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Drainage Research of Different Tube Depth in Horizontal Gas Well

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Abstract: As the structure of horizontal gas wells is more complicated than that of vertical wells, the form of the liquid-carrying in different sections does not well agree. This makes it problematic to apply the widely used liquid-carrying theory of vertical gas wells in horizontal gas wells. Since the theory focused on the critical gas flow rate, it cannot quantify how much liquid it can remove. Simultaneously, it ignores the fact that the liquid-carrying ability of gas flow is limited and the producing liquid has a certain amount of flowing energy. In this study, the gas-liquid flow law of horizontal gas wells and wellhead drainage stability in different tubing depths were firstly studied. Then, the stability of gas drainage for different tubing depths was analyzed and confirmed. Given the disadvantages of the typical theory of critical gas flow, the mathematical model of different tubing depths for gas drainage is established for horizontal gas wells. The innovative model could take the energy of gas flow and liquid flow into account, and quantify the liquid volume which was removed. By verifying the model with the experiments, the result showed that the relative error of the model is generally less than 10%. It shows the research could provide a scientific basis for the analysis and liquid-carrying capacity for horizontal gas wells.

Keywords: horizontal gas well; liquid-carrying model; tubing depth; gas drainage; fluid energy

1. Introduction

In the middle-later development of the gas field, the liquid would appear along with the gas production. For horizontal gas wells, the appearance of liquid would accelerate the reduction of gas production rate and would finally kill the well if the liquid-carrying ability of gas flow is not capable to remove the liquid out of pipe timely [1,2]. To exploit horizontal gas wells effectively and enhance the ultimate recovery, it is not only necessary to attach importance to the initial gas production rate, but also to pay more attention to the middle-later gas production rate.

Under normal circumstances, to continuously stabilize production rate of gas wells with liquid production, they mainly adopted the gas drainage technologies [3]. Compared with the vertical gas well, the liquid-carrying mechanism in horizontal gas wells is much more complicated, which is also a complex problem of gas-liquid two-phase flow [4]. Since the horizontal gas wells have a specially complex well structure, the producing liquid would face different obstacles (barriers) in different sections of tubing depth when it flows through the production tubing. At present, the critical liquid-carrying theory in vertical gas wells can not finely explain the mechanism in different sections, let alone apply it in the horizontal gas well [5]. Therefore, the development of horizontal gas wells can not be guided effectively by the normal vertical gas well.

The loading status judgment of gas wells is the premise to take the drainage measures and there are many related mathematical models to conduct the analysis [6]. While different models are applicable to different gas reservoirs. Presently, the study on liquid-carrying mainly focused on vertical gas wells, which was based on the force analysis of liquid form. Then the calculation models of the gas flow rate at the critical status were obtained for the judgment of the loading status [7].

doi:10.20944/preprints202212.0538.v1

In general, there are two main kinds of critical liquid-carrying models for the analysis of loading status and gas flow ability-droplet models and liquid film models [8]. The droplet model reckons that droplet morphology is the main form of producing liquid in the wellbore, which assumes that the minimum gas flow required for removing the fluid from the well is to carry the largest diameter droplet out of the wellbore continuously. Typical droplet models, Turner model [9], the Coleman model [10] and Lea model [11], etc. The liquid film model considers that the liquid film is the main form of producing liquid and its reverse flow is the main factor leading to the loading. Typical liquid film models like, Taitel model [12], the Barnea model [13] and Zhou model [14] etc.

The classic droplet models and liquid film models are still widely used in gas fields around the world [15], while they only focused on the droplet or liquid film in the wellbore. In these theories, the critical gas flow rate of liquid-carrying is independent of the liquid production rate, the interaction of the gas-liquid phase and the tubing depth. However, in reality, the producing liquid is lifted by the fluid flow to the wellhead, which could be regarded as the energy conversion between the gas phase and the liquid phase. While, the energy that a certain amount of gas flow could convert is limited. Further, the producing tubing would cause additional energy loss for the fluid flow from the inclined section and horizontal section of horizontal gas wells, which is seriously influenced by the tubing depth. Therefore, the liquid-carrying theory of vertical gas wells has a poor application in horizontal wells.

As the volume of gas production and liquid production is the main point of the continuous development and loading status judgment of the gas well health, the previous studies and liquid-carrying models could not meet the need. Therefore, this paper started on the basis of drainage stability analysis of different tubing depths. Then the paper clarified the fact that the different tubing depths seriously affected the liquid-carrying effect of the horizontal gas wells. Further, to avoid the disadvantages of the previous models, the paper proposed a new method to evaluate the liquid-carrying ability of gas flow under different tubing depths, considering the energy of liquid flow and the resistance of the producing tubing in different sections.

2. Experimental section

2.1 On-site structure of horizontal gas wells

The different well structure is the main point, of which the horizontal gas well differs from the vertical gas well. According to the indoor simulation, to explain two viewpoints: a) different tubing depth would affect the stability of gas drainage; b) the pressure loss would differ from each other since the tubing depth was not the same

According to the gas field investigation of Qinghai gas field, Xinjiang gas field, Changqing gas field and Sichuan gas field, etc., the conventional structure of the actual horizontal gas wells can be shown in Figure 1. The producing tubing of the conventional well reaches the upper of the inclined well section.

Figure 1 evidently shows that different tubing depths would have much influence on the tubing diameter distribution of the horizontal gas well and flowing frictional loss of the gas-liquid two phases, etc. Further, the serious loading parts for the horizontal gas wells are used to be the inclined and horizontal sections, which are entirely different from the vertical gas wells. Therefore, the gas-liquid phase flow rhythm and liquid-carrying theory of horizontal gas wells would be affected by the different tubing depths, which would also impose an impact on the implementation of the later gas drainage technology.

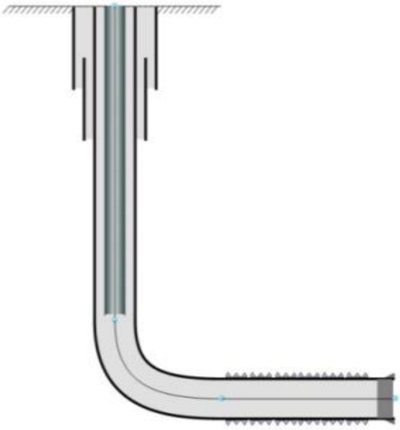


Figure 1. Conventional structure of horizontal gas well.

Nowadays, as the well structure is the major difference between the horizontal gas well and vertical gas well, the study on the liquid-carrying of horizontal gas wells ought to conduct firstly from the optimization of well structure, especially on the tubing depth. Previous scholars were devoted to increasing the speed of gas flow by selecting the smaller tubing diameter and enhancing the ability of liquid-carrying. However, the study of different tubing depths would have big affluence the liquid-carrying of horizontal gas wells, which also belong to the drainage research category, while there is no relevant research presently. Therefore, it is of great importance to study the influence of different tubing depths on the gas-liquid phase flow and to establish the adaptive mechanism for the horizontal gas wells.

2.2 Experimental medium

In order to simulate the practical producing process of the horizontal gas well, the experimental liquid was made up of the report of on-site liquid ingredients. Relying on the compatible experiment, the similar liquid ingredients of the liquid are made and the experimental medium is shown in Table 1.

Table 1. Practical salinity and simulated reservoir liquid.

$MgCl_2$ (mg/L)	$CaCl_2$ (mg/L)	Na_2SO_4 (mg/L)	$NaHCO_3$ (mg/L)	KCl (mg/L)	NaCl (mg/L)	Simulated salinity	Practical salinity
9970	4850	5660	280	500	99800	121060	121060

Detecting the simulated liquid, the main properties under standard conditions are shown in Table 2.

Table 2. Properties of simulated reservoir liquid.

Water Type	Density (mg/L)	Viscosity (mPa·s)	Surface tension (mN)
$CaCl_2$	1.08	1.74	53.37

2.2 Experimental setup and methods

To study the gas-liquid phase flow law of the horizontal gas well under different tubing depths and to compare & analyze the liquid-carrying capacity of gas flow in different sections of the horizontal gas well, the existing multi-phase flow experimental equipment had been redesigned and renovated. The simulated device of the horizontal gas well had increased the discharge metering equipment, gas injection device, foam adding equipment, etc. The schematic diagram is shown in Figure 2.

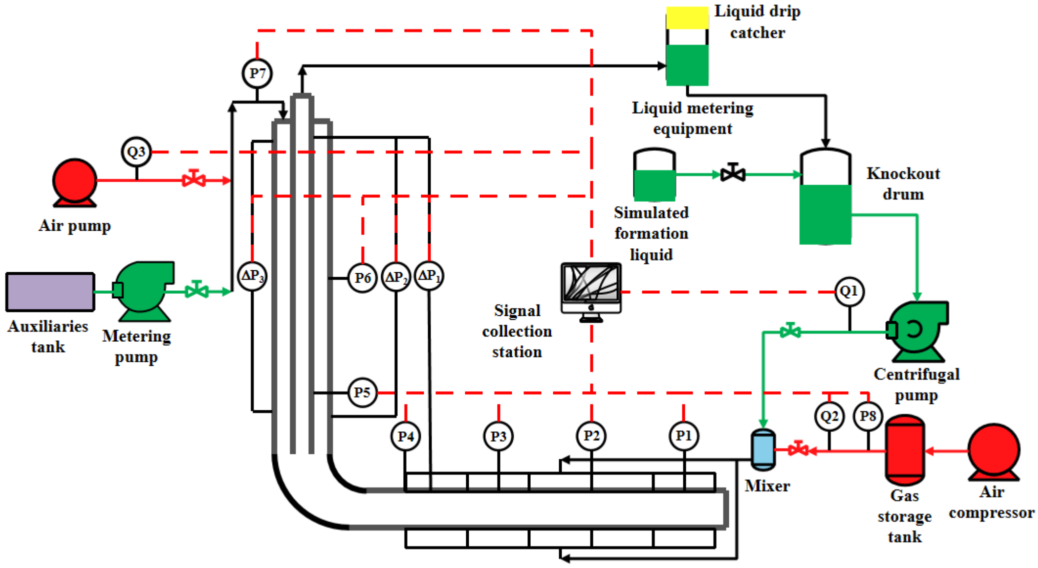


Figure 2. Schematic diagram of experimental device.

Figure 2 shows that the experimental device consists of a circulating water supply system, a gas supply system, a horizontal gas well and a data monitoring and acquisition system. It also designs an auxiliary injection system for the effective injection of foam discharge agent, which can visually observe the impact of the depth of the oil pipe on the fluid carrying flow of the gas flow. The acquisition and monitoring system includes high-speed camera, pressure sensor, temperature sensor, data acquisition part and computer; Set 11 pressure monitoring points, 2 temperature monitoring points and 4 flow monitoring points. It can monitor and record the pressure, differential pressure data, temperature, gas flow and liquid flow fluctuation law on the pipeline of each well section in real-time. During the experiment, the liquid carrying capacity measured by the wellhead liquid metering tank is taken as the reference standard, and the pressure monitoring data on the well section is converted into the pressure gradient of the well section in combination with the length of the pipeline at the measuring point. The wellhead liquid discharge is measured in 0.01s, and the wellhead liquid discharge is compared in the 20s as a stable section during the processing. The device could afford the chance to visually analyze the dynamic phenomenon of the flowing liquid and drainage process in the producing simulation, it could also collect all kinds of data such as pressure, temperature and rate of liquid-carrying or drainage during the producing simulation for post-analysis.

3. Experimental results and discussion

3.1 Effect of tubing depth on drainage stability

The tubing depth would determine the diameter distribution of the horizontal gas well and affect the flowing frictional resistance, then influencing the liquid-carrying effect. In this paper, it firstly explored the drainage stability of different tubing depths and pressure loss of different well sections, etc.

Although the phenomenon of periodic slug flow occurred in the inclined section with the gradual decrease of gas flow rate, the gas flow could continuously remove the liquid if the gas flow rate was capable.

For a certain amount of liquid production rate, different tubing depths would influence the drainage stability. Taking the liquid flow of 0.4m^3/h as an example, the fluctuation of drainage volume changes on the condition of different tubing depths during the gas-liquid phase flowing process, as shown in Figure 3.

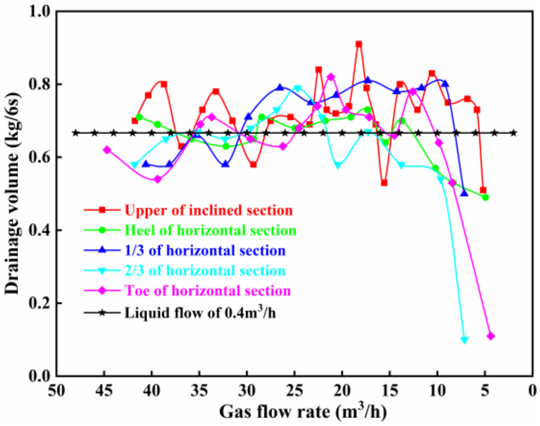


Figure 3. Drainage stability of different tubing depth.

Figure 3 shows that when the gas flow rate is capable to remove the liquid, the gas well will not load and the producing system could be regarded as a relatively stable status. However, when the tubing depth is different, the drainage stability varies. In general, when the tubing reaches the heel of the horizontal section, the fluctuation is smaller than in the other sections, which could be shown in Table 3. It indicates that this type of well structure would keep the wellhead drainage more stable, which is beneficial to the systematic stability of the well production.

Table 1 shows the sensitivity analysis of the tubing depth and liquid production rate.

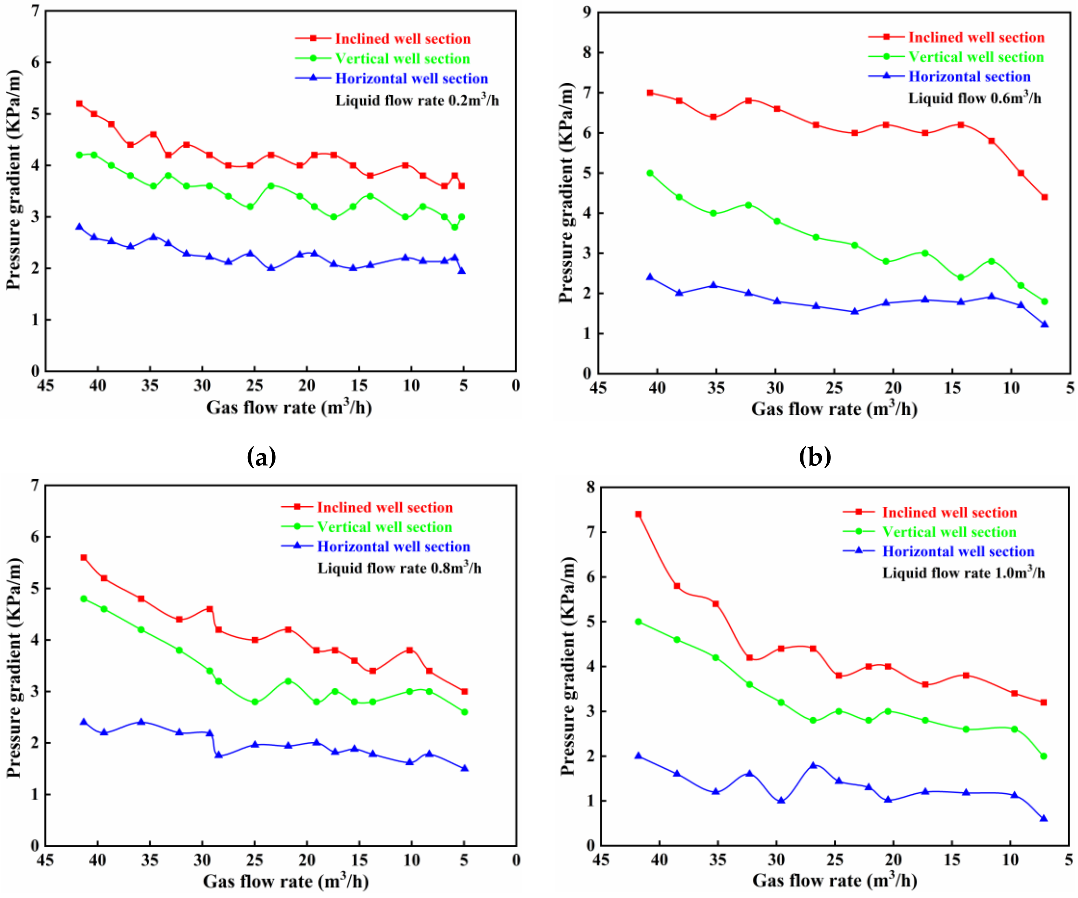
Table 3. Standard deviation between liquid flow rate and production in different tubing depths

Liquid production **Depth of oil tubing**	**0.2 m³/h**	**0.4 m³/h**	**0.6 m³/h**	**0.8 m³/h**	**1.0 m³/h**	**1.2 m³/h**	**1.4 m³/h**
Upper of Inclined Section	0.09190	0.10327	0.11269	0.13098	0.13624	0.21369	-
Heel of Horizontal Section	0.07991	0.08391	0.08285	0.08407	0.08450	0.08646	0.10624
1/3 of Horizontal Section	0.12320	0.23057	0.16282	0.24958	0.29043	0.21640	0.23225
2/3 of Horizontal Section	0.12997	0.19288	0.24197	0.11533	0.11751	0.35977	0.18563
Toe of Horizontal Section	0.12664	0.18202	0.13269	0.14876	0.20972	-	0.21648

Table 3 shows that, for the horizontal gas wells with liquid production ranging from 5m³/d to 32 m³/d, the upper of inclined section is much more beneficial to the stable and continuously producing system if the gas flow is capable to remove the producing liquid.

3.2 Effect of tubing depth on pressure loss of different section

According to the two-phase flow indoor simulation of different tubing depths, the pressure gradient of each section under different liquid flow rates were shown in Figure 4.



(a) (b)

(c) (d)

Figure. 4. Pressure gradient of different section with different liquid production rate. (a) Top of Deviated Section; (b) Heel of Horizontal Section; (c) 1/3 of Horizontal Section; (d) 2/3 of Horizontal Section.

Figure 4 shows that the different tubing depths have a certain influence on the pressure loss of each section. When the oil pipe reaches the upper of the inclined section, of which the horizontal gas well structure is similar to the conventional well structure, the pressure loss of the inclined section is nearly three times that of other sections. Due to the special well structure of the inclined section, the flowing direction is changed when they pass through the inclined section. The fluid is forced to collide with the tubing, resulting in the gas-liquid two-phase turbulence and causing serious energy loss of gas-liquid two-phase energy. Meanwhile, the tubing shoe would also hinder the smooth passage of the fluid passing through the upper of the inclined section. As the density of the gas phase is much smaller than that of the liquid phase, the liquid phase loses more energy than the gas phase due to the dramatic change of the flow direction and the gas-liquid two-phase slippage increases, resulting in a further energy loss, which is not conducive to remove the liquid of the horizontal gas well.

According to the indoor simulation, the pressure loss of the inclined section was plotted in Figure 5, which shows the influence of different tubing depths on the pressure loss of this section.

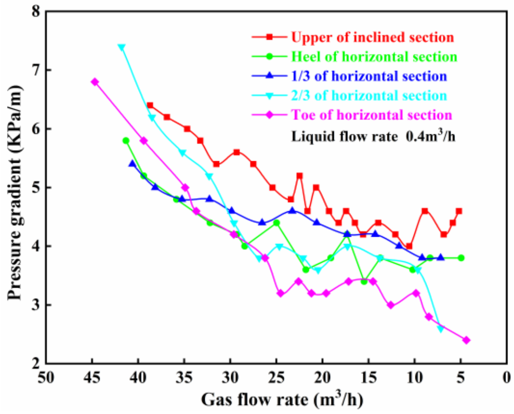
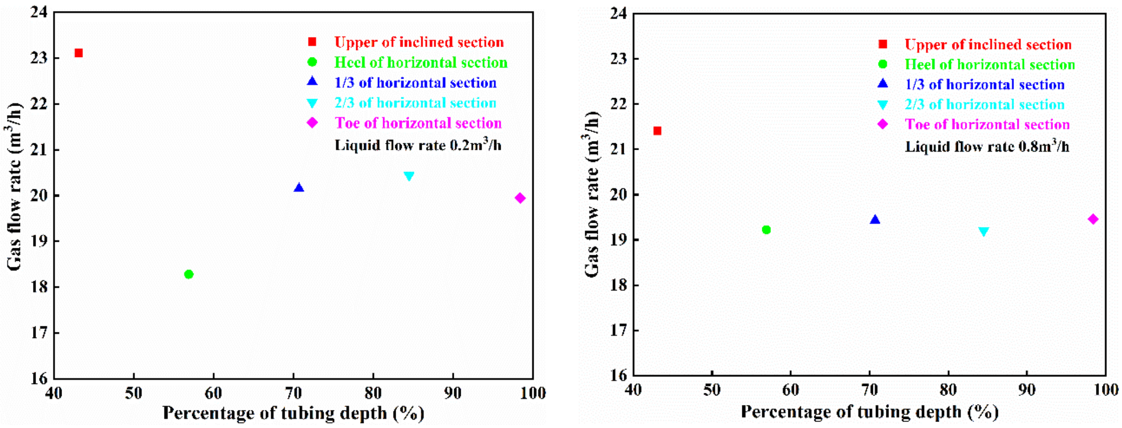


Figure 5. Pressure loss of the deviated section during the different depth of tubing

Figure 6 shows that the pressure in the inclined section decreases gradually along with the decrease of gas flow rate at a certain value of liquid production. While the tubing reaches the upper of the inclined well section, the pressure displays the largest value than the other sections under the certain volume of gas and liquid production. Combing the indoor simulating phenomenon, this could be interpreted by the fact that the fluid will seriously be impacted by the tubing shoe when the tubing is set up at the upper of the inclined section, which will cause additional pressure loss and result in a large pressure loss in this situation.

3.3 Effect of tubing depth on liquid-carrying gas flow rate

According to the different tubing depths, the gas flow rate of the continuous liquid-carrying at different liquid flow rates is plotted and the influence of different tubing depths on the liquid-gas flow rate is shown in Figure 6.



(a) **(b)**

Figure 6. Gas flow rate of carrying liquid in different tubing depth. (a) Liquid Flow Rate 0.2 m³/h; (b) Liquid Flow Rate 0.8 m³/h.

It can be seen from Figure 6 that, when the produced liquid rate is small, the gas flow required for liquid-carrying can be relatively small if the tubing reaches the heel of the horizontal section or deeper sections. This is because the most difficult part to carry liquid is the inclined section. When the tubing reaches the heel of the horizontal section or deeper sections, the tubing diameter of the fluid flow can be effectively reduced. Under the same gas-liquid flow condition, the gas flow rate in the small-diameter circulation channel is greatly increased and the liquid-carrying capacity is enhanced, hence it is easier for the gas flow to carry the liquid at the inclined section than the other sections. Meanwhile, it can be seen from Figure 6 (a) that, as the produced liquid rate is small, the tubing depth at the heel of the horizontal section can further reduce the gas flow rate which required for liquid-carrying. This means the effect of annular air in the vertical section could assist gas drainage in the previous chapter during the small liquid rate.

The indoor simulation results show that the tubing depth can significantly affect the gas drainage and the effect of liquid-carrying for the conventional well structure. Its function is to reduce the cross-section area of the flow channel, increase the gas velocity and finally increase the liquid-carrying capacity to achieve the purpose of gas drainage. At the same time, it is also indicated that the pipe string discharge technology requires that the gas well possesses a certain gas flow rate. However, in consideration of limitation of the gas discharge capacity, this technology can be suitable for the small liquid rate of horizontal gas wells.

3.4 Discussion

The liquid-carrying theory is not suitable for application in horizontal gas wells, because its well structure is complex, the exchanging energy between the gas-liquid phase is quite complicated and the factors that affected the liquid-carrying ability are difficult to accurately consider. Therefore, this paper proposes a new method of fix this problem.

Generally speaking, the tubing depth has a great effect on the gas-liquid two-phase flow and the liquid-carrying theory in the vertical gas well is not suitable to apply in horizontal gas wells. This is because the horizontal well structure is complex, the exchanging energy between the gas-liquid phase is quite complicated and the factors that affected the liquid-carrying ability are difficult to accurately consider.

4. A New Model of Liquid-carrying in horizontal wells

4.1 Model introduction

As the structure of horizontal gas wells is more complicated than that of vertical wells and the form of the liquid-carrying in different sections does not well agree. This makes it problematic to apply the widely used liquid-carrying theory of vertical gas wells in horizontal gas wells. Since the typical theory focused on the critical gas flow rate, it cannot quantify how much liquid it can remove. Simultaneously, it ignores the fact that the liquid-carrying ability of gas flow is limited and the producing liquid has a certain amount of flowing energy.

The different tubing depth has a certain influence on the liquid-carrying in the horizontal gas well. In order to accurately describe the liquid-carrying and quantify the liquid which can be removed, the interior interaction of the gas-liquid phase could be avoided for the analysis convenience and the energy of the gas flow and liquid flow should be taken into account. A calculating model for different tubing depths needs to be established. Only in this way , the rate of removed liquid could be quantified clearly and the new theory could adjust according to the real structure of the horizontal gas wells of different tubing depths.

According to the indoor simulation experiment of gas-water flow in the horizontal gas well, the drainage model of tubing with different depths is established. Take the tubing depth at the upper of the inclined section as an illustration. The physical model is shown in Figure 7.

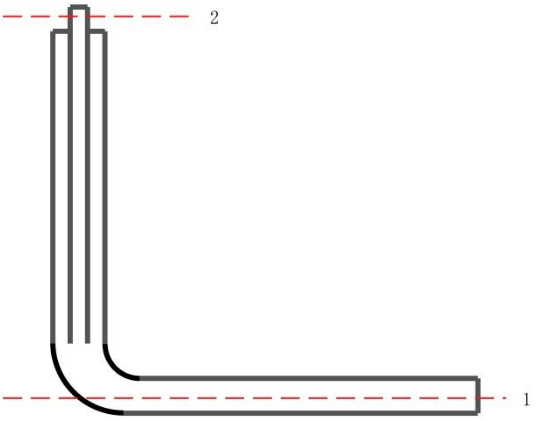


Figure 7. Well structure when the tubing reaches the upper of inclined section.

Making the following assumptions for the established model.

(1) The velocity of the discharged liquid at the reference surface 2 could be approximately calculated according to the amount of removed liquid at the outlet.

(2) The produced flow rate of liquid and gas is stable at the bottom hole of reference surface 1.

(3) Only the wall shear stress and gravity act on the fluid throughout the flowing process, there is no additional force acting on the fluid.

(4) The energy loss caused by the tubing shoe could be approximately calculated by the local resistance formula.

(5) The horizontal section of the indoor device is a non-cementing completion casing.

4.2 Model derivation and establishment

Due to the large liquid density; the produced liquid enters the horizontal section, appearing in the jet state vertically. It can be assumed that the fluid vertically strikes the tubing when the liquid enters into the horizontal section.

Due to the actual production of horizontal gas wells, the liquid is carried out of the pipe mainly by the kinetic energy and pressure energy of gas flow and liquid flow. The liquid is lifted to the wellhead after overcoming the obstacles of gravity, the friction of the tubing wall surface, the loss of thermal energy and the local resistance of the inclined section. According to the conservation of energy, taking the two reference surfaces shown in Figure 7 for the horizontal gas well, the paper establishes the drainage model of different tubing depths by utilizing the energy conservation.

According to the research by Yang Jisheng and Tan X H [16,17], the sum of the kinetic energy and pressure energy of the gas unit time can be expressed as formula (1).

$$E_G = \frac{3}{4} f_g \rho_G A_{out1} v_G^{3} + PB_G Q_G \tag{1}$$

where, P is the pressure at the section, Pa. B_G is the gas volume coefficient at pressure P. Q_G is the gas flow rate, m^3/s. f_g is the gas holdup at the cross-section. A_{out1} is the tubing external cross-sectional area, m^2. v_G is the apparent velocity of gas flow, m/s.

Similarly, the sum of the kinetic energy and pressure energy of the liquid unit time can be expressed as formula (2) [16,17].

$$E_L = \frac{1}{2} \rho_L g v_L^{2} + PQ_L \tag{2}$$

Where, Q_L is the liquid flow rate, m^3/s. v_L is the apparent velocity of liquid flow, m/s.

Under the conditions of indoor simulation, the gravitational potential energy for a certain amount rate of liquid flow and gas flow required to lift the liquid can be expressed as formula (3) [18].

$$E_Z = (\rho_G Q_G + P_L Q_L)gh \tag{3}$$

Where, h is the height of which the liquid and gas are lifted, m.

The shear stress of tubing wall surface works at different tubing depths.

When the fluid is lifted to the wellhead, the shear stress of the inner tubing wall acts on the produced gas and consumes the kinetic energy of the fluid.

When the tubing depth is less than the horizontal section end, namely $0 < \gamma \cdot (S_v + \mathrm{S}_{inc})$, the fluid flows from the heel of the horizontal section to the wellhead. The energy that could be needed to overcome the shear stress can be shown as formula (4).

$$E_{F1} = \tau_{WG1} S \Upsilon H_{gin1} A_{in1} + \tau_{WG3} (1-\Upsilon) S H_{gin2} A_{in2} \tag{4}$$

While the tubing bottom is deeper than the toe of the horizontal section, namely $(S_v + \mathrm{S}_{inc}) / s < \gamma < 1$, the fluid flows from the heel of the horizontal section to the wellhead. The energy that could be needed to overcome the shear stress can be shown as formula (5).

$$E_{F1} = \tau_{WG1} S \Upsilon H_{gin1} A_{in1} + \tau_{WG2} (\Upsilon - (S_v + S_{inc}) / S) S H_{gout1} A_{out1} + \tau_{WG3} (1-\Upsilon) S H_{gin2} A_{in2} \tag{5}$$

Similarly, when the fluid is lifted to the wellhead, the shear stress of the inner tubing wall acts on the produced fluid and the fluid kinetic energy is consumed.

When the tubing depth does not exceed the heel of the horizontal section, namely $0 < \gamma \cdot (S_v + \mathrm{S}_{inc}) / s$, the liquid flow flows from the heel of the horizontal section to the wellhead and the inner casing wall works on the liquid produced by the reservoir, which can be expressed as formula (6).

$$E_{F2} = \tau_{WL1} S \Upsilon H_{lin1} A_{in1} + \tau_{WL3} (1-\Upsilon) S H_{lin2} A_{in2} \tag{6}$$

While the tubing bottom is deeper than the end of the horizontal section, namely $(S_v + \mathrm{S}_{inc}) / s < \gamma < 1$, the flow flows from the end of the horizontal section to the wellhead, and the inner wall of the casing works on the liquid produced by the reservoir. It can be expressed as:

$$E_{F2} = \tau_{WL1} S \Upsilon H_{lin1} A_{in1} + \tau_{WL2} (\Upsilon - (S_v + S_{inc}) / S) S H_{lout1} A_{out1} + \tau_{WG3} (1-\Upsilon) S H_{lin2} A_{in2} \tag{7}$$

For the depth of the tubing, the tubing and casing work on the fluid in the wellbore, it can be expressed as:

$$E_F = E_{F1} + E_{F2} \tag{8}$$

In this formula, τ_{WG1} is frictional resistance of the inner wall of the tubing to gas, N/m; τ_{WL1} is frictional resistance of the inner wall of the tubing to liquid, N/m; τ_{WG2} is frictional resistance of the outer wall of the tubing to gas, N/m; τ_{WL2} is the frictional resistance of the outer wall of the tubing to liquid, N/m; τ_{WG3} is the frictional resistance of the inner wall of the casing to gas, N/m; τ_{WL3} is the frictional resistance of the inner wall of the casing to liquid, N/m; S_v, S_{inc} and S are the length of the straight section, the length of the inclined section, and the total length of the casing, m; Υ is the ratio of tubing penetration depth to total length of casing; H_{gin1}, H_{lin1} are the gas holdup and liquid holdup; H_{gin2}, H_{lin2} are the gas holdup and liquid holdup in tubing shoes to the toe section of the horizontal section; H_{gout1}, H_{lout1} are gas holdup and liquid holdup in the horizontal section; A_{in1}, A_{in2} are the cross-sectional area of oil pipe and casing, m^2; A_{out1} is the outer section of tubing, m^2.

According to the study by [19], the calculation of the shear stress of the wall and the gas can be expressed as:

$$\tau_{WG} = f_G \frac{\rho_G v_G{}^2}{2} \qquad \tau_{WL} = f_L \frac{\rho_L v_L{}^2}{2} \tag{9}$$

In this formula, The gas-liquid friction coefficient can be calculated by the Berrasius equation or the Poisson equation [18].

$$f_L = C_L {Re_L}^{-n} \qquad f_G = C_G {Re_G}^{-m} \tag{10}$$

For different flow patterns, turbulent flow ($R_{eL} > 2000$, $R_{eG} > 2000$), $C_L = C_G = 0.046$, $m = n = 0.2$; For laminar flow, $C_L = C_G = 16$, $m = n = 1$. Reynolds number can be expressed as:

$$Re_g = \frac{\rho_g v_g D_g}{\mu_g} \qquad Re_L = \frac{\rho_L v_L D_L}{\mu_L} \tag{11}$$

When the horizontal well flow continues to carry fluid, although the flow patterns of different good sections are different, combined with the above indoor simulation experiment, it can be basically determined that in the steady-state of continuous liquid carrying, the straight well section exhibits a cyclonic flow, and the inclined section shows the flow pattern of slug and turbulence, and the horizontal section is basically in the wavy flow pattern. In the calculation of the gas-liquid shear stress of the pipe wall, the values of the friction coefficient of gas and liquid for different good sections are different, so it needs to be segmented.

During the flow of gas and water in horizontal gas wells, from the horizontal section to the upper wellhead of the vertical well section, the fluid temperature will change to some extent, resulting in a certain energy loss. The specific calculation formula [16] can be expressed as:

The calculation formula of gas heat loss is:

$$E_{QG} = C_G m_G (t_2 - t_1) = C_G m_G \Delta t \tag{12}$$

The formula for calculating the heat loss of liquid is:

$$E_{QL} = C_L m_L (t_2 - t_1) = C_L m_L \Delta t \tag{13}$$

In this formula, C_G, C_L are specific heat capacity of gas and liquid, J/(kg·°C); m_G, m_L are mass flow through the cross section of the fluid, kg/s; t_1, t_2 are the temperatures at sections 1, 2, respectively, °C; Δt is temperature difference across the section of the fluid, °C。

Compared with vertical wells, there are inclined well sections in the special well structure of horizontal gas wells. The presence of the inclined well section causes the fluid flow passage to suddenly change, causing damage to the internal structure of the water flow, and after the vortex and local resistance are generated, the water flow must readjust the overall structure to adapt to the new conditions [16], generating additional local resistance or energy loss. This energy loss can be calculated by referring to the local resistance commonly used on the oil pipeline [20]. The calculation formula can be expressed as:

$$\Delta P = \xi \frac{G^2}{2{A_{out1}}^2 \rho_L} \left\{ 1 + \left(\frac{\rho_L}{\rho_G} - 1\right) \left[\frac{2}{\xi} X(1 - X) \Delta\left(\frac{1}{s}\right) + X \right] \right\} \tag{14}$$

$$E_S = \xi \frac{{v_L}^2}{g} \rho_L Q_{L1} + \xi \frac{{v_G}^2}{g} \rho_G Q_{G1} \tag{15}$$

In the formula, G is mass flow of gas-liquid two-phase flow, kg/s; ΔP is local resistance loss of elbow, Pa; ξ is local resistance coefficient of gas-liquid two-phase fluid flowing through the elbow; $\Delta(1/s)$ is sliding increment; X is mass gas content, calculated with $X = G_g/G$ For sliding increments, reference can be made to the indoor research conclusions of Chisholm et al. [20,21], which can be calculated using empirical formulas:

$$\Delta\left(\frac{1}{s}\right) = \frac{3.7}{2.5 + R/D} \tag{16}$$

Since the value of *R*/*D* in different cases is different from that of Chisholm et al. [20,21], it is necessary to correct the ξ in combination with the indoor simulation experiment. According to the pressure recording condition of the inclined horizontal section of the indoor full horizontal gas well, combined with the calculation method of the shear stress of the fluid on the pipe wall, the local resistance coefficient ξ can be solved under the condition of a certain production liquid gas, and the local resistance loss E_S occurs when the gas-liquid two phases pass through the inclined well section.

When the fluid flows into the horizontal section, there is also local resistance. However, due to the convective state when the fluid flows into the horizontal section [20], the local energy loss can be expressed as:

$$E_P = 1.3\frac{{v_L}^2}{g}\rho_L Q_{L1} + 1.3\frac{{v_G}^2}{g}\rho_G Q_{G1} \tag{17}$$

Slippage pressure drop loss and gas expansion work during gas-liquid flow

For the gas-liquid two-phase flow in the wellbore, the gas volume will change with the pressure, the gas expands and works, and the shear stress between the gas and liquid phases also works on the gas phase and the liquid phase. But on the whole, the work done in these two cases belongs to internal work. After the work, the energy is converted into the internal energy, potential energy and kinetic energy of the gas-liquid two phases. Therefore, the equilibrium equation established from the energy conservation angle of the two-phase fluid is established. In the middle, the work done by these two internal functions can not be considered.

According to the formula (1) ~ (17), when the gas-water flow is in a stable state at different depths of tubing, the fluid velocity at sections 1 and 2 is stable. When the fluid flows from reference plane 1 to reference plane 2, all the energy sources in the whole process of the fluid flow are the kinetic energy of the horizontal gas and liquid so that the following expression can be obtained.

$$E_{G1} + E_{L1} - E_{QG} - E_{QL} - E_Z - E_F - E_S - E_P = E_{G2} + E_{L2} \tag{18}$$

When the depth of the tubing does not exceed the end of the horizontal section, the model calculation formula is as follows:

$$\begin{aligned}\frac{1}{2}\rho_L g Q_{L2}{v_{L2}}^2 + P_{wh}Q_{L2} = {} & \frac{3}{4}A_{out1}(f_{g1}\rho_{G1}{v_{G1}}^3 - f_{g2}\rho_{G2}{v_{G2}}^3) + \frac{1}{2}\rho_L g Q_{L1}{v_{L1}}^2 + P_{wf}Q_{L1} - (C_G m_G + C_L m_L)\Delta t - (\rho_{G2} g Q_{G2} + \rho_L g Q_{L2})h + \\ & (P_{wf}B_{gwf}Q_{G1} - P_{wh}B_{gwh}Q_{G2}) - (\tau_{WG1}H_{gin1} + \tau_{WL1}H_{lin2})S\Upsilon A_{in1} - (\tau_{WG3}H_{gin2} + \tau_{WL3}H_{lin2})(1-\Upsilon)SA_{in2}\end{aligned} \tag{19}$$

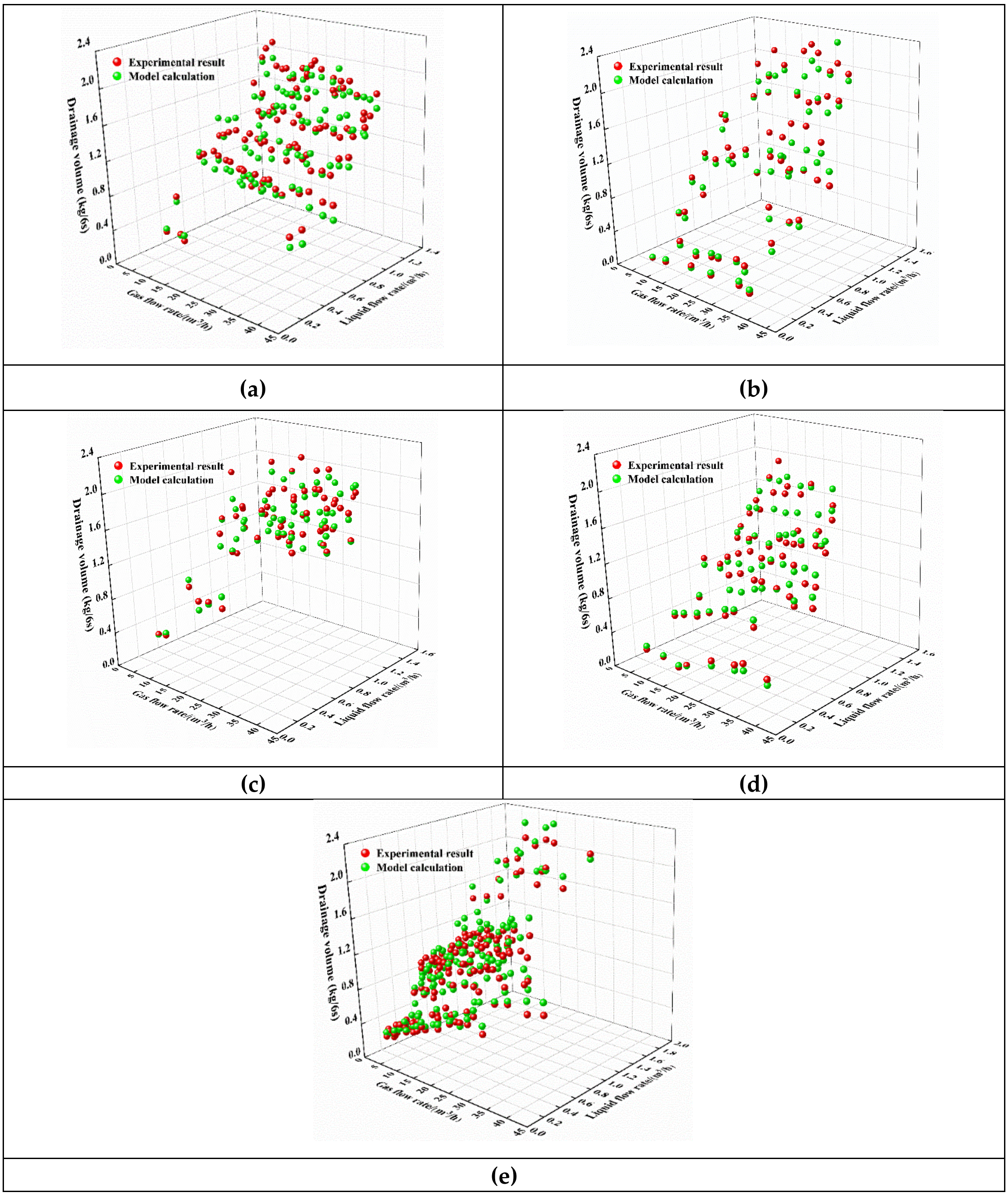
In the formula, Q_{G2}, Q_{L2} are the gas production and discharge volume of the wellhead respectively, m³/h。

Similarly, the model calculation formula when the oil pipe is deeper than the end of the horizontal section can be obtained, and it is necessary to change the work E_F done by the pipe wall friction on the gas-liquid two phases.

It can be obtained from formula (19). For gas wells with certain gas production and liquid production, the analysis can find that the different depths of the oil pipe affect the shear stress of the fluid in the wellbore wall and the flow pattern of each well. Through the above formula (8), it is possible to calculate the work done by the pipe wall shear stress under different depths of the tubing; Under the conditions of indoor simulation experiments, in the production process of horizontal gas wells, the gas entering the wellbore at the horizontal section is consistent with the gas production at the wellhead, $Q_{G1} = Q_{G2}$, For E_{QG}, E_{QL} it can be calculated based on the actual test data. In actual cases, the temperature difference can be calculated by the geothermal gradient to obtain the temperature difference during the production of the complete wellbore, Δt ; Since both ends of the theoretical formula are derived from the wellhead discharge volume, it is possible to determine the amount of liquid discharged at different depths of the tubing under certain production fluids by a trial algorithm, Q_{L2}.

4.3 Model validation

According to the indoor simulation experiment, the deep drain model under the tubing is tested and corrected. The theoretical deepening model of the tubing under certain gas production is verified by theoretical calculation. The calculated model results are drawn in Figure 8.



(a) (b)

(c) (d)

(e)

Figure 8. Comparison of model calculation and experimental result. (a) Upper of the inclined section; (b) Heel of the horizontal section; (c) 1/3 of the horizontal section; (d) 2/3 of the horizontal section; (e) Toe of the horizontal section

From Figure 8, it can be found that the calculation error of the improved model is small. After statistics, it is 8.41%, 9.02%, 7.76%, 8.6%, and 9.44%, respectively, which meets the engineering accuracy requirements, indicating that it is established according to the results of indoor simulation experiments. The deep drain model under the tubing has certain feasibility. The model can be used for the calculation of the liquid discharge at the wellhead of a horizontal gas well with certain gas production, and can also be used as one of the methods for judging the accumulation of horizontal gas wells.

5. Conclusions

(1) The pressure loss analysis of each good section at different depths indicates that the pressure loss in the inclined section is the largest, and when the oil pipe is deeper to the upper end of the inclined section, the liquid will collide with the port when the fluid passes through the port of the oil pipe, which will cause additional pressure loss. The pressure loss in the inclined section is greater, which increases the difficulty of carrying the liquid in the inclined section.

(2) The influence of the depth of the oil pipe on the liquid carrying capacity of the gas flow is analyzed. When the oil pipe is deep to the end of the horizontal section and the liquid production is small, the annular air body is repeatedly compressed and expanded under the liquid plug sealing effect, which can assist the air flow discharge. The effect of the sleeve pressure is cyclical; When the oil pipe is down to other depths, the pressure of the annulus wellhead will not periodically fluctuate, and this auxiliary drainage will not occur; the different depths of the oil pipe will have a certain influence on the drainage performance of the horizontal gas wellhead, under the oil pipe The production system is the most stable when it reaches the end of the horizontal section.

(3) The critical liquid carrying model established by modifying a single droplet of liquid film configuration is abandoned. Starting from the energy conservation equation and combining with the gas-water flow law in the process of liquid carrying, a new model of deep drainage under tubing is established, and the model is verified with experimental data. The verification results show that the model has good precision and can be used as a new method for judging the effusion of different deep horizontal gas wells in oil pipelines.

Author Contributions: Xiuwu Wang: Data curation, Writing - Original draft preparation, Writing - Reviewing and Editing. Wenmin Ma: Writing - Reviewing and Editing, Investigation. Wei Luo: Investigation & Methodology. Ruiquan Liao: Conceptualization, Resources.

Funding: This work is jointly supported by the National Natural Science Found Project (Grant No. 62173049), Youth Fund of Yunnan Provincial Department of science and technology (Grant No. 202001AU070087).

Data Availability Statement: Not applicable

Conflicts of Interest: The authors declare that they have no known competing financial interests and personal relationships that could have influenced the work reported in this paper.

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