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# Modeling analysis of the temperature profile and trapped annular pressure induced by thermal-expanded liquid in a deep gas well

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The trapped annular pressure (TAP) caused by thermal expansion is one of the serious challenges for the safe production of a deep gas well. Therefore, this article proposes a model to calculate the temperature profile of the deep gas well based on the heat transfer process and the gas properties. With the help of the temperature model, the TAP in the tubing–casing annulus is analyzed according to the annular fluid distribution and the volume consistence law. The results indicate that the temperature inside the tubing string decreases faster under higher bottom hole pressure. When the tubing–casing annulus is totally filled with the annular protection liquid, the TAP continues increasing with the production rate. Considering the high production rate, the TAP is inevitable and high enough to damage the integrity of the deep gas well. The nitrogen gas mitigates the TAP by reducing the annular liquid volume and providing the extra space to accommodate the thermal-expanded annular liquid. A good mitigation performance can be achieved no matter how large the production rate is. The mitigation performance can be divided into the fast-decreasing stage, the efficient control stage, and the stable stage. These three stages occur as the nitrogen gas column length increases. The compression of the nitrogen gas volume plays a major role in the fast decrease stage while the reduction of the annular liquid plays a major role in the stable stage. For the best cost-effectiveness, the nitrogen gas column is recommended in the efficient control stage and should not exceed 15%.

## KEYWORDS

deep gas well, temperature distribution, trapped annular pressure, fluid distribution, mitigation performance

## 1 Introduction

Deep natural gas plays an important role in the worldwide energy supply [1] for its high productivity and rich reserves. However, it is also characterized by extreme high temperature and pressure. Taking the Well Luntan-1 in the Tarim Basin as instance, the bottom hole pressure reaches 132 MPa and the bottom hole temperature reaches 178°C while its depth is 8,882 m. Due to the extreme high pressure, the tubing–casing annulus is usually filled with the protection liquid in order to balance the pressure difference [2], so as to avoid the tubing string burst. As a result, the TAP increase after the deep gas well is put into production even if the well integrity is perfect [3], because the annular protection liquid would be heated by the production gas from the high-temperature reservoir [4].

Although the TAP can be eliminated by releasing the thermal-expanded liquid, the cement or the tubing may also be damaged during the pressure rise and releasing process [5, 6], which would lead to the wellbore leakage [7]. Even worse, the tubing or the casing string may deform under the high TAP, just like the casing string in the Well Pompano A-31 [8] and the tubing string in the steam injection well in Canada [9]. Therefore, it is important to avoid the high TAP by taking some suitable control measures. Since the TAP is caused by the wellbore temperature change, it is the foundation for the TAP control optimization to calculate the wellbore temperature. The available research studies have proved that engineering backgrounds have significant impacts on the calculation of the wellbore temperature [10]. For example, A.R.Hasan and Kabir [11] proposed a dimensionless formation temperature to describe the heat transfer between the wellbore and the formation. Wang et al. [12] calculated the wellbore temperature under the lost circulation. Wang et al. [13] built a model to calculate the deep-water well temperature during the cement operation based on the hydration reaction.

With regard to the deep gas well, the pressure and the temperature are so high that the gas properties would certainly be influenced, which would in turn have an impact on the wellbore temperature. Therefore, the temperature calculation of the deep gas well must consider the coupling relationship between the gas properties, temperature, and pressure. Otherwise, the TAP control may fail the expected goal.

Aiming to get the most optimizing control of the TAP, the various measures have been studied, including the thermal insulation [14], the release of the thermal-expanded liquid, and the increase of annular fluid compressibility [15]. Considering the cost and the operational difficulties, nitrogen gas is regarded as one of the most suitable measures to mitigate the TAP, because it is easy to obtain and not so expensive. More importantly, its control performance has been verified by both theory and experiment. Some classical and recent studies are as follows. Vargo et al. [16] analyzed the control law of the TAP by experiments. A water-based fluid and an oil-based fluid are selected to compare the mitigation

performances by injecting the nitrogen gas. The results showed the different changing laws while both had good performances. Sun et al. [17] built a model to calculate the TAP when both gas and liquid exist in the casing annulus of the deep-water well. He showed that the injection volume of the nitrogen gas is one of the key parameters for the successful control. Up until now, nitrogen gas has been applied to control the TAP in the deepwater wells [17] and gas storage wells [18]. However, few researchers study the nitrogen gas applied in the deep gas well to mitigate the TAP in the tubing–casing annulus.

Therefore, this article aims to calculate the temperature profile of the deep gas well. Then, a method is provided to analyze the mitigation performance of the TAP by injection nitrogen gas. To improve the accuracy, the calculation considers the coupling relationship among the temperature, the pressure, and the gas properties. Not only that, the gas compression and the heat transfer are also taken into account to analyze the mitigation performance of the TAP, thus helping to achieve a reliable control performance and prevent well integrity failure, which can provide some support for the long-term safe production of the deep gas well.

## 2 Methods

### 2.1 The temperature profile in the tubing string of a deep gas well

#### 2.1.1 Heat transfer of tubing string

The tubing string is the pathway for the high-temperature natural gas flowing from the deep reservoir to the ground. Therefore, the heat transfers from the tubing string to the formation during the production process due to the temperature difference between the natural gas and the nearby formation. To describe the aforementioned process by a mathematical model, the tubing string is divided into many micro units with the length of  $dz$ . The aforementioned process conforms to the energy conservation law and the momentum conservation law in a single micro unit, as expressed by Eq. 1:

$$\begin{cases} \frac{dp}{dz} + \rho_f g \sin \theta + f \frac{\rho_f v_f^2}{2d_{tn}} + \rho_f v_f \frac{dv_f}{dz} = 0 \\ C_f \frac{dT_f}{dz} + v_f \frac{dv_f}{dz} + \frac{1}{\rho_f} \frac{dp}{dz} + g \sin \theta + \frac{1}{w_f} \frac{dQ}{dz} = 0 \end{cases} \quad (1)$$

where  $p$  is the pressure, Pa;  $z$  is the length of the production string, m;  $\rho_f$  is the density of the natural gas inside the micro unit,  $\text{kg/m}^3$ ;  $g$  is the gravity acceleration speed,  $\text{m/s}^2$ ;  $\theta$  is the well inclination, °;  $f$  is the friction factor between the natural gas and the tubing wall, dimensionless;  $v_f$  is the flow velocity of the natural gas inside the micro unit,  $\text{m/s}$ ;  $d_{tn}$  is the tubing inner diameter, m;  $C_f$  is the specific gas capacity of the natural gas

inside the micro unit, J/(kgK);  $T_f$  is the temperature of the natural gas inside the micro unit, K;  $w_f$  is the gas mass flow rate, kg/s;  $Q$  is the heat flow rate along the wellbore radial direction, J/s.

The friction factor is determined by the flow conditions [19] and fluid rheological properties [20]. It is a key to calculate the pressure drop [21] and can be expressed by Eq. 2 [11]:

$$\begin{cases} f^{-0.5} = -2 \log \left[ \frac{Ra}{3.715d_{tn}} + \left( \frac{6.943}{Re} \right)^{0.9} \right] \\ Re = \frac{\rho_f v_f d_{tn}}{\mu} \end{cases} \quad (2)$$

where  $R_a$  is the roughness of the tubing wall, m;  $Re$  is the Reynolds number, dimensionless; and  $\mu$  is the gas viscosity, Pa s.

The heat flow rate along the wellbore radial direction is expressed by Eq. 3:

$$dQ = \frac{T_f - T_h}{R_{to}} dz \quad (3)$$

where  $T_h$  is the temperature of the wellbore outer boundary, K;  $R_{to}$  is the heat resistance from the tubing to the wellbore outer boundary, mK/W.

The heat continues transferring to the formation after the heat transfers from the tubing to the wellbore outer boundary, which is an unsteady heat transfer in a cylindrical coordinate system, as expressed by Eq. 4:

$$\frac{1}{r} \frac{\partial}{\partial r} \left( r \frac{\partial T_c}{\partial r} \right) = \frac{1}{\alpha_e} \frac{\partial T_c}{\partial t} \quad (4)$$

where  $r$  is the distance from the wellbore center to the formation, m;  $T_c$  is the formation temperature, K;  $\alpha_e$  is the formation thermal diffusion coefficient, m<sup>2</sup>/s; and  $t$  is the time, s.

As a differential equation, Eq. 4 can be turned into an equation about the formation temperature by the Laplace transformation with the specific boundary conditions, but the temperature is still difficult to calculate either by the analytic method or the numerical integration. Therefore, the dimensionless formation temperature is introduced to simplify the engineering calculation, which is fitting by the data of the analytic result and has been widely applied in petroleum engineering [22], as expressed by Eq. 5:

$$dQ_{rf} = \frac{2\pi\lambda_e(T_h - T_c)}{T_D} dz \quad (5)$$

where  $\lambda_e$  is the formation of thermal conductivity, W/(m·°C);  $T_D$  is the dimensionless formation temperature, dimensionless.

The dimensionless temperature can be calculated by Eq. 6:

$$T_D = \begin{cases} 1.1281 \sqrt{t_D} (1 - 0.3 \sqrt{t_D}) t_D \leq 1.5 \\ (0.4063 + 0.5 \ln t_D) (1 + 0.6/t_D) t_D > 1.5 \end{cases} \quad (6)$$

$$tD = \frac{t\alpha_e}{r_w^2}$$

where  $t_D$  is the dimensionless time, dimensionless;  $r_w$  is the well radius, m.

### 2.1.2 Impact of temperature and pressure on gas properties

The gas PVT law indicates that both temperature and pressure have an impact on the gas density, as expressed by Eq. 7:

$$\rho_f = \frac{p_f M_g}{Z_g R T_f} \quad (7)$$

The gas compression factor is also related to temperature and pressure, which can be expressed by Eq. 8 [23]:

$$\begin{cases} Z_g = 1 + \left( 0.31506 - \frac{1.0467}{T_{pr}} - \frac{1.0467}{T_{pr}^3} \right) p_{pr} + \left( 0.5353 - \frac{0.6123}{T_{pr}} + \frac{0.6815}{T_{pr}^2} \right) p_{pr}^2 \\ \rho_{pr} = 0.27 p_{pr} / (Z_g T_{pr}) \\ T_{pr} = T / (92.2 + 176.7 \gamma_g) \\ p_{pr} = p / (4.778 - 0.248 \gamma_g) \end{cases} \quad (8)$$

where  $p_{pr}$  is the pseudo-reduced pressure, dimensionless;  $T_{pr}$  is the pseudo-reduced temperature, dimensionless;  $\gamma_g$  is the relative density of the production gas, dimensionless.

Following this, the gas-flow velocity can be obtained according to the mass conservation law, as expressed by Eq. 9:

$$\frac{dv_f}{dz} = -\frac{v_f}{\rho_f} \frac{d\rho_f}{dz} \quad (9)$$

The gas viscosity can be calculated by using the Satlan formula [24], as expressed by Eq. 10

$$\frac{\mu}{\mu_0} = \left( \frac{T_f}{T_0} \right)^{1.5} \frac{T_0 + B}{T_f + B} \quad (10)$$

where  $\mu_0$  is the gas viscosity, Pa s;  $T_0$  is the temperature, K; and  $B$  is a constant, dimensionless.

### 2.1.3 Solution method and flow chart

Because of the coupling relationship stated in the aforementioned section, it is hard to get the temperature inside the tubing string directly. To solve this problem, the temperature and the pressure inside the single micro unit can be seen as stable when the length of the micro unit is short enough compared with the depth of the deep gas well. And then, the pressure can be expressed by Eq. 11:

$$p_f^i(t) = p_f^{i-1}(t) - \left( \rho_f^i g \sin \theta + f^i \frac{\rho_f^i (v_f^i)^2}{2d_{tn}} \right) \Delta z - \rho_f^i v_f^i \Delta v_f^i \quad (11)$$

$$\Delta v_f^i = \frac{v_f^i}{\rho_f^i} \frac{\rho_f^i - \rho_f^{i-1}}{\Delta z}$$

where  $i$  is the number of the micro unit, dimensionless;  $\Delta z$  is the length of the micro unit, dimensionless; and  $T_{es}$  is the initial formation temperature, K.

Likewise, the temperature of the gas inside the tubing string can be obtained in the same way, as expressed by Eq. 12:

$$T_f^i(t) = \frac{1}{A + \Delta z} \left( AT_f^{i-1}(t) + \Delta z T_e^i + A \Delta z f^i \frac{(V_f^i)^2}{C_f d_{in}} \right) \quad (12)$$

$$A = \frac{w_f C_f [T_D + 2\pi \lambda_e R_{io}^i]}{2\pi \lambda_e}$$

Where,  $A$  is a calculation parameter.

Both Eq. 11 and Eq. 12 should be calculated from the well-bottom to the well-head. The initial conditions are expressed by Eq. 13:

$$\begin{cases} T_f^0 = T_{fb} \\ p_f^0 = p_{fb} \end{cases} \quad (13)$$

where  $T_{fb}$  is the wellbottom temperature, K;  $p_{fb}$  is the bottom hole pressure, Pa.

The solving process has five steps. The first step is to start the calculation. The second step is to calculate the temperature and the pressure of the  $i$ th micro unit by using the gas properties in the  $i$ -1st micro unit. The third step is to recalculate the gas properties by using the temperature and the pressure in the  $i$ th micro unit. The forth step is to recalculate the temperature and the pressure in the  $i$ th micro unit by using the gas properties obtained in the second step. Following the aforementioned steps, the temperature and the pressure errors are compared. If the errors are acceptable, the calculation is continued to the  $i+1$ st micro unit. Otherwise, the calculation is back to the second step until the error is acceptable. The errors are determined by the values obtained from the second step and the forth step, as expressed by Eq. 14:

$$\begin{cases} E1 = |T_{f2} - T_{f4}|/T_{f2} \\ E2 = |p_{f2} - p_{f4}|/p_{f2} \\ EA = 0.01 \end{cases} \quad (14)$$

where  $E1$  is the error of the temperature, dimensionless;  $E2$  is the error of the pressure, dimensionless;  $T_{f2}$  is the temperature obtained from the second step, K;  $T_{f4}$  is the temperature obtained from the fourth step, K;  $p_{f2}$  is the pressure obtained from the second step, Pa;  $p_{f4}$  is the pressure obtained from the fourth step, Pa; and  $EA$  is the acceptable error, dimensionless.

## 2.2 The TAP caused by the thermal expansion

### 2.2.1 Calculation of the TAP

The wellbore temperature would redistribute due to the heat transfer during the production process. As a result, the

temperature of the annular liquid increases and the TAP increases due to the thermal expansion of the annular fluid. The volume consistence law can explain the basic mechanism of the TAP [25, 26]. The trapped annulus has very limited volume to accommodate all of the thermal-expanded annular liquid, so the pressure increases to compress the annular liquid in order to keep the volumes of the trapped annulus and the annular liquid equal. As analyzed previously, the TAP is a function about the annular temperature, the annulus volume, and the annular liquid [27], as expressed by Eq. 15:

$$\Delta p_a = \left( \frac{\partial p_a}{\partial T_a} \right) \Delta T_a + \left( \frac{\partial p_a}{\partial V_a} \right) \Delta V_a + \left( \frac{\partial p_a}{\partial m} \right) \Delta m \quad (15)$$

According to the definitions of the annular liquid isobaric expansion coefficient and the isothermal compressibility, Eq. 15 can be turned into Eq. 16:

$$\Delta p_a = \frac{\alpha}{k_T} \Delta T_a - \frac{\Delta V_a}{k_T \cdot V_f} + \frac{\Delta V_f}{k_T \cdot V_f} \quad (16)$$

where  $\Delta p_a$  is the TAP, MPa;  $\alpha$  is the annular liquid isobaric expansion coefficient,  $K^{-1}$ ;  $k_T$  is the isothermal compressibility,  $MPa^{-1}$ ;  $\Delta T_a$  is the increase of annular temperature, K;  $\Delta V_a$  is the volume change of the trapped annulus,  $m^3$ ;  $V_f$  is the volume of the annular liquid,  $m^3$ ;  $V_a$  is the volume of the trapped annulus,  $m^3$ ; and  $\Delta V_f$  is the volume of the liquid flowing in or out the annulus,  $m^3$ .

It can be known that the temperature change of the annular liquid is indispensable to get the TAP. The temperature of the annular liquid can be calculated based on the wellbore radial heat conservation law and the radial heat-resistance distribution, as expressed by Eq. 17:

$$T_a^i = \frac{T_f^i (1 + T_D) + 2\pi \lambda_e T_e^i (R_{io}^i - R_{zro}^i)}{T_D + 2\pi \lambda_e R_{io}^i} \quad (17)$$

where  $T_a^i$  is the temperature of the  $i$ th annulus, K;  $R_{zro}$  is the thermal resistance of the  $i$ th annulus to the wellbore outer boundary,  $mK/W$ .

The annular liquid has exchanged the heat adequately with the formation before production, so its initial temperature can be regarded as the formation temperature. As a result, the temperature change of the annular liquid can be calculated by Eq. 18:

$$\Delta T_a^i = T_a^i - T_e^i \quad (18)$$

The average temperature change of the annular liquid can be obtained by Eq. 19:

$$\Delta T_a = \sum \Delta T_a^i / NI \quad (19)$$

where  $NI$  is the number of the annulus segment, dimensionless.

TABLE 1 Calculation parameters of the case well.

	Pipe string	Pipe and wellbore diameter/mm	Wall thickness/mm	Setting depth/m
Casing Program	Casing	508.00/660.40	12.70	508.0
	Casing	365.13/444.50	13.88	1800.0
	Casing	282.58/333.40	18.64	5758.0
	Casing	201.70/241.30	15.12	6684.0
	Liner	139.70/171.50	12.09	6242.9–6887.0
	Tubing	114.30/	12.70	1174.2
		114.30/	9.65	6186.0
		88.90/	6.45	Reservoir
Thermal Parameters	Parameter	Value	Parameter	Value
	Formation thermal diffusion coefficient	$11.7 \times 10^{-7} \text{ m}^2/\text{s}$	Formation density	$2.35 \text{ g/cm}^3$
	Heat capacity of production gas	$2310 \text{ J/(kg}\cdot\text{K)}$	Thermal conductivity of formation	$5.1 \text{ W/(m}\cdot\text{K)}$
	Thermal conductivity of annular liquid	$0.61 \text{ W/(m}\cdot\text{K)}$	Tubing inner wall toughness	$1.6 \times 10^{-5} \text{ m}$
	Thermal conductivity of production gas	$0.025 \text{ W/(m}\cdot\text{K)}$	Relative density of production gas	0.75
	Gas adiabatic index	1.29	Viscosity of production gas	$1.55 \times 10^{-6} \text{ Pa}\cdot\text{s}$
	Annular liquid isobaric expansion coefficient	$0.00013 \text{ K}^{-1}$	Annular liquid isothermal compressibility	$0.00040 \text{ MPa}^{-1}$
	Thermal conductivity of cement	$0.52 \text{ W/(m}\cdot\text{K)}$	Thermal conductivity of casing and tubing	$50.5 \text{ W/(m}\cdot\text{K)}$
	Formation heat capacity	$895 \text{ J/(kg}\cdot\text{K)}$	Length of well segment	1 m

### 2.2.2 Mitigation of the TAP

Different from the sustained annular pressure (TAP) caused by wellbore leakage, the TAP would not rebuild after taking some effective measures, so the server risk caused by the high TAP can be avoided. As stated in the introduction, the nitrogen gas has the great potential to mitigate the TAP. Moreover, nitrogen gas is more feasible to be injected into the deep gas well compared with the deepwater well with the subsea wellhead [28]. After injection, the nitrogen gas gathers as a column above the annular liquid column. To get a clear understanding of the injection volume, the relative length is defined to describe the injection volume of the nitrogen gas. The injection volume can be calculated by multiplying the length to the area of the trapped annulus, as expressed by Eq. 20:

$$L_{\text{ND}} = \frac{L_{\text{N}}}{L_{\text{A}}}\% \quad (20)$$

Where,  $L_{\text{ND}}$  is the relative length, %;  $L_{\text{N}}$  is the length of the nitrogen gas column, m; and  $L_{\text{A}}$  is the length of the tubing-casing annulus, m.

The nitrogen gas works in two aspects to mitigate the TAP. First is to decrease the volume of the annular liquid. The volume of the annular liquid is equal to the trapped annulus volume when the annulus is fully filled with the annular liquid, as expressed by Eq. 21. The injection of the nitrogen gas changes this situation by sharing the part volume of the trapped annulus,

as expressed by Eq. 22. Accordingly, the expansion of the annular liquid is not large as before.

$$V_{\text{f}} = V_{\text{a}} \quad (21)$$

$$V_{\text{f}} = V_{\text{a}} - L_{\text{ND}} \times L_{\text{A}} \times A_{\text{a}} \quad (22)$$

Secondly, the nitrogen gas is easy to compress by the high pressure, so some extra space is available to accommodate the thermal-expanded annular liquid, which is called the volume compensation effect [26], as expressed by Eqs. 23, 24. As a result, the pressure need not necessary be so high to compress the annular liquid.

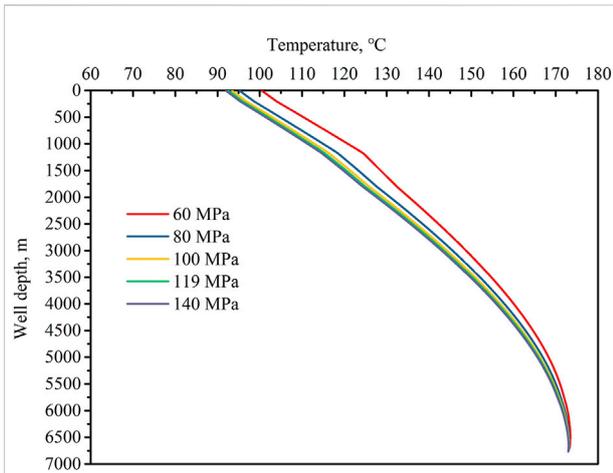
$$\Delta V_{\text{N}} = L_{\text{ND}} \times L_{\text{A}} \times A_{\text{a}} \left[ 1 - \frac{p_{\text{s}} T_{\text{c}}}{(\Delta p_{\text{a}} + p_{\text{s}}) T_{\text{s}}} \right] \quad (23)$$

$$\Delta V_{\text{f}} = -\Delta V_{\text{N}} \quad (24)$$

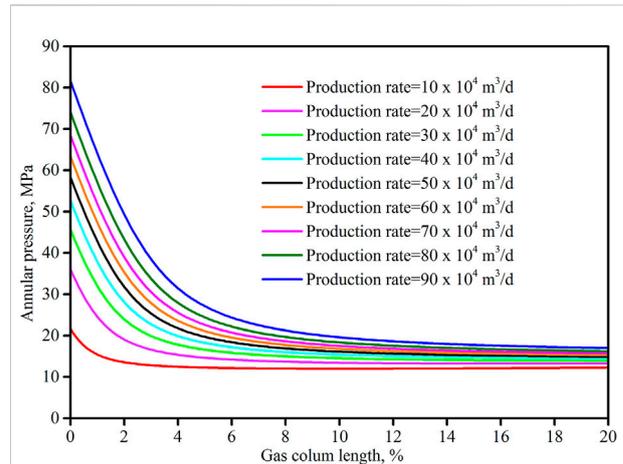
where,  $A_{\text{a}}$  is the area of the annulus cross section,  $\text{m}^2$ ;  $p_{\text{s}}$  is the initial pressure imposed on the nitrogen gas, MPa;  $T_{\text{s}}$  is the initial temperature of the nitrogen gas, K; and  $T_{\text{c}}$  is the temperature of the nitrogen gas, K.

## 3 Results

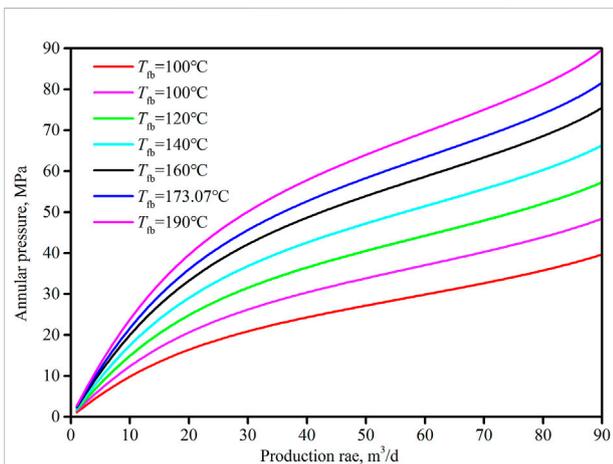
A deep gas well with a depth of 6,850 m is selected as the case well. Its casing program is shown in Table 1 and the cement is back to the wellhead. The packer is in the depth of 6,680 m. The



**FIGURE 1**  
The temperature profiles of the production string under different pressures.



**FIGURE 3**  
The changing law of annular pressure with the nitrogen gas column length under different production rates.



**FIGURE 2**  
The changing law of the TAP as the production rate under different wellbottom temperatures.

wellbottom temperature is 173.07°C and the production rate is set as  $40 \times 10^4 \text{ m}^3/\text{d}$ . The other parameters are shown in Table 1.

### 3.1 Results of the temperature profile

Figure 1 is the temperature inside the tubing string under different values of the bottom hole pressure. It can be seen that the temperature decreases from the wellbottom to the wellhead because of the heat transfer in the well’s radial direction. Through the comparison of the temperature curves, it can be found that the temperature decreases faster under higher bottom hole pressure. For

example, the wellhead temperature is 92.58°C when the bottom hole pressure is 119 MPa, while the wellhead temperature becomes 100.50°C when the bottom hole pressure is 60 MPa. This indicates that the coupling relationship does exist between the temperature and the pressure. According to the volume consistency law, the temperature change and the trapped annular liquid are two essential conditions for the TAP. The temperature profiles shown in Figure 2 are all higher than the original formation temperature profile. With the existence of the annular protection liquid, the deep gas well obviously satisfies the basic conditions to generate the TAP.

### 3.2 Analysis of the TAP

Figure 2 is the TAP-changing law with the production rate when the tubing–casing annulus is totally filled with the annular protection liquid. The TAP increases as the production rate increases, because larger production rate can bring more heat to the annular liquid. The curves also show that the annular pressure increases faster under higher wellbottom temperature. Considering the high temperature and high production rate of the deep gas well, the high TAP is inevitable when the tubing–casing annulus is totally filled with the annular protection liquid. In Figure 3, the TAP can be as high as 81.61 MPa when the wellbottom temperature is 173.09°C and will increase to 89.66 MPa when the wellbottom temperature is 190°C. Such high annular pressures would certainly damage the well’s safety barriers, like the casing, the tubing, the cement, the packers, and the wellhead [29, 30]. As a result, wellbore leakage may happen and finally bring about the SAP [31]. This would make the management of the deep gas well more complex and more difficult, even the abandonment of the expensive gas well.

### 3.3 Mitigation performance

The mitigation performance of nitrogen gas can be obtained by substituting Eq. 20 and Eq. 22 into Eq. 15. The results are shown in Figure 3. It can be seen that the TAP decreases as the nitrogen gas column length increases, but the decreasing speed becomes more and more slow. Taking the curve under  $90 \times 10^4 \text{ m}^3/\text{d}$  as an example, the TAP is reduced from 81.61 MPa to 27.10 MPa when the nitrogen gas column length increases from zero to 5 %, while the decrease of the TAP is only 0.77 MPa (from 17.75 MPa to 16.98 MPa) when the nitrogen gas column length increases from 15 % to 20 %. This trend is consistent with the experimental results of Zhou et al. [32] and Wang et al. [33]. Their experiments indicated that the TAP decreases sharply when the nitrogen gas column length is within 5 % and seems stable when the nitrogen gas column length is close to 20 %. This shows that the nitrogen gas can achieve a good mitigation performance under different production rates of the deep gas well, but the nitrogen gas column length should be further analyzed.

According to the shape of the curves in Figure 3, the mitigation performance can be divided into the fast-decreasing stage, the efficient control stage, and the stable stage. In the fast-decreasing stage, the compression of the nitrogen gas volume plays a major role, but the TAP is still high and exceeds the mitigation goal. In the efficient stage, the compression of the nitrogen gas still plays the major role while the reduction of the annular liquid also starts working. The TAP is in a reasonable range in this stage although the decreasing speed is slower. In the stable stage, the TAP even seems unchanged when the nitrogen gas column length is long enough. In this stage, the reduction of the annular liquid plays a major role.

One thing to be noted that there is no universal division criteria for the three stages because the criteria may be different under different conditions. Commonly speaking and according to Figure 3, the nitrogen gas length is less than 3 % in the fast-decreasing stage and the nitrogen gas length is over 10 % in the stable stage. To get the most efficient mitigation performance, it is better to keep the mitigation performance in the efficient stage. The nitrogen gas column should not be over 15 %, or the mitigation performance can be improved very little.

## 4 Conclusion

1) A mode is established to calculate the temperature profile of the deep gas well by considering the coupling relationship among the temperature, pressure, and gas properties. The case well shows that the temperature decreases faster under higher bottom hole pressure, so the impact of the pressure on the temperature should not be ignored in the deep gas well. Comparing the temperature profiles and the original formation temperature profile, the deep gas well satisfies the basic conditions to generate the TAP.

- 2) The temperature change and the trapped annular liquid are two essential conditions for the TAP. When the tubing–casing annulus is totally filled with the annular protection liquid, the TAP increases as the production rate increases and increases faster under a higher wellbottom temperature. Considering the high production rate of the deep gas well, the TAP is inevitable and high enough to damage the integrity of the well's safety barriers without the suitable control measures, which can lead to the SAP in the deep gas well and make the situation more complex.
- 3) The nitrogen gas mitigates the TAP by reducing the annular liquid volume and providing the extra space to accommodate the thermal-expanded annular liquid. Based on the mitigation mechanism, a model is built to analyze the mitigation performance. The results show that the nitrogen gas can achieve a good mitigation performance under different production rates.
- 4) The mitigation performance can be divided into the fast-decreasing stage, the efficient control stage, and the stable stage. The compression of the nitrogen gas volume plays a major role in the fast-decreasing stage while the reduction of the annular liquid plays a major role in the stable stage. There are no universal division criteria for the three stages because of the different conditions. To get the most efficient mitigation performance, it is better to keep the mitigation performance in the efficient stage, and the nitrogen gas column should not be over 15 %.

## Data availability statement

The original contributions presented in the study are included in the article/supplementary material; further inquiries can be directed to the corresponding authors.

## Author contributions

BZ: Formal analysis, Writing-original draft preparation, Writing-review and editing, Funding acquisition; YZ: Formal analysis, Writing-original draft preparation; JZ: Methodology, Conceptualization; NL: Methodology, Conceptualization, Project administration, Supervision; LC: Data analysis; QW: Drawing figures, Funding acquisition; LL: Formal analysis.

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## Conflict of interest

Authors BZ, YZ, and JD were employed by Research Institute of Safety and Environment Technology, CNPC. Author NL was employed by Research Institute of Petroleum Exploration and Development, PetroChina. Author LC was employed by Research Institute of Oil & Gas Engineering, Tarim Oilfield Company Petrochina. Author LL was employed by Bazhou Branch Company of

Xibu Drilling Engineering Company Limited, CNPC. Author QW was employed by CNPC Engineering Technology R&D Company Limited, Beijing, China.

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