Flow Rate Profile Interpretation for a Two-Phase Flow in Multistage Fractured Horizontal Wells by Inversion of DTS Data

Hongwen Luo,* Beibei Jiang, Haitao Li,* Ying Li, and Zhangxin Chen

ABSTRACT: The use of distributed temperature sensors (DTSs) has become a common practice in real-time downhole monitoring for horizontal wells in oil/gas reservoirs. However, great challenges still exist in translating measured DTS data to flow rate profiles due to lack of robust inversion approaches, especially for multistage fractured horizontal wells (MFHWs) with a gas–water two-phase flow. In this study, a comprehensive inversion system combined with a temperature prediction model and an inversion model has been developed to interpret flow rate profiles for MFHWs with a two-phase flow by inverting downhole DTS data. The temperature model serves as a forward model to predict temperature behaviors of MFHWs. The inversion model is derived from the Levenberg–Marquardt (L–M) algorithm to eliminate the errors between the measured DTS data and the simulated temperature profile. By simulating the temperature behaviors of two-phase flow MFHWs, it has been found that there exist abnormal decreases in the ΔT/Δx ratio (temperature drop/fracture half-length) of the corresponding fractures with the production of water. According to this, two effective methods to diagnose water exit locations for an MFHW are introduced. Two synthetic cases are presented to illustrate the application of the inversion system in detail. Finally, a field application is analyzed and satisfactory inversion results are obtained. The maximum inversion temperature error is less than 0.03 K and the absolute error of the inverted gas production rate is less than 9 m³/day. The interpreted inflow rates of each stage are close to the measured data as well, which validates the reliability of the proposed inversion system. The findings of this study provide a promising tool to interpret flow rate profiles for an MFHW with a two-phase flow.

1. INTRODUCTION

Hydraulic fracturing treatment has become a common practice to enhance the productivity and recovery of oil/gas reservoirs. Because of a complex downhole condition created by fracturing treatment, great challenges exist when performing a quantitative diagnosis of the created fractures and flow profile prediction. In recent years, plenty of measures have been tried to diagnose the hydraulic fractures.1−6 With the development of optical fiber technology, the distributed temperature measurements by distributed temperature sensors (DTSs) show great advantages in indicating downhole hydraulic fractures and flow rate profiles for horizontal wells.7−10

A distributed acoustic sensor (DAS) is generally accompanied by DTSs when the downhole temperature measurement is performed using an optical fiber to obtain more information about the hydraulic fractures and inflow rates. Recently, growing numbers of DTSs have been put into field practice around the world to help diagnose hydraulic fractures during fracturing treatment or a production period for multistage fractured horizontal wells (MFHWs).

Based on the DTS measurements, Sierra et al.11 identified the created fractures from the measured temperature profiles and well completed the performance evaluation after the fracturing treatment for several MFHWs in gas reservoirs. From DAS and DTS maps, the interpretation of fracture propagation and progression has been performed for an MFHW with multi-clusters in each fracturing stage.12−14 With the help of DTS and DAS maps, Molenaaar et al. described how to optimize the fracturing stimulation briefly.15 Except for the DTS/DAS measurements during the fracturing period, successful identification of hydraulic fracture from the measured DTS profile during the warm-back period was carried out by Ugueto et al. as well. Based on the fiber-optic diagnostics, they identified and located the effective hydraulic fractures for several more field MFHWs to evaluate the perforation cluster efficiency.16 The cases mentioned above are mainly qualitative applications of DTS data. To quantitatively interpret the flow rates or fracture parameters from the measured DTS data, the corresponding mathematical models are necessary.

Unlike vertical wells,17−19 the temperature difference along the horizontal well segments is very small. To reflect the subtle temperature change of horizontal wells, microheat effects
(thermal convection, thermal conduction, fluid thermal expansion, etc.) have to be taken into account when temperature models are developed.\textsuperscript{20}–\textsuperscript{22} As for conventional horizontal wells, a temperature model was proposed by Yoshioka et al. to predict the temperature distribution and detect gas/water entries from the measured DTS data.\textsuperscript{23,24} Li and Zhu developed another temperature model to simulate the temperature distribution for horizontal wells in oil reservoirs.\textsuperscript{25} Similar temperature models were developed to simulate the temperature distributions for horizontal wells with an oil–water two-phase flow by Zhu\textsuperscript{26} and Li et al.,\textsuperscript{27} respectively.

In recent years, besides conventional horizontal wells, more temperature prediction models were proposed for MFHWs. Yoshida et al.\textsuperscript{28} derived a new transient temperature prediction model from Yoshioka’s model\textsuperscript{29} to simulate the temperature distribution for an MFHW in a shale gas reservoir. They also performed the sensitivity evaluation of the wellbore temperature profile for different factors. A new semianalytical model\textsuperscript{2} and a fast marching simulation model with higher computational efficiency were proposed, respectively, by Cui et al. to predict the temperature profiles for MFHWs in shale gas reservoirs. Most recently, a numerical temperature model that can be used to predict temperature distributions for an MFHW was proposed by Yoshida et al.\textsuperscript{30} Using their new model, the downhole temperature conditions of two field MFHWs were analyzed later.\textsuperscript{31}

The aforementioned several temperature models can be used to forward predict temperature and pressure distributions in MFHWs. Compared to the forward temperature prediction, flow rate profile interpretation from the DTS data can be described as an inversion problem (Figure 1).

However, to translate the downhole DTS data to flow profiles quantitatively, an effective inversion model is necessary. There are two commonly used algorithms, namely, Levenberg–Marquardt (L–M) and Markov Chain Monte Carlo (MCMC) algorithms, from which the inversion models can be formulated. Based on those two algorithms, scholars developed different inversion models for conventional horizontal wells. Yoshioka et al.\textsuperscript{34} and Cai et al.\textsuperscript{32} both developed an inversion model based on the L–M algorithm to interpret the flow profile for horizontal wells in oil reservoirs. According to the MCMC algorithm, another inversion model was proposed to interpret the flow rate profile for horizontal wells by Li and Zhu.\textsuperscript{25} Furthermore, inversion modes derived from both the L–M and MCMC algorithms were developed by Zhu\textsuperscript{33} and Li,\textsuperscript{34} respectively, to determine the flow rates for horizontal wells from measured DTS data and several field cases were analyzed as well. However, as for MFHWs, very few studies were proposed to interpret flow profiles by inversing downhole DTS data up to now. As the most recent theoretical and field studies on the inversion problem of DTS data, using the temperature model developed by Cui\textsuperscript{35} as the forward model, only an inversion procedure based on the L–M algorithm was introduced by Zhang and Zhu\textsuperscript{36} to predict the flow rate distribution in a fractured horizontal well.

Although a lot of studies have been done on temperature behavior prediction and flow rate estimation, few studies have focused on the temperature behaviors in MFHWs, not to mention an MFHW with a gas–water two-phase flow. Fewer studies were carried out for MFHWs on quantitative flow rate profiling by translating DTS measurements. For two-phase MFHWs, the existence of water production would disturb a normal wellbore temperature distribution. Thus, this inversion problem is extremely complicated when translating measured DTS data to flow profiles for MFHWs with a two-phase flow. A feasible approach to determine flow rate profiles by inversion of DTS data for two-phase MFHWs is urgently needed.

Is this study, first, a comprehensive temperature model developed for two-phase flow MFHWs in our previous study\textsuperscript{37} is used as a forward model to simulate the temperature behaviors in two-phase flow MFHWs. To assure the efficiency of inversion computations, a new inversion model derived from the L–M algorithm is developed to reduce the errors between measured DTS data and simulated DTS profiles.\textsuperscript{38} Subsequently, through temperature behavior simulation and temperature profile characterization for two-phase-flow MFHWs, a convenient approach to identify and locate water exits from the measured DTS data is proposed as well, which is essential to the flow rate profile interpretation of a two-phase-flow horizontal well. Then, several synthetic cases are analyzed to illustrate the work procedures of the developed inversion system when it is applied to MFHWs with different inflow water distributions. Finally, a field MFHW located in the southwest of China is presented to validate the feasibility of this inversion system to interpret a flow rate profile for an MFHW.

The novelty of this paper is that the proposed inversion system realizes the quantitative interpretation of a flow rate profile for a two-phase flow MFHW from DTS measurements. However, using previous inversion models developed by other scholars, it is hard to separate the inflow water rate from the overall flow profile interpretation results. Thus, the biggest advantage of this inversion system is that the inflow water rate of each fracture can be determined besides the gas flow profile. Another novelty of this study is that a convenient approach to identify and diagnose water exit locations for a two-phase flow MFHW from observed DTS profile is proposed. Moreover, we have optimized the inversion procedure by setting a threshold in each iteration step. Namely, iterative inversion calculations can be finished once any satisfactory inversion solution occurs to avoid more invalid iterative steps. Then, the efficiency of inversion computations is greatly improved. The limitation of this study is that the developed inversion system is not applicable for those dual-media reservoirs with natural fractures. To interpret the flow rate profile for MFHWs in dual-media reservoirs, a new forward temperature model needs to be.

Figure 1. Sketch of the inversion problem of DTS data.

ACS Omega Article

Figure 1. Sketch of the inversion problem of DTS data.

http://pubs.acs.org/journal/acsodf

https://dx.doi.org/10.1021/acsomega.0c02639
ACS Omega 2020, 5, 21728–21744
developed considering the influences of natural fractures on the temperature profile.

2. COMPUTATIONAL METHODS

Inversion of DTS data is an iterative process, the purpose of which is to eliminate or decrease errors between downhole temperature measurements and simulated temperature profiles. An inversion task is to reveal the real flow rate profile through a large number of iterative calculations. The inversion task cannot be finished until the predicted DTS profile matches the measured DTS data. Once the temperature convergence is achieved, the current input parameters (permeability, fracture half-length, and fracture width) and simulated results (a flow rate profile and a wellbore pressure profile) can be regarded as the outcomes of this inversion task. To determine a flow rate profile from measured DTS data, there are three essential elements: a forward model, an inversion model, and inversion parameters. The developed models are all solved using C# programs.

2.1. Forward Model. The forward temperature model with the capability to simulate temperature behaviors for a two-phase flow MFHW has been validated in one of our previous studies. As shown in Figure 2, two main domains are included in the forward model: a reservoir system and a wellbore system (hydraulic fractures are included in the reservoir system).

![Figure 2. Schematic of a reservoir flow model in an MFHW.](image)

2.1.1. Reservoir and Fracture Models. On the basis of mass and energy conservation, a flow model and a thermal model are formulated for a reservoir system and hydraulic fractures, respectively.

2.1.1.1. Flow Model. Considering non-Darcy flow and the slippage effect, the flow model is developed under transient conditions to obtain the pressure distribution in a reservoir and hydraulic fractures. The two-phase flow models are expressed as gas phase:

\[
\frac{\partial}{\partial x} \left( k_w k_{fg} \sigma_{fg} \frac{\partial p_w}{\partial x} \right) + \frac{\partial}{\partial y} \left( k_w k_{fg} \sigma_{fg} \frac{\partial p_w}{\partial y} \right) + \frac{\partial}{\partial z} \left( k_w k_{fg} \sigma_{fg} \frac{\partial p_w}{\partial z} \right) = \phi S_{fg} \frac{\partial p_w}{\partial t} + 2\phi \frac{\partial}{\partial z} \left( S_{fg} \right) \tag{1}
\]

water phase:

\[
\frac{\partial}{\partial x} \left( \rho_w k_w \frac{\partial p_w}{\partial x} \right) + \frac{\partial}{\partial y} \left( \rho_w k_w \frac{\partial p_w}{\partial y} \right) + \frac{\partial}{\partial z} \left( \rho_w k_w \frac{\partial p_w}{\partial z} \right) = \frac{\partial}{\partial t} \left( \rho_w S_w \right) \tag{2}
\]

A flow model for the fluids in hydraulic fractures is given as follows:

\[
\frac{\partial}{\partial x} \left( k_{fg} k_{fr} \frac{\partial p_{fr}}{\partial x} \right) + \frac{\partial}{\partial y} \left( k_{fg} k_{fr} \frac{\partial p_{fr}}{\partial y} \right) + \frac{\partial}{\partial z} \left( k_{fg} k_{fr} \frac{\partial p_{fr}}{\partial z} \right) = \phi \frac{\partial p_{fr}}{\partial t} \tag{6}
\]

2.1.2. Wellbore Model. As shown in Figure 3, inside a wellbore, the inflow fluids come from hydraulic fractures and combine with the upstream flow at perforation locations and then the mixed fluids flow from the toe to the heel. A wellbore flow model and a thermal model are formulated to obtain the pressure and temperature distributions along the wellbore, respectively.

2.1.2.1. Flow Model. According to the mass and momentum balance equations, a two-phase flow model inside a wellbore is given as:

\[
\frac{\partial}{\partial x} \left( \frac{\rho_w k_w}{\mu_w} \frac{\partial p_w}{\partial x} \right) + \frac{\partial}{\partial y} \left( \frac{\rho_w k_w}{\mu_w} \frac{\partial p_w}{\partial y} \right) + \frac{\partial}{\partial z} \left( \frac{\rho_w k_w}{\mu_w} \frac{\partial p_w}{\partial z} \right) = \frac{\partial}{\partial t} \left( \rho_w S_w \right) \tag{7}
\]
\[
\frac{\partial p}{\partial y} = -\frac{\rho_p f v_x^2}{R_{\text{sw}}} - \frac{\partial (\rho_m v_x^2)}{\partial y} - \rho_g \sin \theta - \frac{\partial (\rho_m v_y)}{\partial t} 
\]

(7)

2.1.2. Thermal Model. Based on the energy balance, the thermal model developed for a wellbore with multiphase flow is expressed as

\[
\frac{1}{r_v} \frac{\partial}{\partial r} \left( \frac{\beta}{\rho v C_p} \right) \frac{\partial T}{\partial r} = \frac{2U_{T,1}}{R_m (\rho v C_p)_T} (1 - T) + \left( \frac{\rho v C_K T}{(\rho v C_p)_T} \right) \frac{\partial p}{\partial y} - (\rho v)_T \sin \theta - \frac{\partial (\rho v)_T}{\partial y} 
\]

(8)

where

\[
\nu_T = \sum_a \nu_a h_a 
\]

(9)

\[
\left( \frac{\beta}{\rho v C_p} \right)_T = \left( \sum_a \frac{h_a \rho_a}{\rho v C_p} \right) 
\]

(10)

\[
(\rho v)_T = \sum_a \rho_a \nu_a h_a 
\]

(11)

\[
(\rho v C)_T = \sum_a \rho_a \nu_a h_a C_{pa} 
\]

(12)

\[
(\rho v C)_{T,1} = \sum_a \rho_a \nu_a h_a C_{pa} 
\]

(13)

\[
(\rho v C_K T)_{T} = \sum_a \rho_a \nu_a h_a C_{pa} K_{T,a} 
\]

(14)

\[
U_{T,1} = \gamma (\rho v C)_{T,1} + (1 - \gamma) U_T 
\]

(15)

2.1.3. Coupling of the Thermal Model. The heat transfer from the reservoir to the wellbore includes two forms: heat convection at perforated well segments and conduction at cemented wellbore areas.

Thus, the coupling of the temperature model in an MFHW at fracture locations and cemented areas should be carried out, respectively. The reservoir thermal model and wellbore thermal model are coupled as in cemented well segments:

\[
\Gamma_{\text{sw}} = \Gamma_{\text{sw}} \left( T_{\text{sw}} - T_{\text{rel}} \right) 
\]

(16)

in perforated well segments (fractures):

\[
\sum_a \left( \frac{\partial}{\partial r} \frac{\partial T_a}{\partial r} - \sum_a \left( \frac{\partial S_a}{\partial r} \frac{\partial T_a}{\partial r} - \frac{\partial}{\partial r} \frac{\partial T_a}{\partial r} \right) \right) + K_{T_a} \left( \frac{\partial T_a}{\partial r} + \frac{\partial T_a}{\partial r} \right) 
\]

(17)

The detailed derivation of the forward model has been presented in our previous study,\(^\text{37}\) in which a field application has been provided to validate the forward model.

2.2. Inversion Model. The inversion model includes three cores: an error objective function, an inversion algorithm, and a forward model. The error objective function characterizes errors between simulated DTS profiles and measured DTS data. The inversion algorithm is used to find the inversion solutions by eliminating or minimizing the inversion errors iteratively until the temperature convergences are reached.

2.2.1. Error Objective Function. The error objective function is a least-squared norm function, which is defined as

\[
\Gamma(x_{m}^{k}) = (\Delta T_{\text{cal}} - \Delta T_{\text{obs}})(\Delta T_{\text{cal}} - \Delta T_{\text{obs}})^{T} 
\]

(18)

2.2.2. Inversion Algorithm. The L–M algorithm\(^\text{36,46}\) is used to formulate the inversion model to update the inversion parameters in each iteration step by reducing the error objective function iteratively. The final target of an inversion task is to match the simulated DTS profile with the measured DTS data.

The L–M algorithm is an unconstrained optimization algorithm.\(^\text{47-49}\) During the process of inversion calculations, the inversion parameters updated by the L–M algorithm in each iteration step aim to reduce the least-squared norm (eq 18) step by step\(^\text{36,27,62}\).

The inversion solution of an inversion task cannot be obtained until it achieves the satisfactory accuracy, namely

\[
\Gamma(x_{m}^{k}) < \varepsilon 
\]

(19)

In the kth iteration, a simulated wellbore temperature profile can be generated by incorporating the kth updated inversion parameters (\(x_{m}^{k}\)) into the forward model, and the simulated temperature can be expressed as a vector

\[
\Delta T_{\text{cal}} = [T_{\text{cal}1}, T_{\text{cal}2}, \ldots, T_{\text{cal}N}] 
\]

(20)

Similarly, the measured DTS data vector is defined as

\[
\Delta T_{\text{obs}} = [T_{\text{obs}1}, T_{\text{obs}2}, \ldots, T_{\text{obs}N}] 
\]

(21)

Then, a temperature error at the kth iteration can be calculated by incorporating the above two vectors into eq 18. If the kth error satisfies eq 19, the inversion procedure is finished and the currently updated inversion parameters are the final solution of an inversion task. Otherwise, the inversion calculations move to the (k + 1)th iteration step, and the (k + 1)th inversion parameters are calculated as

\[
x_{m}^{k+1} = x_{m}^{k} + \Delta x_{m}^{k} 
\]

(22)

where \(\Delta x_{m}^{k}\) is the increment of the inversion parameters from the current iteration (kth) to the next iteration (k + 1)th, which is defined as

\[
\Delta x_{m}^{k} = [J^{T}(x_{m}^{k})](x_{m}^{k}) + \xi^{k} \Omega^{-1} J^{T}(x_{m}^{k}) e(x_{m}^{k}) 
\]

(23)

To obtain \(\Delta x_{m}^{k}\), we need to run the forward model \(N\) times in each iteration to obtain the temperature Jacobian matrix,\(^\text{36,26}\) which is expressed as

\[
J(x_{m}^{k}) = \begin{bmatrix}
\frac{\partial T_{1}(x_{m}^{k})}{\partial x_{m,1}} & \cdots & \frac{\partial T_{1}(x_{m}^{k})}{\partial x_{m,N}} \\
\vdots & \ddots & \vdots \\
\frac{\partial T_{N}(x_{m}^{k})}{\partial x_{m,1}} & \cdots & \frac{\partial T_{N}(x_{m}^{k})}{\partial x_{m,N}}
\end{bmatrix}
\]

(24)
\[
\begin{align*}
\frac{\partial T(x_m^k)}{\partial x_m^k} = & \frac{1}{\delta} \left[ \sum_{i=1}^{N} \left( T(x_m^k, x_{m,i}^k, x_{m,i}^k, x_{m,i}^k) - T(x_m^k, x_{m,i}^k, x_{m,i}^k) \right) \right] \\
& \delta
\end{align*}
\]

In eq 23, the diagonal matrix is given by
\[
\Omega^k = \text{diag}[J^T(\mathbf{x}_m^k)](\mathbf{x}_m^k)
\]

Subsequently, the \((k+1)\)th updated inversion parameters \((\mathbf{x}_m^{k+1})\) can be obtained by substituting eqs 23–24 into eq 22. Then, we move to the next iteration step to calculate the \((k+1)\)th temperature error.

If \(\Gamma(\mathbf{x}_m^{k}) < \epsilon_1\) or \(\|\mathbf{x}_m^{k+1} - \mathbf{x}_m^{k}\| < \epsilon_2\) (\(\epsilon_1\) and \(\epsilon_2\) are usually less than \(10^{-4}\)), the \((k+1)\)th updated inversion parameters \((\mathbf{x}_m^{k+1})\) are just the solution of a whole inversion task and the inversion procedure is accomplished. Otherwise, the above iteration steps should be repeated until \(\Gamma(\mathbf{x}_m^{k}) < \epsilon_1\) or \(\|\mathbf{x}_m^{k+1} - \mathbf{x}_m^{k}\| < \epsilon_2\). To avoid multiple solutions, even if a simulated temperature matches the observed DTS profile, we have to check whether the inverened production rate (gas and water) converges to the observed production of an MFHW. If yes, the whole inversion task is accomplished; otherwise, we move back to the initial assignment step and continue the iterative inversion calculations until the simulated temperature profile and production rate match the real measured one.

### 3. Results and Discussion

In this section, temperature behaviors in an MFHW with different water–gas ratio (WGR) distributions are simulated. From the simulation results, a convenient method is used to identify and locate water exits in an MFHW. Then, several synthetic cases are presented to demonstrate the application of the developed inversion system.

The basic inputs (reservoir, wellbore, and fluid properties) of the synthetic cases are shown in Table 1. The geometry of the reservoir and wellbore are shown in Figure 4. The inversion procedure is schematically shown in Figure 4. Schematic of the inversion procedure.

**Figure 4.** Schematic of the inversion procedure.

**Table 1. Basic Inputs of the Synthetic Cases**

| Reservoir | Wellbore |
|-----------|----------|
| reservoir length, m | 1000 | 700 |
| reservoir width, m | 600 | 0.22 |
| reservoir thickness, m | 20 | 0.14 |
| porosity, % | 10 | 0.12 |
| reservoir permeability, mD | 0.01 | roughness 0.0015 |
| wellhead temperature, K | 293 | cement thermal conductivity, J/(m·s·K) 6.9 |
| temperature gradient, K/m | 0.03 | wellbore dip, degree 0 |
| initial reservoir temperature, K | 351 | |
| initial pressure, MPa | 30 | |
| water saturation, % | 25 | |
| Rock | |
| rock density, kg/m³ | 2380 | |
| rock heat capacity, J/(kg·K) | 845 | |
| thermal conductivity, J/(m·s·K) | 3.45 | |
| Gas Phase | Water Phase |
| gas density, kg/m³ | 0.9 | water density, kg/m³ 1020 |
| gas viscosity, mPa·s | 0.025 | water viscosity, cP 0.3 |
| gas volume factor, m³/m³ | 0.004 | water heat capacity, J/(kg·K) 4230 |
| gas heat capacity, J/(kg·K) | 2550 | expansion coefficient, 10⁻⁷/K 2 |
| thermal conductivity, J/(m·s·K) | 0.00026 | water volume factor, m³/m³ 1.02 |
| expansion coefficient, 10⁻⁷/K | 10 | |
| compressibility, MPa⁻¹ | 0.026 | |

 exiteds are first identified and located, which lays a foundation for flow rate profile interpretation for a two-phase flow MFHW. A convenient method to diagnose the water exits based on the temperature characteristics on DTS profiles corresponding to a water inflow distribution is proposed. More details are presented in the following case studies. At the beginning of inversion calculations, an initial guess of an inflow rate in each fracture is performed. From a measured DTS profile, once we identify the productive fractures and water exits, the initial guess of an inflow rate can be given according to a temperature drop corresponding to each fracture.10,26 The most important point is to match a simulated wellbore temperature profile with the measured DTS profile through a large number of iterative calculations.

Using the developed inversion model, the inversion parameters are calculated and updated by reducing the temperature errors iteratively. At the kth inversion step, the kth updated inversion parameters \((\mathbf{x}_m^{k})\) are included in the forward model to generate a simulated DTS profile \((T_{\text{cal}})\). Then, the temperature error function \((\Gamma(\mathbf{x}_m^{k}))\) at the kth inversion step can be calculated from eq 18. If \(\Gamma(\mathbf{x}_m^{k}) > \epsilon_1\), we calculate the updated inversion parameters \((\mathbf{x}_m^{k+1})\) and move to the \((k+1)\)th iteration. The iterative calculations are not finished until \(\Gamma(\mathbf{x}_m^{k}) < \epsilon_1\) or \(\|\mathbf{x}_m^{k+1} - \mathbf{x}_m^{k}\| < \epsilon_2\). To avoid multiple solutions, even if a simulated temperature matches the observed DTS profile, we have to check whether the inverted production rate (gas and water) converges to the observed production of an MFHW. If yes, the whole inversion task is accomplished; otherwise, we move back to the initial assignment step and continue the iterative inversion calculations until the simulated temperature profile and production rate match the real measured one.

### 3. RESULTS AND DISCUSSION

In this section, temperature behaviors in an MFHW with different water–gas ratio (WGR) distributions are simulated. From the simulation results, a convenient method is used to identify and locate water exits in an MFHW. Then, several synthetic cases are presented to demonstrate the application of the developed inversion system.

The basic inputs (reservoir, wellbore, and fluid properties) of the synthetic cases are shown in Table 1. The geometry of the reservoir and wellbore are shown in Figure 4. The inversion procedure is schematically shown in Figure 4. Schematic of the inversion procedure.

**Figure 4.** Schematic of the inversion procedure.

exits are first identified and located, which lays a foundation for flow rate profile interpretation for a two-phase flow MFHW. A convenient method to diagnose the water exits based on the temperature characteristics on DTS profiles corresponding to a water inflow distribution is proposed. More details are presented in the following case studies. At the beginning of inversion calculations, an initial guess of an inflow rate in each fracture is performed. From a measured DTS profile, once we identify the productive fractures and water exits, the initial guess of an inflow rate can be given according to a temperature drop corresponding to each fracture.10,26 The most important point is to match a simulated wellbore temperature profile with the measured DTS profile through a large number of iterative calculations.

Using the developed inversion model, the inversion parameters are calculated and updated by reducing the temperature errors iteratively. At the kth inversion step, the kth updated inversion parameters \((\mathbf{x}_m^{k})\) are included in the forward model to generate a simulated DTS profile \((T_{\text{cal}})\). Then, the temperature error function \((\Gamma(\mathbf{x}_m^{k}))\) at the kth inversion step can be calculated from eq 18. If \(\Gamma(\mathbf{x}_m^{k}) > \epsilon_1\), we calculate the updated inversion parameters \((\mathbf{x}_m^{k+1})\) and move to the \((k+1)\)th iteration. The iterative calculations are not finished until \(\Gamma(\mathbf{x}_m^{k}) < \epsilon_1\) or \(\|\mathbf{x}_m^{k+1} - \mathbf{x}_m^{k}\| < \epsilon_2\). To avoid multiple solutions, even if a simulated temperature matches the observed DTS profile, we have to check whether the inverted production rate (gas and water) converges to the observed production of an MFHW. If yes, the whole inversion task is accomplished; otherwise, we move back to the initial assignment step and continue the iterative inversion calculations until the simulated temperature profile and production rate match the real measured one.

### 3. RESULTS AND DISCUSSION

In this section, temperature behaviors in an MFHW with different water–gas ratio (WGR) distributions are simulated. From the simulation results, a convenient method is used to identify and locate water exits in an MFHW. Then, several synthetic cases are presented to demonstrate the application of the developed inversion system.

The basic inputs (reservoir, wellbore, and fluid properties) of the synthetic cases are shown in Table 1. The geometry of the reservoir and wellbore are shown in Figure 4. The inversion procedure is schematically shown in Figure 4. Schematic of the inversion procedure.

**Figure 4.** Schematic of the inversion procedure.

exits are first identified and located, which lays a foundation for flow rate profile interpretation for a two-phase flow MFHW. A convenient method to diagnose the water exits based on the temperature characteristics on DTS profiles corresponding to a water inflow distribution is proposed. More details are presented in the following case studies. At the beginning of inversion calculations, an initial guess of an inflow rate in each fracture is performed. From a measured DTS profile, once we identify the productive fractures and water exits, the initial guess of an inflow rate can be given according to a temperature drop corresponding to each fracture.10,26 The most important point is to match a simulated wellbore temperature profile with the measured DTS profile through a large number of iterative calculations.

Using the developed inversion model, the inversion parameters are calculated and updated by reducing the temperature errors iteratively. At the kth inversion step, the kth updated inversion parameters \((\mathbf{x}_m^{k})\) are included in the forward model to generate a simulated DTS profile \((T_{\text{cal}})\). Then, the temperature error function \((\Gamma(\mathbf{x}_m^{k}))\) at the kth inversion step can be calculated from eq 18. If \(\Gamma(\mathbf{x}_m^{k}) > \epsilon_1\), we calculate the updated inversion parameters \((\mathbf{x}_m^{k+1})\) and move to the \((k+1)\)th iteration. The iterative calculations are not finished until \(\Gamma(\mathbf{x}_m^{k}) < \epsilon_1\) or \(\|\mathbf{x}_m^{k+1} - \mathbf{x}_m^{k}\| < \epsilon_2\). To avoid multiple solutions, even if a simulated temperature matches the observed DTS profile, we have to check whether the inverted production rate (gas and water) converges to the observed production of an MFHW. If yes, the whole inversion task is accomplished; otherwise, we move back to the initial assignment step and continue the iterative inversion calculations until the simulated temperature profile and production rate match the real measured one.
reservoir and hydraulic fractures is shown in Figure 5. The properties of each hydraulic fracture are summarized in Table 2.

![Figure 5. Geometry of hydraulic fractures for basic synthetic MFHW.](image)

Table 2. Fracture Properties of the Synthetic MFHW

| Parameters          | Frac 1 | Frac 2 | Frac 3 | Frac 4 | Frac 5 |
|---------------------|--------|--------|--------|--------|--------|
| Half-length (m)     | 180    | 120    | 200    | 100    | 150    |
| Width (m)           | 0.005  | 0.005  | 0.005  | 0.005  | 0.005  |
| Height (m)          | 20     | 20     | 20     | 20     | 20     |
| Conductivity (mD·cm) | 15     | 15     | 15     | 15     | 15     |

Only the influence of fracture half-length on wellbore temperature behavior and inversion issues are analyzed in this section because the work procedure for other inversion parameters such as fracture width and conductivity are similar.

3.1. Temperature Behavior of a Two-Phase MFHW. The temperature profiles of an MFHW with different water–gas ratio (WGR) distributions are simulated in this section. The synthetic MFHW is assumed to produce at a constant gas production rate of $20 \times 10^4$ m$^3$/day for 10 days. The water production rate is 100 m$^3$/day. The total WGR at the surface is 5:10 000 and the WGR in each fracturing stage is listed in Table 3. In case 1, all of the fractures are assumed to contribute to the water production and the WGR in each fracture is identical. In cases 2–4, the two-phase MFHW produces water from a single fracture at the toe, the heel, and the middle of the horizontal well segment. The inflow rate distribution and flow profile along the horizontal well are shown in Figure 6.

![Figure 6. Inflow rate and flow profiles of different synthetic cases.](image)

Similar to case 1, in case 3, although there is only a single hydraulic fracture at the toe producing water, the temperature profile trend is close to that in the MFHW with identical WGR distributions (basic case or case 1). The temperature variation between case 3 and the basic case is obviously smaller than that in case 1 because the wellbore temperature level is obviously higher on the whole (Figure 7a). Among these four cases, the differences between the temperature profiles of case 1 and the basic case are most significant and the temperature profile level is the highest. Because the wellbore pressure at the toe is the highest in case 1 (the lowest pressure drop at the toe) as can be seen from Figure 8, it would lead to the least energy loss from the reservoir to the wellbore; thus, the temperature at the toe is the highest in case 1 (Figure 9).

To the corresponding inflow rate and fracture half-length (Figure 9), thus, any sudden $\Delta T$ on the measured DTS profile at each perforation location denotes created hydraulic fractures (Figure 7).

Certainly, since the WGR distribution (water exit locations) in each case is different, the temperature profile in this MFHW under each WGR case shows its own specific characteristics. In case 1, the wellbore temperature distribution is very similar to that of the basic case, while the wellbore temperature level is obviously higher on the whole (Figure 7a). Among these four cases, the differences between the temperature profiles of case 1 and the basic case are most significant and the temperature profile level is the highest. Because the wellbore pressure at the toe is the highest in case 1 (the lowest pressure drop at the toe) as can be seen from Figure 8, it would lead to the least energy loss from the reservoir to the wellbore; thus, the temperature at the toe is the highest in case 1 (Figure 9).

![Figure 7. Temperature distributions in different water exit locations.](image)
The difference is that the wellbore temperature at the toe fracture in case 2 (Figure 7b) and the middle fracture in case 4 (Figure 7d) is higher than that in the basic case owing to the water production (marked by the blue circle).

As stated above, the temperature drop ($\Delta T$) is closely related to fracture half-length, and we calculate the corresponding ratio of $\Delta T$ and fracture half-length ($\Delta T/x_f$ ratio) for each fracture (Table 4). It is found that the $\Delta T/x_f$ ratio decreases from the toe to the heel when the WGR in an MFHW is identical (Figure 10).

In fact, this decreasing trend of the $\Delta T/x_f$ ratio from the toe to the heel reflects the ability of the inflow fluids from an individual fracture to cool the wellbore. This is because, once the inflow fluid from a single fracture enters the wellbore, the inflow fluids will mix with upstream fluid inside the wellbore at higher temperatures. With the accumulation of flow rate in the wellbore, the cooling ability of fluid from an individual fracture keeps decreasing from the toe to the heel.

Figure 7. Wellbore temperature distribution of an MFHW with different WGR distributions.

Figure 8. Wellbore pressure distribution of an MFHW with different WGR distributions.

Figure 9. $\Delta T$ at each fracture location along the wellbore temperature profile.
Moreover, the inflow water further decreases the cooling ability of a particular fracture because the production of water heats the wellbore. As can be seen from Figure 10b, an abnormal decrease of the $\Delta T/x_f$ ratio is observed in cases 2 and 4 (marked by the blue circle). Therefore, if an MFHW produces water from a single heel fracture or middle fracture, the $\Delta T/x_f$ ratio in the corresponding fracture (the heel fracture or the middle fracture) is obviously lower than that of the other fractures. In particular, as for case 3, the $\Delta T/x_f$ ratio decreases from the toe to the heel, which is in agreement with the basic case and case 1 (Figure 10a). It demonstrates that the temperature behavior in a two-phase MFHW on producing water from a single fracture at the heel is similar to that in an MFHW with identical WGR distributions. Still, an obviously abnormal decrease of the $\Delta T/x_f$ ratio for the heel fracture is observed (marked by the black circle in Figure 10a).

According to the specific temperature profile characteristics of an MFHW under different cases of WGR distributions, we can diagnose the water exit locations for a field MFHW from downhole temperature measurements. If the fracture parameters (e.g., half-length and width) are known, the $\Delta T/x_f$ ratio of each fracture can be found from a measured temperature profile directly. Then, a particular fracture with the production of water is easy to identify (similar to Figure 10). As for a two-phase MFHW with unknown fracture parameters, a temperature profile in the MFHW without the production of water at the early stage of production is needed (like the basic case). By comparing the temperature profiles in the MFHW with and without the production of water, the characteristics of a temperature difference between those two profiles provide an indication of water exit locations (similar to Figure 7).

### 3.2. Flow Rate Profile Interpretation from DTS Data.

From the above comparisons between temperature profiles in an MFHW with and without the production of water, it has been found that the wellbore temperature closely correlates to fracture parameters and WGR distributions (water exit locations). Thus, interpretation of the flow rate profile for two-phase MFHW can be made through the interpretation of fracture parameters and WGR distribution by inversion of DTS data. Due to the fact that an MFHW with different hydraulic

---

**Table 4. $\Delta T$ and Inflow Rate in Each Fracture**

|          | Frac 1     | Frac 2     | Frac 3     | Frac 4     | Frac 5     | total       |
|----------|------------|------------|------------|------------|------------|-------------|
| basic case | inflow gas, $10^4$ m$^3$/day | 4.7701 | 3.1866 | 5.3258 | 2.6776 | 0.0404 | 20.0005 |
|           | inflow water, m$^3$/day | 0 | 0 | 0 | 0 | 0 | 0 |
|           | $\Delta T$, K | 0.0635 | 0.0415 | 0.0652 | 0.0311 | 0.0433 | 0.2446 |
|           | $\Delta T/x_f$ K/m | 0.3528 | 0.3458 | 0.3260 | 0.3110 | 0.2887 | 1.6243 |
| Case 1    | inflow gas, $10^4$ m$^3$/day | 4.77 | 3.1865 | 5.3259 | 2.6775 | 0.0405 | 20.0004 |
|           | inflow water, m$^3$/day | 23.85 | 15.9325 | 26.6295 | 13.3875 | 20.0205 | 100.002 |
|           | $\Delta T$, K | 0.0561 | 0.0368 | 0.0586 | 0.0272 | 0.0389 | 0.2176 |
|           | $\Delta T/x_f$ K/m | 0.3117 | 0.3067 | 0.2930 | 0.2720 | 0.2593 | 1.4427 |
| Case 2    | inflow gas, $10^4$ m$^3$/day | 4.7703 | 3.1864 | 5.3255 | 2.6775 | 0.0404 | 20.0001 |
|           | inflow water, m$^3$/day | 100.0809 | 0 | 0 | 0 | 0 | 100.0809 |
|           | $\Delta T$, K | 0.0504 | 0.0416 | 0.0652 | 0.0312 | 0.0434 | 0.2318 |
|           | $\Delta T/x_f$ K/m | 0.2800 | 0.3467 | 0.3260 | 0.3120 | 0.2893 | 1.5540 |
| Case 3    | inflow gas, $10^4$ m$^3$/day | 4.7699 | 3.1865 | 5.3256 | 2.6774 | 0.0407 | 20.0001 |
|           | inflow water, m$^3$/day | 0 | 0 | 0 | 0 | 100.0073 | 100.0073 |
|           | $\Delta T$, K | 0.0611 | 0.0353 | 0.0542 | 0.0248 | 0.0286 | 0.2171 |
|           | $\Delta T/x_f$ K/m | 0.3394 | 0.2942 | 0.2712 | 0.2480 | 0.1903 | 1.4169 |
| Case 4    | inflow gas, $10^4$ m$^3$/day | 4.7697 | 3.1864 | 5.3264 | 2.6774 | 0.0403 | 20.0002 |
|           | inflow water, m$^3$/day | 0 | 0 | 100.0298 | 0 | 0 | 100.0298 |
|           | $\Delta T$, K | 0.0605 | 0.0415 | 0.054 | 0.0312 | 0.0433 | 0.2305 |
|           | $\Delta T/x_f$ K/m | 0.3361 | 0.3458 | 0.2700 | 0.3120 | 0.2887 | 1.5526 |

Figure 10. $\Delta T/x_f$ ratio of each fracture.
fractures and WGR may generate similar wellbore temperature profiles, to obtain a unique inversion solution, the basic parameters should be assumed to be known parameters.36,50

3.2.1. MFHW with Identical WGR Distributions. In this synthetic inversion case, all hydraulic fractures are assumed to produce water and the WGRs in all fractures are identical. The WGR distribution is the same as that of case 1 as listed in Table 3. The simulated temperature profiles in this MFHW with identical WGR distributions are assumed to be the measured temperature data (“real DTS data”). The basic parameters are the same as those in the former case (listed in Tables 1 and 2). The fracture half-length is chosen as the inversion target parameter in this case (the others are assumed to be known, Table 2).

As a start of the inversion task, an initial guess of the inflow rate of each hydraulic fracture is given according to the “observed ΔT” (listed in Table 5). Thus, as a start of the inversion procedure, the initial inflow rates of each fracture can be estimated as

$$Q_i = Q_{\text{sum}} \times \frac{\Delta T_i}{\sum_{i=1}^{n_p} \Delta T_i} \quad (27)$$

Then, the distribution of the initial inversion parameters (fracture half-length, etc.) can be determined through the forward model with the initial inflow rates as inputs.

Actually, the total WGR and water production rate can be directly measured at the surface for a field horizontal well. Owing to the assumption of identical WGR distributions in this case, the measured WGR at the surface equals the WGR of each fracture. The initial water production rate in each fracture is the product of the initial inflow rate and WGR. Following the inversion procedure, the inverted temperature profile is getting closer to the true temperature data step by step. Although the inverted inflow rate in each fracture at different iteration steps may be different, the WGR in each fracture at any iteration step must be kept constant.

Using the developed inversion system, the simulated temperature profile converges to the measured temperature data within finite iterative steps. The inversion results of the fracture half-length and flow profile are listed in Table 6.

As can be seen from Figure 11, the inverted temperature profile matches the real DTS data quite well (Figure 11a). The inversion solution of half-length is close to the “true value” (Figure 11b). According to the interpreted half-length, the obtained solutions of the gas flow profile in the wellbore are satisfactory (Figure 11c,d). The interpreted inflow water rate profile is highly consistent with the “observed” water rate profile as well (Figure 11e).

3.2.2. MFHW with a Single Fracture Producing Water. In this case, we demonstrate how to interpret the flow profile for a two-phase MFHW with water production from a single fracture. It is assumed that an arbitrary fracture (e.g., fracture 4 in this case) contributes to the water production. The generated temperature profile in this MFHW with the production of water from fracture 4 is used as the real DTS data. The simulated temperature profile in this MFHW without producing water is used as a reference temperature profile. For a field MFHW, the reference temperature profile can be obtained by monitoring a
Figure 11. Inversion results of the MFHW with identical WGR distributions.

Figure 12. Comparison of the reference temperature profile and the observed temperature profile.
temperature profile at the early production time when there is no water production yet.

Different from the former identical WGR distribution case, it is unknown which fracture is the exact one with the production of water before the inversion task begins. Thus, the identification of water exit locations must first be performed. As mentioned above, if we know the fracture parameters, we can calculate the $\Delta T/\chi_t$ ratio in each fracture and find the particular one with water production directly (similar to Figure 10). Due to the fact that the half-lengths of all fractures are unknown before the inversion task, the identification of water exits can only be performed by comparing the observed DTS profile and the reference temperature profile for this MFHW.

From the comparison of the above two temperature profiles (Figure 12), obviously, an abnormal temperature difference at fracture 4 (Figure 12b) is observed. The energy contained in the produced water further heats the inflow gas from the specific fracture with the production of water. The temperature difference at the location of this particular fracture is more significant. Thus, the specific fracture with the production of water can be identified. Unlike the former case, the measured WGR at the surface cannot be regarded as the WGR of the particular fracture with the production of water in this case, but the inversed water production rate in fracture 4 should match the “real” water production rate. The initial guess of the inflow rate is similar to that in the former case.

The inversion results in this case are listed in Table 6. Figure 13a shows that the inversed temperature profile reaches convergence with the real DTS data. Although, compared to the former case, the deviations of the inversed inflow rate and the
true value are a little greater, the inversion solutions of fracture half-length and flow profile are satisfactory (Figure 13b,c). It is found that the deviations between the “true inflow” of each fracture and the initial guessed inflow rate are greater than those in the aforementioned case, especially for fracture 4. Because the water inflow decreases $\Delta T$ in fracture 4 and the initial inflow rate is estimated according to $\Delta T$, the initial guessed inflow rate of this fracture is underestimated. However, it makes no difference to the accuracy of the inversion results, but slightly more iteration calculations are needed.

### 3.3. Field Application

This field case is presented to illustrate how the developed inversion system is applied to a field MFHW. Different from the synthetic cases, more unknowns must be confirmed before the inversion task begins.

#### 3.3.1. Well Information

Well HW_X1 is a cemented horizontal well with hydraulic fracturing treatment, which is located in Southwest of China. In total, 20 fracturing stages have been designed for this well. The well trajectory and fracturing plugs are shown in Figure 14. The length of the whole horizontal well section is 1196.4 m and the average depth of the pay zone is 3290 m below the surface. The average reservoir pressure is about 34.5 MPa for this well. A fiber-optic cable has been used to measure a downhole wellbore temperature distribution (DTS data). The average gas production rate is $18.4013 \times 10^4$ m$^3$/day during the DTS testing period. The measured water production rate at the surface is 9.40 m$^3$/day. The gas production rates of each fracturing stage were measured using a movable production logging tool (PLT) string. The downhole chemical tracers indicate that the produced water comes from stages 5 and 6. However, there is no further information about the exact inflow water rates of these two fracturing stages.

The measured DTS profile is shown in Figure 15. The geothermal temperature profile is estimated according to the well trajectory and the geothermal temperature gradient (about $2.9 ^\circ C$/100 m) for this reservoir block.

It is well known that during the fracturing treatment of a horizontal well, it is difficult to control the exact location of the effective fracture even if the perforation area is certain. Moreover, it is possible that some of the designed fracturing stages have not been stimulated effectively to generate a productively propped fracture. Thus, the identification of effective fractures from the measured DTS profile must be performed before the inversion task begins. It is worth mentioning that because the fracturing stages with inflow water have been addressed by downhole chemical tracers, we have to use the methods proposed above to diagnose the exact water exit locations from the DTS profile.

From the above temperature behavior analysis of MFHWs, it is clear that any sudden $\Delta T$ in the DTS profile can directly indicate an effective hydraulic fracture. According to this, we have identified and located the effective fractures for this well. It has been found that all of the fracturing stages have been stimulated effectively. The location of each fracture is marked as a red triangle in Figure 15.

#### 3.3.2. Flow Rate Profile Interpretation

Following the inversion procedure (Figure 3), as a start, the initial inflow rates are estimated according to the observed $\Delta T$ from the measured DTS profile (Figure 15). Because the cemented well segments are impermeable, there is no fluid entry at all.
16 shows the observed $\Delta T$ corresponding to the created fractures. The initial guessed inflow rates are shown in Figure 17. Then, according to the guessed inflow rate, the initial fracture parameters can be estimated. Due to the fact that the wellbore temperature behaviors are affected by both the fracture half-length and conductivity directly, to perform the inversion task, one of these two parameters should be assumed as known. Usually, during a fracturing treatment, the estimated conductivity can provide what we need. From the fracturing operation report, the average fracture conductivity of the well is about 16.5 mD-cm. Therefore, the focus of the inversion task for this gas–water two-phase flow MFHW is to interpret the fracture half-length and flow rate profile from the measured DTS data.

With the above-known inputs and assumptions, the simulated temperature profiles reach convergences with the measured DTS data within finite inversion steps and satisfactory inversion results have been obtained. The predicted temperature profile matches the measured DTS data very well (Figure 19). The maximum errors of the inversed temperature are less than 0.03 K and the error objective function is $3.12 \times 10^{-5}$.

The final inversed solution of the total production rate is $18.4005$ m$^3$/day; the absolute error of the inversed production rate is less than $9$ m$^3$/day. Figure 19 shows the inversed flow rate profile of this MFHW. On the flow rate profile, the height of each stair corresponds to the inflow rate of each fracture and the length denotes the fracture spacing.
The detailed inversed results of inflow rates and fracture half-length are shown in Figures 17 and 18, respectively. As can be seen from Figure 18, the fracture half-length corresponding to each fracturing stage differs significantly for this well. There exist obvious dominating fractures ($x_f > 80$ m) in stages 7 and 19. However, the average half-length of this well is about 57 m. Correspondingly, the interpreted inflow rates just validate the significant nonuniformity of the production contribution of each fracture (Figure 17). Comparing Figures 17 and 18, it is easy to notice that the interpreted gas inflow rates of stages 5 and 6 are the least two stages. However, the interpreted fracture half-lengths of these two stages are 64.65 and 76.37 m, respectively, which are far more than the averages of this well. This is because the water production limits the permeability of natural gas in stages 5 and 6. The interpreted inflow water rates of these two stages are 4.296 and 5.101 m$^3$/day, respectively. The inversed total water production rate is 9.397 m$^3$/day, which is close to the measured value (Figure 19).

Compared with the initial guessed inflow rates according to the observed $\Delta T$ (Figure 16), the inversed inflow rates of partial fractures are similar to those of the guessed ones (Figure 17). It demonstrates that the initial assignment of inflow rate based on the observed $\Delta T$ does help to speed the inversion computations. From the comparison of the interpreted inflow rate and measured data by PLT (Figure 20), it is clear that the interpreted inflow rates of all stages are close to the measured ones by PLT. The results of the inflow rate interpretation just provide good validation for the reliability of the developed inversion system in this study.

There is no doubt that there usually exist multiple-solution problems for inversion tasks. Since the fracture conductivity estimated during a fracturing process is available for this field application, we can directly obtain the inversion solution of fracture half-length. However, the inversion results merely from a set of DTS data may not be unique, especially for those field MFHWs with too many unknowns. $^{36,51}$ The obtained inversion solution could only be a data set of target parameters (such as $x_f$ and $F_{CD}$). To obtain a unique inversion solution of the inflow rate from DTS data, extra constraints (DAS$^{52}$ and RTA/PTA) would be helpful to eliminate or decrease the ambiguity of the inversion solution.

4. CONCLUSIONS

From the above analysis and discussion, the conclusions are summarized as follows:

1. In a DTS profile of an MFHW, any sudden $\Delta T$ at the perforation location denotes an effective fracture. A temperature drop ($\Delta T$) at each cluster location is basically proportional to an inflow rate and fracture half-length.

2. For an MFHW with identical WGRs, the $\Delta T/x_f$ ratio in each fracture decreases from the toe to the heel. When the two-phase MFHW produces water from a single fracture, there exists an abnormal decrease in the $\Delta T/x_f$ ratio for the corresponding fracture. The specific temperature characteristics of an MFHW with different WGRs

Figure 19. Interpreted flow rate profile and DTS profile matching for the whole well.

Figure 20. Comparison of inversed inflow rate with PLT data.
distributions provide direct indicators to diagnose water exits for a two-phase MFHW.

(3) Identification of water exit locations lays a foundation for the flow rate profile interpretation for a two-phase MFHW. Two convenient methods have been introduced to diagnose and locate water exit locations for an MFHW when there are known or unknown fracture parameters, respectively.

(4) From the synthetic cases, the interpreted flow profiles and fracture half-length from DTS data are close to the true values. The interpreted inflow water rate profile is coincident with the observed water rate profile as well. This provides good validation for the feasibility of this inversion system to interpret the flow rate profile from measured DTS data for a two-phase MFHW.

(5) A satisfactory inversion solution (the error objective function is $3.12 \times 10^{-5}$ and the maximum temperature error $<0.03$ K) of the field case is obtained. The absolute error of the inverted total gas production rate is less than 9 m$^3$/day and the inversed water rate is close to the measured values at the surface. Moreover, the interpreted inflow rates of all stages are close to the PLT data. The inversion results of the filed case validate the reliability of the developed inversion system in the quantitative interpretation of flow rate profiles for an MFHW with a gas–water two-phase flow.

## AUTHOR INFORMATION

### Corresponding Authors

Hongwen Luo — State Key Laboratory of Oil & Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China; Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, Calgary, Alberta T2N 1N4, Canada; Email: rojielhw@163.com

Haitao Li — State Key Laboratory of Oil & Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China; Email: lihaitao@swpu.edu.cn

### Authors

Beibei Jiang — State Key Laboratory of Oil & Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China

Ying Li — State Key Laboratory of Oil & Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China; Robert Frederick Smith School of Chemical and Biomolecular Engineering, Cornell University, Ithaca, New York 14853, United States; Email: orcid.org/0000-0001-8780-1182

Zhangxin Chen — Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, Calgary, Alberta T2N 1N4, Canada

Complete contact information is available at: https://pubs.acs.org/10.1021/acsomega.0c02639

### Notes

The authors declare no competing financial interest.

## ACKNOWLEDGMENTS

The National Science and Technology Major Project of China (2016ZX05021-005-009HZ) provided funding for this study. The authors are grateful to the Southwest Petroleum University and University of Calgary for technical support.

## NOMENCLATURE

- $A$ surface area of the wellbore segment, m$^2$
- $C_p$ gas compressibility, MPa$^{-1}$
- $C_p$ heat capacity of fluid, J/(kg·K)
- $C_{p, r}$ heat capacity of solid reservoir rock, J/(kg·K)
- $d_f$ fracture spacing, m
- $e(x_{in})$ error term of wellbore temperature
- $f$ friction coefficient
- $f_{cd}$ fracture conductivity, mD·cm
- $g$ gravitational acceleration, m/s$^2$
- $h_f$ fracture height, m
- $J(x_{in})$ Jacobian matrix
- $k$ permeability, mD
- $k_f$ fracture permeability, mD
- $K_T$ Joule–Thomson coefficient, K/MPa
- $k_r$ relative permeability of fluid, mD
- $k_g$ relative permeability of gas
- $k_w$ relative permeability of water
- $K_T$ reservoir heat conductivity, J/(m·s·K)
- $k_T$ reservoir permeability in the $x$ direction, mD
- $k_y$ reservoir permeability in the $y$ direction, mD
- $k_z$ reservoir permeability in the $z$ direction, mD
- $L_x$ reservoir width, m
- $L_y$ reservoir length, m
- $L_z$ reservoir height, m
- $n_f$ number of fractures
- $p$ flow pressure in formation, MPa
- $q_{F_g}$ gas flow rate in fracture, m$^3$/day
- $q_{F_w}$ water flow rate in fracture, m$^3$/day
- $Q$ inflow rate of the $i$th fracture, m$^3$/day
- $Q_{sum}$ flow rate of the whole well, m$^3$/day
- $q_{wb}$ conduction heat transfer rate per unit volume, J/(m$^3$·s)
- $T$ thermal conductivity transfer rate, J/s
- $r$ radius, m
- $r_{eff}$ effective radius, m
- $r_{in}$ inner radius of the wellbore, m
- $r_w$ radius of wellbore, m
- $S_g$ gas saturation, %
- $S_w$ water saturation, %
- $S_i$ production time, days
- $T$ reservoir temperature, K
- $T_{cal}$ calculated temperature profile
- $T_{f}$ fluid temperature in the fracture, K
- $T_{in}$ inflow temperature, K
- $T_{obs}$ observed temperature profile
- $T_{res}$ reservoir temperature, K
- $T_{well}$ wellbore temperature, K
- $v$ velocity of fluid, m/s
- $v_{cal}$ apparent velocity of gas/water, m/s
- $W_f$ fracture width, m
- $x_f$ half of the reservoir width, m
- $x_{in}$ fracture half-length, m
- $x_{in}$ inversion parameters
- $y_r$ half of the reservoir length, m
- $Z$ deviation factor of gas, nondimensional
- $z$ half of the reservoir height, m
SUPERSRIPT

\( k \) number of iterations for the inversion procedure

SUBSCRIPTS

\( \text{eff} \) effective
\( \text{f} \) fluid
\( \text{F} \) in hydraulic fractures
\( \text{g} \) gas phase
\( \text{I} \) inflow
\( \text{m} \) mixed fluids
\( \text{s} \) solid reservoir rock
\( \text{w} \) water phase
\( \text{wb} \) wellbore
\( \alpha \) a single-phase fluid (gas or water)

GREEK LETTERS

\( \psi \) pseudopressure, MPa²/m²·s
\( \mu \) fluid viscosity, mP·s
\( \beta \) thermal expansion coefficient, 10^{-4}/K
\( \phi \) porosity of formation, fraction
\( \sigma_F \) porosity of fracture, fraction
\( \mu_{g} \) gas viscosity, mP·s
\( \sigma \) non-Darcy factor, nondimensional
\( \sigma_{g}^{x} \) non-Darcy factor in the \( x \) direction, nondimensional
\( \sigma_{g}^{y} \) non-Darcy factor in the \( y \) direction, nondimensional
\( \sigma_{g}^{z} \) non-Darcy factor in the \( z \) direction, nondimensional
\( \rho \) density of fluid, kg/m³
\( \rho_{C_p} \) average heat capacity, J/(kg·K)
\( \rho_{I} \) density of inflow fluid, kg/m³
\( \rho_{s} \) pseudo-reduced density, nondimensional
\( \gamma \) pipe-open ratio, fraction
\( \theta \) dip of horizontal well sections, degree
\( \Delta T \) temperature drop, 10^{-3} K
\( \Delta x \) vmesh size in the \( x \) direction, m
\( \Delta x_m^{i} \) increment of inversion parameters
\( \Delta y \) mesh size in the \( y \) direction, m
\( \Delta T_i \) the observed temperature drop corresponding to the \( i \)th fracture, K
\( \Delta z \) mesh size in the \( z \) direction, m
\( \Omega \) diagonal matrix
\( \zeta \) the damping factor

ABBREVIATIONS

DAS distributed acoustic sensor
DTS distributed temperature sensor
L–M Levenberg–Marquardt
MFHW multifractured horizontal well
PLT production logging tool
RTA rate transient analysis
PTA pressure transient analysis

REFERENCES

(1) Tang, H.; Killough, J. E.; Heidari, Z.; Sun, Z. In A New Technique to Characterize Fracture Density Using Neutron Porosity Logs Enhanced by Electrically-Transported Contrast Agents, SPE Technical Conference and Exhibition; 2016.
(2) Zhang, J.; Xing, Y.; Zheng, L. Using artificial intelligent technique to identify fractures. Well Logging Technol. 2005, 29, 52–54.
(3) Zhang, T.; He, Y.; Ding, K.; Wang, Z.; Ding, L.; He, F. Discussion on Identification of Artificial Fracture for Deep Sandstone Reservoir in Junggar Basin-Applications in Mobei Oil and Gas Field; Xinjiang Petroleum Science & Technology, 2003; pp 9–12.

(4) Cui, J.; Yang, C.; Zhu, D.; Datta-Gupta, A. Fracture Diagnosis in Multiple-Stage-Stimulated Horizontal Well by Temperature Measurements With Fast Marching Method. SPE J. 2016, 21, 2289–2300.
(5) Rui, Z.; Cui, K.; Wang, X.; Lu, J.; Chen, G.; Ling, K.; Patil, S. A quantitative framework for evaluating unconventional well development. J. Pet. Sci. Eng. 2018, 166, 900–905.
(6) Chen, M.; Kang, Y.; Zhang, T.; You, L.; Li, X.; Chen, Z.; Wu, K.; Yang, B. Methane diffusion in shales with multiple pore sizes at supercritical conditions. Chem. Eng. J. 2018, 334, 1455–1465.
(7) Cui, J.; Zhu, D.; Jin, M. Diagnosis of Production Performance After Multistage Fracture Stimulation in Horizontal Wells by Downhole Temperature Measurements. SPE Prod. Oper. 2016, 31, 280–288.
(8) Li, J.; Liang, B.; Zeng, Y.; Huang, C.; Lu; W.; Shen, J.; Ge, L. The application of gas-production profile logging data in the development of Jiaoshiba shale gas field in Fuling area. J. Yangtze Univ. (Ed. Nat. Sci.) 2017, 14, 75–81.
(9) Wang, F. Determination Method of Gas Production Contribution of Multistage Fractured Horizontal Well in Shale Gas Reservoir; Liaoqing Chemical Industry, 2017; pp 989–993.
(10) Luo, H.; Li, H.; Li, Y.; Lu, Y.; Tan, Y. Investigation of temperature behavior for multi-fractured horizontal well in low-permeability gas reservoir. Int. J. Heat Mass Transfer 2018, 127, 375–395.
(11) Sierra, J.; Kaura, J.; Guatierii, D.; Glasbergen, G., Sarker, D.; Johnson, D. DTS Monitoring of Hydraulic Fracturing: Experiences and Lessons Learned, SPE Annual Technical Conference and Exhibition; 2008.
(12) Sookprasong, P. A.; Hurt, R. S.; Gill, C. C. In Downhole Monitoring of Multicluster, Multistage Horizontal Well Fracturing with Fiber Optic Distributed Acoustic Sensing (DAS) and Distributed Temperature Sensing (DTS), International Petroleum Technology Conference; 2014.
(13) Sookprasong, P. A.; Hurt, R. S.; Gill, C. C.; Lafollette, R. In Fiber Optic DAS and DTS in Multicluster, Multistage Horizontal Well Fracturing: Interpreting Hydraulic Fracture Initiation and Propagation through Diagnostics, SPE Annual Technical Conference and Exhibition; 2014.
(14) Sookprasong, P. A.; Gill, C. C.; Hurt, R. S. In Lessons Learned from DAS and DTS in Multicluster Multistage Horizontal Well Fracturing: Interpretation of Hydraulic Fracture Initiation and Propagation through Diagnostics, IADC/SPE Asia Pacific Drilling Technology Conference; 2014.
(15) Molenaar, M. M.; Fidan, E.; Hill, D. In Real-Time Downhole Monitoring of Hydraulic Fracturing Treatments Using Fibre Optic Distributed Temperature and Acoustic Sensing, SPE/EAGE European Unconventional Resources Conference and Exhibition; 2012.
(16) Gustavo, A.; Ugueto, C.; Huckabee, P. T.; Molenaar, M. M.; Wyker, B.; Somanchi, K. Perforation Cluster Efficiency of Cemented Plug and Perf Limited Entry Completions; Insights from Fiber Optics Diagnostics, 2016.
(17) Ramey, H. J., Jr. Wellbore Heat Transmission. J. Pet. Technol. 1962, 14, 427–435.
(18) Hasan, A. R.; Kabir, C. S. Aspects of Wellbore Heat Transfer During Two-Phase Flow (includes associated papers 30226 and 30970). SPE Prod. Facil. 1994, 9, 211–216.
(19) Kabir, C. S.; Hasan, A. R.; Jordan, D. L.; Wang, X. A Wellbore/Reservoir Simulator for Testing Gas Wells in High-Temperature Reservoirs. SPE Form. Eval. 1996, 11, 128–134.
(20) Brady, J. L.; Watson, B. A.; Warner, D. W.; North, R. J.; Sommer, D. M.; Colson, J. L.; Kleinberg, R. L.; Wolcott, D. S.; Sezginer, A. In Improved Production Log Interpretation in Horizontal Wells Using a Combination of PulsedNeutron Logs, Quantitative Temperature Log Analysis, Time Lapse LWD Resistivity Logs and Borehole Gravity, SPE Western Regional Meeting, Bakersfield, California; Society of Petroleum Engineers, 1998.
(21) Carnegie, A.; Roberts, N.; Clyne, I. In Application of New Generation Technology to Horizontal Well Production Logging—Examples from the North West Shelf of Australia, SPE Asia Pacific Oil and Gas Conference and Exhibition, Perth, Australia; Society of Petroleum Engineers, 1998.
(22) Chace, D.; Wang, J.; Mirzwiniski, R.; Maxit, J.; Trcka, D. In Applications of a New Multiple Sensor Production Logging System for Horizontal and Highly-Deviated Multiphase Producers, SPE Annual Technical Conference and Exhibition, Dallas, Texas; Society of Petroleum Engineers, 2000.
(23) Yoshika, K. Detection of Water or Gas Entry Into Horizontal Wells by Using Permanent Downhole Monitoring Systems; Texas A&M University, 2007.
(24) Yoshika, K.; Zhu, D.; Hill, A. D.; et al. A New Inversion Method To Interpret Flow Profiles From Distributed Temperature and Pressure Measurements in Horizontal Wells. SPE Prod. Oper. 2009, 24, S10–S21.
(25) Li, Z.; Zhu, D. Predicting Flow Profile of Horizontal Well by Downhole Pressure and Distributed-Temperature Data for Waterdrive Reservoir. SPE Prod. Oper. 2010, 25, 296–304.
(26) Zhu, S. Theoretical Study on the Interpretation of Inflow Profile Based on the Distributed Optical Fiber Temperature Sensing; Southwest Petroleum University, 2016.
(27) Zhu, S.; Li, H.; Wang, Y. Analysis of temperature behavior in the horizontal well based on temperature modeling and distributed temperature sensing. Pet. Sci. Technol. 2016, 34, 1678–1684.
(28) Yoshida, N.; Zhu, D.; Hill, A. D. Temperature-Prediction Model for a Horizontal Well With Multiple Fractures in a Shale Reservoir. Spe Prod. Oper. 2014, 29, 261–273.
(29) Yoshika, K.; Zhu, D.; Hill, A. D.; Dawkrajai, P.; Lake, L. W. Prediction of Temperature Changes Caused by Water or Gas Entry into a Horizontal Well. SPE Prod. Oper. 2007, 22, 425–433.
(30) Yoshida, N.; Hill, A. D.; Zhu, D. Comprehensive Modeling of Downhole Temperature in a Horizontal Well with Multiple Fractures, In SPE Asia Pacific Hydraulic Fracturing Conference; 2016.
(31) Yoshida, N. Modeling and Interpretation of Downhole Temperature in a Horizontal Well with Multiple Fractures; Texas A&M University, 2016.
(32) Cai, J. Study on Prediction and Interpretation Model of Wellbore Temperature for a Horizontal Well; Southwest Petroleum University, 2016.
(33) Zhu, S. Theoretical study on the interpretation of inflow profile based on the distributed optical fiber temperature sensing; Southwest Petroleum University, 2016.
(34) Li, Z. Interpreting horizontal well flow profiles and optimizing well performance by downhole temperature and pressure data; Texas A&M University, 2010.
(35) Cui, J. Diagnosis of Multiple Fracture Stimulation in Horizontal Wells by Downhole Temperature Measurements; Texas A&M University, 2015.
(36) Zhang, S.; Zhu, D. In Inversion of Downhole Temperature Measurements in Multistage Fracture Stimulation in Horizontal Wells, SPE Technical Conference and Exhibition; 2017.
(37) Luo, H.; Li, H.; Zhou, X.; Li, Y.; Li, Y.; Zhu, X. Modeling temperature behavior of multistage fractured horizontal well with two-phase flow in low-permeability gas reservoirs. J. Pet. Sci. Eng. 2019, 173, 1187–1209.
(38) Luo, H.; Li, H.; Lu, Y.; Li, Y.; Guo, Z. Inversion of distributed temperature measurements to interpret the flow profile for a multistage fractured horizontal well in low-permeability gas reservoir. Appl. Math. Modell. 2020, 77, 360–377.
(39) Qu, Z.; Huang, D.; Li, X.; Hu, L.; Li, Y.; Fu, W.; Zhang, W. Research and Application of Fracture Parameter Optimization of Fractured Horizontal Well in Low Permeability Gas Reservoir; Fault-Block Oil & Gas Field, 2014; Vol. 21, pp 486–491.
(40) Ma, X.; Fan, F.; Zhang, S. Fracture Parameter Optimization of Horizontal Well Fracturing in Low Permeability Gas Reservoir. Nat. Gas Ind. 2005, 25, 61–63.
(41) Yan, W. Improvement of the Mathematical Model of Gas–Water Two-Phase Flow in Low-Permeability Gas Reservoir and its Application in Numerical Simulation; Southwest Petroleum University, 2005.
(42) Chen, Z. In Reservoir Simulation: Mathematical Techniques in Oil Recovery, CBMS-NSF Regional Conference Series in Applied Mathematics; SIAM: Philadelphia, 2007.