CHAPTER

3

Selection and Determination of Tubing and Production Casing Sizes

OUTLINE

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3.1 OVERVIEW

The selection and determination of tubing and production casing sizes and the hole structure design are the important links in the well completion process. The traditional practice is that the hole structure is designed and the production casing size is determined by drilling engineering. After a well completion operation, the tubing size and the mode of production are selected and determined by production engineering on the basis of the production casing that has been determined. The result of this practice is that the production operations are limited by the production casing size, many oil and gas wells cannot adopt the adaptable technology and technique, the stimulation is difficult to conduct, and the requirement of increasing the fluid production rate of the oil well cannot be achieved at the high water cut stage. In order to change this traditional practice, this chapter will prove the rational selection and determination of production casing size to the full extent. In accordance with the reservoir energy and the requirements of production engineering, the rational tubing size should first be determined under a different production mode, and the admissible minimum production casing size is then selected and determined. At the flowing production stage, the rational tubing size can be selected and determined using the sensitivity analysis of tubing size, which is based on the nodal analysis. At the artificial lift stage, the rational tubing size is closely related to the requirement of stable oil production during oil field development and the specific lifting mode. Therefore, the nodal analysis is briefly described at first, and the selection and determination of tubing and production casing sizes are then described in detail.

The tubing and production casing sizes of oil and gas wells should be selected and determined before well completion. The tubing size can be changed, but the production casing cannot be changed after well completion. Therefore, the type of well, production mode, stimulation, oil properties, and requirements of production engineering in the entire production process should be considered when a production casing size is selected and determined; that is, natural gas wells, flowing wells, artificial lift wells, stimulation, and heavy oil production have different requirements for selecting tubing and production casing sizes. Thus, for a specific well, the aforementioned factors should be considered when the rational tubing and production casing sizes are determined.

For a natural gas well, both production optimization and stimulation should be considered. Therefore, the tubing and production casing sizes should be computed as shown in Equation (3-1):

(3-1)

$$\text{Tubing and production casing sizes of natural gas well} = \max\{T_1, T_2, T_3\}$$

where T_1 = tubing and production casing sizes by production optimization; T_2 = tubing and production casing sizes by stimulation; T_3 = tubing and production casing sizes by other special technological requirements; max = maximum value function.

For a conventional oil production well, the tubing and production casing sizes should be calculated as shown in Equation (3-2):

(3-2)

$$\text{Tubing and production casing sizes of conventional oil production well} = \max\{t_1, t_2, t_3, t_4\}$$

where t_1 = tubing and production casing sizes at flowing stage by production optimization; t_2 = tubing and production casing sizes by artificial lift selected; t_3 = tubing and production casing sizes by stimulation; t_4 = tubing and production casing sizes by other special technological requirements; and max = maximum value function.

For a heavy oil production well, the tubing and production casing sizes should be calculated as shown in Equation (3-3):

(3-3)

$$\text{Tubing and production casing sizes of heavy oil production well} = \max\{T_{t1}, T_{t2}, T_{t3}\}$$

where T_{t1} = tubing and production casing sizes by artificial lift selected; T_{t2} = tubing and production casing sizes by heavy oil production; T_{t3} = tubing and production casing sizes by other special technological requirements; max = maximum value function.

After the tubing and production casing sizes are determined, the casing program of a specific well is determined in accordance with well depth, technical requirements of drilling technology, complexity of oil and gas reservoir, and characteristics of overburden.

The slim hole (hole size $\leq$5 in.) completion mode includes open hole, slotted liner, and liner cementing perforated completions. In addition, the monobore well completion technique has been used by Shell. The slim hole completion is basically the same as the conventional wellbore completion, except that the matching techniques of the slim hole, including perforating, stimulation, artificial lift, downhole tools, and fishing tools, should be considered in order to ensure the normal production from a slim hole.

3.2 OVERVIEW OF NODAL ANALYSIS

The oil and gas flow from reservoir to surface separator is shown in Figure 3-1.

The total fluid pressure loss from reservoir deep to surface separator is composed of several sections of pressure loss caused by resistance: pressure loss through porous media (first pressure subsystem), pressure loss through well completion section (second pressure subsystem), total pressure loss through tubing string (third pressure subsystem), and total pressure loss through flowline (fourth pressure subsystem).

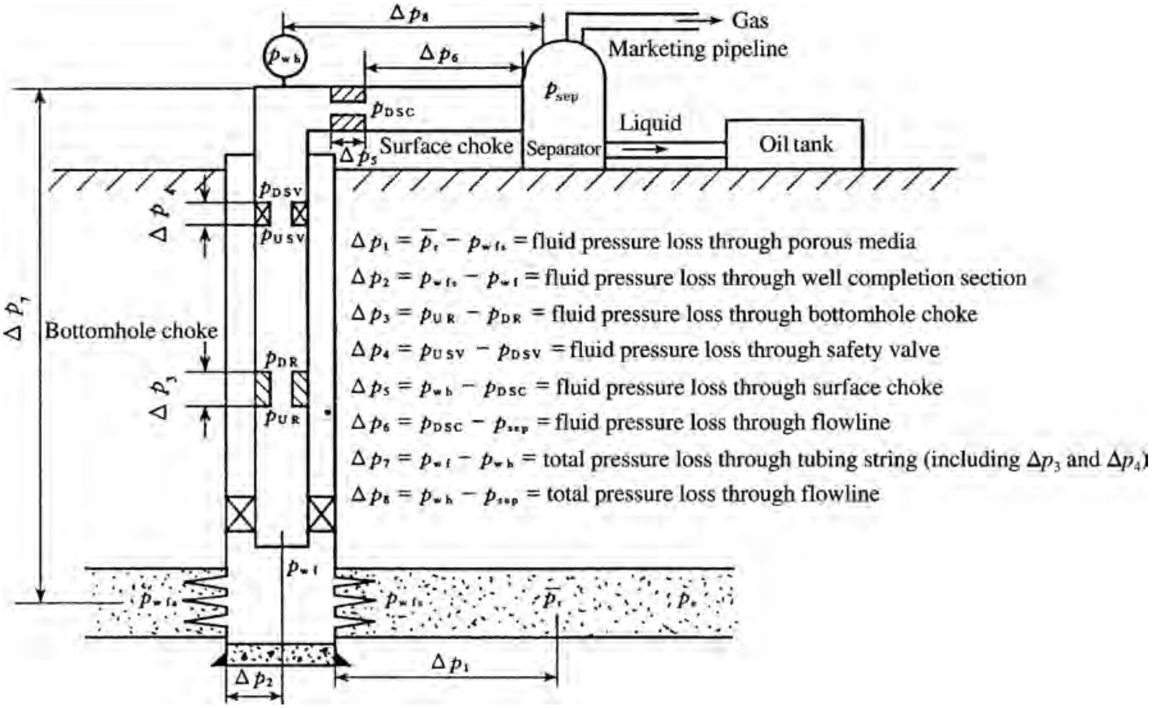

FIGURE 3-1 Various pressure losses in the production system.

1. Fluid pressure loss through porous media

   In accordance with the relation between reservoir pressure, bottomhole flowing pressure, oil saturation pressure, and the theory of mechanics of fluid through porous media, the pressure distribution relations of single-phase liquid flow, single-phase gas flow, two-phase flow of oil and gas, three-phase flow of oil, gas, and water, and dissolved gas drive and the oil and gas inflow performance relationship can be derived; thus the total fluid pressure loss through porous media can be determined.
2. Fluid pressure loss through well completion section

   The fluid pressure loss through well completion section is closely related to the well completion mode and can be calculated by calculating the total skin factor *S* under a different completion mode.
3. Total fluid pressure loss through tubing string

   This pressure loss can be determined by the calculation under the multiphase flow condition in tubing string. At present, there are various methods to calculate multiphase flow in pipe.
4. Total fluid pressure loss through flowline

   The same calculation method as that of multiphase flow in pipe is used.

The oil and gas production passes through the four subsystems in the preceding list, which can be joined together into a unity by setting up nodes. If the analog calculation of each subsystem is conducted, the whole production system can be mathematically simulated. The nodal analysis method uses just such an analogy calculation process to analyze and optimize the production system of an oil and gas well. When a specific problem is to be solved by using the nodal analysis method, it is usual to take aim at some node (known as the solution node) in the system. The production system of an oil and gas well can be simplified into two large parts (that is, inflow and outflow parts) by selecting the solution node. For instance, when the solution node is selected at p_{wf} of the bottomhole of the oil well, the inflow part includes the two subsystems, that is, the fluid flow through porous media and the fluid flow through completion section, while the outflow part includes the other two subsystems, that is, the fluid flow through tubing string and the fluid flow through surface flowline. Thus, the following two major problems can be solved.

1. Under the condition of constant parameter values of the outflow part, the completion section can be optimized using the nodal systems analysis method. For instance, for a perforated well, the parameters of perforated completion, including perforation density, perforation diameter, perforation length, and phase angle, can be optimized using this analysis method.
2. However, under the conditions of constant completion mode and completion parameter values, the tubing size and choke can be optimized. The sensitivity analysis of tubing size, which is described later, is just a worsening of this problem.

Nodal analysis of an oil and gas well not only can be used for solving the problem mentioned earlier, but also can be used for solving others, including determining the dynamic performance of an oil and gas well under current production conditions, optimizing the production restriction factor of an oil and gas well and presenting adaptable stimulation and adjustment measures of an oil and gas well, determining the production state when flowing stops or is turned to pumping and analyzing the reason, determining the optimum moment of turning to an artificial lift and its optimum mode, and finding a way to enhance the production rate.

To sum up, for a new well, the maximum daily fluid production and the minimum flowing pressure in the future for the entire production process of the oil well should be predicted using the numerical simulation method or the method of predicting the future inflow-performance relationship (IPR) curve in order to optimize completion parameters and tubing size using the nodal analysis method. This is what well completion engineering pays the most attention to. For an oil and gas well that has been put into production, the nodal analysis method is helpful for scientific production management.

The theory and practice of nodal analysis have been described in detail in the related literature.

3.3 SELECTION AND DETERMINATION OF TUBING AND PRODUCTION CASING SIZES FOR FLOWING WELLS

Tubing is one of the important component parts in the production system of a flowing well and is the main channel for oil and gas field development. The pressure drop for fluid lifting from the bottomhole to the surface can be up to 80% of the total pressure drop of the oil and gas well system. Any oil well system has an optimum tubing size. Undersized tubing will limit the production rate due to the increased friction resistance caused by excessive flow velocity. Contrarily, oversized tubing may lead to an excessive liquid phase loss due to slippage effect or an excessive downhole liquid loading during lifting. Therefore, sensitivity analysis of tubing size should be carried out using the nodal analysis method. On the basis of the sensitivity analysis of tubing size, the tubing and production casing sizes required during the flowing period can be determined. However, the production casing size of the well cannot be determined yet. The reason is that the tubing and production casing sizes of the oil and gas well should meet the requirements of the well during the entire production life, whereas the flowing period of the oil and gas well is limited, and the tubing and production casing sizes are often on the small side. After the flowing period, the oil and gas well may turn to artificial lift production. The tubing and production casing sizes in the flowing production period of an oil and gas well cannot meet the requirements of stable production in the artificial lift production period. For a waterflooding oil field, after entering the high water cut period of the oil well, the large-size pump with a high pumping rate should often be used in order to ensure stable oil production and rational producing pressure drawdown. For a different lifting mode, different tubing and production casing sizes should be adopted. The pump diameter should be determined in accordance with the daily fluid production rate during the whole development period of the oil field, and the corresponding tubing and production casing sizes are then selected. In addition, different tubing and production casing sizes are required by stimulation and sand control technology. Therefore, the tubing and production casing sizes can only be finally determined after all of the aforementioned factors are taken into consideration.

By comparison with other production modes, under flowing and gas lift production modes, a certain production rate and a certain tubing shoe pressure (flowing bottomhole pressure if the tubing shoe is in the middle of the oil reservoir) should be maintained. Under the other production modes, the flowing bottomhole pressure can be reduced to the full extent if that is allowed by reservoir pressure and casing condition.

Importance of Sensitivity Analysis of Tubing Size

The tubing size should be optimized in order to ensure the lowest energy consumption for lifting and the longest flowing time, that is, to utilize rationally the energy of the oil and gas reservoir.

The inflow performance relationship (IPR) curve indicates the relationship in a well between the flowing bottomhole pressure at a stabilized production rate and the liquid production rate, which can be obtained on the basis of reservoir pressure, flowing bottomhole pressure, liquid production rate, and open flow rate under zero flowing bottomhole pressure. The tubing performance relationship (TPR) curve, which is obtained on the basis of the tubing shoe pressure (flowing bottomhole pressure if the tubing shoe is in the middle of the oil reservoir) calculated in accordance with the flow rule (single- or two-phase flow) in tubing under the given gas-liquid ratio, water cut, well depth, and wellhead pressure for different production rates, reflects the lifting capability of lifting tubing, which is only dependent on tubing flow parameters, such as wellhead pressure, well depth, tubing diameter, and gas-liquid ratio, and is independent of reservoir productivity.

Many methods of calculating the IPR can be used, and the Vogel formula shown in Equation (3-4) is generally adopted:

(3-4)

$$\frac{q_o}{q_{oma}} = 1 - 0.2\frac{p_{wf}}{p_r} - 0.8\left(\frac{p_{wf}}{p_r}\right)^2$$

where q_o is the surface production rate of the oil well at p_{wf}, m^3/d; q_{omax} is the surface production rate of the oil well at $p_{wf} = 0$, m^3/d; p_{wf} is the flowing bottomhole pressure, MPa; and p_r is the average reservoir pressure in the oil drainage area, MPa.

Many methods of calculating the TPR can be used, and the Orkiszewski and Hagedom Brown method is generally adopted in practice.

The coordination between inflow and outflow performances should be studied using the IPR and TPR curves in accordance with the nodal analysis method in order to ensure the optimum utilization of natural energy.

The tubing performance relationship is shown in Figure 3-2. This figure indicates when a

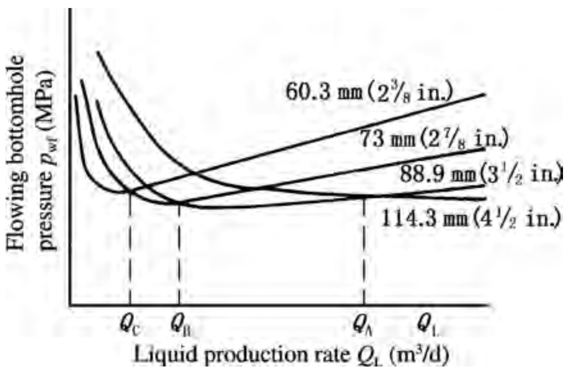

FIGURE 3-2 The effect of tubing size on lifting capability of tubing in a flowing well.

high production rate $Q_L > Q_A$, 114.3-mm (4 ½ in.) tubing has the highest lifting efficiency; when $Q_A > Q_L > Q_B$, 73-mm (2 ⅞ in.) tubing is more economic; and when $Q_L < Q_C$, 60.3-mm (2 ⅜ in.) tubing is most appropriate.

Sensitivity Analysis and Optimization of Tubing Size of Flowing Well

The fluid flow in tubing during flowing production can be analyzed in accordance with the aforementioned vertical flow rule in tubing. The most sensitive factors affecting the pressure gradient distribution of multiphase vertical flow in tubing include tubing size, production rate, gas-liquid ratio, viscosity, and water cut. For a well design, the gas-liquid ratio, viscosity, and water cut are basically in a range, whereas the production rate can be controlled and changed. In accordance with the theory of multiphase flow in tubing, each production rate value corresponds to the optimum tubing size so that the pressure gradient (or pressure depletion) in tubing can be the minimum. For a given production rate, an undersized tubing may have an excessive flow velocity so that the friction resistance may be increased, whereas an oversized tubing may have a flow velocity on the low side so that a serious gas slippage effect may be caused. Therefore, only by selecting an appropriate tubing size can the friction resistance and liquid phase loss due to slippage effect be in the optimum state and the maximum energy utilization efficiency be achieved.

Because the production rate is an important parameter for optimizing and selecting the tubing size and the optimum tubing size is different under different production rates, the production rate acts as a variable in all analyses. In the flow process from the reservoir to the surface, the production rate is closely related to the pressure, thus the pressure acts as the other variable. The effect of change in tubing size is often analyzed using the coordinate diagram of pressure p and production rate Q. The optimum tubing size is generally determined using the nodal analysis method.

There are two methods of analyzing the optimum tubing size. (1) Under given surface conditions (such as separator pressure, wellhead pressure, or surface flowline size), the tubing size capable of maximizing the production rate is the optimum tubing size. (2) Under a specific production rate, the tubing size capable of minimizing the producing gas-oil ratio, maximizing gas expansion energy utilization efficiency, and ensuring the longest flowing production time is the optimum tubing size; that is, there are two methods of optimizing and selecting the tubing size or two different objective functions. In accordance with the specific conditions of an oil field, one of these methods can be selected or the two methods can be used for determining the optimum tubing size; the optimum tubing size is finally determined by composite consideration. The methods generally used include the optimization method based on the surface tubing pressure derived by a given separator pressure; the optimization method on the basis of a given surface tubing pressure; and the optimization method of ensuring a relatively long flowing period.

Optimization Method Based on Surface Tubing Pressure Derived by Given Separator Pressure. In order to ensure the flow from wellhead to separator for the produced fluid, the minimum wellhead tubing pressure p_{wh} should be achieved on the basis of the surface pipe network design and the specific well location. In general, the minimum entering pressure is required by entering the separator. Thus the wellhead tubing pressure can be derived in accordance with the entering pressure, surface flowline size, path of surface flowline, and flow rate in the pipeline. If a choke is needed by controlling the flowing well production, the choke pressure differential Δp_{choke} through the choke should be added. Thus, the wellhead tubing pressure p_{wh} under the minimum separator pressure can be obtained. Obviously, the p_{wh} is related to the production rate Q. The higher the production rate, the higher the minimum wellhead tubing pressure p_{wh} required. In Figure 3-3, curve 1 is the surface flowline and wellhead tubing pressure curve (no choke); curve 2 is the combined

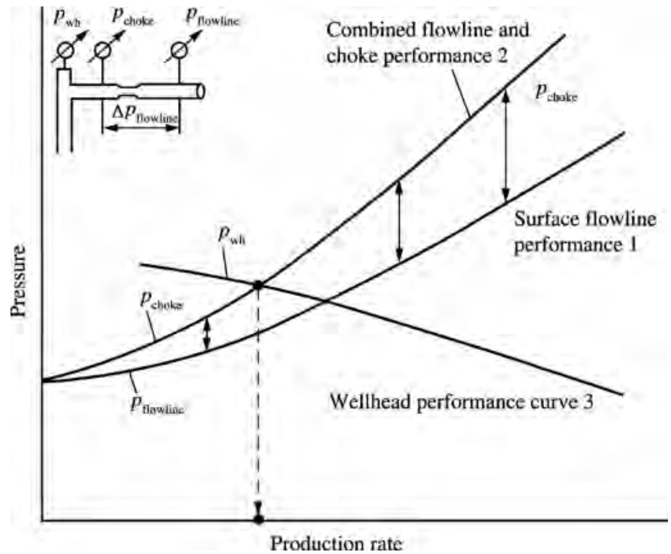

FIGURE 3-3 The pressure system analysis using wellhead as node under a given separator pressure.

flowline, choke, and wellhead tubing pressure curve; and curve 3 is the remaining wellhead pressure p_{wh} of flow from reservoir to wellhead vs. production rate curve (OPR curve), as shown in Figure 3-4.

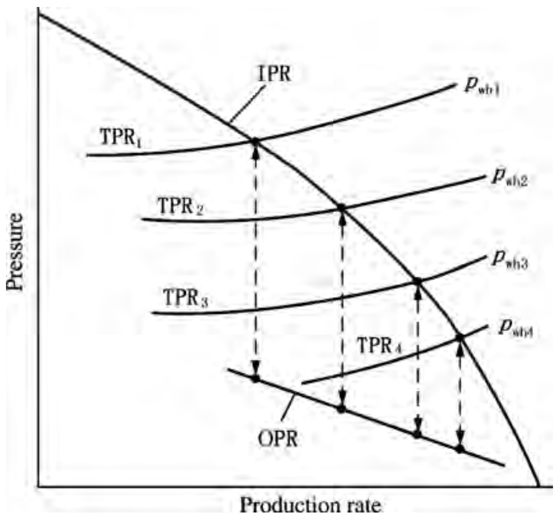

FIGURE 3-4 Wellhead pressure relationship curve (OPR curve) taking reservoir flow and tubing flow as oil well flow system.

Obviously, the changes in surface parameters (including choke size, surface flowline, and separator pressure) will change the TPR curve as shown in Figure 3-4. The changes of reservoir condition, completion mode, and tubing size (such as reservoir pressure reduction with time, different perforating parameters, and change in tubing diameter) will also affect the OPR curve.

Under uncertain wellhead tubing pressure p_{wh}, the change in tubing size is displayed by the OPR curve. The wellhead inflow performance curves under the three tubing sizes and the wellhead outflow performance curves under the two choke sizes are shown in Figure 3-5. Obviously, when the choke size is d_{ch1}, the tubing with diameter d_{t1} is the optimum production tubing; and when the choke size is d_{ch2}, the tubing with diameter d_{t3} is the optimum production tubing.

Optimization Method Based on the Given Wellhead Tubing Pressure p_{wh}. In many circumstances, the conditions of surface flowline cannot be determined in advance and the first method cannot be used for the sensitivity analysis of tubing size. Thus, the tubing size is optimized by setting wellhead tubing pressure p_{wh}.

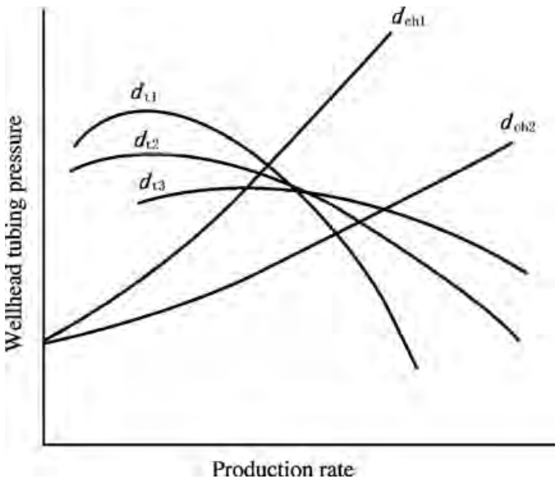

FIGURE 3-5 Sensitivity analysis of tubing size under uncertain wellhead tubing pressure.

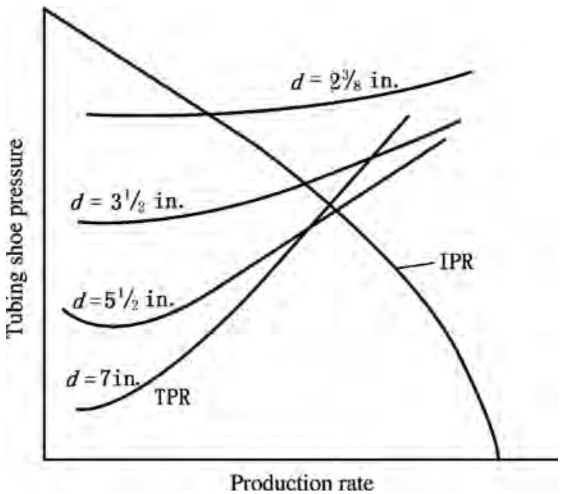

FIGURE 3-6 Sensitivity analysis of tubing size under given wellhead tubing pressure.

The inflow performance relationship (IPR) curve is first obtained. Then, in accordance with the given wellhead tubing pressure p_{wh} and the various production rates supposed, the tubing shoe pressures are calculated under different tubing sizes. (The tubing shoe pressure is equal to the flowing bottomhole pressure p_{wf} if the tubing shoe is in the middle of the oil reservoir.) The production rate vs. tubing shoe pressure p_{wf} relationship (TPR, that is, tubing performance relationship) curves under the different tubing sizes can be obtained. Figure 3-6 shows the TPR curves under various tubing sizes. The intersections of the TPR curves and the IPR curve are just the production points under the various tubing sizes.

In general, increasing the tubing size will increase the production rate of a flowing well. However, when the tubing size exceeds the critical tubing size, the increase in tubing size may lead to a decrease in production rate, as shown in Figure 3-6.

Case 1. The Shen 77 well of the Liaohe Shenyang oil field has the following known parameter values: mean reservoir pressure $p_r = 16.3$ MPa, depth in middle of reservoir $H = 1673.1$ m, producing gas-liquid ratio $GLR = 108.7\ m^3/m^3$, saturation pressure $p_b = 18.89$ MPa, relative density of oil $\gamma_o = 0.856$, relative density of gas $\gamma_g = 0.73$, and water cut $f_w = 0$. The IPR curve obtained with the measured production data is shown in Figure 3-7. The wellhead tubing pressure $p_{wh} = 4.4$ MPa, the wellhead temperature $T_{wh} = 20°C$, and the bottomhole temperature $T_{wb} = 68°C$. Try determining the optimum tubing size under flowing production mode.

Solving Process. The outflow performances of the various tubing sizes are calculated using the Orkiszewski method, and it is found that when the tubing size d_t exceeds 60.3 mm (2 ⅜ in.), the well will stop flowing. Figure 3-8 shows the tubing outflow curve of the well. Figure 3-9 shows

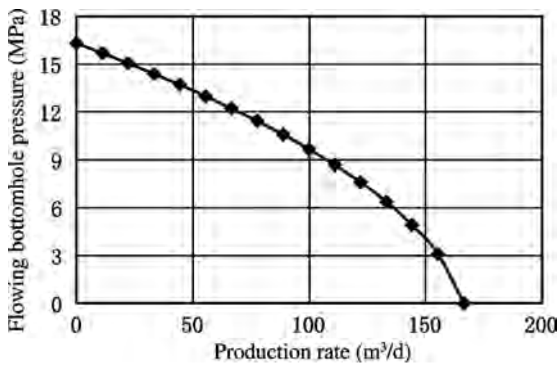

FIGURE 3-7 IPR curve of Shen 77 well.

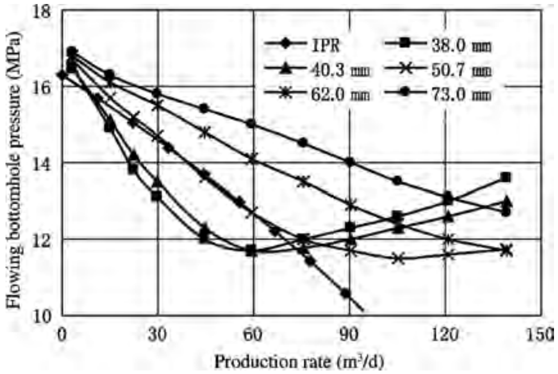

FIGURE 3-8 Outflow curves of Shen 77 well (obtained by matching the measured data) under various tubing sizes (tubing sizes in figure are inside diameters).

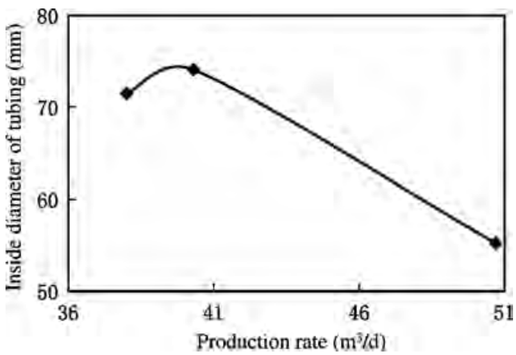

FIGURE 3-9 Production rate vs. tubing size for Shen 77 well.

the production rate vs. tubing size relationship obtained by the values of the intersections of the IPR curve and the TPR curves. Obviously, the production rate is very sensitive to the tubing size. When the tubing size is increased from 42.2 mm (1.660 in., inside diameter 35.1 mm) to 48.3 mm (1.900 in., inside diameter 40.3 mm), the production rate is obviously increased. When the tubing size is further increased to 60.3 mm (2 ⅜ in., inside diameter 50.7 mm), the production rate may be greatly decreased. Thus, the optimum tubing size is 48.3 mm (1.900 in., inside diameter 40.3 mm).

Case 2. The Tazhong 402 well of the Talimu oil field has the following known parameter values: mean reservoir pressure $p_r = 42.49$ MPa, depth in

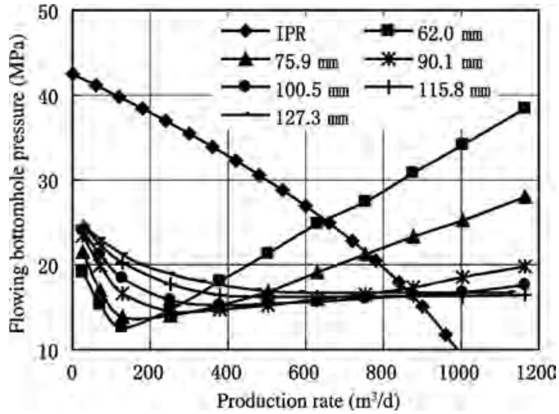

FIGURE 3-10 Tazhong 402 well system analysis curves (tubing sizes in figure are inside diameters).

middle of reservoir H = 3695 m, producing gas-liquid ratio GLR = 220 m^3/m^3, oil saturation pressure $p_b = 42.49$ MPa, relative density of oil $\gamma_o = 0.8331$, relative density of gas $\gamma_g = 0.7851$, and water cut $f_w = 0$. The IPR curves obtained by matching the data of step-rate testing are shown in Figure 3-10 and indicate a high-productivity oil well. The wellhead tubing pressure $p_{wh} = 2.0$ MPa. The wellhead temperature $T_{wh} = 30°C$, while the bottomhole temperature $T_{wb} = 85°C$. Try determining the optimum tubing size under flowing production mode.

Solving Process. The outflow performance relationship curves under various tubing sizes are obtained by analyzing and calculating. These - tubing sizes include 73.0 mm (2 ⅞ in., internal diameter 62 mm), 88.9 mm (3 ½ in., inside diameter 75.9 mm), 101.6 mm (4 in., inside diameter 90.1 mm), 114.3 mm (4 ½ in., inside diameter 100.5 mm), 127 mm (5 in., inside diameter 115.8 mm), and 139.7 mm (5 ½ in., inside diameter 127.3 mm). The Q - d_t curve and the p_{wf} - d_t curve, which are obtained by the values of intersections of the IPR curve and the TPR curves, are shown in Figure 3-11 and Figure 3-12, respectively. The production rate increases with the increase of tubing size when the tubing size is smaller than 114.3 mm (4 in.), whereas the production rate will start reducing when the tubing size is increased to 127 mm (5 in.). Thus, the optimum tubing size is 114.3 mm (4 ½ in.).

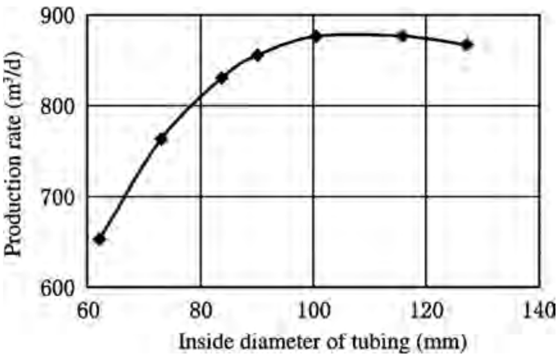

FIGURE 3-11 Production rate vs. inside diameter of tubing for Tazhong 402 well.

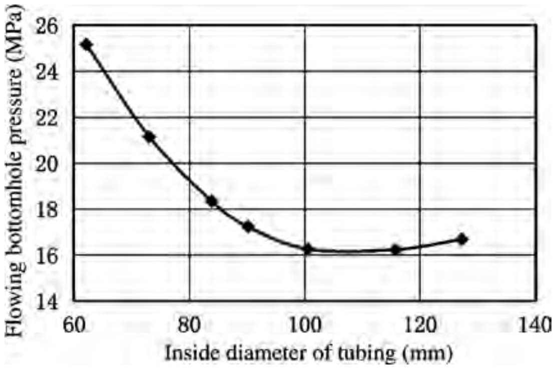

FIGURE 3-12 Flowing bottomhole pressure vs. inside diameter of tubing for Tazhong 402 well.

This example shows that a larger tubing should be used in a high-productivity well, but an oversized tubing may reduce the production rate by reason of slippage and increase the well construction cost.

Case 3. The offshore Oudna oil field in Tunisia has the following known parameter values: original reservoir pressure $p_r = 16$ MPa, depth in middle of reservoir $H = 1600$ m, producing gas-liquid ratio $GLR = 4.5\ m^3/m^3$, oil saturation pressure $p_b = 1.56$ MPa, relative density of oil $\gamma_o = 0.82$, relative density of gas $\gamma_g = 0.76$, relative density of reservoir water $\gamma_w = 1.05$, and water cut $f_w = 2\%$. The wellhead temperature $T_{wh} = 40°C$ and the bottomhole temperature $T_{wb} = 77.4°C$. The fluid productivity index of $764.6\ m^3/(d \cdot MPa)$ is obtained by well-testing analysis. Try determining the optimum tubing size to achieve the production rate of $3000\ m^3/d$ under gas lift mode when the reservoir pressure is reduced to 13 MPa. (The tubing pressure value of 0.6 MPa is necessary for transport.)

Solving Process. The gas lift performance curve under various tubing sizes is obtained by analyzing and calculating as shown in Figure 3-13. When the tubing size is smaller than 168.27 mm (6 ⅝ in., inside diameter 153.6 mm), the production rate increases with the increase of tubing size under constant gas lift gas injection rate; and when the tubing size is larger than 168.27 mm (6 ⅝ in., inside diameter 153.6 mm), the production rate decreases with the increase of tubing size. The gas lift gas injection rate under production rate of $3000\ m^3/d$ (on gas lift performance curve) vs. corresponding inside diameter of tubing is shown in Figure 3-14. In order to obtain the production rate of $3000\ m^3/d$, the tubing size of 168.27 mm (6 ⅝ in., inside diameter 153.6 mm) needs the minimum gas lift gas injection rate and has the highest efficiency. Thus, the optimum tubing size is 168.27 mm (6 ⅝ in., inside diameter 153.6 mm).

Tubing Size Optimization Method of Ensuring Longer Flowing Period. Flowing oil production is the most economic production method and the flowing period of the oil well should be prolonged to the full extent. The key to that lies in economically and rationally utilizing the energy

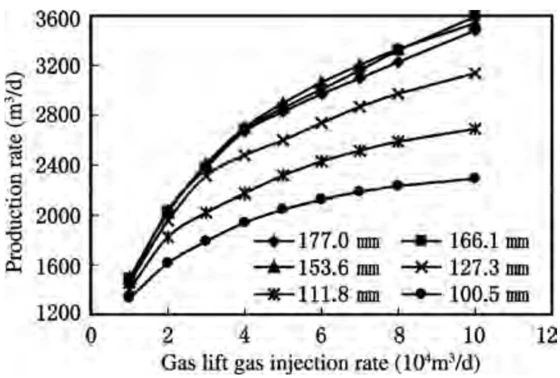

FIGURE 3-13 Gas lift performance curves of oil well in Oudna oil field under various tubing sizes (tubing sizes in figure are inside diameters).

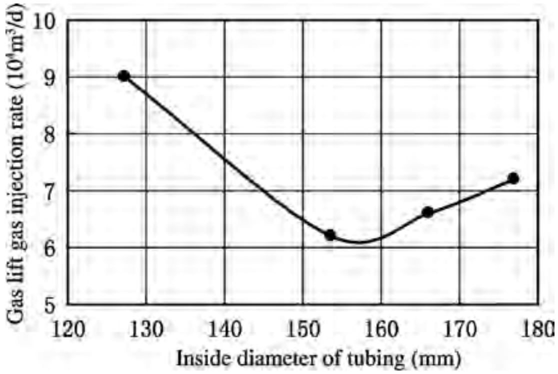

FIGURE 3-14 Inside diameter of tubing to achieve the production rate required vs. gas lift gas injection rate.

of reservoir fluids, including the pressure energy of fluid and expansion energy of gas. When the flowing wellhead tubing pressure is lower than the saturation pressure or even when the flowing bottomhole pressure is lower than the saturation pressure, the reservoir energy is mainly released in the form of gas expansion energy. When the gas-liquid ratio of the fluid produced from the reservoir is not enough, the oil well may stop flowing.

The production rate and the bottomhole pressure will gradually decrease in the whole flowing production process. The decrease in flowing bottomhole pressure will lead to the increase in producing gas-oil ratio, which will first rapidly increase on the basis of the lower initial value and then gradually decrease to a point lower than the initial point. Thus, the problem of prolonging the flowing period of the oil well changes into the problem of rationally utilizing gas expansion energy.

It has been believed that the tubing size selected should still ensure producing under the maximum lifting efficiency at the end of the flowing period. The formula of selecting tubing diameter is shown in Equation (3-5).

(3-5)

$$d = 0.074\left(\frac{\gamma_1 L}{p_{wf} - p_{wh}}\right)^{0.5}\left[\frac{Q_1 L}{\gamma_l L - 10(p_{wf} - p_{wh})}\right]^{1/3} \times 25.4$$

where d = internal diameter of tubing, mm; γ_1 = relative density of liquid; Q_1 = production rate at the end of the flowing period, t/d; L = tubing length, m; p_{wf} = flowing bottomhole pressure at the end of the flowing period, 10^5Pa; p_{wh} = flowing tubing pressure at the end of the flowing period, 10^5Pa.

The production rate at the end of the flowing period can be determined by the intersections of the future inflow performance IPR curve and tubing TPR curve. The tubing size, which can maximize the current production rate, can be used for obtaining the tubing IPR curve. The intersections of the IPR curve and TPR curve at different stages of drop in reservoir pressure are drawn. The tangential point of the IPR curve and TPR curve is just the quit flowing point. The production rate and the bottomhole pressure at this time are respectively the quit flowing production rate and the quit flowing bottomhole pressure. In practice, the tubing performance curve may also gradually change. With continuous production, the water cut and viscosity may gradually increase and the gas-liquid ratio may gradually decrease; thus the TPR curve also changes. When the wellhead tubing pressure is constant, the TPR curve may gradually move up, whereas the IPR curve may move down, as shown in Figure 3-15.

After the quit flowing production rate and bottomhole pressure are predicted, the tubing size that can maximize the flowing period can be selected using Equation (3-5).

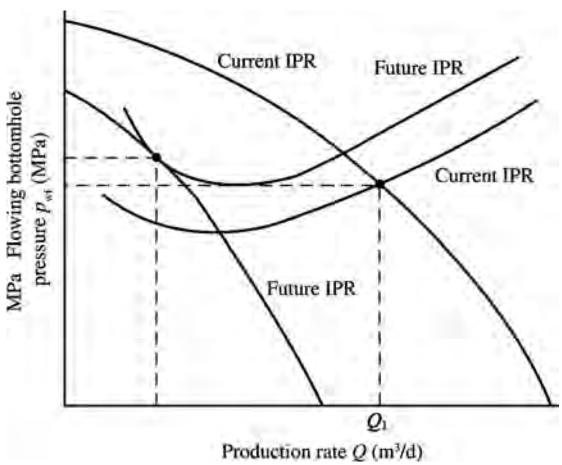

FIGURE 3-15 The change of production point with decrease of reservoir pressure and the prediction of quit flowing point.

Case 4. A certain well has predictive $Q_1 = 75 \times 10^3$kg/d, minimum wellhead tubing pressure $p_{wh} = 2 \times 10^5$Pa, flowing bottomhole pressure $p_d = 23 \times 10^5$Pa, well depth L = 1000 m, and relative density of produced fluid $\gamma_1 = 0.9$. Try selecting the tubing size with the longest flowing period.

Solving Process. The inside diameter of the tubing is calculated using Equation (3-5).

$$d = 0.074\left(\frac{0.9 \times 1000}{23 - 2}\right)^{0.5}\left[\frac{75 \times 1000}{0.9 \times 1000 - 10(23 - 2)}\right]^{1/3} \times 25.4 = 58.7 \text{ mm}$$

Tubing with an inside diameter closer to this value, such as 2 ⅞-in. (inside diameter 62.0 mm) tubing, can be used.

Method of Analyzing Tubing Size Sensitivity Affected by Inflow Performance. The principles and methods of optimizing tubing size for flowing wells have been briefly described in the preceding sections. The inflow performance and outflow performance of a production well are influenced and conditioned by each other. The inflow performance is the internal factor of conditioning the system, whereas the tubing itself is only an external factor. Therefore, the effect of inflow performance change on tubing size should be analyzed.

The reservoir pressure may reduce with the production time, and that may lead to inflow performance change and gradual fluid property change, thus changing the tubing outflow performance and possibly changing the optimum tubing size. In order to simplify the analysis, the effect of inflow performance change on the optimum tubing size is only discussed here.

Case 5. The Tuha Wenxi 1 well has the following data: mean reservoir pressure 24.6 MPa, depth in middle of reservoir 2513 m, producing gas-liquid ratio 116 m^3/m^3, oil saturation pressure 18.89 MPa, relative density of oil 0.8147, relative density of water 1.05, relative density of gas 0.824, water cut 30%, fluid productivity index under the flowing bottomhole pressure higher than saturation pressure 5 $m^3/(d \cdot MPa)$, given wellhead tubing pressure 1.5 MPa, bottomhole temperature 79°C, and wellhead temperature 20°C. Try analyzing the change of the optimum tubing size when the reservoir pressure reduces from 20.6 MPa to 18.6 MPa.

Solving Process. The inflow performance relationships on the basis of the given data and three different reservoir pressures are shown in Figure 3-16. The production rate vs. tubing size under the different reservoir pressures is obtained on the basis of the intersections of the inflow performance curves and the tubing performance curves, as shown in Figure 3-17. When the reservoir pressure is 24.6 MPa, the optimum tubing size is 48.3 mm (1.900 in.) or 60.3 mm (2 ⅜ in.). When p_r is reduced to 20.6 MPa, the production rate is obviously reduced, the tubing larger than 60.3 mm (2 ⅜ in.) may stop the flowing of the oil well, and the optimum tubing size is changed to 48.3 mm (1.900 in.). When the reservoir pressure is reduced to 18.6 MPa, the optimum tubing size is 42.2 mm (1.660 in.).

If flowing production can only be achieved using such a small tubing, a series of problems of production technology will certainly result (such as difficulty of paraffin removal). Thus it is better to use a larger tubing for turning to artificial lift, and the economic benefit may be much better. Therefore, this method can be used for predicting the time of turning to pumping.

Production Casing Size Determination of Flowing Well

The tubing size should first be optimized and determined on the basis of oil field development mode (waterflooding and flowing or artificial lifting production), oil production rate, liquid production rate, recovery rate, reservoir pressure, rule of water cut rising, water cut, ultimate recovery factor, timing of turning to artificial lift from flowing production, oil properties (thin oil, heavy oil, high pour-point oil, and condensate oil), sand production situation of oil well, and stimulation. After that, the maximum size of the matching downhole tools (such as the maximum outside diameter of downhole safety valves of different specifications) should also be considered and the production casing size should be finally determined.

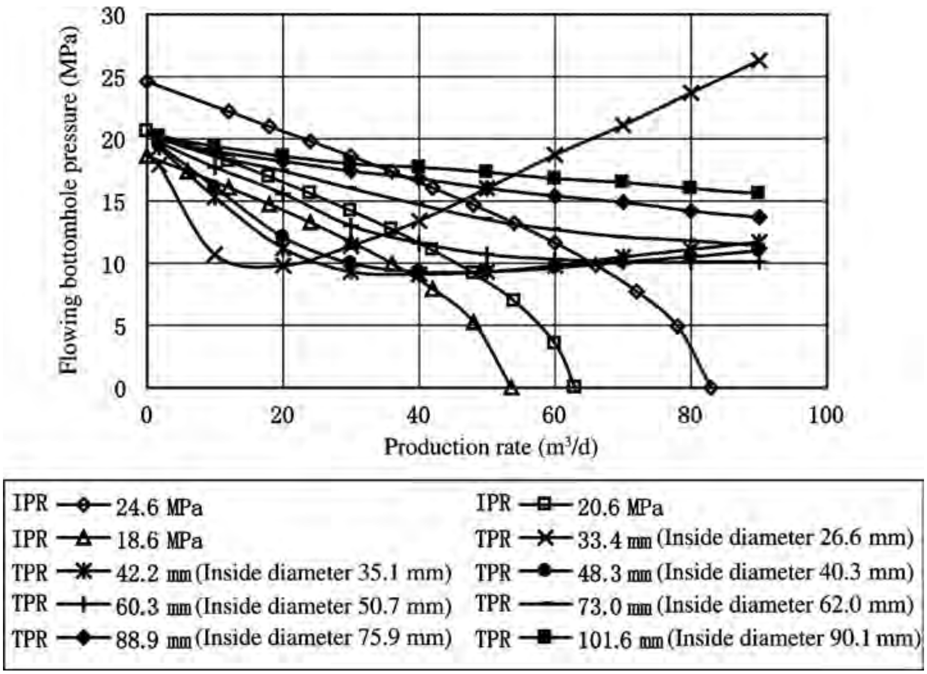

FIGURE 3-16 Tubing sensitivity analysis under changing reservoir pressure.

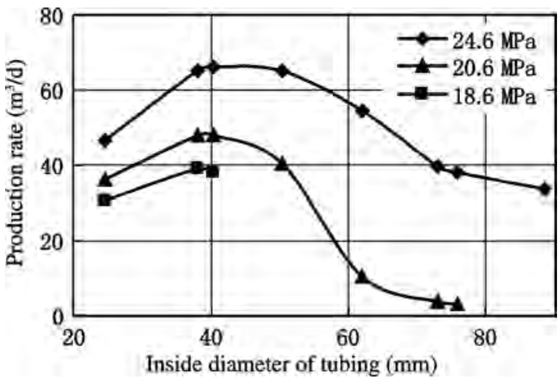

FIGURE 3-17 Tubing size vs. production rate under different reservoir pressures.

3.4 SELECTION AND DETERMINATION OF TUBING AND PRODUCTION CASING SIZES FOR GAS WELLS

Tubing size optimization of a natural gas well should ensure the minimum energy consumption of lifting under rational production rate of the gas well, and should consider the maximum tubing size meeting the requirement of carrying liquid and the minimum tubing size meeting the requirement of avoiding erosion.

Selection and Determination of Tubing Size of Natural Gas Well

Selection and Determination Method of Tubing Size with Minimum Energy Consumption of Lifting under Rational Production Rate. The tubing size of the gas well should avoid excessive pressure loss in tubing and should ensure a certain tubing pressure for a longer period in order to meet the requirement of the surface engineering. The pressure loss is generally calculated using the gas phase conduit flow pressure drop calculation method under different production rates, flowing bottomhole pressures, and tubing sizes.

The inflow performance curve of a gas well is generally obtained using the exponential deliverability equation or the binomial deliverability equation.

The exponential deliverability equation is as follows

(3-6)

$$q_g = C \times \left(p_r^2 - p_{wf}^2\right)^n$$

where q_g = daily gas production rate, $10^4 m^3/d$; p_r = mean reservoir pressure, MPa; p_{wf} = flowing bottomhole pressure, MPa; C = gas productivity index (related to gas reservoir permeability and thickness, gas viscosity, and bottomhole cleanliness)$10^4 m^3/d(MPa)^{-n}$; n = filtrate index depending on gas flow mode (n = 1 for linear flow; n<1 for high flow velocity or multiphase flow).

The binomial deliverability equation is shown in Equation (3-7).

(3-7)

$$\frac{p_r^2 - p_{wf}^2}{q_g} = A + Bq_g$$

where A = laminar coefficient; B = turbulence coefficient.

The A means the pressure loss induced by viscosity and the Bq_g means the pressure loss induced by inertia. The sum of both form the total pressure drop of inflow. When the flow velocity is low and the flow is linear, the Bq_g can be negligible and the $(p_r^2 - p_{wf}^2)$ vs. q_g relationship is linear. When the flow velocity increases or the flow is multiphase flow, the inertia resistance (that is, Bq_g) should be considered.

Case 6. A certain gas well has the following data: well depth H = 3000 m, mean gas reservoir temperature T = 50°C, relative density of gas $\gamma_g = 0.65$, tubing wall roughness e = 0.016 mm, and wellhead tubing pressure = 2 MPa. Try determining the tubing performance curves for the inside diameters of tubing, that is, d = 40.8 mm, 50.7 mm, 62.0 mm, and 101.6 mm.

Solving Process. The flowing bottomhole pressures are calculated under the various tubing sizes and the various gas production rates $Q_{sc} = 1, 10, 20, 40, 60, 80 \times 10^4 m^3/d$ in accordance with the flowing bottomhole pressure calculation formula. The tubing performance curves are shown in Figure 3-18. It is shown that with the increase in gas production rate the TPR curves of smaller tubings are getting steeper while the TPR curves of larger tubings are more gentle. The gas flow velocity and friction resistance increase as the tubing size decreases.

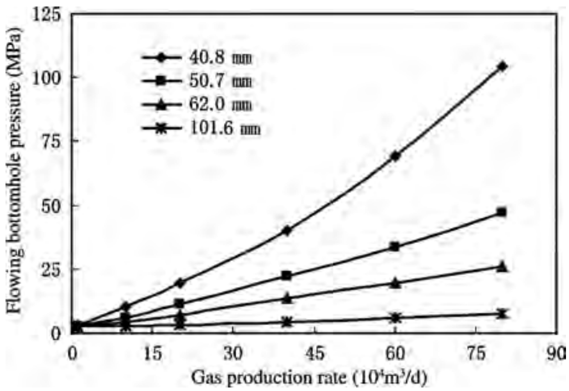

FIGURE 3-18 Tubing performance curves of pure gas well (tubing sizes in figure are inside diameters).

Case 7. A certain water-bearing gas well has the following data: well depth H = 3000 m, tubing size = Φ73 mm (2 ⅞ in.), relative density of gas $\gamma_g = 0.65$, relative density of reservoir water $\gamma_w = 1.05$, reservoir water viscosity $\mu_w = 0.8$ MPa · s, and wellhead tubing pressure $p_{wh} = 2$ MPa. Calculate and draw the tubing performance curve under the various water production rates $Q_w = 1, 10, 20, 50, 100\ m^3/d$.

Solving Process. The flowing bottomhole pressures are calculated using the Hagedorn-Brown two-phase flow calculation method with progressive increase by $10 \times 10^4 m^3$ under different water production rate (Q_w) values, and the tubing performance curves of the gas well under different water production rates are obtained (Figure 3-19).

Figure 3-19 shows that when the gas production rate is very low, the effective density of the mixture in tubing is high and the flowing bottomhole pressure is relatively high; with an increase in gas production rate, the mixture density decreases and the flowing bottomhole pressure decreases to some extent; and with a continuous increase in gas production rate, the flow velocity increases, the friction resistance increases, and the flowing bottomhole pressure contrarily increases. When the water production rate is very low, the effective density of the mixture is slightly

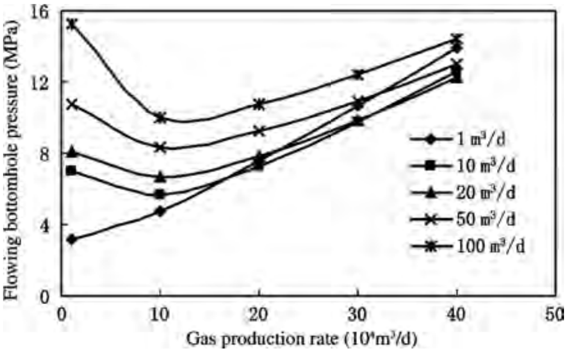

FIGURE 3-19 Tubing performance curves of a water-bearing gas well (the different curves in the figure correspond to the different water production rates).

affected by water and the flowing bottomhole pressure has no decreasing stage, and the flowing bottomhole pressure increases with the increase in gas production rate.

The TPR curves mentioned earlier are obtained by giving tubing pressure and changing production rate. If a constant tubing pressure is sometimes not needed, the change in tubing pressure under the coordinated condition of reservoir pressure and tubing flow should be determined (Figure 3-20). In the figure, the ordinate represents pressure including reservoir pressure, flowing bottomhole pressure, and tubing pressure. The outflow performance relationship

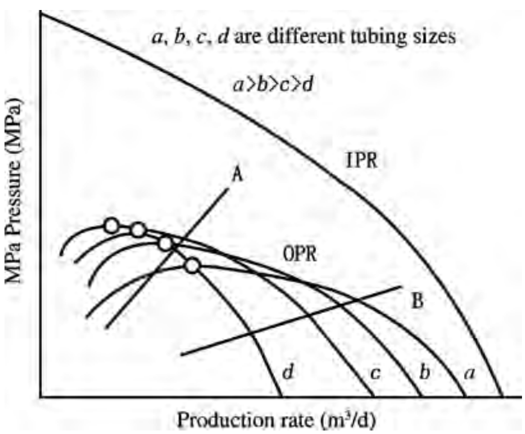

FIGURE 3-20 Effect of tubing size on gas-well deliverability.

(OPR) curve, known as the gas well outflow curve, is derived on the basis of the inflow performance relationship (IPR) curve and the wellhead tubing pressure is obtained using the given flowing bottomhole pressure and the tubing flow formula.

The IPR curve of a water-bearing gas well and the OPR curves of different tubing sizes shown in Figure 3-20 indicate that the production of the gas well is controlled by choke, and the two straight lines A and B represent respectively the choke performance relationships (CPR) of two chokes of different sizes. In accordance with the stability analysis, the gas well production should be conducted on the right side of the peak value for each OPR curve; otherwise, a pressure surge and production stoppage may be caused. When the daily gas production rate is low, a larger diameter tubing may cause gas well production to stop, whereas a smaller diameter tubing can maintain gas well production. Contrarily, in a higher gas production rate range, a larger diameter tubing has a higher flow efficiency. Therefore, a large diameter tubing is used in the initial gas field development period while a small diameter tubing is adopted in the late gas field development period in order to utilize rationally the gas reservoir energy and prolong the gas production period.

Figure 3-20 also shows that the lifting pressure drop of a gas well is not certain to increase with the increase in production rate, and it has a lower value at a certain critical production rate. Different tubing sizes have different gas well production rates, different lifting pressure drops, and different tubing pressures. Therefore, the tubing size should be rationally selected in order to meet the requirement of optimizing production.

Case 8. The results of calculation of the Kelaz 2 gas well are shown in Table 3-1.

Solving Process. Taking the flowing bottom pressure of 70 MPa as an example, the curves can be drawn (Figure 3-21). It can be shown that when the flowing bottomhole pressure is lower, the pressure loss is low and the requirement of high production rate can still be met.

TABLE 3-1 Pressure Loss in Tubing

Tubing Size [in (ID mm)]	Daily Production Rate (10^4m^3)	Flowing Bottom Pressure (MPa)					
		70	60	50	40	30	20
7 (157.07)	200	10.41	9.68	8.80	7.72	6.40	4.88
	300	10.79	10.10	9.27	8.27	7.11	6.01
	400	11.40	10.75	9.99	9.12	8.21	7.83
	500	12.20	11.63	10.97	9.73	9.73	10.71
	600	13.22	12.72	12.20	11.76	11.76	17.02
	700	14.43	14.05	13.70	14.46	14.46	—
$5^1/_2$ (121.36)	200	11.39	10.74	9.97	9.08	8.12	7.61
	300	13.10	12.59	12.04	11.53	11.42	15.27
	400	15.58	15.30	15.13	15.32	17.39	—
	500	18.80	18.95	19.39	21.08	—	—
	600	23.06	23.70	25.30	32.30	—	—
	700	28.29	29.89	34.38	—	—	—
5 (108.61)	200	12.47	11.90	11.27	15.33	10.12	11.45
	300	15.60	15.32	15.14	23.74	17.37	—
	400	20.18	20.41	21.14	—	—	—
	500	26.43	27.63	30.74	—	—	—
	600	34.85	34.48	—	—	—	—
	700	47.08	—	—	—	—	—

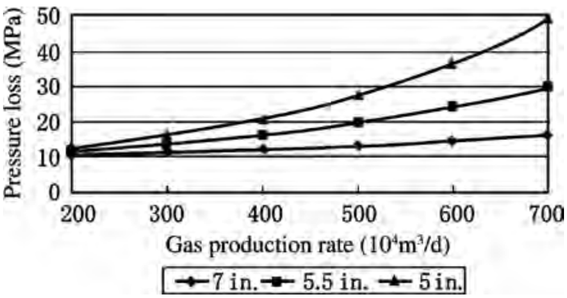

FIGURE 3-21 Pressure losses of different inside diameters of tubing under flowing bottomhole pressure of 70 MPa.

Method of Selecting and Determining Maximum Tubing Size under Condition of Meeting Carrying Liquid in Gas Well. The tubing size of the gas well should meet the requirement of carrying liquid in order to avoid the downhole liquid accumulation due to slippage and the increase in flowing bottom pressure that may cause a decrease in production rate. Thus the maximum tubing size limit should be determined. Generally, the following Jones Pork formula is used for calculation:

(3-8)

$$Q_{min} = 35.119 D^{2.5} \sqrt{p_{wf}/(M_t TZ)^2}$$

where Q_{min} = minimum allowable production rate, $10^4m^3/d$; D = inside diameter of tubing, cm; p_{wf} = flowing bottomhole pressure, MPa; M_t = relative molecular mass of downhole fluid; T = flowing bottomhole temperature, K; Z = gas deviation factor under bottomhole condition, dimensionless.

The maximum inside diameter of tubing vs. daily production rate curves of a gas well under the different flowing bottomhole pressures are shown in Figure 3-22.

The maximum allowable tubing size under different flowing bottomhole pressures and different daily gas production rates can be determined as shown in Figure 3-22. When the tubing size selected does not exceed the maximum allowable size, the downhole liquid accumulation may be avoided.

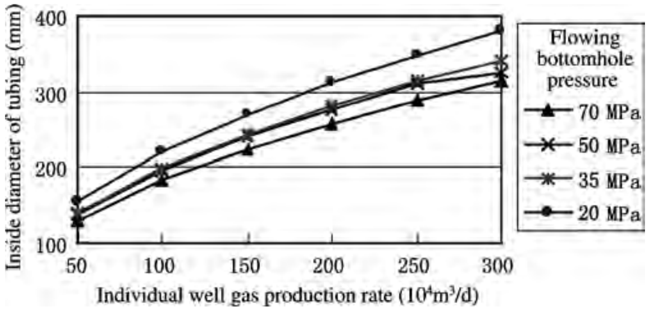

FIGURE 3-22 Maximum allowable tubing size meeting requirement of carrying liquid.

Case 9. A certain gas well has the following inflow performance: $Q_g = 0.3246\ (13.495^2 - p_{wf}^2)^{0.8294}$ (Q_g: $10^4 m^3/d$, p: MPa). Relative density of gas $\gamma_g = 0.6$. Depth in middle of reservoir H = 2100 m. Reservoir temperature is 80°C and wellhead temperature T_{wh} is 25°C. The given wellhead tubing pressure p_{wh} is 6 MPa. Try analyzing the effects of tubing sizes of 2 ⅜ in. (60.3 mm, inside diameter 50.7 mm) and 3 ½ in. (88.9 mm, inside diameter 75.9 mm) on the deliverability of the system.

Solving Process. First the inflow performance relationship (IPR) curves of a gas well are drawn (Figure 3-23). Then the outflow performance relationship (TPR) curves (TPR1 and TPR2) of the two tubing sizes are drawn, using the calculation method of vertical tubing flow of a pure gas well. The following results are obtained by the intersections of the IPR curve and the two TPR curves: production rate $Q_{g1} = 15.1 \times 10^4 m^3/d$ ($p_{wf} = 8.97$ MPa) when $d_{t1} = 60.3$ mm (2 ⅜ in.); and production rate $Q_{t2} = 18.27 \times 10^4 m^3/d$ ($p_{wf} = 7.37$ MPa) when $d_{t2} = 88.9$ mm (3 ½ in.). In this case history, the production rate of the system can be increased by 21.0% when the tubing size is increased from 2 ⅜ in. to 3 ½ in.

The maximum allowable tubing sizes under the different daily production rates and flowing bottomhole pressures can be calculated using Equation (3-8) and are listed in Table 3-2.

Selection and Determination Method of Minimum Tubing Size Avoiding Erosion due to Excessive Flow Velocity in Gas Well. A serious erosion may occur in the tubing of a gas well

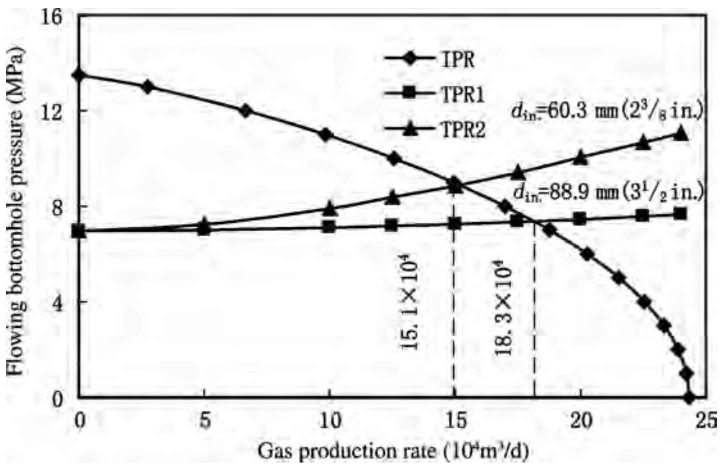

FIGURE 3-23 Effects of different tubing sizes on production rates.

TABLE 3-2 Maximum Allowable Tubing Sizes Required by Carrying Liquid

Flowing Pressure (MPa)	Daily Gas Production Rate ($10^4m^3/d$)					
	50	100	150	200	250	300
70	128.9	182.3	223.3	257.8	288.3	314.2
50	138.7	196.2	240.3	277.4	310.2	325.9
35	140.5	198.7	243.7	281.0	314.1	342.8
20	155.9	220.5	270.1	311.8	348.6	381.9

due to excessive flow velocity, thus leading to premature failure of the tubing. The Beggs formula is generally used for calculation.

1. Beggs erosion velocity formula, as shown in Equation (3-9):

   (3-9)

   $$V_e = \frac{C}{\rho_g^{0.5}}$$

   where V_e = erosion velocity, m/s; ρ_g = gas density, kg/m^3; C = constant, dimensionless (generally 1.22; 1.5 or so under favorable corrosion conditions).
2. Anti-erosion production rate formula, as shown in Equation (3-10):

   (3-10)

   $$Q_{max} = 55.164 \times 10^4 A \sqrt{\frac{p}{ZT\gamma_g}}$$

   where: Q_{max} = limiting anti-erosion production rate, $10^4m^3/d$; A = internal cross-sectional area, m^2; p = mean pressure in tubing, MPa; T = mean temperature in tubing, K; Z = gas deviation factor under bottomhole condition, dimensionless; γ_g = relative density of gas.

The minimum anti-erosion tubing sizes can be calculated using Equation (3-10) under different flowing bottomhole pressures and gas production rates as listed in Table 3-3.

The daily gas production rate vs. minimum anti-erosion tubing size can be drawn under the different flowing bottomhole pressures (see Figure 3-24). The minimum anti-erosion tubing sizes under different flowing bottomhole pressures and gas production rates are shown.

Case 10. The erosion failure of tubing wall and downhole tools may be caused during high-velocity gas flowing in tubing. In consideration of the effect of erosion on the tubing size selection for the Kela 2 gas well, the binomial deliverability equation is shown in Equation (3-11).

(3-11)

$$\frac{73.89^2 - p_{wf}^2}{q} = 2.4033 + 0.0034q$$

where q = gas flow rate, $10^4m^3/d$; pwf = flowing bottomhole pressure, MPa.

TABLE 3-3 Minimum Anti-Erosion Tubing Sizes

Flowing Bottomhole Pressure (MPa)	Daily Gas Production Rate ($10^4m^3/d$)					
	200	300	400	500	600	700
70	83.54	102.42	118.34	132.37	145.05	156.72
60	85.33	104.62	120.89	135.23	148.20	160.12
50	87.83	107.67	124.43	139.17	152.53	164.81
40	91.52	112.17	129.58	144.95	158.84	171.62
30	97.46	119.40	137.87	154.19	168.93	182.50
20	108.00	132.11	152.46	170.42	186.65	201.59

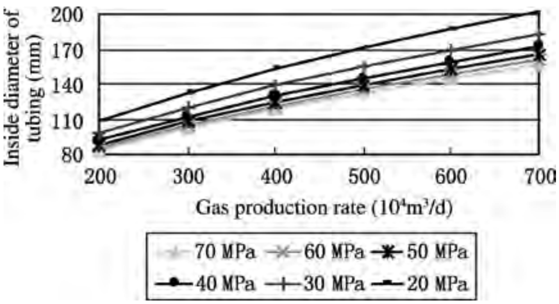

FIGURE 3-24 Minimum anti-erosion tubing sizes.

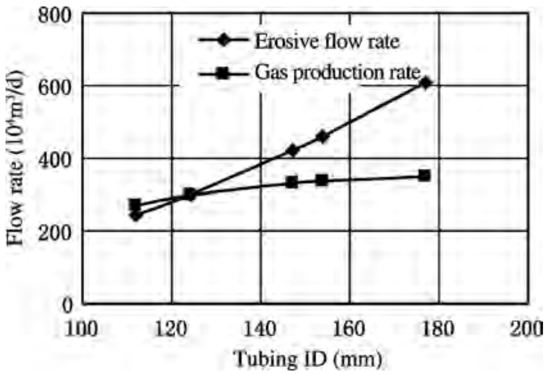

FIGURE 3-25 Effect of tubing ID on flow rate.

The relative density of gas (γ_g) is 0.578. The relative density of gas condensate (γ_o) is 0.843. The relative density of reservoir water is 1.01. The water cut is 80%. The gas-liquid ratio is 145,000 m^3/m^3. The depth in the middle of the reservoir is 3670 m. The reservoir temperature is 103.5°C. The wellhead temperature is 76.2°C. The tubing pressure is 55 MPa. Try selecting the rational tubing size.

Solving Process. The erosion may be caused by high-rate gas flowing in tubing and will be very obvious when the flow rate exceeds a certain flow rate (erosive flow rate). Thus the throughput capacity of the gas well tubing is constrained by the erosive flow rate. The critical anti-erosion production rate can be calculated in accordance with the daily throughput capacity determined by erosive flow rate and Equation (3-10).

The sensitivity analyses of tubing sizes of 193.7 mm (7 ⅝ in.), 177.8 mm (7 in.), 168.2 mm (6 ⅝ in.), 139.7 mm (5 ½ in.), and 127 mm (5 in.), corresponding to which the inside diameters are respectively 177.0 mm, 154.0 mm, 147.2 mm, 124.2 mm, and 112.0 mm, are made and the corresponding gas production rates are obtained. The corresponding erosive flow rates are calculated by substituting inside diameters of tubing into Equation (3-10). The gas production rate and erosive flow rate vs. tubing size curves are obtained (Figure 3-25). It is shown that the erosion will be generated under smaller tubing. In order to avoid erosion and reduce cost to the full extent, a tubing between 168.2 mm (6 ⅝ in.) and 177.8 mm (7 in.) is selected.

Production Casing Size Determination of Natural Gas Well

The production casing size selection of a natural gas well should ensure minimum lifting friction resistance or energy consumption under the rational natural gas production rate, maximum tubing size meeting the requirement of carrying liquid, and minimum tubing size decreasing erosion force. In addition, the maximum size of the matching downhole tools (such as the maximum outside diameter of downhole safety valve), the stimulations in the process of putting the well into production, and the measures of dewatering gas production in the late producing period should also be considered in order to select the rational tubing size. Finally, the production casing size is determined (see Table 3-4).

The outdated nominal tubing diameter is the inside diameter, while the updated or international nominal tubing diameter is the outside diameter (see Tables 3.5 and 3.6).

3.5 SELECTION AND DETERMINATION OF TUBING AND PRODUCTION CASING SIZES FOR ARTIFICIAL LIFT WELLS

When the reservoir energy is insufficient or the water cut is higher despite sufficient reservoir energy, the artificial lift method should be used in order to maintain oil well production under rational producing pressure drawdown.

TABLE 3-4 Matching Tubing Size with Production Casing Size for Oil and Gas Wells

Outside Diameter of Tubing [mm (in.)]	Production Casing Size [mm (in.)]	Outside Diameter of Tubing [mm (in.)]	Production Casing Size [mm (in.)]
≤60.3($2^3/_8$)	127(5)	127.5(5)	177.8~193.7(7~$7^5/_8$)
73.0($2^7/_8$)	139.7($5^1/_2$)	139.7($5^1/_2$)	193.7($7^5/_8$)~244.5($9^5/_8$)
88.9($3^1/_2$)	168.3~~177.8($6^5/_8$~7)	177.8(7)	244.5($9^5/_8$)
101.6(4)	177.8(7)	193.7($7^5/_8$)	273.1($10^3/_4$)
114.3($4^1/_2$)	177.8(7)	244.5($9^5/_8$)	339.7($13^3/_8$)

Note: When the downhole safety valve is set, the production casing above the safety valve should be enlarged by one grade (generally 100–200 m from the surface).

TABLE 3-5 Comparison of Updated Nominal Tubing Sizes and Outdated Nominal Tubing Sizes

Nominal Diameter [mm (in.)]	Inside Diameter of Tubing (mm)	Outside Diameter of Tubing (mm)	Outdated Standard (in.)
33.4(1.315)	26.4	33.4	1
42.2(1.660)	35.2	42.2	$1^1/_4$
48.3(1.900)	40.3	48.3	$1^1/_2$
60.3($2^3/_8$)	50.7	60.3	2
73.0($2^7/_8$)	62.0	73.0	$2^1/_2$
88.9($3^1/_2$)	75.9	88.9	3
101.6(4)	90.1	101.6	$3^1/_2$

TABLE 3-6 Common Production Casing Sizes

Nominal Diameter (in.)	Outside Diameter of Casing (mm)	Casing Wall Thickness (mm)
$4^1/_2$	114.3	5.21, 6.35, 7.37, 8.56
5	127.0	5.59, 6.43, 7.52, 9.20
$5^1/_2$	139.7	6.20, 6.98, 7.72, 9.17, 10.54
$6^5/_8$	168.3	7.32, 8.94, 10.59, 12.07
7	177.8	5.87, 6.91, 8.05, 9.20, 10.36, 11.51, 12.65, 13.72
$7^5/_8$	193.7	7.62, 8.33, 9.93, 10.92, 12.70
$8^5/_8$	219.2	6.71, 7.72, 8.94, 10.16, 11.43, 12.70, 14.15
$9^5/_8$	244.5	7.93, 8.94, 10.03, 11.05, 11.99, 13.84
$10^3/_4$	273.0	7.09, 8.89, 10.16, 11.43, 12.57, 13.84, 15.11, 16.51, 17.78
$11^3/_4$	298.9	8.46, 9.52, 11.05, 12.42
$13^3/_8$	339.7	8.38, 9.65, 10.92, 12.19, 13.06

Different artificial lift methods require different matching tubing sizes and different corresponding production casing sizes due to different lifting devices and equipment and different well conditions. For instance, when the conventional tubing pump of Φ56 mm is used for oil pumping, the matching tubing size should be Φ73 mm (2 ⅞ in.) and the maximum outside diameter of the pump is 89.5 mm, and then the production casing of Φ139.7 mm (5 ½ in.) can be selected under the single-string production with no sand control. If the inside casing gravel pack sand control method should be used and the pump is required to be set at reservoir position (this factor should be considered when a wire-wrapped screen size is selected), the production casing should be larger than Φ177.8 mm (7 in.). When the conventional tubing pump of Φ110 mm is used for oil pumping, the matching tubing size should be Φ114.3 mm (4 ½ in.), and the maximum outside diameter of the pump is 146 mm, then the production casing size should be at least Φ177.8 mm (7 in.) even if the single-string production with no sand control is adopted. If the inside casing gravel pack sand control method is required, the production casing of Φ244.5 mm (9 ⅝ in.) is more adaptable.

When the tubing and production casing sizes of the artificial lift well are determined, the mode of lift should be emphatically considered. The common artificial lift production modes include sucker rod pump, electric submersible pump, hydraulic piston pump, hydraulic jet pump, screw pump, and gas lift production. Sucker rod pumping accounts for more than 90% in China. The other key to determination of the type of pump and the tubing and production casing sizes is the daily fluid production rate level in the middle and late periods of waterflooding.

Prediction of Daily Liquid Production Rate Level in the High Water Cut Period

For a new well with adequate energy, flowing production can be initially adopted, but the daily liquid production rate is relatively low because a certain tubing shoe pressure should be maintained. After oil well production is turned to artificial lift production during oil field waterflooding, in order to adjust the producing pressure drawdown, utilize reservoir potential, and achieve stable oil production, the daily fluid production rate should be gradually increased with the increase in water cut and flowing bottomhole pressure, thus maintaining the rational producing pressure drawdown.

The well completion design should be completed before drilling. Thus, leadership and foresight should be provided for selection and determination of tubing and production casing sizes. The daily liquid production rate during the whole oil field development, especially in the high water cut period, and the requirements for tubing and production casing sizes should be considered.

In general, the daily liquid production rate in the flowing period is relatively low and the corresponding tubing and production casing sizes are also relatively small. After turning to artificial lift production, especially in the high water cut period, larger tubing and production casing sizes are required in order to adapt production under the condition of a large pump. After the lift mode of the oil well is determined, the possible daily liquid production rate in the future should be predicted and the tubing and production casing sizes are then selected and determined; otherwise, the production rate may be limited due to the unreasonable strings in many oil wells. For instance, a certain well selects sucker rod pumping and the conventional tubing pump is selected. The initial daily oil production rate is 50t/d. The water cut is 10%. The daily liquid production rate is 55.6 t. If the mean pump efficiency is 60% and a tubing pump of Φ56 mm is selected, the matching tubing size is Φ73 mm (2 ⅞ in.), the outside diameter of the pump is 89.5 mm, and the production casing of Φ139.7 mm (5 ½ in.) is possible. However, when the water cut of this well $f_w = 90\%$, the stable oil production rate of 40t/d is required, and the daily liquid production rate level should be at least 400 t/d. If the mean pump efficiency is still 60%, the tubing pump of Φ110 mm should be selected. At this time, the tubing size matching with the pump is Φ114.3 mm (4 in.) and the outside diameter of the pump barrel is 146 mm; thus, the production casing should be at least Φ177.8 mm (7 in.). If this well is in the high water cut period and sand control is required, the production casing of 7 in. cannot meet the requirement. The daily oil production rate of 40t/d cannot be reached, and the oil production rate has to be reduced.

Therefore, the selection and determination of tubing and production casing sizes in consideration of the future daily production rate level are scientific and realistic practices. After a well is completed, the tubing size is changeable, whereas the production casing size is unchangeable. In order to discharge liquid by a large pump in the high water cut period, a larger production casing size is better. Therefore, in the initial flowing and artificial lift period, rational tubing size is adopted on the basis of production optimization (nodal systems analysis), whereas in the high water cut period during which a large pump is needed for discharging the liquid, the tubing size can be changed to a larger tubing size.

The daily liquid production rate in the high water cut period can be predicted in accordance with the requirement of stable oil production design. In the development program, the daily oil production rate level (allocating oil production rate) is formulated on the basis of the reservoir oil properties, reservoir parameters, and requirement of allocation of oil field development. In the waterflooding oil field, the daily liquid production rate of the oil well should be increased after entering into the high water cut period of the oil well in order to meet the requirement of stable oil production. The empirical method shown in Equation (3-12) is commonly used in the field:

(3-12)

$$Q_L = \frac{Q_{po}}{1 - f_w}$$

where Q_{po} = daily allocating oil production rate of oil well in development design, m^3/d; Q_L = daily liquid production rate predicted, m^3/d; f_w = water cut.

The numerical simulation method or the method of predicting the future IPR curve should be used for calculating accurately the daily liquid production rate in the high water cut period.

Artificial Lift Mode Determination

On the basis of the maximum tubing diameter or the minimum production casing diameter, in accordance with the predicted highest daily liquid production rate level in the high water cut period and the theoretical discharge capacity and discharge head calculated by supposing pump efficiency of 60%, with reference to downhole conditions, surface environment, operation condition, maintenance and management, and economic benefit, artificial lift mode is optimized and selected. In general, artificial lift mode is selected and determined using the methods described in the following sections.

Preliminary Selection of Artificial Lift Mode. Artificial lift mode is preliminarily selected in accordance with adaptability to production conditions, as shown in Table 3-7.

Production Mode Optimization Using the Grade Weighted Method. The evaluation parameters related to the feasibility and complexity of various artificial lift modes are digitized, compared, and graded. The first type parameter (X) is the parameter related to the feasibility of successful use of artificial lift mode and is divided into five grades (Grades 4, 3, 2, 1, and 0 represent respectively excellent feasibility, good feasibility, moderate feasibility, poor feasibility, and infeasible). The second type parameter (Y) is the parameter related to the method complexity, investment, and steel product consumption and is divided into three grades (Grades 3, 2, and 1 represent respectively favorable complexity, moderate complexity, and unfavorable complexity). X, Y, and Z are respectively calculated using Equations (3-13), (3-14), and (3-15), with reference to Table 3-8 and Table 3-9 under the specific conditions of the oil well. The artificial lift methods with higher Z values are selected as

TABLE 3-7 Adaptability Comparison between Artificial Lift Systems

Item	Adaptability Condition	Sucker Rod Pump	Screw Pump	Electric Submersible Pump	Hydraulic Piston Pump	Hydraulic Jet Pump	Gas Lift	Plunger Lift
Basic conditions of system	Degree of complexity	Simple	Simple	Complex bottomhole	Complex surface	Complex surface	Complex surface	Complex surface
	One investment	Low	Low	High	High	High	Highest	Highest
	Operation cost	Low	Low	High	Low; High in high water cut period	Low	Low; High for small oil field	Low; High for small oil field
Discharge capacity m^3/d	Normal range	1∼100	10∼200	80∼700	300∼600	10∼500	30∼3180	20∼32
	Maximum	410	(1000)	1400 (3170)	(1293)	1590 (4769)	(7945)	63
Pump depth m	Normal range	3000	1500	2000	4000	2000	3000	3000
	Maximum	4421	3000	3084	5486	3500	3658	3658
Downhole conditions	Slim hole	Appropriate	Appropriate	Inappropriate	Appropriate	Appropriate	Appropriate	Appropriate
	Separate-zone production	Inappropriate	Inappropriate	Appropriate	Appropriate	Inappropriate	Appropriate	Appropriate
	Directional well	General wear	Serious wear	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate
	Degree of cavitation	Strong	Strong	Strong	Strong	Strong	Strong	Strong
Surface environment	Offshore and city	Inappropriate	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate
	Harsh climate	General	General	Appropriate	Appropriate	Appropriate	Appropriate	Appropriate

Operation problems	High gas-oil ratio	Adaptable	General	Inadaptable	General	Adaptable	Very adaptable	Very adaptable
	Heavy oil and high pour-point oil	Good	Good	Inadaptable	Very good	Very good	Inadaptable	Inadaptable
	Sand production	Good	Adaptable	Inadaptable	General	General	Very adaptable	Very adaptable
	Corrosion	Adaptable	Adaptable	Adaptable	Adaptable	Adaptable	Adaptable	Adaptable
	Scaling	Adaptable	Inadaptable	Inappropriate	Adaptable	Adaptable	General	General
	Working system adjustment	Convenient	Convenient	Lack of flexibility	Lack of flexibility	Convenient	Convenient	Convenient
	Power source	Electricity, natural gas, oil	Electricity, natural gas, oil	Electricity	Electricity, natural gas, oil	Electricity, natural gas, oil	Electricity, natural gas, oil	Electricity, natural gas, oil
	Requirement for power media	None	None	None	Special power fluid	Water power fluid	Avoiding hydrate	Avoiding hydrate
Maintenance and management	Pump inspection	Pulling out tubing for tubing pump	Pulling out tubing	Pulling out tubing	Hydraulic or wire pulling and running	Hydraulic or wire pulling and running	Wire pulling and running	Wire pulling and running
	Mean repair-free period (a)	2	1	1.5	0.5	0.5	3	3
	Auto-control	Appropriate	General	Appropriate	Appropriate	Appropriate	General	General
	Production test	Basically matching	Unmatching	Basically matching	Basically matching	Unmatching	Completely matching	Basically matching

Notes: 1. The discharge capacity values in parentheses ( ) mean the discharge capacity values achievable when the external diameter of production casing is larger than 177.8 mm.
2. If a frequency converter is used, the working system adjustment for various artificial lift modes is convenient, but the cost is high.
3. For the various artificial list modes, the flowing bottomhole pressures can be reduced to zero under sufficient production casing strength except gas lift mode, under which a certain tubing shoe pressure (that is, flowing bottomhole pressure when tubing is set in the middle of reservoir) is required in order to lift the well liquid.

TABLE 3-8 Local Feasibility Parameter Assessment Values (X)

No.	Related Contents of Local Parameter	Symbol	Sucker Rod Pump	Electric Submersible Pump	Hydraulic Piston Pump	Hydraulic Jet Pump	Gas Lift	Surface-Driven Screw Pump
1	High production rate (>100 m^3/d)	X_1	2	4	2	2	4	2
2	Medium production rate (5–100 m^3/d)	X_2	3	4	3	3	4	3
3	Low production rate (<5 m^3/d)	X_3	4	1	4	4	0	4
4	High discharge head (>1350 m)	X_4	1	3	4	4	4	0
5	Medium discharge head (450–1350 m)	X_5	3	4	4	4	4	2
6	Low discharge head (<450 m)	X_6	4	4	4	4	4	4
7	Failure-free time, rate of well utilization	X_7	2	3	3	3	3	3
8	Well test, production test	X_8	3	2	2	2	4	2
9	Automated oil production, parameter adjustment	X_9	2	4	3	3	3	3
10	Integrity of production technology	X_{10}	2	2	3	3	3	3
11	Oil production method efficiency	X_{11}	1	3	3	2	2	3
12	Ability of separate production in a well	X_{12}	2	2	2	2	3	2
13	Adaptability to slant and directional well	X_{13}	1	3	4	4	4	3
14	Adaptability to 70°C well temperature	X_{14}	3	3	3	3	4	3
15	Adaptability to well temperature higher than 70°C	X_{15}	2	0	3	3	4	2
16	Mechanical admixture in produced liquid≤1%	X_{16}	2	3	2	2	4	4
17	Mechanical admixture in produced liquid≥1%	X_{17}	0	0	0	0	3	4
18	Scaling and corrosion	X_{18}	1	1	1	1	2	2
19	Water cut	X_{19}	2	3	2	3	2	3
20	Enhanced oil recovery ability	X_{20}	1	4	1	1	2	2
21	High gas-oil ratio	X_{21}	2	2	2	2	4	3
22	High paraffin content	X_{22}	2	3	2	2	1	4
23	Heavy oil (<100)	X_{23}	2	1	4	4	2	4
24	High wellhead tubing pressure	X_{24}	1	2	3	3	2	2
25	Harsh climate, offshore	X_{25}	1	2	3	3	2	2
26	Adaptability to slim hole	X_{26}	2	2	1	3	4	2

TABLE 3-9	Local Complexity Parameter Assessment Values (Y)							
No.	Related Contents of Local Parameter	Symbol	Sucker Rod Pump	Electric Submersible Pump	Hydraulic Piston Pump	Hydraulic Jet Pump	Gas Lift	Surface-Driven Screw Pump
1	Serviceability	Y_1	3	3	3	3	2	2
2	Simplicity and convenience of equipment	Y_2	2	3	2	2	2	3
3	Energy utilization efficiency	Y_3	2	3	2	1	1	2
4	Mobility of equipment	Y_4	1	3	2	2	2	3
5	Demulsification ability	Y_5	2	1	2	1	1	3
6	Degree of simplicity and ease of oil well equipment	Y_6	1	3	1	2	1	3
7	Initial investment efficiency	Y_7	2	1	2	2	2	3
8	Utilization rate of metal	Y_8	1	3	1	1	1	3

the preliminary results, and the technical and economic demonstration is then conducted in accordance with the technical design of a typical well, and the artificial lift mode meeting the requirements is finally determined.

(3-13)

$$X = \sqrt[n]{\prod_{i=1}^{n} X_i}$$

(3-14)

$$Y = \sqrt[n]{\prod_{i=1}^{n} Y_i}$$

(3-15)

$$Z = \sqrt{XY}$$

Chart Method of Selecting Oil Production Mode. The two methods of selecting the oil production mode are as follows:

1. A rational usable range chart of sucker rod pump, electric submersible pump, and hydraulic piston pump, which was obtained by reference to the related charts in the late 1980s and in combination with the oil field conditions and use experience in China, is shown in Figure 3-26. The artificial lift mode can be determined by the location of the predicted coordinate point of discharge head and liquid production rate.
2. The optimum usable range charts of gas lift, plunger lift, sucker rod pump, electric

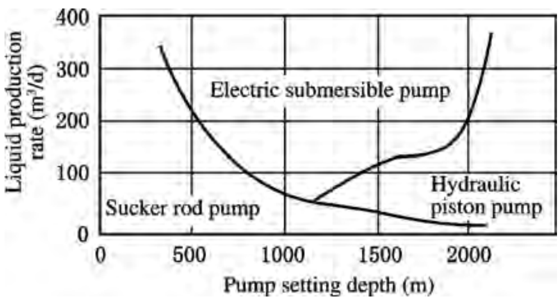

FIGURE 3-26 Rational usable ranges of sucker rod pump, electric submersible pump, and hydraulic piston pump.

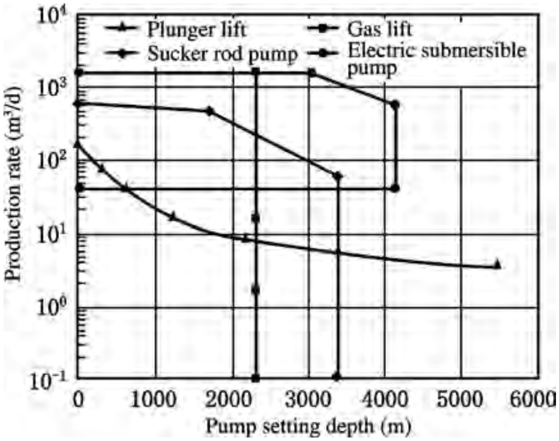

FIGURE 3-27 Optimum usable ranges of plunger lift, sucker rod pump, gas lift, and electric submersible pump.

submersible pump, hydraulic piston pump, and jet pump, which were presented by Blais et al. in 1986, are shown in Figures 3-27 and 3-28. The artificial lift mode can be determined by the location of the coordinate point of the predicted discharge lead and liquid production rate.

After artificial lift modes are determined using these methods, the tubing and production casing sizes are selected and determined on the basis of the artificial lift modes.

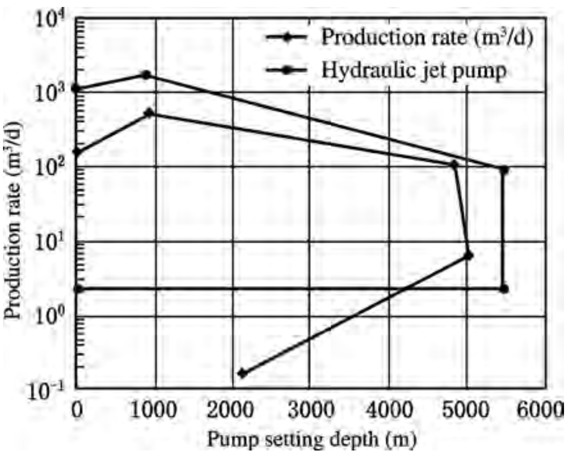

FIGURE 3-28 Optimum usable ranges of hydraulic piston pump and hydraulic jet pump.

Selection and Determination of Tubing and Production Casing Sizes for Sucker Rod Pump Well

Sucker rod pumping has played a leading role in artificial lift production mode worldwide all along. At present, sucker rod pumping has been adopted by more than 90% of artificial lift production wells in China. Sucker rod pumps are divided into two categories: conventional and special pumps. Special pumps include anti-sanding-in pumps, gas control pumps, heavy oil pumps, dual gassy fluid pumps, heavy oil sand control pumps, double-acting pumps, and pumps in series.

- Sucker rod pump
  - Conventional pump
  - Special pump
    - Anti-sanding-in pump
    - Gas control pump
    - Heavy oil pump
    - Dual gassy fluid pump
    - Heavy oil sand control pump
    - Double-acting pump
    - Pumps in series

The procedure for selecting the tubing and production casing sizes of sucker rod pumping wells is as follows.

1. Predicting daily liquid production rate level in the high water cut period of an oil well.
2. Selecting theoretical discharge capacity. The theoretical pump discharge capacity Q_{tL} vs. daily liquid production rate Q_L relationship is shown in Equation (3-16):

(3-16)

$$Q_{tL} = \frac{Q_L}{\eta_p}$$

where Q_{tL} = theoretical pump discharge capacity, m³/d; Q_L = daily liquid production rate predicted, m³/d; η_p = actual pump efficiency, % (generally 60% selected preliminary).
3. Selecting the nominal diameter of the pump on the basis of theoretical discharge capacity of the pump.
4. Determining production casing size. The tubing size and the maximum outside diameter of the pump can be obtained on the basis of the nominal diameter of the pump. The production casing size matching the pump size is determined under the condition of gravel

pack sand control well or non-sand control well and the condition of single-string or dual-string production.

The pump barrel of the tubing pump is at the lower end of the tubing string and the sucker rod is run in the pump barrel with the plunger. The tubing pump has mainly a pump barrel and plunger. Thus a relatively large pump size with a theoretical discharge capacity can be chosen. It can be used in shallow and moderately deep pumping wells with high productivity (Table 3-10).

The rod-insert pump has inside and outside working barrels and has relatively small pump size and discharge capacity. It is used in deep wells with low liquid levels and low production rates (see Table 3-11).

In practice, the pumping unit cannot operate under the maximum stroke, maximum strokes per minute, and maximum load; the fullness coefficient cannot be equal to 1; and the pump efficiency cannot be equal to 100%. When the pump size is selected, pump efficiency of 50% to 80% and (stroke) × (strokes per minute) value≤36 can be preliminarily selected.

The special pumps, such as the anti-sanding-in pump, gas control pump, hydraulic feedback heavy oil pump, circulation flow heavy oil pump, and dual gassy fluid pump, will not be discussed in detail because they are rarely used. However, the methods of selecting production casing size are the same as that of the conventional tubing pump and conventional rod-insert pump.

Case 11. The allocating oil production rate of a certain well on the basis of development design is 15 m^3/d. The underground oil viscosity is 14.5 MPa · s. The oil well has no sand production. The oil field adopts waterflooding. Try selecting the production casing size.

Solving Process. (1) The daily liquid production rate in the high water cut period is predicted using Equation (3-12). When the water cut $f_w = 80\%$, $Q_{L1} = 75\ m^3/d$; when $f_w = 90\%$, $Q_{L2} = 150\ m^3/d$; and when $f_w = 95\%$, $Q_{L3} = 300\ m^3/d$. (2) The conventional tubing pump is selected.

TABLE 3-10 Matching Conventional Tubing Pump (Integral Pump Barrel) with Tubing and Production Casing

Nominal Diameter of Pump (mm)	Outside Diameter of Connecting Tubing (mm)	Theoretical Discharge Capacity (m^3/d)	Maximum Outside Diameter (mm)	Casing Size Recommended (in.)	
				Non-Sand Control Well	Gravel-Pack Sand-Control Well
32	73.0	14~35	89.5	5~5$^1/_2$	7
38	73.0	20~44	89.5	5~5$^1/_2$	7
44	73.0	26~66	89.5	5~5$^1/_2$	7
57	73.0	40~110	89.5	5~5$^1/_2$	7
70	88.9	67~166	107	5$^1/_2$	7
83	101.6	94~234	114	7	7
95	114.3	122~306	132.5	7	7
110	114.3	164~410	146	7~9$^5/_8$	9$^5/_8$
Plunger stroke length range: 1.2–5.0 m					

Notes: 1. Under theoretical discharge capacity, lower limit strokes per minute = 10/min, stroke = 1.2 m; upper limit strokes per minute = 6/min, stroke = 5 m.
2. For an inside casing gravel pack sand control well, the production casing size should be increased by one grade and a production casing size larger than 7 in. should be selected in order to ensure sand control effectiveness and increase thickness of gravel pack zone. For an outside gravel pack sand control well, the production casing size should be decreased by one grade. If the pump is required to be set below the top of a perforated interval, the production casing size should be increased by one grade. Generally, the distance between pump and perforation should not be less than 80 m in order to protect the reservoir from surges.

TABLE 3-11 Matching of Conventional Rod-Insert Pump with Tubing And Production Casing

Nominal Diameter of Pump (mm)	Outside Diameter of Connecting Tubing [mm (in.)]	Theoretical Discharge Capacity (m^3/d)	Maximum Outside Diameter (mm)	Casing Size Recommended (in)	
				Sand Control Well	Non-Sand Control Well with Gravel Pack
32	60.3($2^3/_8$)	14∼35	89.5	5∼$5^1/_2$	7
38	73.0($2^7/_8$)	20∼49	89.5	5∼$5^1/_2$	7
44	73.0($2^7/_8$)	26∼66	89.5	5∼$5^1/_2$	7
51	73.0($2^7/_8$)	35∼88	107	$5^1/_2$	7
56	88.9($3^1/_2$)	43∼106	107	$5^1/_2$	7
57	88.9($3^1/_2$)	44∼110	107	$5^1/_2$	7
63	88.9($3^1/_2$)	54∼135	114	7	7
Plunger stroke length range: 1.2–5.0 m					

Notes: 1. Under theoretical discharge capacity, lower limit strokes per minute = 10/min, stroke = 1.2 m; upper limit strokes per minute = 6/min, stroke = 5 m.
2. For an inside casing gravel pack sand control well, the production casing size should be increased by one grade and a production casing size larger than 7 in. should be selected in order to ensure sand control effectiveness and increase thickness of gravel pack zone. For an outside gravel pack sand control well, the production casing size should be decreased by one grade. If the pump is required to be set below the top of a perforated interval, the production casing size should be increased by one grade. Generally, the distance between pump and perforation should not be less than 80 m in order to protect the reservoir from surges.

Suppose the pump efficiency η_p is 80% when the water cut is high. The theoretical discharge capacities of the pump under the water cuts of 80%, 90%, and 95% are 93.8 m^3/d, 187.5 m^3/d, and 375 m^3/d, respectively, in accordance with Equation (3-16). In order to ensure the stable oil production rate of 15 m^3/d in the high water cut period, the pump of Φ110 mm with a theoretical discharge capacity of 164–410 m^3/d can be selected using Table 3-10. The tubing of Φ114.3 mm (4 ½ in.) and the maximum pump OD of 146 mm can also be selected. The production casing of Φ177.8 mm (7 in.) should be selected. The calculation results show the pump size required when the ultimate liquid production rate is reached. Thus the tubing and production casing sizes can be derived. When the well is completed, whether the sucker rod pump or electric submersible pump is adopted should be considered, and then the tubing and production casing sizes are selected and the economization and effectiveness of both types of pumps are compared.

Selection and Determination of Tubing and Production Casing Sizes for Hydraulic Piston Pump Well

A hydraulic piston pump has a wide discharge capacity range (30–1274 m^3/d) and is adaptable to mid-viscosity oil, high pour-point oil, and deep pumping conditions; thus it has become an important component part of artificial lift production technology in China. The adaptability and the technological conditions are shown in Table 3-12.

The common hydraulic piston pumps include a single-acting pump with variable pressure ratio, balanced single-acting pump, long-stroke double-acting pump, and dual hydraulic motor double-acting pump. The power fluid circulation and tubing string assembly are shown in Table 3-13.

The selection procedures of tubing and production casing sizes of a hydraulic piston pump are similar to that of a sucker rod pump and are as follows.

TABLE 3-12 Adaptability and Technological Conditions of Hydraulic Piston Pump

Item	Adaptability	Application Ranges or Technological Conditions
Lift height	Strong	Normal range 3500 m, up to 5486 m
Liquid production rate	Wide range	Up to more than 600 m^3/d for oil well with casing of Φ140 mm (5 1/2 in.); up to more than 1000 m^3/d for oil well with casing of Φ178 mm (7 in.)
High gas-liquid ratio	Conditional adaptation	No limitation if gas flows out through separate passage. A certain submergence is required if gas is produced through pump.
Borehole deviation or bending	Strong	Deviation angle of about 45°
Scaling	Moderately strong	Anti-scaling additive is carried by power fluid, or magnetic anti-scaler is used.
Sand production	Poor	Sand content of power fluid should be lower than 0.01%.
High pour-point oil well	Strong	Flow rate and temperature of power fluid should be ensured.
Heavy oil well	Moderately strong	Thin crude oil or water base power fluid should be used and flow rate and temperature should be ensured.
Corrosion	Moderately strong	Corrosion inhibitor should be carried by power fluid.
Selective zone production	Strong	Pump and tubing string appropriate to selective zone production are used.

TABLE 3-13 Power Fluid Circulation and Tubing String Assembly

Outside Diameter of Production Casing [mm (in.)]	Outside Diameters of Tubing Strings Assembled [mm (in.)]		
	Open Single String	Dual Parallel String	Dual Concentric String
127(5)	60.3($2^3/_8$) 73.0($2^7/_8$)	—	—
140($5^1/_2$)	60.3($2^3/_8$) 73.0($2^7/_8$) 88.9($3^1/_2$)	60.3×33.4 ($2^3/_8$×1.315)	73.0×48.3 ($2^7/_8$×1.900) 88.9×48.3 ($3^1/_2$×1.900)
178(7)	60.3($2^3/_8$) 73.0($2^7/_8$) 88.9($3^1/_2$) 101.6(4) 114.3($4^1/_2$)	60.3×60.3 ($2^3/_8$×$2^3/_8$) 73.0×40.3 ($2^7/_8$×1.900)	73.0×48.3 ($2^7/_8$×1.900) 88.9×48.3 ($3^1/_3$×1.900) 101.6×60.3 (4×$2^3/_8$) 114.3×73.0 ($4^1/_2$×$2^7/_8$)

1. Predict the daily liquid production rate in the late development period.
2. Select and determine the theoretical discharge capacity Q_{tL} of the pump.
3. Find the matching tubing size and maximum outside diameter of the pump in the technical parameter table of a hydraulic piston pump. Then determine the production casing size in accordance with single-string production or dual-string production.

The long-stroke double-acting hydraulic piston pump is the most common hydraulic piston pump and is appropriate to the oil pumping of

TABLE 3-14 Matching of Long-Stroke Double-Acting Hydraulic Piston Pump with Tubing and Production Casing

Model Number of Pump		SHB2.5×10/20	SHB2.5×20/20	SHB2.5×30/20	SHB3.0×50/20
Tubing size [mm (in.)]		73.0($2^7/_8$)	73.0($2^7/_8$)	73.0($2^7/_8$)	88.9($3^1/_2$)
Discharge capacity (m^3/d)		100	200	300	500
Maximum outside diameter (mm)		114(102)	114(102)	114	114
Recommended nominal diameter of production casing	Single-string production	139.7 mm, 127 mm ($5^1/_2$, 5 in.)	139.7 mm, 127 mm ($5^1/_2$, 5 in.)	139.7 mm ($5^1/_2$ in.)	139.7 mm ($5^1/_2$ in.)
	Dual-string production	177.8 mm (7 in.)	177.8 mm (7 in.)	177.8 mm (7 in.)	193.7∼244.5 mm ($7^5/_8$∼$9^5/_8$ in.)

the oil well with high productivity and a high liquid production rate. Matching the pump with tubing and production casing is shown in Table 3-14.

Case 12. On the basis of the parameters of Case 11, try selecting the tubing and production casing sizes of a hydraulic piston pump well.

Solving Process. By calculating as Case 11, when the water cut is 95%, the daily liquid production rate is up to 300 m^3/d in order to ensure the stable oil production rate of 15 m^3/d. When the long-stroke double-acting hydraulic piston pump is adopted, at least the ×HB 3.0 × 50/20 pump should be selected. Its theoretical discharge capacity is 500 m^3/d (by taking the pump efficiency of 80%, the actual discharge capacity can be up to 400 m^3/d). The outside diameter of tubing is 76.2 mm (3 in.) and the production casing size is Φ139.7 mm (5 ½ in.).

Selection and Determination of Tubing and Production Casing Sizes for Hydraulic Jet Pump Well

A main feature of a hydraulic jet pump is that there is no moving component and water can be used as the power fluid. The other surface equipment and downhole working barrel are the same as that of a hydraulic piston pump. The discharge capacity can be up to 4769 m^3/d and is second only to that of gas lift. The discharge head can be up to 3500 m and is second only to that of a hydraulic piston pump. However, the pump efficiency is relatively low and the maximum pump efficiency is only up to 32%. The hydraulic jet pump can be used for oil pumping production and is appropriate especially to the high pour-point oil production and the oil production in the high water cut period, during which the hydraulic piston pump can be replaced by the hydraulic jet pump. The hydraulic jet pump is also appropriate for formation tests, drillstem tests, blocking removal, spent acid removal, and scavenging, due to its simple structure and strong adaptability.

The selection procedures of tubing and production casing sizes of hydraulic jet pump wells are as follows.

1. The maximum daily liquid production rate in the high water cut period is predicted using the aforementioned method of predicting the daily liquid production rate level in the high water cut period.
2. The lifting rate H is calculated as shown in Equation (3-17).

(3-17)

$$H = \frac{p_3 - p_4}{p_1 - p_3}$$

where H = lifting rate; p_1 = working pressure at nozzle inlet, MPa (pump depth multiplied by power fluid pressure gradient plus wellhead pressure of the system); p_3 = discharge pressure of mixed liquid, MPa (pump depth

TABLE 3-15 Empirical Values of Key Parameters

Lifting Rate H	Jetting Rate M	Area Ratio R
<>0.15	>1.5	0.17
0.15~0.25	1.5~1.0	0.21
0.25~0.3	1.0~0.7	0.26
0.3~0.45	0.7~0.5	0.33
0.45~0.8	0.5~0.1	0.41

multiplied by mixed liquid pressure gradient plus wellhead backpressure); p_4 = suction pressure, MPa (submergence multiplied by crude oil pressure gradient).

3. The jetting rate and area ratio are determined in accordance with the empirical values in Table 3-15.
4. The maximum power fluid flow rate is obtained by the theoretical pump discharge capacity divided by the jetting rate minimum.
5. The nozzle diameter is estimated using Equation (3-18):

(3-18)

$$d_1 = \sqrt{\frac{Q_e}{9.6 \times 10^7 \alpha \sqrt{\frac{p_1 - p_4}{\rho}}}}$$

where d_1 = nozzle diameter, m; Qe = power fluid flow rate, m^3/d; α = flow rate coefficient determined by testing results ($\alpha = 3.1$ when power fluid is water and $\alpha = 8.5$ when power fluid is heavy oil); ρ = power fluid density, kg/m^3.

6. Throat diameter is predicted using the following formula:

(3-19)

$$d_2 = \sqrt{\frac{{d_1}^2}{R}}$$

where d_2 = throat diameter, mm; R = area rate (see Table 3-15).

7. The tubing and production casing sizes are determined on the basis of nozzle diameter and throat diameter in accordance with Table 3-16 and the type of pump selected.

Case 13. In accordance with the development program of a certain well, the allocating oil production rate in the late period is 7 m^3/d, the working pressure at the nozzle inlet is 26.7 MPa, the suction pressure is 12.1 MPa, and the discharge pressure of mixed liquid is 17.0 MPa. The water base power fluid is adopted. Try selecting the production casing size.

Solving Process

1. On the basis of the allocating oil production rate of 7 m^3/d and the predicted water cut of 95%, the maximum daily liquid production rate of 139 m^3/d is predicted in accordance with Equation (3-12).
2. The lifting rate H is calculated as follows.

$$H = \frac{17.0 - 12.1}{26.7 - 17.0} = 0.51$$

TABLE 3-16 Matching of Conventional Jet Pump with Tubing and Production Casing

Index	Type of Jet Pump			
	SPB 2.5 Series	Casing-Type Jet Pump	Up-Jet-Type Jet Pump	Φ62 mm Short-Type Jet Pump
Nozzle diameter	1.9~6.0	2.1~3.9	1,8~6.8	1.8~6.8
Throat diameter	4.5~9.8	3.3~6.2	2.9~11.0	2.9~11.0
Tubing OD	73	73	60.3	73
Maximum OD of pump	114	114	89	114
Minimum ID of casing	127(5$^1/_2$ in.)	127(5$^1/_2$ in.)	100(4$^1/_2$ in.)	127(5$^1/_2$ in.)

Note: The power fluid of a casing-type jet pump flows in from casing and the mixed liquid flows out through tubing.

3. The jetting rate of 0.5 and the area ratio of 0.41 are obtained using Table 3-15.
4. The power fluid flow rate Q_e is predicted as follows.

$$Q_e = \frac{139}{0.5} = 278 \text{ m}^3/\text{d}$$

5. The nozzle diameter is predicted using Equation (3-18).

$$d_1 = \sqrt{\frac{278}{9.6 \times 10^7 \times 3.1\sqrt{\frac{26.7 - 12.1}{1000}}}} - 0.0028 \text{ m}$$
$$= 2.8 \text{ mm}$$

6. The throat diameter is predicted using Equation (3-19).

$$d_2 = \sqrt{\frac{2.8^2}{0.41}} = 4.4 \text{ mm}$$

7. On the basis of the nozzle diameter and the throat diameter, the short-type jet pump of Φ62 mm is selected, and the maximum pump OD of 114 mm and the minimum production casing ID of 127 mm are obtained. Thus the production casing of Φ139.7 mm (5 ½ in.) or Φ177.8 mm (7 in.) should be selected.

Selection and Determination of Tubing and Production Casing Sizes for Electric Submersible Pump Well

The electric submersible pump is adaptable to oil wells (including directional wells) of high discharge capacity, low and medium viscosity oil, low sand content, and pump depth less than 2500 m. The electric submersible pump can also be used in the gravel pack sand control well under the conventional production condition of heavy oil. At present, the theoretical discharge capacity of the electric submersible pump adaptable to the production casing of Φ139.7 mm (5 ½ in.) can be up to 550 m^3/d. Therefore, the selection procedures of tubing and production casing sizes of electric submersible pump wells are same as that of a hydraulic piston pump. Matching the electric submersible pump with tubing and production casing is shown in Table 3-17.

Matching the TRW Reda Pumps electric submersible pump with tubing and production casing is shown in Table 3-18.

Case 14. On the basis of the parameters of Case 12, try selecting the production casing size of the electric piston pump well.

Solving Process. By calculation similar to Case 11, in order to ensure the daily oil production rate of 15 m^3/d under the water cut of 95%, the daily liquid production rate of 300 m^3/d is required. In accordance with Table 3-17, the QYB120-425 pump with theoretical discharge capacity of 425 m^3/d can be used. By taking the pump efficiency of 80%, the actual discharge capacity can be up to 340 m^3/d, which can meet the requirement of daily liquid production rate of 300 m^3/d. The corresponding tubing size of Φ73 mm (2 ⅞ in.) can be selected. For a conventional well with no sand control, the production casing size of Φ139.7 mm (5 ½ in.) is selected. For the gravel pack sand control well, the production casing of Φ177.8 mm (7 in.) can be selected in order to ensure sand control effectiveness by increasing the thickness of the gravel pack sand control zone. If a larger discharge capacity is required in the late production period, a larger production casing, that is, the production casing of Φ177.8 mm (7 in.) for conventional wells and the production casing of Φ244.5 mm (9 ⅝ in.) for sand control wells, can be adopted in order to leave some selection margin for adopting the electric submersible pump with larger discharge capacity in the future. For instance, a higher daily liquid production rate can be obtained by selecting the G-160 or G-225 type of pump in Table 3-18.

Selection and Determination of Tubing and Production Casing Sizes for Gas Lift Oil Production Well

Gas lift production is especially adaptable to sand production wells, medium and low viscosity oil wells, high gas-oil ratio wells, deep wells, and directional wells, and is an important artificial lift production mode. The advantages and

TABLE 3-17 Matching Partial Chinese Electric Submersible Pumps with Tubing and Production Casing

Manufacturer	Model Number	Tubing Size (mm)	Rated Discharge Capacity (t/d)	Outside Diameter (mm)	Casing Size Recommended (in.)	
					Conventional Well	Gravel Pack Well
Tianjing Electric Motor	A10	60.3, 73.0	100	95	5½	7
	A15	60.3, 73.0	150	95	5½	7
	A20	60.3, 73.0	200	95	5½	7
	A42	60.3, 73.0	425	95	5½	7
	A53	60.3, 73.0	500	95	5½	7
Zibo Submerged Electric Pump Manufacturer	5.5QD100	60.3, 73.0	100	100, 98	5½	7
	5.5QD160	60.3, 73.0	160	100, 98	5½	7
	5.5QD200	60.3, 73.0	200	100, 98	5½	7
	5.5QD250	60.3, 73.0	250	100, 98	5½	7
	5.5QD320	60.3, 73.0	320	100, 98	5½	7
	5.5QD425	60.3, 73.0	425	100, 98	5½	7
Huxi Electric Motor Manufacturer	QYB120-75	60.3, 73.0	75	100, 98	5½	7
	QYB120-100	60.3, 73.0	100	100, 98	5½	7
	QYB120-150	60.3, 73.0	150	100, 98	5½	7
	QYB120-200	60.3, 73.0	200	100, 98	5½	7
	QYB120-250	60.3, 73.0	250	100, 98	5½	7
	QYB120-320	60.3, 73.0	320	100, 98	5½	7
	QYB120-425	60.3, 73.0	425	100, 98	5½	7
	QYB120-550	60.3, 73.0	550	100, 98	5½	7

Note: The electric submersible pump in this table should be used in the production casing of 5 1/2 in. The tubing sizes include 60.3 mm (2 3/8 in.) and 73.0 mm (2 7/8 in.).

limitations of gas lift production are listed in Table 3-19.

The modes of gas lift include continuous gas-lift and intermittent gas-lift. The intermittent gas-lift can be further divided into conventional intermittent gas-lift, chamber gas-lift, and plunger gas-lift. The continuous gas-lift is only discussed because the daily liquid production rate of intermittent gas-lift is much lower than that of continuous gas-lift.

The selection procedures of tubing and production casing sizes for a gas lift well are as follows:

1. Predict the daily liquid production rate level Q_L.
2. Determine the tubing and production casing sizes meeting the requirement of daily liquid production rate QL for a single-string gas-lift well using Tables 3-20 and 3-21.

The tubing and production casing sizes of the gas lift well with a high production rate under the condition of tubing-casing annulus production (known as reverse lift, that is, gas injection into tubing and oil production from annulus) are selected and determined using the following recommended procedure:

1. On the basis of the possibly provided gas injection rate, gas injection pressure, and gas properties, the tubing with sufficiently small frictional pressure drop is selected.
2. A sensitivity analysis of production casing size is made and the optimum production casing size is selected and determined.

TABLE 3-18 Matching TRW Reda Pumps Electric Submersible Pump with Tubing and Production Casing

Model Number	Outside Diameter (mm)	Type of Pump	Maximum Power (kw)	Theoretical Discharge Capacity (t/d)	Casing Size Recommended (in.) Conventional Well	Gravel Pack Well
338	85.9	A—10	62	33~66	127 mm (5)	177.8 mm (7)
		A—14E	62	58~86		
		A—25E	62	90~140		
		A—30E	62	115~195		
		A—45E	79	160~240		
400	101.6	D—9	62	26~53	139.7 mm ($5^1/_2$)	177.8 mm (7)
		D—12	62	33~66		
		D—13	62	53~80		
		D—20E	62	75~115		
		D—26	78	106~146		
		D—40	78	125~240		
		D—51	78	180~260		
		D—55E	78	190~320		
		D—82	161	280~480		
450	117.35	E—35E	99	135~200	139.7 mm ($5^1/_2$)	177.8 mm (7)
		E—41E	99	140~235		
		E—100	161	380~560		
540	130.3	G—52E	161	210~310	177.8 mm (7)	244.5 mm ($9^5/_8$)
		G—62E	161	240~360		
		G—90E	161	320~480		
		G—110	224	420~600		
		G—160	224	580~840		
		G—180	224	660~960		
		G—225	224	636~1140		

TABLE 3-19 Advantages and Limitations of Gas Lift Production

Method	Advantages	Limitations
Gas lift	Low deep well investment cost and lift cost. Most effective for high gas-liquid ratio well. Low lift operation cost for sand production well. Easy to change production conditions, wide adaptive range. Adaptable to slant well and crooked well. Appropriate to high liquid production rate well. Convenient for production test.	Sufficient gas source adjacent to the oil field is required. High cost required by purchasing the gas lift gas. High lift cost when corrosive gas exists. Difficult to maintain low downhole liquid level when perforation interval is long. Unsafe high-pressure gas. Production casing is required to be able to bear pressure.

TABLE 3-20 Matching of Tubing with Production Casing for Single-String Gas-Lift Well

Minimum Liquid Production Rate (t/d)	Maximum Liquid Production Rate (t/d)	Tubing ID mm (OD in.)	Casing Size Recommended (in.)	
			Conventional Well	Gravel Pack Well
4~8	55	26.6(1.315)	5~5 $^1/_2$	7
8~12	96	35.1(1.660)	5~5 $^1/_2$	7
12~20	159	40.3(1.990)	5~5 $^1/_2$	7
31~40	397	50.3(2 $^3/_8$)	5 $^1/_2$	7
50~80	476	62.0(2 $^7/_8$)	5 $^1/_2$	7
30~120	636	75.9(3 $^1/_2$)	5 $^1/_2$	7
159~240	1590	100.5(4 $^1/_2$)	5 $^1/_2$~7	7

TABLE 3-21 Matching Tubing with Production Casing for Tubing-Casing Annulus Gas-Lift Well (Medium Production Rate)

Minimum Liquid Production Rate (t/d)	Maximum Liquid Production Rate (t/d)	Tubing Size (in.)	Production Casing Size (in.)
476	1270	2 $^3/_8$	5 $^1/_2$
795	2380	2 $^3/_8$	7.0
636	1900	2 $^7/_8$	7.0
500	1590	3 $^1/_2$	7.0

Case 15. On the basis of the given data in Case 5, the production technology of tubing-casing annulus gas lift is adopted. Try analyzing the optimum tubing and production casing sizes for the production rate of 3200 m^3/d under the gas lift production mode when the reservoir pressure is reduced to 13 MPa. In order to be convenient for transporting, the wellhead tubing pressure of 0.6 MPa is necessary. The maximum gas injection flow rate of 10×10^4 m^3/d can be provided and the gas injection pressure is 15 MPa.

Solving Process. Under the condition of tubing-casing annulus gas lift, the gas flow in tubing should be studied in order to determine the tubing size. If the tubing size is too small, the frictional resistance may be high due to the reverse direction of frictional resistance against the gas flow. However a tubing that is too large may increase the cost. The tubing sensitivity analysis is conducted and the gas injection point pressure vs. the inside diameter of the tubing curve is obtained (Figure 3-29). The 3 ½-in., 4-in., and 4 ½-in. ID tubings have close gas injection point pressures (that is, close frictional resistances). In consideration of decreasing the cost and because the gas injection rate of 10×10^4 m^3/d is not necessarily required, the 3 1/2-in. ID tubing is selected. The 3-in. ID tubing has a relatively large effect on gas injection point pressure; thus it is inappropriate.

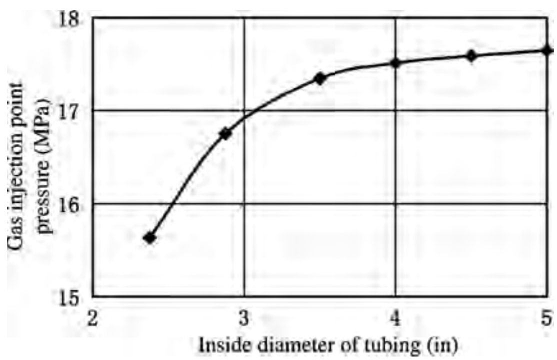

FIGURE 3-29 Frictional pressure drop analysis of tubing.

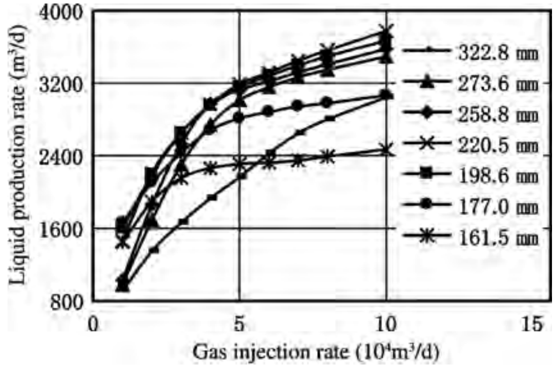

FIGURE 3-30 Effect of casing size on gas lift performance curve (the curves are obtained by calculating under various tubing IDs).

The casing size sensitivity analysis is conducted. Figure 3-30 shows that under the gas injection rate lower than $10 \times 10^4 m^3/d$, the 12.71-in., 6.97-in., and 6.36-in. ID casings cannot meet the production requirement due to the too large annulus of the former (high slippage loss) and the too small annulus of the latter two (high friction loss). The production casing size vs. gas injection rate curve is obtained by using the four casing sizes meeting the requirement and the corresponding gas injection rate under the liquid production rate of 3200 m^3/d (Figure 3-31). In order to achieve the required production rate of 3200 m^3/d, the production casing size of 9 ⅝ in. (222.4 mm ID) has the minimum necessary gas injection rate and the highest efficiency; thus, it is the optimum production casing size.

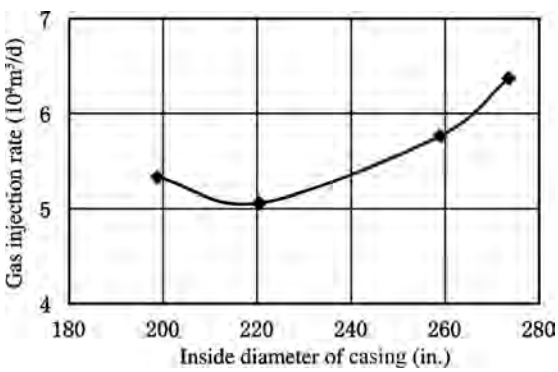

FIGURE 3-31 The casing size required by necessary production rate vs. gas injection rate.

Selection and Determination of Tubing and Production Casing Sizes for a Screw Pump Production Well

This type of pump is appropriate to the production well with crude oil viscosity lower than 2000 MPa · s, sand content lower than 5%, discharge head of 1400–1600 m, discharge capacity lower than 200 m^3/d, and working temperature lower than 120°C. With the increase of high-viscosity crude oil production and high-viscosity polymer gas production by tertiary recovery in recent years, oil production using a screw pump has been widely used. In the late 20th century, with the advance in synthetic rubber technology and vulcanizing binding technology, the screw pump has been greatly improved in France. At present, the screw pump has been adapted to the production of oil with viscosity lower than 15,000 MPa · s, sand content lower than 60%, and temperature not exceeding 120°C, and it has a discharge head up to 3000 m and discharge capacity up to 1050 m^3/d. A screw pump has a large discharge capacity and a slightly large outside diameter. The tubing and production casing sizes for a screw pump well can be determined by reference to Table 3-22 on the basis of the late liquid production rate (water cut of 95%) predicted by the development program.

Selection and Determination of Production Casing Size for Dual-String Production Well

Selection and Determination of Production Casing for Dual-String Gas Lift Well. The selection procedure of production casing size for a dual-string gas lift production well is as follows.

1. The daily liquid production rates Q_{L1} and Q_{L2} of upper and lower oil reservoirs are respectively predicted.
2. The tubing sizes corresponding to Q_{L1} and Q_{L2} are obtained using Table 3-20.
3. The recommended production casing size is obtained using Table 3-23 on the basis of the tubing sizes obtained.

TABLE 3-22 Relation between Theoretical Discharge Capacity and Maximum Outside Diameter of Screw Pump

Producing Area	Connecting Tubing [mm (in.)]	Theoretical Discharge Capacity (mm)	Maximum Outside Diameter of Pump (mm)	Adaptable Minimum Casing Diameter [mm (in.)]
China	60.3($2^3/_8$)	4~17	73	127(5)
	73.0($2^7/_8$)	32~180	90	139.7($5^1/_2$)
	88.0($3^1/_2$)	35~108	114	139.7~177.8($5^1/_2$~7)
	101.6(4)	64~500	114	139.7~177.8($5^1/_2$~7)
Other countries	60.3($2^3/_8$)	15~80	78	127(5)
	73.0($2^7/_8$)	60~240	94	139.7~($5^1/_2$)
	88.0($3^1/_2$)	120~300	108	139.7~177.8($5^1/_2$~7)
	101.6(4)	180~840	120	139.8(7)
	127.0(5)	430~1000	138	139.8(7)

TABLE 3-23 Matching of Tubing Size* with Production Casing Size* for Dual-String Gas-Lift Well

Upper-Reservoir (or Lower-Reservoir) Gas-Lift Tubing (1) Size (in.)	Upper-Reservoir (or Lower-Reservoir) Gas-Lift Tubing (2) Size (in.)	Minimum Casing Size Recommended (in.)
1.315	1.315~$2^7/_8$	$5^1/_2$
1.660	1.315~$2^7/_8$	$5^1/_2$
1.990	1.315~$2^7/_8$	$5^1/_2$~7
$2^3/_8$	1.315~$2^7/_8$	$5^1/_2$~7
$2^7/_8$	1.315~$2^7/_8$	$5^1/_2$~7
$3^1/_2$	1.315~$2^7/_8$	7~$9^5/_8$
$4^1/_2$	1.315~$2^7/_8$	7~$9^5/_8$
	1.315~$2^7/_8$	$9^5/_8$~$11^3/_4$
$3^1/_2$	$3^1/_2$	$9^5/_8$
$4^1/_2$	$3^1/_2$	$10^3/_4$

Note: If a large value is taken as the tubing (2) size, the casing size enlarged by one grade is taken.
*Tubing and casing sizes mean outside diameter.

Case 16. A certain oil well includes two oil reservoirs, that is, upper and lower oil reservoirs, and dual-string separate-zone production in a well under gas lift is designed. The daily liquid production rate Q_{L1} of 450 m^3/d for the upper reservoir and the daily liquid production rate Q_{L2} of 1000 m^3/d for the lower reservoir are predicted. Try selecting the production casing size.

Solving Process. Using Table 3-24, the tubing of Φ73 mm (2 ⅞ in.) with a collar of 89.5 mm OD is appropriate for the upper reservoir, while the Φ101.6 mm (4-in.) tubing with a collar of 121 mm OD is appropriate for the lower reservoir. The sum of the two collar ODs has reached 210.5 mm (8 ¼ in.). In consideration of the clearances between the tubings and between tubing and casing, in which the packer should be set, at least a Φ244.5 mm (9 ⅝-in.) production casing should be selected (see Table 3-24).

TABLE 3-24 Recommended Production Casing Size for Dual-String Production Well

Tubing Size Required by Upper (or Lower) Reservoir (in.)	Tubing Size Required by Lower (or Upper) Reservoir (in.)	Minimum Casing Size Recommended (in.)
1.315	1.315~$3\frac{1}{2}$	$5\frac{1}{2}$
1.315	1.315~$3\frac{1}{2}$	$5\frac{1}{2}$
1.990	1.315~$2\frac{7}{8}$	$5\frac{1}{2}$
$2\frac{3}{8}$	1.315~$2\frac{7}{8}$	$5\frac{1}{2}$~7[1]
$2\frac{3}{8}$	$3\frac{1}{2}$~4	7
$2\frac{7}{8}$	$1\frac{9}{32}$~$2\frac{7}{8}$	$5\frac{1}{2}$~7[1]
$2\frac{7}{8}$	$2\frac{3}{8}$~$2\frac{7}{8}$	7
$3\frac{1}{2}$	2~$2\frac{7}{8}$	7
$3\frac{1}{2}$	$3\frac{1}{2}$	$9\frac{5}{8}$
$4\frac{1}{2}$	$3\frac{9}{32}$~2	7
$4\frac{1}{2}$	$2\frac{3}{8}$~$3\frac{1}{2}$	$9\frac{5}{8}$
$4\frac{1}{2}$	$4\frac{1}{2}$	$10\frac{3}{4}$

[1]Tubing and casing sizes mean outside diameters.

Selection and Determination of Production Casing Size for Other Dual-String Production Well. For the oil well with great interzone difference, dual-string production can adjust the interzone contradiction. The production casing size for a dual-string production well is much larger than that of a single-string production well. The tubing size required by each zone is selected using the previously mentioned method, while the production casing size corresponding to a dual-string production well can be selected in accordance with Table 3-24.

Selection and Determination of Production Casing Size for Oil Production Well of Electric Submersible Pump with Y-Shaped Adapter. An electric submersible pump with a Y-shaped adapter can be used for oil wells (especially offshore oil wells) in which multizone production, production logging, through-tubing perforation, and coiled tubing operation will be conducted.

The production casing size under this condition can be selected in accordance with the thinking and method of selecting and determining production casing size for a dual-string production well (Table 3-24). At present, it is common that a tubing of 2 ⅞ in. and a bypath of 2 ⅜-2 ⅞ in. are run in the production casing of Φ244.5 mm (9 ⅝ in.).

3.6 EFFECTS OF STIMULATION ON TUBING AND PRODUCTION CASING SIZE SELECTION

Stimulation mainly includes hydraulic fracturing and acidizing and is used for both the measure of putting into production and the measure of blocking removal and increasing production rate. No special requirement for tubing size should be met during matrix acidizing due to the lower displacement. However, the hydraulic sand fracturing of the sandstone reservoir and the hydraulic sand fracturing and acid fracturing of the carbonatite reservoir (especially for deep wells and high breakdown pressure wells) may affect the selection of tubing and production casing sizes.

Hydraulic fracturing and acidizing are high-pressure high-displacement operations. The higher hydraulic friction resistance can be caused by a high pumping rate in the wellbore, thus leading to the excessive wellhead pressure and the unavailable power loss of the fracturing unit. Thus the reservoir cannot be fractured. The relationship among wellbore friction loss, wellhead pressure, and reservoir breakdown pressure is shown in Equation (3-20).

(3-20)

$$p_{wh} = \alpha H + \Delta p_f - 10^{-6}\rho g H + \Delta p_h$$

where p_{wh} = wellhead pressure during fracturing, MPa; α = reservoir breakdown pressure gradient, MPa/m; H = depth in middle of reservoir, m; Δp_f = fraction loss of fracturing fluid in wellbore, MPa; ρ = fracturing fluid density, kg/m^3; g = gravitational acceleration, m/s^2; Δp_h = total friction resistance of fracturing fluid through perforations, MPa.

It is shown that when the reservoir breakdown pressure αH is high (breakdown pressure gradient α is great or well is deep), p_{wh} can only be reduced by decreasing Δp_f and Δp_h. In general, Δp_f is much greater than Δp_h. Thus the key lies in decreasing the wellbore friction loss Δp_f.

The fracturing fluids used in the field include Newtonian and non-Newtonian fluids. The fracturing fluid of Newtonian fluid has the wellbore friction resistance pressure drop described in Equation (3-21):

(3-21)

$$\Delta p_f = f\,\frac{Hv^2}{2D_g}\times 10^{-2}$$

where f = friction resistance coefficient, dimensionless; H = well depth, m; D = inside diameter of tubing, m; v = fracturing fluid flow velocity in wellbore, m/s; Δp_f = friction resistance pressure drop, MPa; g = gravitational acceleration, m/s^2.

The relationship between the displacement Q and the flow velocity v during fracturing is shown in Equation (3-22).

(3-22)

$$v = \frac{Q}{15\pi D^2}$$

where Q = fracturing fluid pumping rate, m^3/min; D = inside diameter of tubing, m; V = fracturing fluid flow velocity, m/s.

By substituting Equation (3-22) into Equation (3-21), the formula in Equation (3-23) is obtained:

(3-23)

$$\Delta p_f = 2.29\times 10^{-7} f\,\frac{HQ^2}{D^5}$$

where Δp_f = friction resistance pressure drop, MPa; Q = fracturing fluid, m^3/min; D = inside diameter of tubing, m.

The other symbols are as explained earlier.

It is shown that the Δp_f is directly proportional to the well depth H and the square of the pumping rate and is inversely proportional to the fifth power of the tubing ID. The pumping rate of hydraulic fracturing is generally 2–6.0 m^3/min and will be up to about 6 m^3/min during the limited entry fracturing.

For low-permeability tight sand, the scale of hydraulic fracturing has been greatly increased and the massive hydraulic fracturing (MHF) technique has been developed. The hydraulic fluid volume is up to several thousand cubic meters, the proppant volume is up to several hundred to several thousand tons, and the fracture length is up to several hundred to several thousand meters. In the medium and late stage of the MHF operation, the fracture length has been great and the fluid loss into formation through the fracture wall face may be great. In order to continue to extend and spread the fracture, a high pumping rate is required. This can be explained using the formula in Equation (3-24):

(3-24)

$$Q \times \Delta t = V_w + \Delta V_F$$

where Q = fracturing fluid pumping rate, m^3/min; Δt = unit time, min; V_w = fluid loss into formation through fracture wall face per unit time, m^3; ΔV_F = fracture volume increment per unit time, m^3.

It is shown that in order to maintain the fracture volume increment ΔV_F per unit time as a positive value (that is, to increase continuously the fracture volume), a high pumping rate of fracturing fluid is necessary because the fluid loss into formation through the fracture wall face per unit time increases with the increase in fracture length. The fracture extension and spreading cannot be achieved by a fracturing fluid volume lower than the fluid loss. The massive hydraulic fracturing is a fracturing operation with a very high pumping rate, which is even higher than that of limited entry fracturing and up to 6–10 m^3/min.

The deep well and high pumping rate operation has a large wellbore friction resistance pressure

TABLE 3-25 Calculated Values of Friction Resistance Pressure Drop in Tubing During Fracturing and Wellhead Pressure

Tubing Size [ID mm (OD in.)]	Tubing Friction Loss (MPa) Pumping Rate $3\ m^3/min$	Tubing Friction Loss (MPa) Pumping Rate $6\ m^3/min$	Wellhead Pressure (MPa) Pumping Rate $3\ m^3/min$	Wellhead Pressure (MPa) Pumping Rate $6\ m^3/min$
50.3($2^3/_8$)	107.99	430.81	152.95	475.77
62.0($2^7/_8$)	33.48	133.37	78.44	178.33
75.9($3^1/_2$)	12.89	51.26	57.85	96.22
88.6(4)	5.76	22.87	50.72	67.83
100.3($4^1/_2$)	2.87	11.38	47.84	56.34
114.1(5)	1.56	6.16	46.52	51.11

Note: Clear water viscosity is 1 MPa · s. Well depth H = 4000 m. Breakdown pressure $p_f = 92$ MPa. Relative density of fracturing fluid is 1.2.

drop Δp_f . The methods of reducing friction resistance pressure drop include the method of reducing effective viscosity of fracturing fluid or adding a friction-reducing agent into fracturing fluid (which can only reduce friction resistance to 40% to 60% of clear water friction resistance) and the method of increasing tubing size, which is the most effective. This can be shown in Table 3-25 on the basis of Equation (3-23).

Table 3-25 indicates that the reservoir cannot be fractured by using the tubing of 50.7 mm ID (2 ⅜ in.) and 1000-type fracturing unit under the pumping rate of 3 m^3/min. However, the reservoir has begun to be fractured by using a tubing of slightly larger ID to 62.0 mm ID (2 ⅞ in.) and the wellhead pressure of 78.44 MPa. The reservoir can be easily fractured when the tubing ID increases and is above 75.9 mm (3 ½ in.). Under the pumping rate of 6 m^3/min, the reservoir cannot be fractured by using a tubing of smaller ID than 75.9 mm (3 ½ in.). However, the reservoir can be easily fractured when the tubing ID is above 88.6 mm (4 in.).

Figures 3-32 and 3-33 show the pumping rate vs. friction loss relationships obtained by Halliburton under various tubing and casing IDs.

When a non-Newtonian fluid is used as fracturing fluid or acidizing fluid, the relation between shear stress and shear rate can be considered as a power law model:

$$\tau = K'\gamma^{n'}$$

where τ = shear stress; γ = shear rate; K' = liquid consistency coefficient; n' = liquid flow regime index.

K' and n' are determined by experiment. The friction loss can still be calculated using the one-way resistance pressure drop and Equation (3-21). The friction resistance coefficient is also obtained by experiment and is related to the Reynolds number and n' values. It should be indicated that the water-base gel fracturing fluid used presently is basically a viscoelastic fluid, so the actual situation cannot be accurately reflected by calculation in accordance with the power-law model. The friction resistance pressure drop value is obtained by using the instant pumping off in the fracturing operation. The value obtained is compared with the clear water friction resistance pressure drop value and the percentage is obtained. The water-base plant gel fracturing fluid friction loss in tubing is generally lower than the friction loss of clear water and is related to fracturing fluid, material, formulation, and shear rate. The water-base plant gel fracturing fluid friction loss is generally about 60% of clear water fracturing fluid friction loss. The friction resistance pressure drop of hydroxypropylguar (HPG) gum titanium gel fracturing fluid has been lower than 45% of that of clear water under some conditions. Because the long-chain linear molecules may restrain the turbulence of water and reduce the friction resistance, the high molecular polymer can reduce the friction resistance pressure drop. However, it should still be

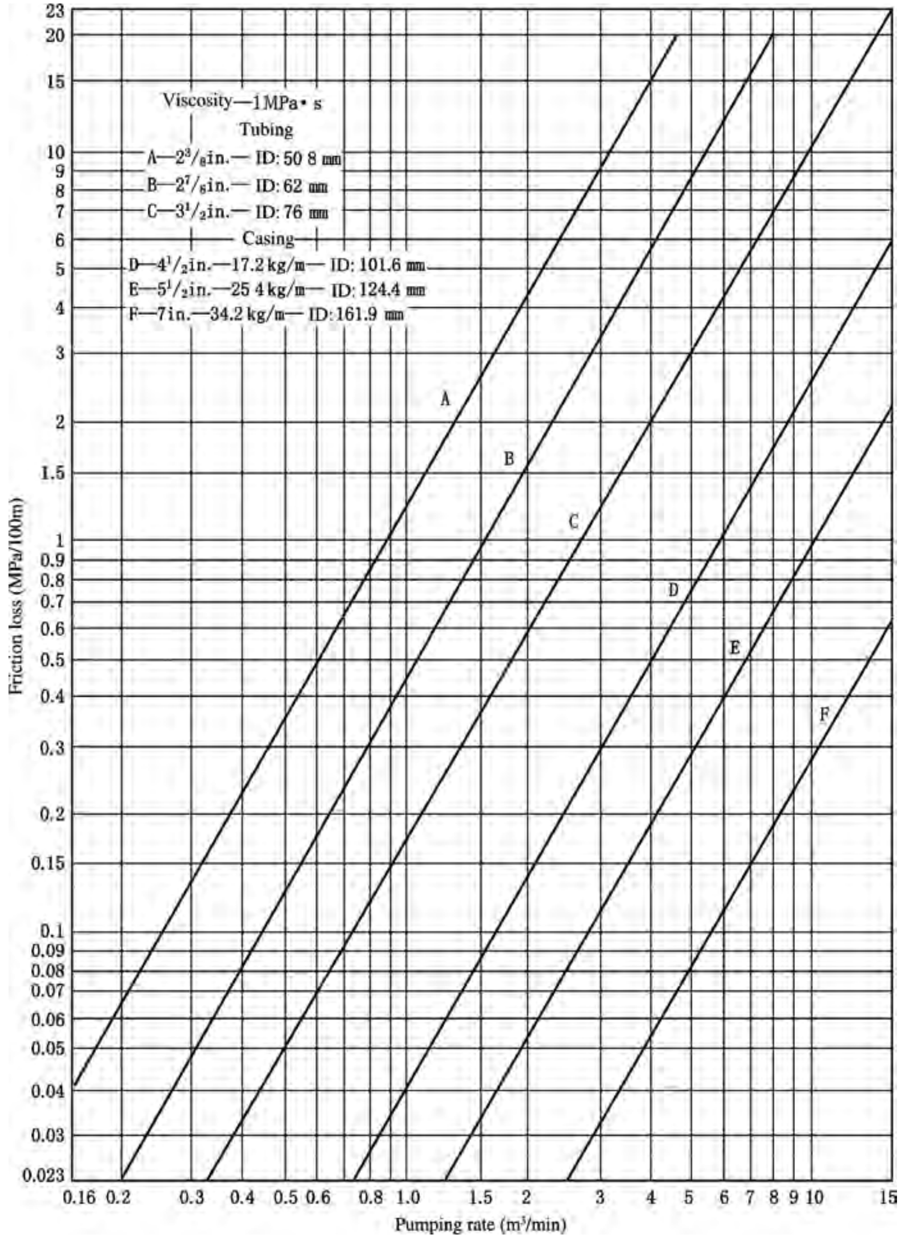

FIGURE 3-32 Friction loss vs. pumping rate for clear water fracturing fluid.

indicated that the friction loss sensitivity is greatly affected by the tubing size. For instance, during hydraulic fracturing in a certain area a small tubing of 2 ⅞ in. was first used, the friction resistance pressure drop exceeded 30 MPa under the pumping rate of 2 m^3/min and the tubing length of 3000 m, the operating wellhead pressure exceeded 70 MPa, and the reservoir could not be fractured under a high breakdown pressure. When the tubing size was changed to 3 ½ in., the operating wellhead pressure was reduced to about 50 MPa and the reservoir could be fractured. Under the

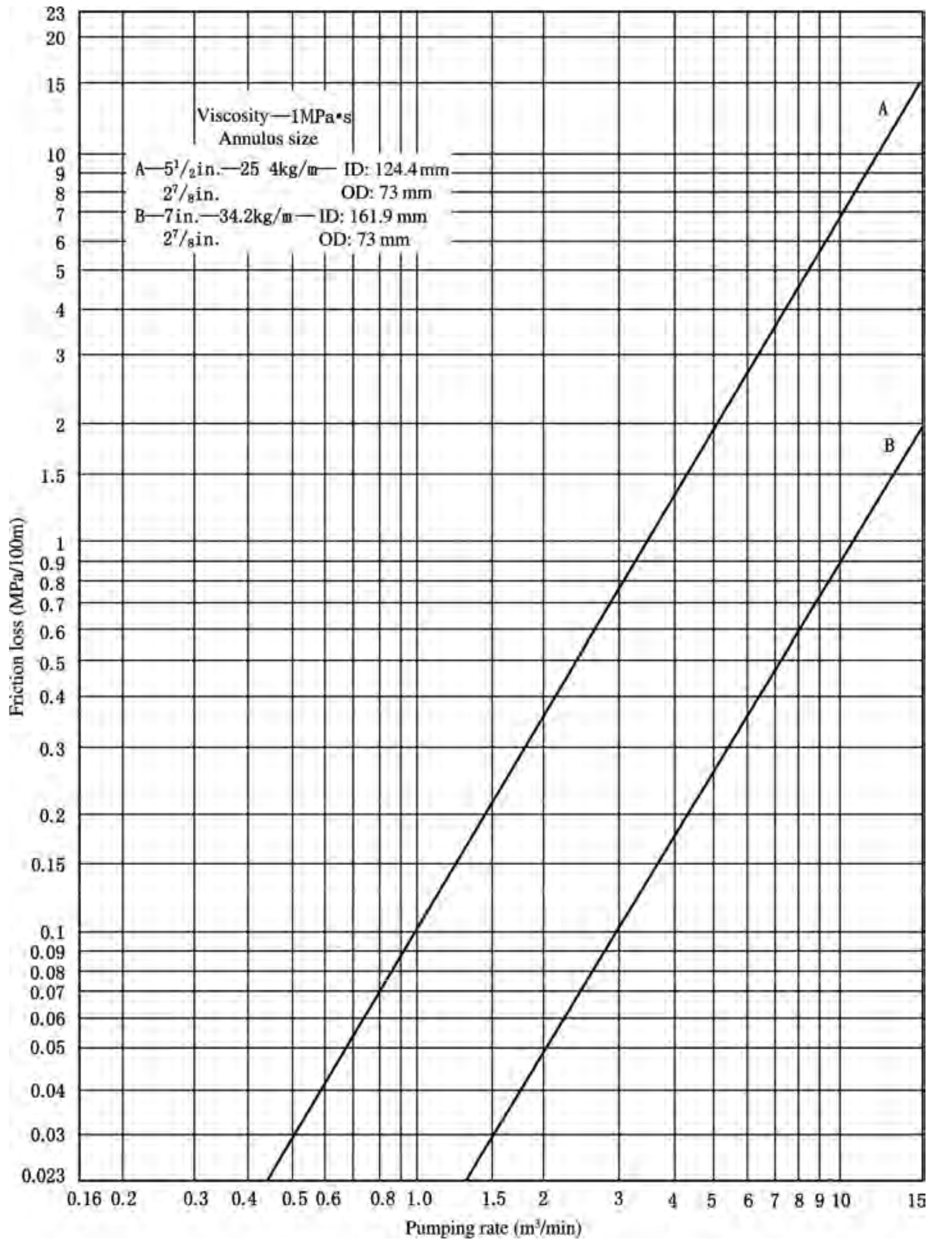

FIGURE 3-33 Friction loss vs. pumping rate for fracturing fluid.

aforementioned conditions, the clear water friction resistance pressure drop is 46.5 MPa (Figure 3-32) and the friction resistance pressure drop of fracturing fluid is 63.5% of that of clear water. Despite the fact that the friction-reducing effect of polymer has been achieved, the friction resistance pressure drop value is still high. When the tubing size is increased from 2 ⅞ in. to 3 ½ in., the friction resistance pressure drop of clear water is changed into only 17.6 MPa, that is, 40% of that of 2 ⅞-in.

tubing. When the friction-reducing effect of fracturing fluid is also considered, the pumping rate is possibly increased (for example, to 3 m^3/min), the friction resistance pressure drop is only 35 MPa, and the wellhead pressure can be decreased to a value below 54 MPa, thus improving the fracturing operation condition.

With the increase in tubing size, the friction resistance pressure drop in tubing decreases rapidly. Therefore, for a high breakdown pressure well or deep well, a relatively large tubing size and corresponding large production casing size should be designed.

The tubing friction resistance pressure drop and the operating wellhead pressure are predicted under the different tubing sizes on the basis of reservoir breakdown pressure gradient and well depth in accordance with Equation (3-20) and Equation (3-21) or Figures 3-32 and 3-33. The minimum tubing size can be selected by the criterion of operating wellhead pressure $\leq$80% $\times$ working pressure of the fracturing unit. The corresponding minimum production casing size is selected in accordance with the matching relation between tubing and production casing sizes, as shown in Table 3-4. On this basis, by reference to the preselected tubing and production casing sizes for the artificial lift well, appropriate tubing and production casing sizes are selected and determined.

3.7 SELECTION AND DETERMINATION OF TUBING AND PRODUCTION CASING SIZES FOR HEAVY OIL AND HIGH POUR-POINT OIL PRODUCTION WELLS

Heavy oil is asphalt-based crude oil and has low or no flowability due to the high content of colloid and asphaltene and the high viscosity. The heavy oil viscosity is sensitive to change in temperature (Figure 3-34). With the increase in temperature the heavy oil viscosity may rapidly decrease and vice versa. This inherent feature of heavy oil makes the recovery methods

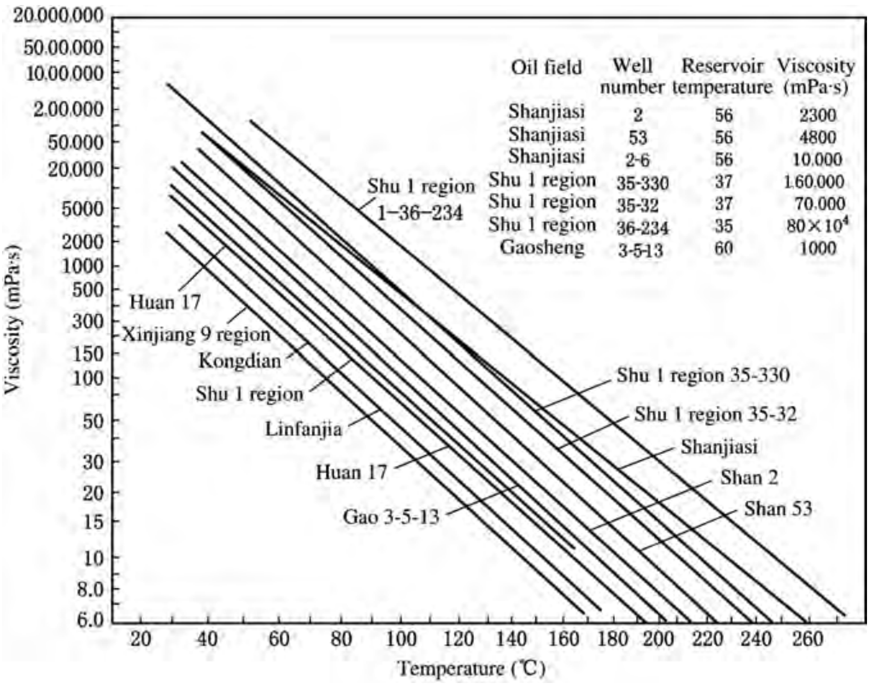

FIGURE 3-34 Heavy oil viscosity vs. temperature.

different from that of conventional light oil and makes the recovery process complicated. At present in China the ordinary heavy oil with a viscosity lower than 150 MPa · s under reservoir conditions is recovered by waterflooding, while the ordinary and extra-heavy oils with a viscosity higher than 150 MPa · s are recovered by steam injection.

Heavy Oil Recovery by Waterflooding

The heavy oil with a viscosity lower than 150 MPa · s under reservoir conditions is commonly recovered by waterflooding because this heavy oil generally contains a higher dissolved-gas content and has a certain flowability under reservoir conditions, despite the fact that the surface crude oil viscosity may be up to several thousand millipoises. The features of waterflooding include mature technique, simple technology, relatively low investment, and good economic benefit. Therefore, waterflooding is the first selected recovery method. For instance, the conventional waterflooding has been adopted in the Gudao, Gudong, Chengdong, and Shengtuo oil fields of the Shengli oil region and the Jing 99 block, Niuxintuo, and Haiwaihe oil fields of the Liaohe oil region, and good development results have been achieved through continuous adjustment.

Flowing Production. The flowability of heavy oil is low due to the high intermolecular friction resistances of colloid and asphaltene. The friction head loss of fluid flow in tubing can be calculated using the hydraulics formula in Equation (3-25):

(3-25)

$$H_f = f\,\frac{L}{D}\cdot\frac{v^2}{2g}$$

where H_f = friction head loss, m; f = friction resistance coefficient, dimensionless; L = tubing setting depth, m; D = tubing diameter, m; v = liquid flow velocity, m/s.

The friction head loss vs. tubing setting depth relationships under a certain heavy oil viscosity and the different tubing diameters are calculated using Equation (3-25) and are shown in Figure 3-35.

It is well known that the higher the crude oil viscosity, the greater the friction head loss. As shown in Figure 3-35(a), under the same crude oil viscosity, the friction head loss increases with the increase of fluid flow velocity in

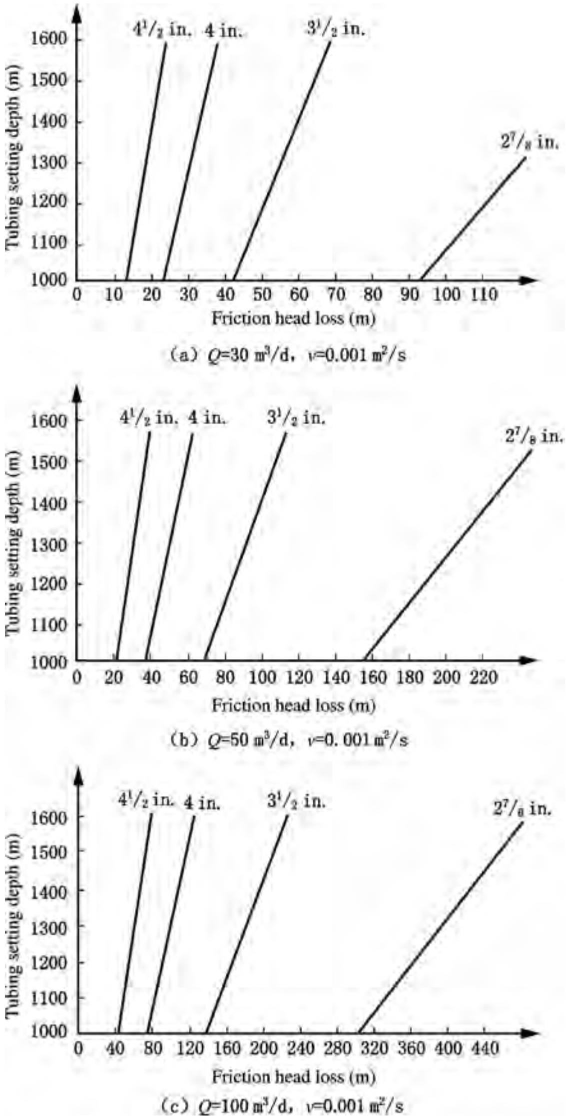

FIGURE 3-35 Effect of tubing diameter on friction head loss.

tubing and decreases with the increase of tubing diameter. For heavy oil with high viscosity, tubing with a relatively large diameter should be adopted in order to maintain flowing production, and the corresponding production casing with a larger diameter should also be selected.

Oil Production by Pumping Unit and Deep Well Pump. Because of the limitations of traditional ideas, small size tubing was set in most heavy oil wells in the early development period. On the downstroke of the sucker rod, the dropping velocity of the sucker rod is reduced by the great friction resistance of heavy oil to the sucker rod, and the movement of the sucker rod lags behind the movement of the hanging point of the horsehead. When the hanging point is rising, the sucker rod is still dropping. Not only the normal movement of sucker rod may be affected, but also the impact of the horsehead on the sucker rod may be caused. Thus the impact load may be generated, the service life is reduced, and even mechanical failure may result (see Figure 3-36).

In view of this, when the pumping unit and deep well pump are used for producing heavy oil, the upstroke friction resistance and the downstroke resistance should first be reduced. The friction resistance of the wellbore liquid column to the sucker rod can be calculated using the formula shown in Equation (3-26):

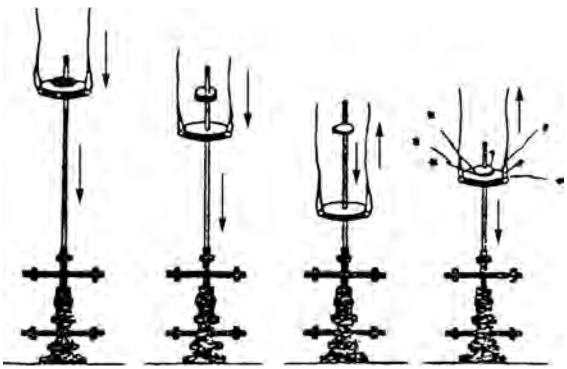

FIGURE 3-36 Crude oil viscosity effect during heavy oil pumping (sucker rod flotation).

(3-26)

$$F_r = \frac{2\pi\mu L v}{10^3}\left(\frac{1}{\ln m} + \frac{4b^2}{a} + \frac{4b}{a}\right)$$

$$v = \frac{S_n}{30}$$

$$m = \frac{d_t}{d_r}$$

$$a = m^4 - 1 - \frac{(m^2-1)^2}{\ln m}$$

$$b = \frac{m^2 - 1}{2\ln m} - 1$$

where F_r = friction resistance of wellbore liquid column to sucker rod, N; μ = liquid viscosity, MPa · s; L = pump setting depth, m; v = sucker rod movement velocity, m/s; S = length of stroke, m; n = strokes per minute, $\min^{-1}$; d_t = tubing diameter, m; d_r = sucker rod diameter, m.

It is shown that the friction resistance is related to the wellbore liquid viscosity, flow velocity, and tubing diameter. The friction resistance curves under the different tubing diameters and the different crude oil viscosities (Figure 3-37) indicate that the friction resistance increases with the increase in viscosity and the decrease in tubing diameter. Therefore, the large-diameter tubing of 101.6–114.3 (3 ½-4 ½ in.) should be used in order to reduce the friction resistance and reduce the sucker rod flotation and impact on the horsehead.

When heavy oil is produced by large-diameter tubing and pumps, the friction resistance and sucker rod flotation can be reduced, and the pump stroke efficiency and pumping rate can be increased. Under the conventional waterflooding of heavy oil, the oil-water viscosity ratio is high, the early water breakthrough occurs, the water cut rapidly increases, most oil should be produced in the high water cut period, the water-free recovery factor is only 2% to 5%, and the yearly average water cut increases by about 3%. When the water cut is higher than 50%, the liquid production rate should be increased by 2 to 20 times in order to maintain a stable oil production rate (see Table 3-26).

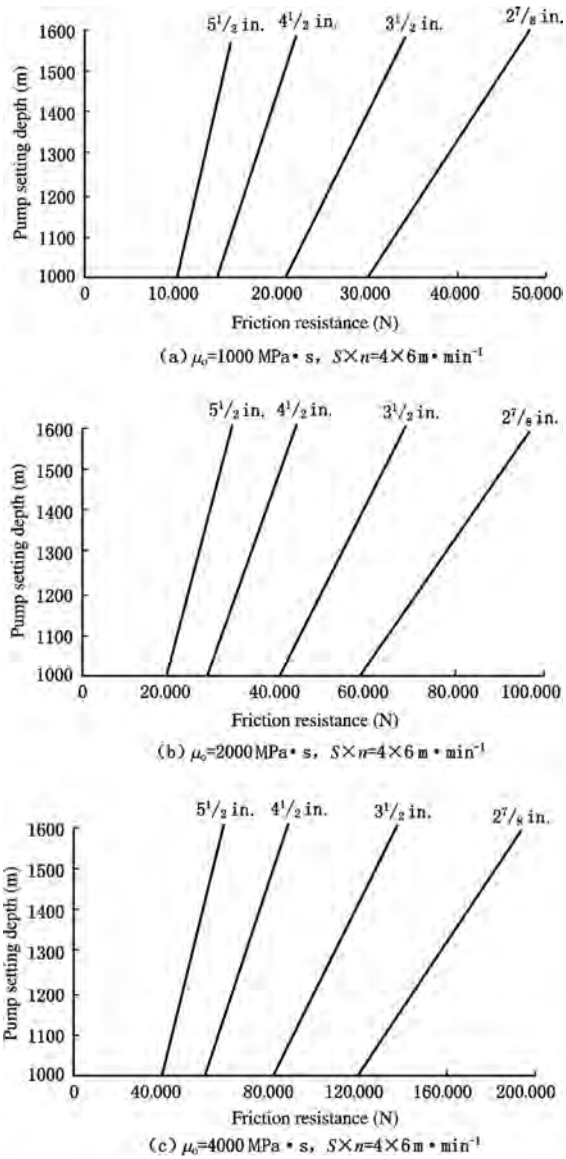

FIGURE 3-37 Effects of tubing diameter on friction resistance of liquid to sucker rod.

Therefore, in order to increase the liquid production rate and maintain a stable oil production rate, the tubing diameter should also be increased.

In the Gudao oil field of the Shengli oil region, the surface stock tank oil viscosity is 250–5700 MPa · s, the reservoir oil viscosity is 20–130 MPa · s, and the oil-water viscosity ratio is 80–350. This oil field was put into production in 1973 and started waterflooding in April 1974. The water cut increased rapidly due to the high oil viscosity, and a large amount of crude oil would be produced in the high water cut period. In order to maintain a stable oil production rate and increase the liquid production rate, the original pumps of Φ43–56 mm have been changed into pumps of Φ70 mm and Φ83 mm. When pumps of Φ43–56 mm were used, the individual-well daily oil production rate was 20 t/d, and the tubing diameter of 2 ⅞ in. could meet the requirement. When the water cut increases to 80%, the liquid production rate of 100 t/d is required by retaining the stable oil production rate. Thus the oil well pumps of Φ70 mm and Φ83 mm are required, the corresponding tubing diameter should be above 3 ½ in., and the relatively large production casing diameter should be selected in the well completion design.

Heavy Oil Recovery by Steam Injection

Huff and Puff. Huff and puff is a commonly used method of producing heavy oil. In China most heavy oil is produced using huff and puff. At the steam injection stage, the injected steam heats the reservoir, the crude oil viscosity is decreased, and the flowability of crude oil is increased. When a well is put on, the heated crude oil flows into the well under the effects

TABLE 3-26 Water Cut vs. Liquid Production Rate

Water cut (%)	0	10	20	30	40	50	60	70	80	90	95
Liquid production rate (t/d)	15.0	16.6	18.8	21.4	25.0	30.0	37.5	50.0	75.0	150	300

of elastic energy and gravity. In the wellbore, with the flow of crude oil toward the wellhead, the fluid temperature gradually decreases due to heat conduction, and the oil viscosity gradually increases. Therefore, both the oil pumping condition during production and the wellbore heat loss condition during steam injection should be considered in the huff and puff well tubing string design.

The heat-insulated tubing string should be set in the well in order to decrease wellbore heat loss and improve steam quality at the steam injection stage. This string consists of tubing, insulating layer, and outside pipe. The different string sizes have different overall heat transfer coefficients, and the insulating layer thickness and annulus size will play important roles. The overall heat transfer coefficients for different sizes of wellbore string configuration (Table 3-27) indicate that the small heat-insulated string has great overall heat transfer coefficient and great wellbore heat loss. In the production casing of 7 in., the insulating effectiveness of the heat-insulated string of 2 ⅜ in. × 4 in. is higher than that of the heat-insulated string of 2 ⅞ in. × 4 in. due to the larger insulating layer thickness. However, the mechanical strength (in a deep well) and safety load of the former are lower than that of the latter. Moreover, the low bottomhole steam pressure and high wellbore steam pressure are caused by the former due to the high flow velocity, high friction resistance, and great wellbore pressure drop of the small tubing size (Figure 3-38). Therefore,

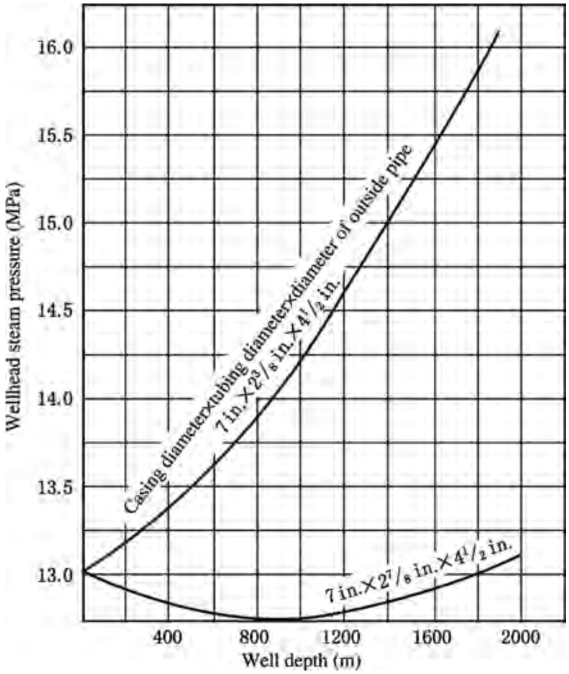

FIGURE 3-38 Wellhead steam pressure under different tubing sizes.

on the premise of ensuring good insulating effectiveness, a larger diameter string should be used to the full extent for steam injection and later pumping.

The liquid production rate of huff and puff is high. The condensate water of injected steam should be rapidly produced, and the crude oil should be produced as much as possible, thus the huff and puff production effectiveness may

TABLE 3-27 Overall Heat Transfer Coefficient U_∞ [W/(M² · K)] under Different Sizes of Wellbore String Configuration

No.	Sizes of Wellbore String Configuration (in.)	Insulating Layer Thickness (mm)	Annulus Clearance (mm)	Steam Injection Temperature (°C)		
				250	300	350
1	$7\times2^3/_8\times4$	17	28.7	1.91	2.52	2.67
2	$7\times2^7/_8\times4$	10.5	28.7	4.13	4.48	4.78
3	$7\times2^7/_8\times4^1/_2$	16	22.5	3.58	3.79	4.02
4	$5^1/_2\times2^3/_8\times3^1/_2$	10.4	17.7	4.18	4.85	5.41
5	$5^1/_2\times2^3/_8\times4$	16.8	11.1	3.99	4.01	4.33

be increased. As a result, the tubing size should meet the requirement of the liquid production rate. If a small size tubing is used, the fluid flow velocity may be very high under a high production rate. Under the same tubing size, with the increase in flow rate or (stroke × strokes per minute) value, the friction resistance of liquid to sucker rod will increase (Figure 3-39), and the friction resistance will increase with the increase in oil viscosity (Figure 3-40). Thus the problems (including sucker rod flotation, impact of the horsehead on the sucker rod, and decrease in stroke efficiency) that may be generated under the conventional water-flooding of heavy oil will occur.

In order to reduce friction resistance during the movement of the sucker rod in the tubing liquid, a larger diameter tubing should be selected. For instance, when the liquid viscosity is 1000 MPa · s, and the working parameter S × n is 3.3 m × 6 min^{-1}, the friction resistance of 2 ⅞-in. tubing is 1.4 times that of 3 ½-in. tubing and 2.2 times that of 4 ½-in. tubing (Table 3-28). Obviously, the friction resistance can be effectively reduced by using the tubing of 3 ½ to 4 ½ in. Correspondingly, a larger production casing should be adopted.

It is shown that a large diameter string is required by the huff and puff during both the

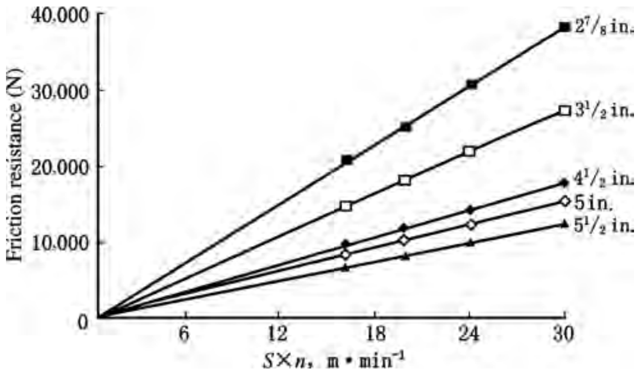

FIGURE 3-39 Flow velocity vs. friction resistance to sucker rod under different tubing sizes.

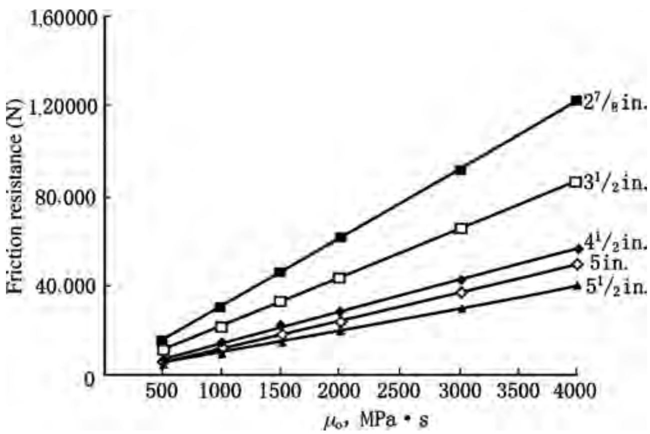

FIGURE 3-40 Oil viscosity vs. friction resistance to sucker rod under different tubing sizes.

TABLE 3-28 Friction Resistances to Sucker Rod under Different Tubing Sizes and Different S × n Values

Tubing Diameter (in)		$2^7/_8$	$3^1/_2$	$4^1/_2$	$5^1/_2$
Friction resistance under different S×n value (N)	$2.7\times6\cdot\text{min}^{-1}$	20,500	14,500	9500	6600
	$3.3\times6\cdot\text{min}^{-1}$	25,000	17,800	11,600	8100
	$4.0\times6\cdot\text{min}^{-1}$	30,400	21,600	14,000	9800
	$5.0\times6\cdot\text{min}^{-1}$	38,000	27,000	17,600	12,300

Note: The results are obtained by calculating under viscosity of 1000 MPa · s and sucker rod diameter of 25 mm.

steam injection and the liquid production in order to increase the production effectiveness of the huff and puff.

Heavy Oil Recovery by Steam-Flooding. Steam-flooding is an important method of heavy oil recovery. When heavy oil is produced by huff and puff to some extent, with the decrease in reservoir pressure and the increase in water saturation, the effectiveness will decrease gradually. In order to further enhance the crude oil recovery factor, the huff and puff should be substituted by steam-flooding. Laboratory studies and field practice indicate that the liquid productivity of the production well will greatly affect the recovery effectiveness of steam-flooding, and the liquid production rate should be higher than the steam injection rate; that is, the production-injection ratio should be up to 1.2–2.0 in order to achieve good recovery effectiveness. For instance, in the steam-flooding pilot test area of the Du 66 block of the Shuguang oil field in the Liaohe oil region, the optimized steam injection rate is 135 t/d. Under this steam injection rate, the steam-flooding production effectiveness of the different liquid production rates of the production well indicate that when the liquid production rate of the production well is lower than or equal to the steam injection rate, that is, the production-injection ratio is lower than or equal to 1, the production effectiveness of steam-flooding is low (the oil-steam ratio and recovery factor are low); when the liquid production rate of the production well is higher than the steam injection rate, that is, the production-injection ratio is higher than 1, the production effectiveness of steam-flooding is improved (Table 3-29).

The Tangleflags oil field in Canada has stock tank oil viscosity of 13,000 MPa · s, reservoir thickness of 27 m, and reservoir depth of 450 m. The combined steam-flooding tests of vertical and horizontal wells were conducted by Sceptre in 1988 and met with success. The main experience and practice include:

TABLE 3-29 Effects of Liquid Production Rate of Production Well on Steam-Flooding Effectiveness

Liquid Production Rate (t/d)	Production Time (d)	Cumulative Steam Injection (t)	Cumulative Oil Production (t)	Average Oil Production Rate (t/d)	Oil-Steam Ratio	Recovery Factor (%)	Production-Injection Ratio	Net Oil Production Increment (t)
80	126	17,010	2410	19.1	0.142	4.1	0.59	992
100	147	19,845	2860	19.5	0.144	4.8	0.74	1206
120	218	29,430	3870	17.8	0.132	6.5	0.89	1417
140	304	41,040	5190	17.1	0.126	8.7	1.04	1770
160	1341	1,81,035	23,050	17.2	0.127	38.8	1.18	7963
180	788	1,06,380	16,390	20.8	0.154	27.6	1.33	7525
200	751	1,01,385	16,010	21.3	0.158	26.8	1.48	7561
220	706	95,310	15,150	21.5	0.159	25.5	1.63	7207

1. The productivity of the oil reservoir should be fully understood. The drainage radius predicted initially by numerical simulation in this region is 50 m. The practical production data indicate that the drainage radius should be up to 80 m. The predicted maximum liquid production rate is 650 m^3/d, while the actual liquid production rate has been up to 1200 m^3/d. Due to the initial underestimation of the liquid production rate, a pump of 3 ¾ in., which was initially set, has been inappropriate for production and was changed later from 4 ¾ in. through 5 ¾ in. to 7 ¾ in. The corresponding liquid production rate was also increased. Be that as it may, the high production period was missed. Later a pump of 7 ¾ in. was used. The tubing diameter is 7 ⅝ in. and the production casing diameter is 10 ¾ in. (Figure 3-41). During oil pumping, slow downstroke movement and quick upstroke movement are adopted in order to increase the fullness coefficient. The actual liquid production rate is up to 1200 m^3/d and the daily oil production rate is 480 m^3/d under the water cut of 60%. If the maximum liquid production rate had initially been predicted accurately, the effectiveness would be better.
2. The period after steam breakthrough is an important production period. Before steam breakthrough the production rate of a production well is relatively low. Only after steam breakthrough can the liquid production rate be increased and most of the crude oil will be produced in the period with a water cut of up to 60% to 80%. In this period a sufficiently high liquid production rate of the production well and a production-injection ratio higher than 2 should be ensured. Thus a sufficiently large string and the matching large diameter production casing should be set in a production well.

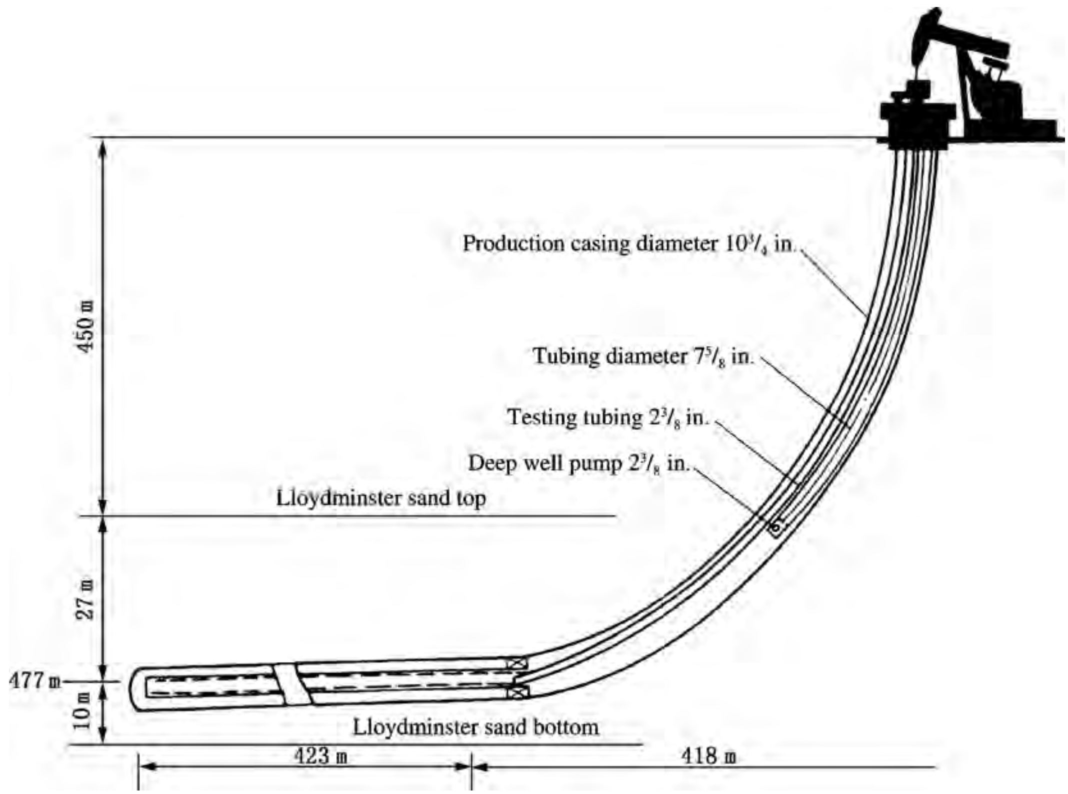

FIGURE 3-41 Typical production well completion in Tangleflags oil field.

High Pour-Point Crude Production

High pour-point crude is a paraffin-based crude oil and has a high pour point and low viscosity. Crude oil viscosity is highly sensitive to the change in temperature (Figure 3-42). When the temperature is higher than the pour point, the crude oil is a Newtonian fluid and the viscosity can be reduced to several to several dozen MPa · s. However, when the temperature is lower than the wax precipitation point, the fluid configuration may change and become non-Newtonian. The crude oil viscosity is not only related to temperature, but to shear rate. The flow performance reduces obviously with the decrease in temperature. Therefore, when the temperature is higher than the pour point of oil, the oil viscosity is low, the flowability is good, and the oil flows easily from reservoir to bottomhole. However, when the crude oil flows from bottomhole to wellhead, with the decrease in temperature, the wax precipitates from the crude oil. When the temperature is lower than the wax precipitation point, the crude oil viscosity increases, the flowability decreases, and even the crude oil cannot flow due to the

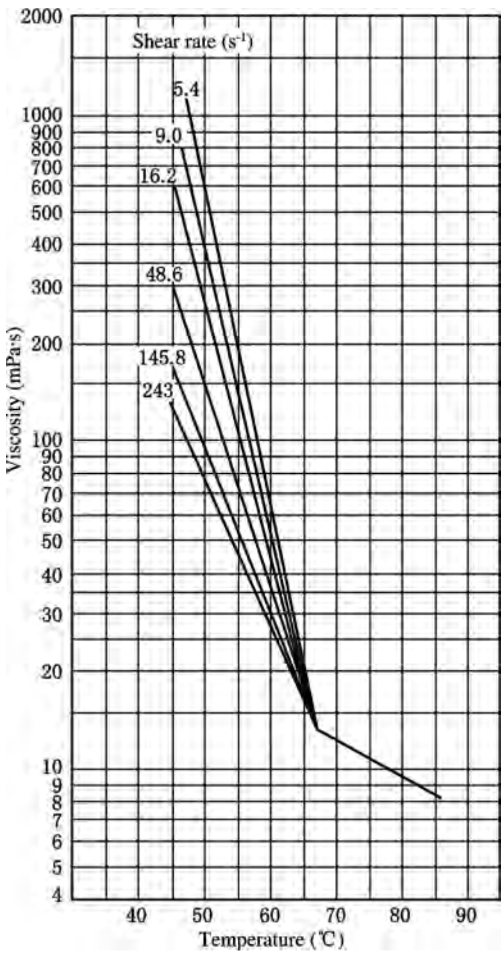

FIGURE 3-42 Rheological curves of high pour-point crude of Shenbei oil field in Liaohe oil region.

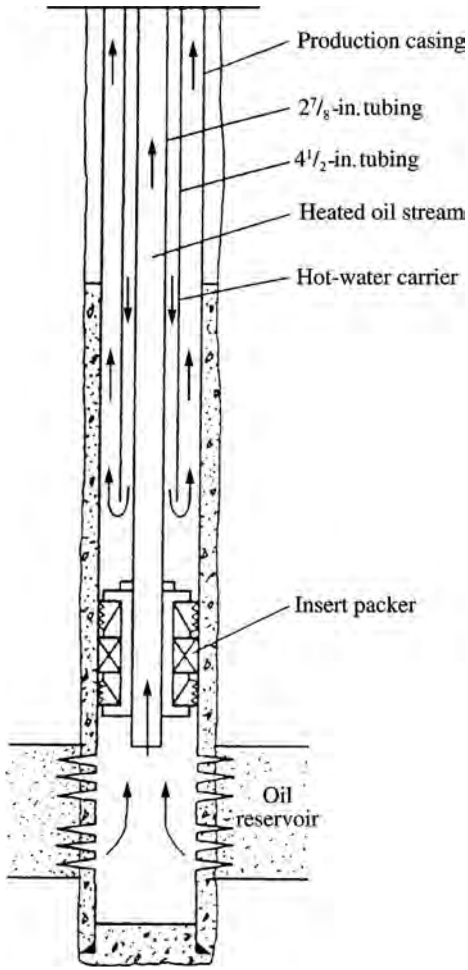

FIGURE 3-43 Concentric string hot-water circulation production.

solidification of wax. Thus the key to high pour-point oil production lies in keeping a higher oil temperature than the pour point. The crude oil flow in the near-wellbore zone and in the wellbore should be ensured and the precipitation of wax should be prevented.

At present, the following approaches can be taken in order to ensure the normal production of high pour-point crude:

1. Self-controlled electric heating cable
2. Hollow sucker rod (electric heating and hot-water circulation)
3. Hydraulic piston pump
4. Electric submersible pump
5. Concentric string hot-water circulation (Figure 3-43)

The former four selections are mainly dependent on the liquid production rate and the technological conditions, and no special requirement for production casing size. In the fifth selection, the concentric tubing string configuration requires that the outer tubing should be larger than the inner tubing. In general, the outer tubing of 4 ½ in. and the inner tubing of 2 ⅞ in. are set in the production casing of 7 in., thus forming a hot-water circulation path.

As mentioned earlier, the selection of tubing and production casing sizes may be affected by natural gas wells, flowing wells, artificial lift wells, stimulation, heavy oil, or high pour-point oil production. Therefore, these aspects should be considered when rational tubing and production casing sizes are determined.

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