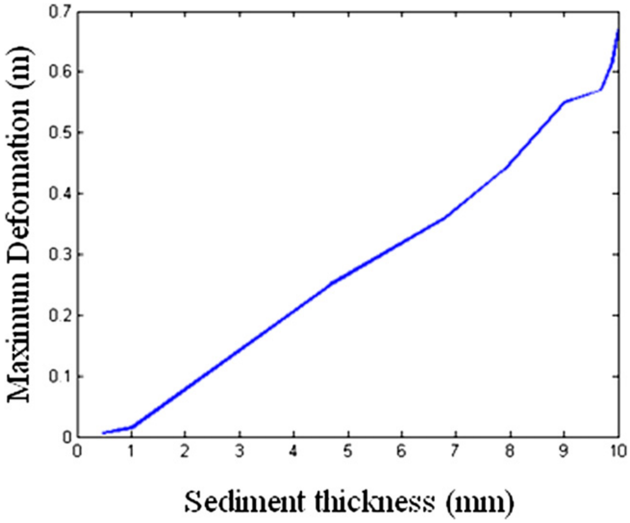


**Fig. 10.** Predicted increase in tube bending with respect to sediment thickness.

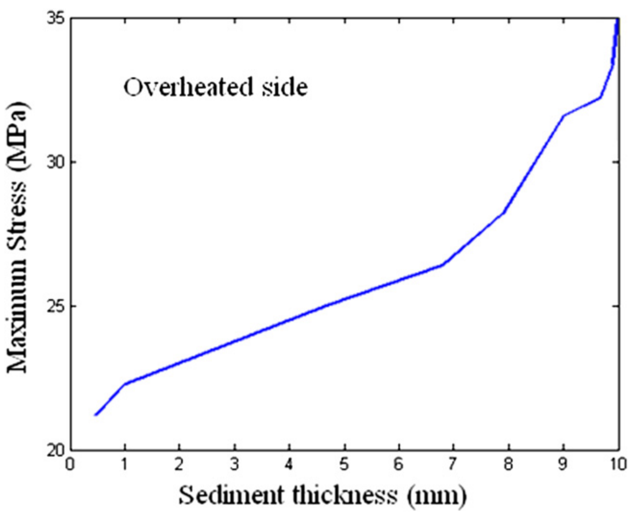


**Fig. 11.** Predicted increase in tube stress with respect to sediment thickness (overheated side).

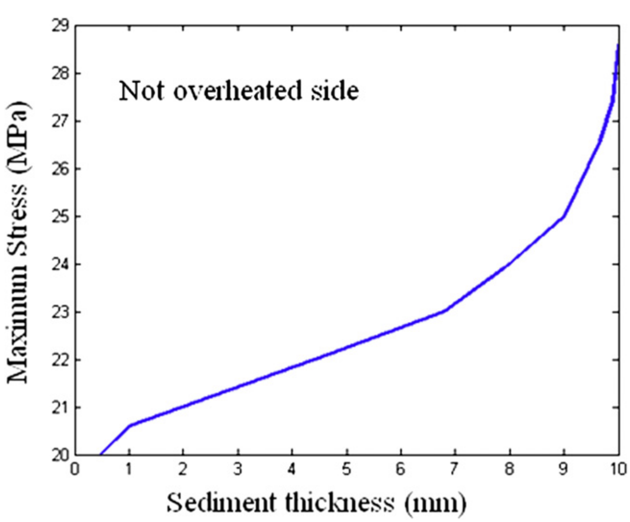


**Fig. 12.** Predicted increase in tube stress with respect to sediment thickness (not-overheated side).

**Table 7**
Larson–Miller parameter for service exposed tubes normal side giving 84644 h lifetime.

| Material condition | Test temperature (°C) | Stress (MPa) | Larson–Miller parameter |
|---|---|---|---|
| Rupture Test | 700 | 60 | $LMP_1 = 21456$ |
| Rupture strength ASTM A200 | 700 | 60 | $LMP_2 = 36700$ |
| F.E. Analysis | 680 | 28.6 | $LMP_3 = 39000$ |

**Table 8**
Larson–Miller parameter for service exposed tubes overheated side giving 50 h lifetime.

| Material condition | Test temperature (°C) | Stress (MPa) | Larson–Miller parameter |
|---|---|---|---|
| Rupture Test | 700 | 60 | $LMP_1 = 21018$ |
| Rupture strength ASTM A200 | 700 | 60 | $LMP_2 = 36700$ |
| F.E. Analysis | 680 | 35 | $LMP_3 = 38400$ |

The LMP used in calculating remaining life is based on a assuming a simple shift between the minimum rupture curve and the experimental data [6]:

$$LMP_{new} = LMP_1 + LMP_3 - LMP_2 \qquad (2)$$

The new LMP values are then 23756 and 22718 for the normal and overheated sides, respectively and the corresponding remaining lifetimes for the normal and overheated sides are 84644 and 50 h, respectively.

In the creep-rupture range, the accumulation of damage is a function of the actual operating tube metal temperatures. It should be noted that a life assessment based on the maximum temperature can be conservative, since the actual operating is usually less than the maximum. It is clear from the calculations above that the presence of the residue in the tube and the consequent increase in temperature in the region has a substantial effect on the tube life without taking into account the environmental and the corrosive factors.

## 4. Conclusions

Crude oil heater 9Cr–1Mo steel tubes from a refinery plant after 24 year of service at nominally 650 °C and 27 MPa were studied to predict their remanent life. An experimental program using accelerated creep testing and metallographic investigation in parallel with a numerical analysis was used to perform the remanent life calculation of the service aged tubes. The method employed involved the prediction of the increase in temperature with increasing sediment deposition during the operating life times. In addition the predicted temperatures were used to derive appropriate creep properties at relevant temperatures in a 3D pipe FEM creep analysis to predict the pipe bending deformation rate. These compare well with the actual service exposed pipe measurements and conditions. All results indicate that in the overheated side of the tube, the creep life was reduced substantially but on the side under normal operating temperature significant remanent life still exists. It is also shown that the growth of sediment thickness is approximately proportional to the rise in temperature and pipe deformation (pipe bend).

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