Influence of Cement Return Height on the Wellhead Uplift in Deep-Water High-Pressure—High-Temperature Wells

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ABSTRACT: In oil and gas production in deep-water high-pressure—high-temperature (HP−HT) wells, wellhead uplift may cause the seal failure of wellbore integrity. Aiming at the oil and gas production stage in deep-water HP−HT wells, we considered the influence of cement sheath cementation and developed a model for calculating the height of wellhead uplifts, and simulation experiments for wellhead uplifts were carried out under the condition of the double pipe string at different cement return heights and multilayer pipe string coupling cementing and noncementing based on a self-developed HP−HT wellhead uplift simulation device. The results show that the elongation of the double pipe string under the condition of a cement return height of 100% is reduced significantly compared with that under the condition of a cement return height of 50%. Also, the maximum elongation of the multilayer pipe string under the condition of coupling and cementing is significantly reduced compared with that under the condition of noncementing. These show that cement sealing has a binding effect on wellhead uplifts. The error between the calculated and the experimental results is less than 10%; thus, the model can be used to predict the wellhead uplift height under different working conditions and provide technical guidance for designing scientific measures to prevent wellhead uplifts.

1. INTRODUCTION
With the development of deepwater drilling technology, wellbore integrity is increasingly under scrutiny. According to the survey of wellbore integrity conducted by Norwegian Petroleum Safety Authority (PSA) on 106 offshore wells with different development years and production categories, 18% of them had problems with wellbore integrity, and 7% of them were forced to close wells because of wellbore integrity, which caused significant environmental and economic losses. In the process of deep-well testing and production, the high-temperature (HT) flow produced in the deepwater wells will cause additional pressure in casing annulus. If the axial force generated by excessive temperature change is greater than the bearing capacity of the shear pin at the wellhead, the wellhead will move up and seriously threaten wellbore integrity. In Marlin offshore field in the Gulf of Mexico, excessive annular pressure during oil production resulted in the deformation and fracture of the casing and tubing of well A-2 few hours after production. On the account of temperature effects, the Christmas tree flange was pulled off, which resulted in the leakage of natural gas and other accidents in a gas well in the South China Sea. Therefore, it is very important to investigate the effect of cement return height on wellhead uplifts in deep-water HT—high-pressure (HT−HP) wells, which has become the research focus of the deep-water oil and gas industries.

In 1986, Klementich and Jellison analyzed the working life of a single string and studied the influence of stress on the string under the conditions of wellhead device uplifts and thermal expansion of annular pressure. Aasen and Aadnoy established a mathematical model for casing load and wellhead migration during the completion and production of oil and gas, but they did not consider the influence of the pressure field on the rising of the Christmas tree. McSpadden and Glover established a model that predicts multilayer pipe string loads and the height of wellhead uplifts by considering the complex casing structure and pipe thermal deformation. Liang analyzed the temperature and expansion effects of HT wells and that in the steam injection thermal recovery process. The methods of controlling wellhead uplift by optimizing the cement return height were further discussed. Jun established a model to predict the height of wellhead uplifts in view of the friction-constraint of the cement sheath on the casing after cement sheath bonding failure near the wellhead under the condition of full sealing in offshore thermal...
recovery wells. Yuanhua et al. proposed a model for predicting the height of wellhead uplifts for multilayer pipe strings. They employed the particle swarm optimization algorithm to obtain the free length of each layer of the casing based on the series of production and wellhead uplift height data inversion and developed a wellhead device uplift height prediction method.

Zhi and Han established a model for calculating the annual thermal expansion pressure, and considering the thermal stress caused by axial and radial temperature differences in casings, the axial load generated by the interaction of the casing-cement-formation combination, and annular thermal expansion pressure, they developed a wellhead uplift calculation model. Yanbin and Deli established a model for calculating the height of wellhead uplifts in deep-water wells during production and studied the influence of cement return height and temperature on the height of wellhead uplifts. Yafeng et al. analyzed the lifting mechanism of the wellhead device in gas wells, established a model for calculating the lifting distance in multilayer pipe wellheads, and performed an example calculation. Tiejun developed a novel prediction method for multifactor wellhead uplifts by multifactor sensitivity analysis. Gang et al. established a three-dimensional wellbore temperature field analysis model for offshore thermal production wells and a model for multilayer pipe string complex wellhead uplifts. They further developed a set of wellhead uplift mechanism analysis method. Ning developed a model for wellhead lift analysis using the WellCat software and calculated the wellhead uplift based on the wellbore temperature profile and the thermal load extension of free casing. Qi established a model for calculating the wellbore temperature and annulus pressure in deep-water oil and gas development wells. Yiguo developed a model for predicting the wellbore temperature and that for predicting the height of wellhead uplifts in HT–HP gas wells with large production. He verified the models using the finite element method.

Hao established a model for calculating the wellbore temperature and pressure field in HT–HP gas wells and developed a method for predicting the height of wellhead uplifts and the wellhead device lifting mechanism. Based on the wellbore temperature calculation for HT–HP gas wells, Dajiang established a multilevel pipe string mechanical model considering the annular fluid expansion, end effect, and casing heat effect and carried out the prediction of the height of the wellhead device uplift. Xiaolei considered the influence of temperature on the mechanical properties of casings, established a model for predicting the height of wellhead uplifts under the action of multiple factors, and analyzed the key factors affected by temperature changes. The research on wellhead uplift in foreign countries is relatively early, and it is carried out from the perspective of wellhead thermodynamics, which played a great role in reference and promoting the research on wellhead uplift in China. Current theoretical models for predicting wellhead uplifts do not consider the effect of the cement sheath bonding strength. In addition, there is no report on the wellhead uplift simulation experiment under the condition of cement sheath bonding.

In this study, considering the influence of cement sheath bonding strength, we developed a model for calculating the wellhead lifting height based on the self-developed HT–HP wellhead uplift simulation. Wellhead uplift simulation experiments were performed under the condition of double-layer pipe strings for different cement return heights and multilayer strings coupled with and without cementing. We obtained the influence of cementation on the string elongation. The analysis revealed that the model can be used to describe the problem of wellhead uplifts in deep-water HT–HP wells and provide a technical reference for predicting the height of wellhead uplifts and optimizing the cement return height in the field.

2. RESULTS AND DISCUSSION

2.1. Simulation Experiment for Free Elongation of a Multilayer Pipe String. Under the condition of free elongation of the strings, the elongation of the 7 in. string was minimal (2.977 mm after 1.5 h stabilization at 150 °C) due to the slow rise in the temperature of B-annulus. The elongation of the 2–7/8 in. string was the maximum (5.246 mm after 1.5 h stabilization at 150 °C) due to the rapid increase in temperature. The elongation of the 4–1/2 in. string was between the 2–7/8 and 7 in. strings, and the elongation was 4.123 mm after 1.5 h at 150 °C. The experimental data are listed in Table 1, and the elongation versus temperature curves of the layer strings are shown in Figure 1.

The elongation increases with the rise in temperature for the 2–7/8, 4–1/2, and 7 in. strings. The increase rate was higher in

Table 1. Test Data for Free Elongation of the Single-Layer String

| temperature of heating rod (°C) | 2–7/8 in. string | A-annulus | B-annulus | 2–7/8 in. string | 4–1/2 in. string | 7 in. string |
|-------------------------------|------------------|-----------|-----------|------------------|------------------|-------------|
| 45 °C stable for 1.5 h         | 45.7             | 36.0      | 27.4      | 0.360            | 0.154            | 0.019       |
| 65 °C stable for 1.5 h         | 64.0             | 58.2      | 31.5      | 1.151            | 0.692            | 0.082       |
| 85 °C stable for 1.5 h         | 87.9             | 78.0      | 46.8      | 2.131            | 1.557            | 0.637       |
| 105 °C stable for 1.5 h        | 105.4            | 90.3      | 63.9      | 3.345            | 2.563            | 1.502       |
| 125 °C stable for 1.5 h        | 124.5            | 98.5      | 74.0      | 4.394            | 3.448            | 2.335       |
| 150 °C stable for 1.5 h        | 140.0            | 100.0     | 79.9      | 5.246            | 4.123            | 2.977       |

Figure 1. Curve of free elongation of single-layer strings with temperature under different temperatures.
the 2–7/8 in. string, followed by the 4–1/2 in. string and then the 7 in. string. Considering room temperature of 20 °C, the linear expansion coefficient of the 2–7/8 in. string was 10.9 × 10^{-6} °C^{-1} and that of the 4–1/2 and 7 in. strings was 14.7 × 10^{-6} and 6.5 × 10^{-6} °C^{-1}, respectively.

2.2. Simulation Experiment of Double-Layer String Elongation at a Cement Return Height of 50%. When the slurry return height was 50% of the annulus height, the 2–7/8 and 4–1/2 in. strings were affected by the cementation of the cement sheath. The 2–7/8 in. string showed the largest elongation due to the rapid increase in its temperature, and the elongation after stabilizing for 1.5 h at 150 °C was 4.797 mm, which is about 20% (0.449 mm) lower than that of the free elongation state. The 4–1/2 in. string was affected by the heat transfer of the cement, and its elongation after stabilizing for 1.5 h at 150 °C was 3.871 mm, which is about 22.4% (0.252 mm) lower than that of the free elongation state. The experimental data are listed in Table 2, and the elongation versus temperature curves for the layer strings are shown in Figure 2.

Table 2. Test Data for Double-Layer String Elongation at a Cement Return Height of 50%

| Temperature of Heating Rod (°C) | Elongation (mm) |
|--------------------------------|-----------------|
| stable at 45 °C for 1.5 h       | 45.3            |
| stable at 65 °C for 1.5 h       | 65.0            |
| stable at 85 °C for 1.5 h       | 85.0            |
| stable at 105 °C for 1.5 h      | 105.0           |
| stable at 125 °C for 1.5 h      | 127.3           |
| stable at 150 °C for 1.5 h      | 144.6           |
| 7/8 in. pipe                    | 45.1            |
| A-annulus                       | 0.576           |
| 2–7/8 in. string                | 1.479           |
| 1/2 in. string                  | 2.489           |
| 4–1/2 in. string                | 3.468           |
| 2–7/8 in. string                | 3.463           |
| 1/2 in. string                  | 4.105           |
| 4–1/2 in. string                | 4.797           |
| 2–7/8 in. string                | 3.871           |
| 1/2 in. string                  | 3.026           |
| 4–1/2 in. string                | 2.916           |

2.3. Simulation Experiment for Double-Layer String Elongation at a Cement Return Height of 100%. When the cement return height of the double-layer string was 100% of the annulus height, the 2–7/8 and 4–1/2 in. strings were bound by the cement, which is greater than the cementation ability recorded in Section 2.3. The elongation of the 2–7/8 in. string after stabilizing for 1.5 h at 150 °C was 4.129 mm. Due to the effect of cement heat transfer, the temperature of the 4–1/2 in. string increased slowly; thus, the elongation was small (2.916 mm after 1.5 h at 150 °C). The experimental data are listed in Table 3, and the elongation versus temperature curves for the layer strings are shown in Figure 3.

Table 3. Experimental Data for Double-Layer String Elongation at a Cement Return Height of 100%

| Temperature of Heating Rod (°C) | Elongation (mm) |
|--------------------------------|-----------------|
| stable at 45 °C for 1.5 h       | 47.0            |
| stable at 65 °C for 1.5 h       | 65.6            |
| stable at 85 °C for 1.5 h       | 85.0            |
| stable at 105 °C for 1.5 h      | 105.0           |
| stable at 125 °C for 1.5 h      | 126.6           |
| stable at 150 °C for 1.5 h      | 150.7           |
| 2–7/8 in. pipe                  | 0.428           |
| 1/2 in. string                  | 1.283           |
| 4–1/2 in. string                | 2.175           |
| 2–7/8 in. string                | 2.974           |
| 1/2 in. string                  | 3.597           |
| 4–1/2 in. string                | 4.129           |
| 2–7/8 in. string                | 2.413           |
| 1/2 in. string                  | 2.916           |

The elongation of the 2–7/8 and 4–1/2 in. strings increased with increasing temperature. The increasing rate was higher in the 2–7/8 in. string. The elongations and elongation rates declined compared with those obtained at a cement return height of 50%, indicating that the binding effect of cement is significant after solidification.

2.4. Simulation Experiment for Wellhead Uplift under the Condition of Multilayer String Coupling and Non-cementing. Under the condition of multilayer string coupling without cementing, the elongation of all the layer strings increased with an increase in temperature. The temperature of the B-annulus was relatively low and its string was the shortest; hence, the elongation of the 7 in. string was the minimum (4.044 mm after 1.5 h at 150 °C). The temperature of the 2–7/8 in. string increased faster and its length was the largest; hence, its elongation was the largest (5.143 mm after 1.5 h at 150 °C). Because the temperature of the A-annulus and the 4–1/2 in. string was between those of the 2–7/8 and 4–1/2 in. strings, the elongation was also between that of the two strings. The
The elongation of the 4–1/2 in. string was 4.558 mm after 1.5 h at 150 °C, which is higher than that of the 2–7/8 in. string and lower than that of the 7 in. string. The experimental data are listed in Table 4, and the elongation versus temperature curves of the layer strings are shown in Figure 4.

| temperature of heating rod (°C) | temperature (°C) | In 2–7/8 in. pipe | A-annulus | B-annulus | 2–7/8 in. string | 4–1/2 in. string | 7 in. string |
|-------------------------------|------------------|-------------------|-----------|-----------|-----------------|-----------------|-------------|
| stable at 45 °C for 1.5 h     | stable at 45 °C  | 45.4              | 44.2      | 38.5      | 0.329           | 0.261           | 0.190       |
| stable at 65 °C for 1.5 h     | stable at 65 °C  | 63.1              | 59.2      | 50.1      | 1.033           | 0.846           | 0.673       |
| stable at 85 °C for 1.5 h     | stable at 85 °C  | 85.0              | 75.7      | 65.0      | 2.017           | 1.655           | 1.338       |
| stable at 105 °C for 1.5 h    | stable at 105 °C | 105.3             | 96.8      | 85.7      | 3.142           | 2.618           | 2.155       |
| stable at 125 °C for 1.5 h    | stable at 125 °C | 124.8             | 111.0     | 98.5      | 3.993           | 3.346           | 2.811       |
| stable at 150 °C for 1.5 h    | stable at 150 °C | 150.8             | 123.0     | 110.9     | 5.143           | 4.558           | 4.044       |

**Figure 4.** Elongation curve of wellhead uplift with temperature under the condition of multilayer string coupling without cementing.

### 2.5. Simulation Experiment for Wellhead Uplift under the Condition of Multilayer String Coupling with Cementing

The overall elongation was affected by the cementation of the strings in B- and C-annulus. The elongation of the 2–7/8 in. string after stabilizing at 150 °C for 1.5 h was 4.28 mm, which is 16.8% lower than that without cementing. Also, the elongation of the 7 in. string after stabilizing under the same condition was 2.572 mm, which is 36.4% lower than that under no cementing and that of the 4–1/2 in. string was 2.867 mm, which is 37.0% lower. The experimental data are listed in Table 5, and the elongation versus temperature curves of the layer strings are shown in Figure 5.

As can be seen from the abovementioned analysis, the bonding strength of cement sheath limits the elongation of the string; the greater the bonding strength of the cement sheath, the lower the elongation of the string, so increasing the bonding strength of cement sheath could reduce the height of wellhead uplift.

### 2.6. Comparison of the Simulation Experiment and Model Calculation of Wellhead Uplift under the Condition of Multilayer String Coupling with Cementing

Based on the calculation model of wellhead uplift established in Section 2.4, the calculation of wellhead uplifts is carried out for the experiment model and scheme shown in Figure 11. The calculation model considers the effects of multilayer string coupling, thermal stress, trap pressure, and cement sheath bonding on the elongation of pipe strings. The bonding strength of cement sheath is 2.35 MPa by tests and the calculation data are shown in Table 6. The comparison curve of calculation and experimental results of the wellhead uplift under the condition of multilayer string coupling with cementing is shown in Figure 6.

**Table 4. Test Data for Wellhead Uplift under the Condition of Multilayer String Coupling without Cementing**

| temperature of heating rod (°C) | temperature (°C) | In 2–7/8 in. pipe | A-annulus | B-annulus | 2–7/8 in. string | 4–1/2 in. string | 7 in. string |
|-------------------------------|------------------|-------------------|-----------|-----------|-----------------|-----------------|-------------|
| stable at 45 °C for 1.5 h     | stable at 45 °C  | 45.4              | 47.1      | 41.8      | 0.175           | 0.054           | 0.046       |
| stable at 65 °C for 1.5 h     | stable at 65 °C  | 66.3              | 64.3      | 57.2      | 0.583           | 0.236           | 0.229       |
| stable at 85 °C for 1.5 h     | stable at 85 °C  | 82.2              | 79.0      | 73.2      | 1.133           | 0.559           | 0.506       |
| stable at 105 °C for 1.5 h    | stable at 105 °C | 105.4             | 99.6      | 88.6      | 2.003           | 1.065           | 0.931       |
| stable at 125 °C for 1.5 h    | stable at 125 °C | 123.0             | 114.9     | 106.0     | 2.823           | 1.724           | 1.442       |
| stable at 150 °C for 1.5 h    | stable at 150 °C | 150.8             | 140.7     | 132.9     | 4.280           | 2.867           | 2.572       |

**Table 5. Test Data for Wellhead Uplift under the Condition of Multilayer String Coupling with Cementing**

**Figure 5.** Elongation vs temperature curves of wellhead uplift under the condition of multilayer string coupling with cementing.
Temperature is one of the important factors that cause wellhead uplift in the oil and gas production process in deep-water HT–HP wells. Via free elongation experiment and calculation of multilayer pipe strings, the linear expansion coefficient of the strings was obtained to range from $10 \times 10^{-6}$ to $20 \times 10^{-6}$ C$^{-1}$. For more accurate prediction of the height of wellhead uplifts, the measured linear expansion coefficient should be used. The cementation strength of cement sheath has a significant effect on the elongation of the strings. Compared with the cement return height of 50%, the elongation of the string was significantly reduced at the cement return height of 100% in double-layer strings. Compared with the multilayer string coupling without cementing, the maximum elongation of strings can be reduced by 36.5% under the cementing condition.

Relative to the simulation experiments, the error of the developed model is less than 10%; thus, it can accurately predict the height of wellhead uplifts. Based on the theoretical analysis and experimental simulation of wellhead uplift, using the pipes with a low linear expansion coefficient and increasing the bonding strength of cement sheath appropriately could reduce the height of wellhead uplift.

### 4. CALCULATION METHOD

#### 4.1. Prediction Method for Single String Wellhead Uplift

Assuming the temperature of a section of the free string increases from $T_0(H)$ to $T(H)$ during production in deep-water HT–HP wells, the height of the single string axial uplift caused by the temperature difference can be calculated as follows$^{[12]}$

$$
\Delta L_i = \int_{0}^{L_i} \alpha_i \left(T_i(H) - T_0(H)\right) \, dH
$$

where $\Delta L_i$ is the height of the axial uplift of the single string resulting from the temperature change, $m_{L_i}$ is the length of the noncementing section of layer $i$ string, $\alpha_i$ is the linear expansion coefficient of the string (12.1 $10^{-6}$ C$^{-1}$); $T_i(H)$ is the temperature of layer $i$ string at $H$ in the production process, °C; and $T_0(H)$ is the initial temperature of layer $i$ string at $H$, °C. It can be seen from eq 1 that the greater the $\alpha_i$ the greater the $\Delta L_{op}$ so using the pipes with low linear expansion coefficient could reduce the height of wellhead uplift.

#### 4.2. Prediction Method for Multilayer String Wellhead Uplift

The stress analysis diagram of a multilayer string system is shown in Figure 7. Assuming the length of each free section of the string does not increase after a certain period of production, the stiffness of each free section of the string can be calculated as follows$^{[12]}$

$$
K_i = \frac{A_iE_i}{L_i}
$$

where $K_i$ is the stiffness of layer $i$ string, N/m; $E_i$ is the elastic modulus of layer $i$ string, Pa; $A_i$ is the cross-sectional area of the string wall in layer $i$, m$^2$; and $L_i$ is the length of layer $i$ free section string, m. The string s of each layer is connected at the wellhead to form a multilayer pipe string coupling system. The stiffness of the multilayer pipe string system is expressed as

$$
K_s = \sum K_i
$$

The axial thermal strain of each layer string is given by$^{[12]}

$$
\epsilon_i = \alpha_i \left(T_i(H) - T_0(H)\right)
$$

where $\epsilon_i$ is the axial thermal strain of layer $i$ string.
and the thermal load generated by the restraint is expressed as

$$F_i = \sum A_i E_i \epsilon_i$$

(5)

where $\epsilon_i$ is the thermal strain of layer $i$ string; $\alpha_i$ is the linear thermal expansion coefficient of layer $i$ string, °C$^{-1}$; $\Delta T_{ij}$ is the temperature change in section $j$ at layer $i$ string, °C; $L_{ij}$ is the length of section $j$ at layer $i$ string; $m_i$ and $F_i$ is the thermal load generated by the restriction of the multistring system, N.

The height of the wellhead uplift caused by temperature change is given by

$$\Delta L_t = \frac{F_t}{K_s}$$

(6)

and that caused by the weight of the free section string is

$$\Delta L_m = \frac{q_i L_i}{K_s}$$

(7)

The axial load generated by the tubing and annulus pressures on the wellhead equipment is

$$F_e = \pi \alpha_i^2 p_i + \pi (\epsilon_c^2 - \epsilon_{so}^2) p_c$$

(8)

The height of wellhead uplift caused by tubing and annulus pressures is given by

$$\Delta L_e = \frac{F_e}{K_s}$$

(9)

The change in the wellhead uplift height caused by other equipment, including wellhead, is given by

$$\Delta L_w = \frac{W_h}{K_s}$$

(10)

The change in the wellhead uplift height caused by the cement sheath cementation in the cementing section is

$$\Delta L_c = \frac{P_w S_w + P_{sh} S_{sh}}{K_s}$$

(11)

Then, the lifting height of the wellhead device is

$$\Delta L = \Delta L_t + \Delta L_m + \Delta L_e + \Delta L_w + \Delta L_c$$

(12)

In the abovementioned equations, $q_i$ is the line weight of layer $i$ string, N/m; $F_e$ is the axial load of the tubing and annulus
pressures on the wellhead device, \( N \); \( r_i \) is the inner diameter of the tubing, m; \( r_o \) is the outer diameter of the tubing, m; \( r_c \) is the outer diameter of the casing, m; \( P_t \) is the tubing pressure, Pa; \( P_a \) is the annulus pressure, Pa; \( W_H \) is the weight of other equipment, including the wellhead device, N; \( \Delta L_w \) is the height of the wellhead lifting caused by other equipment, including the wellhead device, m; \( P_n \) is the interfacial cementation strength within the cement sheath, Pa; \( S_n \) is the cementing area of the interface between the cement sheaths, m\(^2\); \( P_w \) is the cementing strength of the outer interface of the cement sheath, Pa; and \( S_w \) is the cementing area of the outer interface of the cement sheath, m\(^2\).

5. EXPERIMENTAL SECTION

5.1. Simulation Experiment Device for Wellhead Uplift in the HT–HP Well. The HT–HP wellhead uplift simulation experiment device was designed based on the experimental requirements, which is shown in Figure 8. This device uses 9–5/8, 7, 4–1/2, and 2–7/8 in. strings to simulate the annulus of A, B, and C. The lengths of the strings were 4.0, 3.5, 3.0, and 2.5 m, respectively. The bottom and top of the device were welded by the butt welding method, which was designed according to the strength calculations. The height of the annular welding block was 45 mm, which fully guarantees the overall strength, stiffness, and leak proof of the device. The length of the heating rod in the 2–7/8 in. string was 2.5 m, the heating power was 4 kW, and a temperature control accuracy of ±0.5 °C was employed. A grating sensor was used to measure the elongation of the string with a measurement accuracy of 0.001 mm.

5.2. Simulation Experiment for Free Elongation of a Multilayer Pipe String. In this experiment, the 2–7/8, 4–1/2, and 7 in. strings were at the free elongation state, and the A- and B-annulus were filled with a brine of density 1.03 g/cm\(^3\). The string elongation was measured in a temperature range of 45–150 °C. The measurements were taken after every 20 °C increase in temperature. The experimental model is shown in Figure 9, and the experimental results of the string elongation are listed in Table 1.

5.3. Simulation Experiment of Double-Layer String Elongation at a Cement Return Height of 50%. In this experiment, the 2–7/8, 4–1/2, and 7 in. strings were at the cement return state, 50% for the A- and B-annulus, and the C-string was not cemented. The A- and B-annulus were filled with a brine of density 1.03 g/cm\(^3\). The string elongation was measured in a temperature range of 45–150 °C. The measurements were taken after every 20 °C increase in temperature. The experimental model is shown in Figure 10, and the experimental results of the string elongation are listed in Table 1.
experiment, the 2–7/8 and 4–1/2 in. strings formed a double-layer string annulus. 50% of the annulus was filled with slurry, and above the cement surface was filled with saltwater of density 1.03 g/cm³. The elongation of the strings was measured in the temperature range of 45–150 °C at an interval of 20 °C. The experimental model is shown in Figure 10, and the measured string elongations are listed in Table 2.

5.4. Simulation Experiment for Double-Layer String Elongation at a Cement Return Height of 100%. In this experiment, the 2–7/8 and 4–1/2 in. strings formed a double-layer string annulus, and 50% of the annulus was filled with slurry. The elongation of the strings was measured in the temperature range of 45–150 °C at an interval of 20 °C. The experimental model is shown in Figure 11, and the recorded string elongations are listed in Table 3.

5.5. Simulation Experiment for Wellhead Uplift under the Condition of Multilayer String Coupling and Non-cementing. Herein, the 2–7/8, 4–1/2, and 7 in. strings formed a A- and B-annulus, and the annulus was filled with saltwater of density 1.03 g/cm³ and then sealed. The elongation of the strings was measured between 45 and 150 °C at every 20 °C increase in temperature. To ensure safety, the pressure was released when the trap pressure rose to 20 MPa. The experimental model is shown in Figure 12, and the recorded string elongations are listed in Table 4.

5.6. Simulation Experiment for Wellhead Uplift under the Condition of Multilayer String Coupling with Cementing. Compared with the experimental model shown in Figure 9, herein, a layer of the 9/8, 7/8, and 5/8 in. string was added outside the 7 in. string and A-annulus was filled with saltwater of density 1.03 g/cm³ and sealed. The cement return height of B-annulus was 50% and the annulus above the cement surface was filled with saltwater of density 1.30 g/cm³ and sealed. The elongation of the strings was measured in the temperature range of 45–150 °C at an interval of 20 °C. The experimental model is shown in Figure 13, and the recorded string elongations are shown in Table 5.

5.7. Test Experiment for Bonding Strength of the Cement Sheath. In order to obtain the bonding strength of the cement sheath and casing, a bonding strength testing device was designed, the cement sheath bonding strength test was carried out with the same slurry formula, and the average value of bonding strength was recorded, which was 2.35 MPa. The experimental process is shown in Figure 14.

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**Notes**

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**Figure 14. Test process diagram of cement sheath bonding strength. (a) Before testing. (b) During testing. (c) After testing.**
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