Determination of the Transportation Limits of Heavy Crude Oil Using Three Combined Methods of Heating, Water Blending, and Dilution

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ABSTRACT: Conventional methods for pipeline transportation of heavy or extraheavy crude oils adopt heating, water blending, and dilution, and several methods are generally required to be used simultaneously to ensure normal transportation. However, how to determine the optimal transport boundary conditions for heavy oils is still one of the technical challenges. In this paper, the circulating piping experiment at different water contents (0−90 wt % with an interval of 10 wt %) and temperatures (65−90 °C with an interval of 5 °C) of three heavy oils from the Xinjiang oilfield is carried out. The apparent viscosity calculated from the experimental data of the circulating pipeline shows that when the water content is below the phase inversion point, the apparent viscosity increases and when the water content is close to the phase inversion point, the apparent viscosity increases nearly three times. Only when the water content is greater than the phase inversion point, the apparent viscosity shows a downward trend. Also, then, various viscosity prediction models with different independent variables, which mainly included temperature, water content, and dilution ratio, are selected and verified. Based on experimental data of six crude oils, a prediction model of the phase inversion point is established. Simultaneously, a method for determining the boundary conditions of heavy oils using the combined methods of heating, water blending, and dilution is proposed, while a set of simple decision diagrams of boundary conditions for heavy oil is also described. Finally, verified by the heavy oil pipeline of the Bohai LvDa oilfield, the gathering and transportation limits determined by this method are consistent with the operating parameters of the oilfield.

1. INTRODUCTION

With the consumption of conventional petroleum resources on the planet, to increase production capacity, unconventional oil resources, including heavy or extraheavy crude oil, have gradually attracted the attention of producers. Nevertheless, unconventional oil resource exploitation still faces many technical problems, such as how to economically and rationally transport heavy crude oil. As an unconventional crude oil resource, heavy crude oil accounts for the great mass of the world’s potentially recoverable crude oil reserves. However, the poor fluidity of heavy oil makes it difficult to economically extract, transport, and refine. Clearly, the efficiency of determination of the transportation limits is crucial to achieve heavy oil resource exploitation.

To achieve economic exploitation of heavy crude oil resources, many methods of viscosity reduction and drag reduction are commonly employed, which typically include heating, water blending, dilution, core annular flow, and lubricated transportation. However, the selection of the appropriate method and operating conditions for heavy oil transportation requires a comprehensive understanding of the viscosity characteristics of heavy oils, as well as the limits on the stability of these systems. Moreover, the viscosity of the mixing oil may be disturbed by many factors including temperature, dilution ratio, and water content. For these reasons, it is necessary to predict operating conditions to provide better conditions for heavy oil flow, yielding a significant improvement in the safety of pipeline flow while minimizing operating expenses.

As the temperature rises, the viscosity of heavy crude oil drops sharply. When the temperature reaches a certain value, the range of viscosity changes with temperature is very small. However, as the temperature of crude oil transportation increases, the energy consumption required to heat the crude oil rises sharply, eventually resulting in uneconomical transportation. Therefore,
accurately determining the optimal operating temperature is the key point to reduce the viscosity of heavy crude oil. Several mathematical viscosity prediction models at different temperatures have been established (as shown in Table 1), which are mainly based on the American Petroleum Institute (API) gravity, for different oil systems.9–13

Moreover, heavy oil blending with light oil has a good viscosity reduction effect and is a mature technology and widely used in heavy oil production.14,15 For adjusting the light oil blending process, the preferred light oil type, dilution ratio, and delivery temperature need to be based on the viscosity of the mixing oil. The measured viscosity has a higher reliability than the calculated value, but the experimental workload is large. Reliable viscosity calculation models to calculate the viscosity of mixing oil can effectively reduce the experimental workload and improve work efficiency. As shown in Table 2, many viscosity prediction models have been established to determine the viscosity of the mixed oil with different amounts of light oil.16–19

In addition, heavy oil blending with water is the main method adopted in China. Jing carried out a pipeline experiment on a highly viscous oil–water two-phase flow and found that pressure drops are significantly influenced by temperature, water fraction, and mixture velocity.20 Tan modified the Roscoe and Brinkman viscosity model for unstable oil-in-water (O/W) dispersions through experimental research on oil–water dispersed flow without a surfactant.21 From these studies, it is found that due to the effect of oil–water emulsification, the viscosity of crude oil does not show a downward trend as the effect of dilution with light oil, but the viscosity increases first, then reaches a peak, and finally decreases. This effect is mainly related to the phase inversion point of oil–water emulsification.22 Therefore, how to reduce the viscosity while ensuring the minimum water production to transport more heavy oil is the focus of this research.

The phase inversion point of emulsions is identified by means of transition from an O/W emulsion to a water-in-oil (W/O) emulsion (or contrariwise). The highest point of viscosity at different water contents is assumed to be the phase inversion point to study the related effects. At present, in-depth oil–water inversion research is being carried out, and many researchers have established prediction models for the phase inversion point. To eliminate the limitations of the empirical model, Yeo and Brauner established models through the system free energy theory.23,24 However, these models need to measure the droplet diameter of the oil–water emulsion before and after the phase inversion point. If the calculation of the droplet diameter is not accurate, the prediction accuracy will be lower. As shown in Table 3, Yeh, Arirachakaran, Chen, Decarre and Fabre, and...
Table 4. Correlations Used in Viscosity Prediction in the Literature at Different Water Contents

| authors and published year | water content (Φw) | viscosity (mPa s) | models and correlations | category |
|---------------------------|--------------------|------------------|------------------------|----------|
| Einstein (1911)\textsuperscript{39,40} | Φw ≤ inversion point | \( \mu_w = 1 + 2.5\varphi \) | linear |
| Becher (2001)\textsuperscript{41} | Φw ≤ inversion point | \( \mu_w = 1 + K_1\varphi + K_2\varphi^2 + K_3\varphi^3 \) | power |
| Vand (1945)\textsuperscript{42} | Φw ≤ inversion point | \( \mu_w = 1 + 2.5\varphi + 7.31\varphi^2 + 16.2\varphi^3 \) | power |
| Monson (1938)\textsuperscript{43} | Φw ≤ inversion point | \( \mu_w = 1 + 2.5\varphi + 2.19\varphi^2 + 27.4\varphi^3 \) | power |
| Guth-Simha (1936)\textsuperscript{44} | Φw ≤ inversion point | \( \mu_w = 1 + 2.5\varphi + 14.1\varphi^2 \) | power |
| Jing1 (2019)\textsuperscript{13} | 0–30 wt % | 200–8000 | \( \mu_m = \mu_{oE} e^{-\left[\frac{0.0029}{\varphi} + 3.052\varphi \right]} \) | exponential |
| Jing2 (2019)\textsuperscript{13} | 0–30 wt % | 8000–55 000 | \( \mu_m = \mu_{oE} e^{-0.378\varphi} e^{-4.400\varphi_0} \) | exponential |
| Zhang (2017)\textsuperscript{36} | 0–99 wt % | \( \mu_m = (1 - \varphi)^{-2.5} \left( \frac{\mu_{oE}}{\varphi_0} \right)^m \) | power |
| Wen (2016)\textsuperscript{14} | 65–90 wt % | \( \mu_m = [\mu_1(1 - \varphi^2) + \mu_2\varphi^2(1 - \varphi)]1 + \mu_3(1 + \frac{\mu_4 + \mu_5}{\varphi + \varphi_0})(\varphi + \varphi_0)] \) | linear |

Wang established prediction models for crude oil based on relevant experimental data, but the applicability of these models for heavy oil remains to be verified.\textsuperscript{29-31}

Einstein was the first researcher to predict the viscosity of W/O emulsions.\textsuperscript{29,30} This model is widely used for the viscosity prediction of low-water-cut crude oil. Later, many researchers corrected the formula based on the results of different crude oil experiments.\textsuperscript{31-33}\textsuperscript{41-43}\textsuperscript{44} Based on the nonlinear fitting method, Jing set up a new viscosity model based on the viscosity of five heavy crude oils at low water content.\textsuperscript{13} According to the Taylor viscosity model and experimental data of crude oil—water systems, Wen established a model for mixed oil samples with high water content, which is characterized by the influence of shear rate, emulsified water content, and crude oil compositions.\textsuperscript{35} This model must determine the mixing coefficient (\( \varphi_m \)) and the emulsified water fraction (\( \varphi_0 \)). The relevant models are given in Table 4.

Based on the above methods, the determination of the limit of heavy oil has attracted more and more attention through the combination of heating, water blending, and dilution. It is of great significance for guiding heavy oil exploitation. In this paper, a method for determining boundary conditions is proposed to correlate temperature, water content, and dilution ratio, while a simple decision diagram for boundary conditions is also drawn. The main purpose is to determine the transportation method of heavy and extraheavy crude oils. The main research contents of this paper are as follows:

1. First, the viscosity of the water-containing heavy oil is measured by an Anton Paar viscometer. Then, the viscosity results are combined with microscopic images to analyze the causes of deviations in viscosity measurements at different water contents.
2. Second, three kinds of heavy oils from the Xinjiang oilfield are selected to carry out the circulating piping experiment at different water contents. The trend of the apparent viscosity change of heavy oil at different water contents is analyzed. Based on experimental data of six crude oils, a phase inversion point prediction model is established.
3. Then, through relevant literature research, various viscosity prediction models currently used in petroleum applications are summarized. Also, these models are validated by circulating piping experiment data and the viscosity prediction model that is most suitable for heavy crude oil with different parameters is selected.
4. Finally, a method to determine boundary conditions of heavy crude oil using three combined methods of heating, water blending, and dilution is proposed, while a set of simple decision diagrams for boundary conditions is also drawn. Meanwhile, a pipeline in the LvDa oilfield (LO) is used as the research target, and the results of the proposed model are used as the initial value of the OLGA commercial software for calculations.

2. RESULTS AND DISCUSSION

2.1. Apparent Viscosity Test

2.1.1. Rheological Test and Microstructure Observation. Three oil samples from the Bohai LvDa oilfield (LD) are selected to study the rheological properties of a W/O or O/W emulsion. The properties of three crude oils are presented in Table 13. In this study, the water mass percentage of different emulsions, which are made under the same preparation conditions, is adjusted from 0 to 90 wt % with an interval of 10 wt %. At 70 °C, the influence of water mass percentage on the apparent viscosity of heavy oils is shown in Figure 1.

![Figure 1](https://dx.doi.org/10.1021/acsomega.0c00097)

**Figure 1.** Apparent viscosity as a function of the water mass fraction at 70 °C by the rheological test.

As described in Figure 1, the apparent viscosity of emulsions gradually increases as the water mass fraction increases, and its growth trend is relatively stable at low water mass fraction (water ratio ≤30 wt %). The viscosity data of the rheological test at this time is more reliable. When the water mass fraction is above 30 wt %, there is an obvious fluctuation in apparent viscosity. The reason is that the water mass fraction has a strong impact on the
emulsion system, which significantly affects the accuracy of the rheological test results. As shown in Figure 2, water is not dissolved in oil but wrapped by oil. As the water content increases, the water becomes denser and the particles gradually become larger. This phenomenon hypothesizes that the saturated water in the sponge is precipitated by pressure when the moisture content of the emulsified oil is higher than the phase inversion point. As shown in Figure 3, when the water percentage of heavy crude oil is larger than the phase inversion point, the water of the heavy oil precipitates due to the pressure and adheres to the wall surface of the rotor, causing the test to slip. This is similar to the Dos Santos study, which shows that slip phenomena tend to reduce the apparent viscosity in the pipeline flow.37

2.1.2. Circulating Piping Experiment. 2.1.2.1. Verifying the Reliability of the Piping Experiment. Rheological experiments and circulating piping experiments are performed on the dehydrated XJ1, XJ2, and XJ3 crude oils. The results of the comparison of the apparent viscosity are shown in Figure 4 and Table 5. By comparing the experimental results, it can be found that the deviation between the apparent viscosity of the circulating pipeline test and the rheometer test is basically within ±20%, and the average standard deviation of the three crude oils is 15.6%, which proves that the circulating pipeline test results are reliable.

2.1.2.2. Apparent Viscosity by the Piping Experiment. For the purpose of obtaining a general conclusion, heavy oils are selected as the oil phase for the pipeline flow experiment of two-phase dispersed mixtures including three kinds of heavy oils from the Xinjiang oilfield of China. Then, according to the experimental pressure drop, the apparent viscosity of heavy oils in the pipeline is calculated. The relative viscosities calculated from the pressure drop data at different water contents by the circulating pipeline experiment are listed in Table 6. It should be explained that because the mixture of oil and water with the water content of 30−60% of heavy oil is easy to emulsify, it is difficult for the oil pump to suck in and work smoothly. Besides, the viscosity of the crude oil at the phase inversion point is the largest, which makes transportation difficult. Therefore, as the viscosity of crude oil increases, it becomes more difficult to conduct experiments near the phase inversion point. Finally, some data points in Table 6 are missing.

Figure 5 displays the changing relation between the apparent viscosity and water content of three kinds of oil−water mixtures. It can be found that these three heavy oils display a similar trend. The apparent viscosity increases with the increase of water content from zero to the phase inversion point first and decreases sharply with the continuously increasing water content after the phase inversion point, which is the limit of a...
The apparent viscosity increases with the increasing water content when the water content is greater than that of the O/W emulsions. Also, the apparent viscosity of the emulsion form on the viscosity of oil-water mixtures near the phase inversion point exceeds the working limit of the pump, because the viscosity of oil-water mixtures of XJ2 and XJ3 is higher than that of the corresponding oil-water mixtures of XJ1 with the same water content. However, when the water content of these three heavy oils is greater than 80 wt %, the increase in temperature and water content has a little effect on the apparent viscosity of oil-water mixtures. The viscosity reduction efficiency of three heavy oils at different water contents is given in Figure 6. It shows that when the water content is low, the apparent viscosity decreases; when the water content is close to the phase inversion point, the apparent viscosity increases by nearly three times; and when the water content is greater than the phase inversion point, the apparent viscosity shows a downward trend. In conclusion, the viscosity of heavy oil has a great influence on the apparent viscosity of oil-water mixtures and heavy oils have an optimal water content delivery limit.

2.1.2.3. Determination of the Phase Inversion Point. It is found from the related literature that the phase inversion point of the same kind of oil has only a slight change with temperature,38,39 Therefore, the influence of temperature on the phase inversion point is neglected in this paper. The phase inversion point of six crude oils measured by the stirring method is shown in Table 7. The phase inversion point data of XJ crude oil is in good agreement with the viscosity variation trend of the circulating piping flow experiment, but the phase inversion point data of LD crude oil has a large deviation from the rheometer test results, which reflects the error of the rheometer in evaluating the inversion point of crude oil. The experimental data are used to verify the models and correlations of the phase inversion point in the literature, and the calculation results are also listed in Table 7. It shows that all prediction results have large deviations from experimental values, indicating that these prediction models of the phase inversion point are not applicable to heavy oils. Moreover, there are also large deviations between these models and the trend of the phase inversion point is opposite to that of viscosity, indicating that a unified prediction model of the phase inversion point for heavy oil has yet to be established. Figure 7 shows the effect of crude oil viscosity on the phase inversion point. It could be noted that as the viscosity of heavy oils increases, the experimental value of the phase inversion point also increases. However, the trend of predicted values for all models is the opposite. To understand how the viscosity of different heavy oils affects the phase inversion point,
a formula with the viscosity as a parameter to calculate it for different crude oils is explored.

The viscosity of three crude oils with different phase inversion points is fitted in the form of an exponential function and a logarithmic function. As shown in Figure 7, the $R^2$ value is the largest in the exponential function, which proves that the linear fit is relatively reliable. Therefore, the relationship between the phase inversion point and the viscosity can be calculated using

$$\mu = N 17.6475 0.1042$$

As shown in Table 7, the standard deviation of the experimental and predicted values of the new model is 2.85%, indicating that the prediction results are relatively accurate.

$$N = 17.647 \mu_0^{0.1042}$$

(1)

2.2. Viscosity Prediction Models. 2.2.1. Effect of Water Blending. The apparent viscosity of the three heavy oils in the oil–water dispersion mixture is calculated using the existing models, and the results are shown in Figures 8 and 9. The

### Table 7. Comparison of the Phase Inversion Point between the Predicted Value and the Experimental Value of Six Crude Oils

| samples | viscosity 50 °C (mPa·s) | density 20 °C (kg·m⁻³) | experimental value | Yeh | Arirachakaran | Wang | Chen | Decarre and Fabre | new model |
|---------|--------------------------|-------------------------|---------------------|-----|----------------|------|------|-------------------|-----------|
| XJ1     | 5458                     | 948.9                   | 43                  | 1.34| 8.59          | 3.04 | 4.18 | 19.93             | 43.26     |
| XJ2     | 21 624                   | 967                     | 51                  | 0.68| 1.97          | 1.79 | -5.47| 16.31             | 49.93     |
| XJ3     | 26 898                   | 968.9                   | 52                  | 0.61| 0.92          | 1.64 | -6.87| 15.79             | 51.08     |
| LD1     | 1930                     | 961.3                   | 36                  | 2.23| 13.60         | 4.56 | 7.18 | 22.65             | 38.82     |
| LD2     | 196                      | 922.5                   | 32                  | 6.67| 24.60         | 10.49| 23.47| 30.74             | 30.59     |
| LD3     | 122                      | 918.4                   | 29                  | 8.30| 26.88         | 12.39| 26.15| 32.53             | 29.11     |
| standard deviation (%) | 89.79                     | 61.17                   | 83.01               | 71.79| 40.75         | 2.85 |
predicted viscosity trend curves of the three kinds of heavy oils are basically the same, showing the same trend as the experimental value. First, the predicted viscosity gradually increases as the water percentage increases. Then, when the water percentage reaches the phase inversion point, the predicted viscosity reaches a maximum value, and as the water percentage continues to increase, the predicted viscosity rapidly decreases. Finally, when the water percentage is greater than a certain value, the viscosity does not change much as the water percentage increases. Table 8 lists the comparison of the relative error between the calculated values of the various models and the actual measured values for the viscosity of crude oils with different water contents.

At low water content, it can be seen that the calculated values of the six models are not completely consistent with the measured values. When the oil viscosity is relatively low (XJ1), the Jing2 models have a higher prediction accuracy. As the viscosity increases, the calculated value of Jing1 models...
and Einstein models are lower than the actual values, and the predicted values of the Vand, Monsen, Guth-Simha, and Zhang models are higher than the actual values, but the relative deviations of most points predicted by the Jing2 model are relatively within 20%. Therefore, the Jing2 model will be used to predict the apparent viscosity for low-water-content heavy crude oil.

At high water content, Einstein and his related models consider only the effect of water viscosity, and oil viscosity is not involved, so these formulas are no longer applicable. Moreover, relevant scholars have carried out less research on the viscosity prediction of high-water-content crude oil. By comparing the predicted values with the experimental values, the average absolute error of the Wen model is 33.2%. Because the apparent viscosity of the oil-water mixture fluctuates greatly when the water content is high, this paper requires relatively low prediction accuracy. Therefore, the Wen model is adopted to predict the viscosity of high-water-content heavy crude oil.

2.2.2. Effect of Temperature. Table 9 presents a series of the measured viscosity data of five heavy oils at different temperatures in ref 40. It can be seen that the five crude oils are all high-viscosity crude oils with a viscosity range of 3240–8120 mPa·s at 50 °C and a temperature range of 30–75 °C. The apparent viscosity of the five heavy oils at different temperatures is predicted using published and previously summarized correlations and compared with experimental data. The comparison results are shown in Figure 11a.

As shown in Figure 11a, the predicted viscosities of the Hossain, Naseri, and Elsharkawy–Alikhan models are all higher than the measured viscosities. On the contrary, the predicted value using the Alomair model is much smaller than the experimental value. The above prediction models are difficult to meet the current engineering calculation requirements. This may be due to the error in the API measurement data. The density measurement of heavy oils is difficult due to their high viscosity and poor fluidity. This leads to a large error in the API value of the heavy oil, so the model prediction accuracy is low. For another reason, the above models are mainly based on the experimental data of low-viscosity crude oil and are not suitable for high-viscosity crude oil. However, the Jing model does not consider the influence of the API and directly uses the viscosity at 50 °C as a known variable. Because the Jing model is suitable for a temperature range of 40–90 °C, it can be observed in Figure 11a that the viscosity prediction accuracy for 30 °C is low. When the temperature is above 40 °C, the average relative error of the predicted values is 15.56%, indicating that the prediction accuracy is relatively high.

The Jing model is verified based on the rheological experimental data of three heavy dehydrated crude oils. The results are shown in Table 10 and Figure 11b. It shows that the relative deviation between the experimental and the predicted values is basically within 30%, and the average absolute error is only 7.0%. Therefore, this paper uses the Jing model to calculate the viscosity of various heavy oils at different temperatures.

2.2.3. Effect of Dilution Ratio. In this study, the experimental data of the viscosity of heavy oils blended with light oils, including two heavy oils and five light oils, are cited from the relevant literature. As seen in Figure 12, the comparison results show that whether the Cragoe model, the Lederer model, the Arrhenius model, or the double logarithmic model is used, the calculated values of the viscosity of the mixed crude oil are different from the measured values. It can be seen in Table 11 that the calculated value of the Cragoe model is relatively accurate, the average relative error is only 11.11%, and the maximum relative error is 42.48%, which is within the acceptable range. Therefore, this paper uses the Cragoe model to predict the viscosity at different dilution ratios.

2.3. Determination of Boundary Conditions. 2.3.1. Proposing a Method for Determining Boundary Conditions. Among all available methods for heavy crude oil viscosity reduction, the methods of dilution, water blending, and heating are widely used in heavy oil transportation. To meet the gathering and transportation needs of high-viscosity crude oil, it is usually necessary to combine the above several methods.41 Although each of the methods for reducing viscosity is studied

![Figure 10](https://example.com/image10.png)

**Figure 10.** Comparison of the apparent viscosity between the predicted values and experimental values at low water content.

![Figure 11a](https://example.com/image11a.png)

**Figure 11a.** Comparison of the calculated and measured viscosities for different crude oil samples at different water contents.

| Table 9. Experimental Data on the Viscosity of Different Crude Oils at Different Temperatures in the Literature |
| --- | --- | --- | --- | --- | --- |
| samples | viscosity (mPa·s) | oil A | oil B | oil C | oil D | oil E |
| density at 20 °C (kg/m³) | 961.3 | 957.9 | 970.2 | 963.1 | 949.3 |
| API | 15.70 | 16.22 | 14.35 | 15.42 | 17.56 |
| temperature (°C) | 30 | 40 | 50 | 60 | 70 | 75 |
| 14 120 | 16 220 | 16 400 | 18 600 | 17 780 | 18 900 |
| 16 220 | 16 400 | 18 600 | 17 780 | 18 900 |
| 16 400 | 18 600 | 20 800 | 23 000 | 24 200 |
| 18 600 | 20 800 | 23 000 | 25 200 | 27 400 |
| 20 800 | 23 000 | 25 200 | 27 400 | 29 600 |
| 23 000 | 25 200 | 27 400 | 29 600 | 31 800 |
| 25 200 | 27 400 | 29 600 | 31 800 | 34 000 |
| 27 400 | 29 600 | 31 800 | 34 000 | 36 200 |
| 29 600 | 31 800 | 34 000 | 36 200 | 38 400 |

https://dx.doi.org/10.1021/acsomega.0c00097
ACS Omega 2020, 5, 9870–9884
extensively, there is no uniform prediction model for the combination of the above methods. A schematic diagram of the calculation methodology of the gathering and transportation limits of heavy crude oil is shown in Figure 13. The specific estimation process is as follows:

Step 1: Calculating the phase inversion point of heavy oil. According to the phase inversion point prediction model established in this paper, the phase inversion point is calculated based on the viscosity of pure crude oil at 50 °C. Then, whether the water content of heavy oil is low or high is determined.

Step 2: Diluting with light oil. When the conditions of $\Phi_{h,w} \leq N - 10\%$ and $\Phi_{l,w} \leq N - 10\%$ occur, light oil can be added to reduce the viscosity, and the optimal dilution ratio ($X_l$) and the viscosity of mixed oil ($\mu_{m1}$) are calculated according to Figure 13 and the empirical formula given in Section 2.2.3. In addition, when the water percentage of light oil and heavy oil is relatively large, the dilution method is not economical. Therefore, the next step of blending with water is directly carried out.

Step 3: Blending with water. When the transport range is high water content and the viscosity of mixing oil is more than 2000 mPa·s, based on empirical data, the optimum water content ($\Phi_w$) and viscosity ($\mu_{m2}$) are calculated according to Figure 13. When the transport range is high water percentage and the viscosity of mixing samples is less than 2000 mPa·s, the minimum water content is determined by the empirical formula established in Section 2.2.1. The optimized empirical formula is used to calculate according to Figure 13, and the optimal mixing ratio ($\Phi_w$) and oil viscosity ($\mu_{m2}$) are obtained.

Step 4: Heating. Using the new parameter estimation as described in Figure 13, the corresponding mixed oil temperature is obtained according to the empirical formula. Also, the empirical formula is shown in Section 2.3. Finally, the optimal temperature ($T$) and mixed oil viscosity ($\mu_{m}$) are obtained.

2.3.2. Model Verification and Application. The fluid parameters of the on-site pipeline transportation used to verify the boundary model in this paper are taken from a heavy oil pipeline of the Bohai LvDa oilfield with a length of about 15.9 km and are summarized in Table 12. The actual value of the apparent viscosity of the on-site pipeline under transport conditions is also listed in Table 12. Besides, the prediction-related parameters for optimal transport conditions according to the boundary model are shown in Table 12. The results show

Figure 11. Comparison of predicted values and experimental values of the viscosity of different calculation models.

Table 10. Comparison of Relative Errors between the Predicted and Measured Values of the Jing Model at Different Temperatures

| samples | method | 30 °C | 35 °C | 40 °C | 45 °C | 50 °C | 55 °C | 60 °C | 65 °C | 70 °C | 75 °C | 80 °C | 85 °C | 90 °C |
|---------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| XJ1     | experiment | 53 376 | 28 300 | 15 706 | 94 146 | 54 548 | 35 000 | 22 921 | 15 353 | 10 730 | 8 030 | 6 086 | 4 656 | 3 574 |
|         | prediction | 57 817 | 27 913 | 14 854 | 8 515 | 5 177 | 3 500 | 21 884 | 14 999 | 10 560 | 7 626 | 5 622 | 4 222 | 3 222 |
| XJ2     | experiment | 303 959 | 146 327 | 72 635 | 38 769 | 21 624 | 12 484 | 7 581 | 4 613 | 3 110 | 2 381 | 1 768 | 1 325 | 1 037 |
|         | prediction | 361 069 | 152 274 | 72 080 | 37 266 | 20 655 | 12 111 | 7 439 | 4 752 | 3 137 | 2 132 | 1 485 | 1 058 | 7 68 |
| XJ3     | experiment | 381 837 | 181 939 | 92 247 | 48 139 | 26 898 | 15 565 | 9 436 | 5 873 | 3 732 | 2 702 | 1 940 | 1 393 | 9 33 |
|         | prediction | 482 730 | 199 265 | 92 589 | 47 092 | 25 722 | 14 883 | 9 032 | 5 705 | 3 728 | 2 509 | 1 732 | 1 223 | 8 81 |

maximum relative error (%) | 26.4 |
average absolute error (%) | 7.0 |

Figure 12. Comparison of predicted and measured viscosities of four original models.

Table 11. Comparison of Relative Errors between the Predicted and Measured Values of the Related Models at Different Dilution Ratios

| correlations | Arrhenius | double logarithmic | Cragoe | Lederer |
|--------------|-----------|--------------------|--------|--------|
| average relative error (%) | −94.77 | 22.02 | 11.11 | 15.86 |
| average absolute error (%) | 94.77 | 26.20 | 18.70 | 19.03 |
| maximum relative error (%) | 233.06 | 59.51 | 42.48 | 44.94 |

When the conditions of $\Phi_{h,w} \leq N - 10\%$ and $\Phi_{l,w} \leq N - 10\%$ occur, light oil can be added to reduce the viscosity, and the optimal dilution ratio ($X_l$) and the viscosity of mixed oil ($\mu_{m1}$) are calculated according to Figure 13 and the empirical formula given in Section 2.2.3. In addition, when the water percentage of light oil and heavy oil is relatively large, the dilution method is not economical. Therefore, the next step of blending with water is directly carried out.

Step 3: Blending with water. When the transport range is high water content and the viscosity of mixing oil is more than 2000 mPa·s, based on empirical data, the optimum water content ($\Phi_w$) and viscosity ($\mu_{m2}$) are calculated according to Figure 13. When the transport range is high water percentage and the viscosity of mixing samples is less than 2000 mPa·s, the minimum water content is determined by the empirical formula established in Section 2.2.1. The optimized empirical formula is used to calculate according to Figure 13, and the optimal mixing ratio ($\Phi_w$) and oil viscosity ($\mu_{m2}$) are obtained.

Step 4: Heating. Using the new parameter estimation as described in Figure 13, the corresponding mixed oil temperature is obtained according to the empirical formula. Also, the empirical formula is shown in Section 2.3. Finally, the optimal temperature ($T$) and mixed oil viscosity ($\mu_{m}$) are obtained.
that the predicted values of the boundary model agree well with the actual value.

2.4. Simple Decision Diagram for Boundary Conditions. Through the establishment and selection of the above relevant formulas, the simple graphical limits of temperature, water cut, and dilution ratio are established to facilitate the rough determination of the heavy oil gathering method. Assuming that 3000 mPa·s is the highest crude oil transport

Figure 13. Schematic diagram of the calculation methodology.

Table 12. Comparison of the Predicted Value and Actual Value of Crude Oil Gathering and Transportation Conditions

| input value          | output value          |
|----------------------|-----------------------|
| type, μₖ, 50 (mPa·s) | Nₖ, (%) μₖ, 50 (mPa·s) | Nₖ, (%) water yes or no | Xₖ, (%) μₖ₉¹ (mPa·s) Φₖ, (%) μₖ₉² (mPa·s) T (°C) μₖm (mPa·s) |
| predicted            | 3911 6−15 929 0 yes 68 1430 47.7 414.2 40 772 |
| actual               | 67 1457 50 41−55 844 |

![Diagram of the calculation methodology](https://example.com/diagram.png)
viscosity after treatment, the viscosity of the mixed oil at various temperatures, different water contents, and different dilution ratios is shown in Figures 4—6.

Figure 14 shows the result calculated according to the Jing model. When a viscosity value of 50 °C crude oil is input, the viscosity at each temperature is easily obtained. It can be clearly seen in Figure 14 that heavy oils of different viscosities (3000—30 000 mPa s) above a certain temperature can satisfy the conveying conditions of 3000 mPa s or less.

When the oil sample is extraheavy crude oil, it is generally necessary to increase the delivery temperature to reduce the flow resistance. First, the phase inversion point is calculated. Then, it is converted into high-temperature viscosity. Finally, the viscosity of high or low water content by 10% before and after the phase inversion point is calculated. Figure 15 shows the calculation result of a phase inversion point calculation formula, a low-water-viscosity calculation formula, and a high-water-viscosity calculation formula (eq 14, the Jing2 model, and the Wen model). The viscosity of the crude oil at different water contents can be known by inputting the viscosity of the crude oil at 50 °C and then converting it into the corresponding viscosity at 70 °C. As is clear in Figure 15, the extraheavy crude oils of different viscosities (10 000—40 000 mPa s) can satisfy the conveying conditions of 3000 mPa s or less in various water content ranges by heating to 70 °C.

The viscosity of mixed oils with different proportions of dilution between high-viscosity crude oil with different viscosities (3000—30 000 mPa s) and low-viscosity crude oil with different viscosities (5—1000 mPa s) is shown in Figure 16. It is the result calculated according to the Cragoe model. The viscosity of the mixed oil after a certain low-viscosity crude oil is blended at a certain diluting ratio can satisfy the conveying condition of 3000 mPa s or less.

3. CONCLUSIONS

The better conditions for heavy oil flow are determined by temperature, dilution ratios, and water blending, and accurate determination of these parameters is important for economic transportation. The relevant conclusions of this paper are summarized as follows:

1. When the water content is close to or greater than the phase inversion point, the viscosity results have a large deviation from the rheometer test. The cause of this deviation is defined as the segregation of water in a sponge under pressure. Therefore, the pressure drop of three heavy crude oils with different water contents is tested by the circulating piping experiment, and the apparent viscosity is calculated by pressure drop values. Based on the experimental data measured by the stirring method, a phase inversion point prediction model is established. In contrast, the new phase inversion point prediction model has the highest prediction accuracy and the standard deviation of the experimental values and predicted values is only 2.85%.

2. The apparent viscosity calculated from the experimental data measured by the circulating pipeline shows that water content has a greater impact on crude oil viscosity. When the water content is close to the phase inversion point, the apparent viscosity increases nearly three times or more. Through the verification, the Wen and Jing2 models are selected to predict the viscosity of water-cut heavy crude oil, the Jing model is chosen for the prediction of the viscosity of heavy oil at different temperatures, and the Cragoe model is chosen for the prediction of the viscosity of heavy oil diluted with light oil.

3. Finally, a new method for determining the better conditions of heavy crude oil transportation with different temperatures, water contents, and dilution ratios is proposed. Compared with the on-site pipeline transportation parameters of China’s Bohai LvDa oilfield, the results show that the prediction results are in good agreement. According to the phase inversion point prediction model and the viscosity prediction model, the distribution map of heavy crude oil gathering and transportation limit below 3000 mPa s is drawn. Through the distribution diagram, the better conditions for heavy oil flow can be initially estimated.

4. EXPERIMENTAL SECTION

4.1. Materials. The basic compositions and physical properties of the oil samples from Xinjiang and LvDa oil fields used in this paper are listed in Table 13. Impurities and water have been removed from oil samples according to the Chinese national standard SY/T 6520 by a dehydration and desalination device made in China. The water content of crude oil can be reduced to less than 0.1 wt % after processing. In addition, the tap water from the China Chengdu Water Supply Company is used in this study. The water quality analysis report showed that the salinity and pH are 132 and 7.32 mg L⁻¹, respectively.

4.2. Apparatus. A DWY-8T automatic dehydrator is used to remove water from the crude oil. A digital display thermostat water bath (Haake, Germany) is used to heat and keep oil samples at a constant temperature. A Longteng SJ30-5B electronic balance (Shenzhen, China) with an accuracy of 1/10 000 g is used to measure the weight of various samples. A JB60-SH homomixer with a stirring speed range of 100—3000 r·min⁻¹ is used to mix the samples.
Figure 16. Variation of the mixed oil viscosity with dilution ratio and light oil viscosity.

Table 13. Basic Properties and Compositions of LD and XJ Crude Oils

| samples                        | XJ1 | XJ2 | XJ3 | LD1 | LD2 | LD3 |
|--------------------------------|-----|-----|-----|-----|-----|-----|
| viscosity of dehydrated crude oil at 50 °C (mPa·s) | 5458 | 21 624 | 26 898 | 1930 | 196 | 122 |
| density at 20 °C (kg·m⁻³)      | 948.9 | 967.0 | 968.9 | 961.3 | 922.5 | 918.4 |
| API                            | 17.6 | 14.8 | 14.5 | 15.7 | 21.9 | 22.6 |
| freezing point (°C)            | 10  | 29  | 23  | 4  | 6  | 8  |
| emulsified water content (wt %)| 7.2 | 30.4 | 12.9 | 0  | 0  | 0  |
| asphaltene (wt %)              | 2.24 | 6.68 | 7.66 | 0.87 | 1.89 | 1.93 |
| resin (wt %)                   | 30.08 | 44.01 | 49.49 | 25.34 | 13.81 | 12.79 |
| wax (wt %)                     | 1.35 | 0.85 | 0.32 | 5.27 | 14.32 | 17.64 |

Figure 17. Simulation installation of watery heavy crude oil flow.
rpm (Shaoxing, China) is used to mix heavy oil, light oil, and water. An Anton Paar Viscotherm VT2 (Graz, Austria) is used to determine the viscosity of mixed samples.

4.3. Experimental Procedure. Heavy oil and water are separately added to the beaker to adjust the water content from 0 to 90 wt% with an interval of 10 wt%. It is heated in a water bath, and the temperature of the mixture is maintained at 70 °C for 10 min. Then, a JB60-SH homomixer stirs the mixed oil sample at 1500 rpm for 5 min under normal pressure. In the initial rheological experiment, the mixed oil sample is poured into the cup of the rheometer, setting the temperature to 50 °C, and the range of stirring speed is 0–300 rpm to acquire 50 sets of data for 5 min.

The simulation device of the circulating piping flow of mixed oil samples is shown in Figure 17. First, the oil and water are separately added to the mixing tank in proportion, and the water content is adjusted from 0 to 90 wt% with an interval of 10% to conduct a series of experiments. Then, the circulating water bath is turned on, and the mixed oil sample is heated to 70 °C and kept at a constant temperature for 30 min. Finally, the screw pump is turned on for the experiment. After the experimental data is stable, the control cabinet collects data for 1 min. The structure of the oil–water mixing tank is shown in Figure 18.

4.4. Data Processing. 4.4.1. Apparent Viscosity. The calculation methods for the apparent viscosity of crude oils with different water contents are different. A generalized Re number is commonly used to calculate the apparent viscosity of emulsified crude oil. This article uses conventional calculation methods, as follows: first, we assume that the oil flow in the study temperature range is of a Newtonian fluid. Then, the average density, average pressure drop, and corresponding average flow rate are calculated according to the pressure drop, flow rate, and density change of the test pipe unit length at different temperatures over time. Finally, the apparent viscosity based on the basic hydraulic equation of the conventional fluid is calculated. The specific calculation process is as follows:

First, the pressure drop per unit pipe length is calculated

\[ \Delta \bar{p} = \frac{\Delta p}{L} \]  \hspace{1cm} (2)

Second, the frictional losses along the test tube section \((h_i)\) are calculated

\[ h_i = \Delta \varepsilon + \frac{1000(\Delta \rho)}{\rho g} \]  \hspace{1cm} (3)

Then, the relationship between frictional losses along the test tube section \((h_i)\) and hydraulic friction coefficient losses along the test tube section \((\lambda)\) can be obtained from the Darcy formula

\[ h_i = \frac{1}{2} \frac{v^2}{d g} \]  \hspace{1cm} (4)

The above two formulas can be used to calculate the hydraulic friction coefficient in the meantime

\[ \lambda = \frac{n^2 d^2 g h_i}{8 Q^2} \]  \hspace{1cm} (5)

Empirical formulas for the calculation of common hydraulic friction are as follows:

When \(Re \leq 2000\), the flow regime is laminar

\[ \lambda = \frac{64}{Re} \]  \hspace{1cm} (6)

When \(3000 < Re < \frac{58.7}{\varepsilon^2}\), the flow regime is in the hydraulic smooth zone

\[ \lambda = \frac{0.3164}{\sqrt{Re}} \]  \hspace{1cm} (7)

When \(\frac{58.7}{\varepsilon^2} < Re < \frac{665 - 765 \log \varepsilon}{\varepsilon}\), the flow regime is in the mixed friction zone

\[ \frac{1}{\sqrt{\lambda}} = -1.8 \log \left[ \frac{6.8}{Re} + \left( \frac{\Delta}{3.7d} \right)^{1.11} \right] \]  \hspace{1cm} (8)

When \(Re > \frac{665 - 765 \log \varepsilon}{\varepsilon}\), the flow regime is in the hydraulic rough area
\[ \lambda = \frac{1}{2 \ln\left(\frac{3.74}{\Delta}\right)} \]  
(9)

\[ \varepsilon = \frac{2\Delta}{d} \]  
(10)

By performing cyclic iterative verification of the above-mentioned empirical formula of hydraulic friction resistance, the value of Reynolds number \( Re \) can be calculated in reverse. From the Reynolds number calculation formula, the relationship between Reynolds number \( Re \) and oil viscosity can be obtained

\[ Re = \frac{4Q}{\pi d^2 \mu} = \frac{4Qn}{\pi d_i \mu} \]  
(11)

Finally, the apparent viscosity of the oil can be obtained from the above formula

\[ \mu = \frac{4Qn}{\pi d_i \mu} \]  
(12)

### 4.4.2. Relative Deviation

The absolute deviation and the mean absolute deviation of experimental and predicted values can be calculated by the following equations

\[ W_i = \left| \frac{Q_{p,i} - Q_{e,i}}{Q_{e,i}} \right| \times 100\% \ (i = 1, 2, 3, \ldots, n) \]  
(13)

\[ W_{ave} = \frac{1}{n} \sum_{i=1}^{n} W_i \]  
(14)

where \( Q_{e,i} \) is the experimental value and \( Q_{p,i} \) is the predicted value. \( W_i \) and \( W_{ave} \) are the absolute deviation of predicted and experimental values, respectively.

### ACKNOWLEDGMENTS

This work was supported by the National Natural Science Foundation of China (Grant nos. 51779212 and 51911530129), the Sichuan Science and Technology Program (Grant no. 2019YJ0350), and the National Science and Technology Major Project of China (Grant no. 2016ZX05025004-005).

### ABBREVIATIONS

- \( \mu_w \): viscosity of the mixture oil, mPa·s; \( \mu_o \): viscosity of the pure oil, mPa·s; \( \mu_w \): viscosity of the water, mPa·s; \( \mu_{op} \): viscosity of the pure oil at 50 °C, mPa·s; \( \mu_o \): viscosity of the dispersed phase, mPa·s; \( \mu_o \): viscosity of the continuous phase, mPa·s; \( \mu_o \): apparent viscosity of heavy oil, mPa·s; \( \mu_o \): apparent viscosity of light oil, mPa·s; \( \mu_{op} \): apparent viscosity of heavy oil at 50 °C, mPa·s; \( \mu_{op} \): apparent viscosity of light oil at 50 °C, mPa·s; \( \rho_o \): density of heavy oil, kg/m³; \( \rho_o \): density of light oil, mPa·s; \( T \): temperature, °C; \( N \): phase inversion point of crude oil, %; \( N_{op} \): phase inversion point of heavy oil, %; \( N_{op} \): phase inversion point of light oil, %; \( \phi \): mass content of the dispersed phase, dimensionless; \( X_o \): mass content of light oil, wt %; \( m \): mass of oil, kg; \( X_o \): mass content of heavy oil, wt %; \( \Phi_w \): oil content of a crude oil emulsion, wt %; \( \Phi_{op} \): water content of a crude oil emulsion, wt %; \( \Phi_{op} \): mass fraction of the dispersed phase, wt %

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