Petroleum Reservoir Evaluation and Development No. 4

Citation: LU Cong, LI Qiuyue, GUO Jianchun. Research progress of distributed optical fiber sensing technology in hydraulic fracturing[J]. Petroleum Reservoir Evaluation and Development, 2024, 14(4): 618–628.

Research progress of distributed optical fiber sensing technology in hydraulic fracturing

LU Cong, LI Qiuyue, GUO Jianchun

State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, Sichuan, China

Abstract: Distributed optical fiber sensing technology, a cutting-edge method for monitoring hydraulic fracturing, has been successfully applied in various oil fields to enable real-time monitoring, achieving notable results. This paper aims to enhance industry understanding of the basic principles, theoretical model research progress, and field applications of different types of sensing technologies. The discussion begins with the foundational principles of distributed optical fiber temperature sensing and acoustic sensing technologies used in hydraulic fracturing. It systematically reviews the research progress of theoretical models for these technologies and their application in monitoring liquid production profiles and crack propagation morphologies. The paper concludes by suggesting future directions for the development of distributed fiber sensing technology. The findings indicate that: (1) Distributed optical fiber sensing technology can convert temperature or acoustic wave signals into data reflecting ambient temperature or strain changes, facilitating real-time monitoring during hydraulic fracturing. (2) Maturity of Temperature Sensing Models: Compared to acoustic sensing, the theoretical models for temperature sensing technology are more mature, enabling accurate calculations of liquid production profiles and fracture morphologies. (3) Application in Hydraulic Fracturing: The technology is primarily used to monitor fracturing fluid injection and fracture propagation, crucial aspects of the hydraulic fracturing process. In conclusion, distributed optical fiber sensing technology significantly advances the exploration and development of unconventional reservoirs in China. It enhances hydraulic fracturing effect evaluation techniques, playing a vital role in the sustainable development of the Chinese oil and gas industry. **DOI:** 10.13809/j.cnki.cn32-1825/te.2024.04.012-en

Keywords: distributed optical fiber sensing technology; temperature sensing technology; acoustic wave sensing technology; hydraulic fracturing monitoring; liquid production profile; fracture propagation

Hydraulic fracturing technologies have presented a rapid development trend in recent years and corresponding monitoring technologies also receive more and more attention. The latest technical development tendency indicates that distributed optical fiber sensing technology has been the most promising and feasible technical approach in hydraulic fracturing monitoring [1]. The distributed optical fiber sensing technology makes demodulation on optical signals by means of backscattering waves to achieve temperature and acoustic sensing [2]. This technology used in hydraulic fracturing monitoring at present includes Distributed Temperature Sensing (DTS) technology and Distributed Acoustic Sensing (DAS) technology [3–4]. It can manage real-time monitoring in a whole well section with a higher accuracy and is free of influence from electromagnetic radiation, by comparison with conventional hydraulic fracturing monitoring technologies. However, it appears at a later stage and possesses inadequate theoretical models and interpretation technologies [5–6].

The primary research progress for theoretical models of the distributed optical fiber sensing technology is embodied in the explanation and analysis of liquid production profile distribution after fracturing by DTS technology. The explanation and analysis of liquid production profile distribution after fracturing refers to that oil and gas reservoirs are coupled with wellbores of horizontal wells to construct a prediction and interpretation model for temperature profiles in wellbores. Furthermore, the permeability and liquid production profile distribution along horizontal wells can be known through the inversion of data about temperature profiles in wellbores [7]. In addition, DTS technology is applied earlier in hydraulic fracturing, and it can arrive at real-time monitoring for temperature profiles in the whole well section and process during the hydraulic fracturing process. Hydraulic fracture propagation information can be mastered through demodulation calculation on optical signals. Excepting the wide application of DTS technology in hydraulic fracturing monitoring, DAS technology also emerges gradually with the large-scale implementation of the multi-cluster perforation fracturing technology in horizontal wells during the development process of unconventional reservoirs. DAS technology is first employed in military, communication, engineering and other fields. It was adopted in the international oil and gas field in 2002 and has become a research focus currently [8–10]. This technology can perform real-time and permanent monitoring of acoustic signals along wellbores

---

Received: 2023-08-18

during the hydraulic fracturing process and is a highly promising hydraulic fracturing monitoring method. Unfortunately, the research on its theoretical models remains in the initial stage, with a lack of corresponding prediction and interpretation models. Overall, the research and application of theoretical models for distributed optical fiber sensing technology are significant for the development of hydraulic fracturing monitoring technology and the effective exploration of unconventional oil and gas resources.

Besides, after the technical principles of DTS and DAS are introduced, the research progress of their theoretical models is systematically analyzed to summarize their application as well as development during the hydraulic fracturing process. Thus, it provides a reference for the understanding of the basic principles and application of distributed optical fiber sensing technology.

1 Principles and underground installation of distributed optical fiber sensing technology

The basic principle of distributed optical fiber sensing technology is that optical fibers are taken as sensing elements to collect and analyze optical signals in backscattering lights transmitted by optical fibers based on the principle of Optical Time-Domain Reflectometry (OTDR). Eventually, it is designed to further conduct real-time monitoring of the changes in ambient temperature, pressure and other factors around optical fibers. Demodulation can precisely reflect the ambient changes around optical fibers when a variation occurs in the strength, phase, spectrum, coherence and other parameters of optical signals [11].

The OTDR principle was first proposed by ROGERS [12–13] at the end of the 1970s. It relies on the time resolution that pulse spreads backscattering lights to measure the spatial distribution of the polarization property in optical fibers, providing important technical support for the achievement of distributed optical fiber sensing monitoring. The backscattering of optical signals mainly contains three types, namely Rayleigh scattering, Raman scattering and Brillouin scattering. DTS technology employs the optical backward Raman scattering effect [14–15].

1.1 DTS mechanism

When incident light propagates through an optical fiber medium, scattering occurs primarily in the forward or backward direction due to the confinement of the fiber. Raman scattering, a type of backward scattering, is particularly sensitive to the temperature of the fiber's surrounding environment and is minimally affected by other signals. As an inelastic scattering process, Raman scattering conserves the total energy during the generation of scattered light, resulting in the optical fiber medium either absorbing or releasing the energy difference between the incident and scattered light. When the fiber medium absorbs energy, Stokes scattering occurs; when it releases energy, anti-Stokes scattering occurs. The scattering spectrum within the optical fiber is shown in Fig. 1 [16].

Experimental studies have shown that anti-Stokes scattering is highly sensitive to temperature, with its intensity modulated by temperature changes. From the perspective of quantum energy levels, when photons interact with molecules, anti-Stokes scattering—a nonlinear optical effect—occurs. Photons in this process are excited and migrated to molecules with a high energy state, and finally emancipate energy to produce scattering photons. Then, molecules take in the energy of photons and disentangle the energy in the manner of inelastic collision, strengthening the intensity of anti-Stokes scattering lights. As for that, the number of molecules in the vibrationally excited state determines the intensity of scattering lights. Since higher temperatures lead to a greater population of molecules in the excited state, the intensity of anti-Stokes scattering increases with temperature. In contrast, the intensity of Stokes scattering is independent of temperature. Therefore, by analyzing the ratio of anti-Stokes to Stokes intensities, it is possible to infer temperature variations around the optical fiber. This principle forms the basis of DTS technology [17].

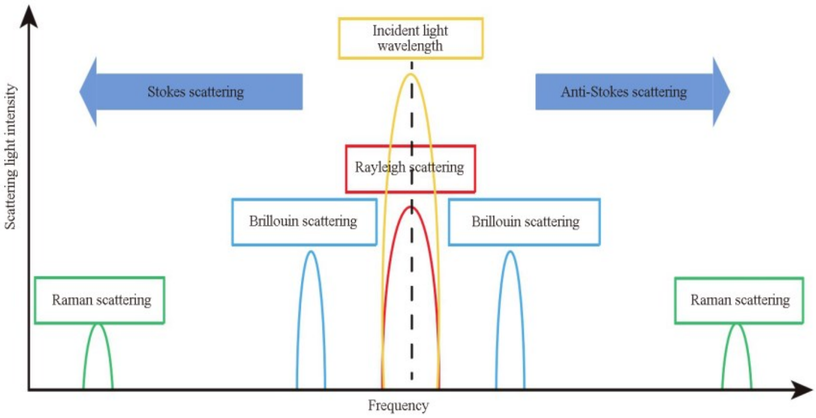

Fig. 1 Scattering spectra in optical fibers [16]

1.2 DAS mechanism

Similar to Raman scattering, Brillouin scattering also has the sensitivity to external temperature, but its smaller frequency shift, narrower bandwidth and demanding lasers limit its wide application. Rayleigh scattering is noticed by fewer people in the initial development of distributed optical fiber technology for its insensitivity to temperature changes. JUSKAITIS et al. [18–19] and SHATALIN et al. [20] corroborated through experiments that the coherence effect of Rayleigh scattering is sensitive to the strain of optical fibers in 1992–1994. It indicates that the distributed optical fiber sensing technology based on Rayleigh scattering can measure the strain changes around optical fibers, and then DAS technology following this principle is gradually emphasized. The advancement of phase-sensitive OTDR technology gives birth to the accomplishment of quantitative real-time monitoring on the stress changes of external disturbance points along optical fibers. Micro strain will occur in optical fibers if it is triggered by acoustic waves or other vibrations around optical fibers. A linear relationship is presented between phase changes and this micro disturbance, and thus the overall phase retardation change can be expressed as

$$\Delta\varphi = \beta\Delta l + l\Delta\beta = \beta l\frac{\Delta l}{l} + l\left(\frac{\partial\beta}{\partial n}\right)\Delta n + l\left(\frac{\partial\beta}{\partial\alpha}\right)\Delta\alpha \qquad (1)$$

where $\Delta\varphi$ is phase retardation change; β is a transmission constant; Δl is the changes from length of optical fibers in m; l is the length of optical fibers in m; $\Delta\beta$ is the changes in the transmission constant; n is the fiber core refractive index of optical fibers; Δn is the changes in the fiber core refractive index of optical fibers; α is the diameter of the fiber core in μm; $\Delta\alpha$ is the changes in the diameter of the fiber core in μm.

The refractive index of optical fibers at a corresponding location may vary with the disturbance around them owing to their elastic-optic effect. Therefore, Rayleigh scattering in the fiber core of optical fibers interferes with the variation in the phase of optical signals [21]. Apart from the phase, intensity, frequency and other parameters of lights may also shift with strain changes around optical fibers. As a result, the strain changes around optical fibers can be comprehended through the analysis of changes in such parameters, which is called the basic principle of DAS technology.

The monitoring technology for strain changes around optical fibers is known as Distributed Strain Sensing (DSS) technology. DSS technology comprises Distributed Strain Sensing based on Brillouin Scattering, Distributed Strain Sensing based on weak fiber Bragg gratings and Distributed Strain Sensing Based on Rayleigh Frequency Shift (DSS-RFS). Among them, the last one embraces higher accuracy than the first two. DSS-RFS has been gradually accepted in the petroleum field over recent years. The basic principle for this method is explained as follows: Constructive and destructive interference among Rayleigh backscattering in a certain laser frequency results in the irregular amplitude fluctuation of coherent OTDR (C-OTDR) along the length of optical fibers, further acquiring a unique Rayleigh scattering spectrum. The frequency shift of the Rayleigh scattering spectrum may vary in the case that the temperature or strain changes in the cross-section of optical fibers. It is required that DTS be separately used to measure temperature changes on multi-mode optical fibers from cables, which are the same as DSS-RFS optical fibers, for elimination of the frequency shift changes caused by temperature changes and to further removal of the influence of temperature changes. The inherent distinction between DSS-RFS and DAS technologies lies in that the former measures the amplitude of Rayleigh scattering under various laser frequencies, but DAS assesses the phase difference of Rayleigh scattering under a single frequency. Different measurement conditions introduce two distinguishable measurement approaches in terms of spatial and temporal resolution [22].

1.3 Underground installation of distributed optical fibers

Primary installation methods for distributed optical fibers involve outside casings, outside tubing and inside tubing. The arrangement of outside casings points to that optical fibers are fixed on casings outside during the completion process. This method can directly monitor cementing and completion, the temperature of near-well fluids during the whole fracturing production, formation strain caused by fracture initiation and propagation, etc. The deployment in outside tubing means that optical fibers are attached to the outside walls of tubing and enter wells with tubing, which can monitor the temperature dynamics of fluids in tube-casing annulus. The placement inside tubing generally uses heavier rods or coiled tubing to put optical fibers into wells. It is a recyclable mounting process and suitable to monitor temperature and pressure distribution within wellbores [23–25].

2 Research progress about theoretical models of DTS

With the continuous development of DTS technology, its application in hydraulic fracturing monitoring across various oil and gas fields has become increasingly widespread, placing higher demands on the advancement and refinement of temperature monitoring theoretical models.

2.1 A flow heat transfer model within wellbores

In 1962, RAMEY [26] established a foundational heat transfer model for wellbores, which has served as the basis for many subsequent temperature monitoring models. Ramey developed a wellbore-formation heat transfer model based on the energy equation and the conservation of mechanical energy. The model accounts for heat resistance within the wellbore, assuming steady-state heat transfer inside the wellbore, while heat transfer toward the surrounding formation is modeled as unsteady radial conduction.

$$T_1(z,t) = aZ + b - aA + (T_0 + aA - b)\mathrm{e}^{-z/A} \tag{2}$$

$$T_1(z,t) = aZ + b - A\left(a + \frac{1}{778c}\right) + \left[T_0 - b + A\left(a + \frac{1}{778c}\right)\right]\mathrm{e}^{-z/A} \tag{3}$$

where A is a time-related function, and is specifically expressed as

$$A = \frac{Wc\left[k + r_1 U f(t)\right]}{2\pi r_1 U k} \tag{4}$$

$$f(t) = \frac{2\pi k(T_2 - T_e)}{\mathrm{d}q/\mathrm{d}Z} \tag{5}$$

In Eq. (2) to Eq. (5), T_1 is the temperature of fluids within tubing in K; z is the starting position of injection in m; t is the starting time of injection in s; a is the geothermal gradient in K/m; Z is the depth under land surface in m; b is the land surface temperature in K; T_0 is the surface temperature of injected fluids in K; c is the specific heat of fluids under the constant pressure in J/(kg·K); W is the velocity of injected fluids in m/s; k is the thermal conductivity of formations in W/(m·K); r_1 is the radius inside tubing in *m*; U is the total heat transfer coefficient inside and outside tubing based on r_1 in W/(m^2·K); T_2 is the temperature outside casings in K; T_e is the formation temperature in K; q is the heat transfer rate in W/m^2.

This model can be employed to evaluate the temperature changes of fluids, tubing and casings with formation depth and time, and to compare the calculation with the measured temperature of field gas and water injection wells. It is proved that the two temperatures are a perfect match for each other and the method is confirmed to be reliable, which plays a guiding role in a more complicated heat transfer problem within wellbores. The development of this model lays a foundation for subsequent research on temperature monitoring models, while it ignores the influence of friction resistance loss and kinetic energy by replacing the heat transfer process between formations with the total heat transfer coefficient.

SATTER [27] took into account phase changes during the steam injection process and established a wellbore temperature calculation model regarding this process with the improvement of RAMEY's method. SHIU et al. [28] simplified RAMEY's method through the correlation of specific coefficients in RAMEY's equation. WILHITE [29] proposed a classic approach to calculate the total heat transfer coefficient in 1967. It clarified the relationship between various heat transfer coefficients and the total heat transfer coefficient during the wellbore and formation heat transfer process. This calculation method is still utilized in temperature monitoring models. SAGAR et al. [30], from the angle of a basic non-dynamical principle, founded a common model of wellbore temperature distribution to predict two-phase flow and calculated the Joule-Thomson coefficient in 1991 based on RAMEY's achievement. HAGOORT [31] verified the accuracy of RAMEY's model again in 2004 and found higher temperature prediction with the application of his model to predict wellbore temperature at the initial production or injection.

Moreover, the non-steady-state wellbore temperature model is put forward continuously as the application of permanent underground temperature monitoring approaches in oil fields. LIVESCU et al. [32] erected a non-steady-state multiphase flow wellbore heat transfer model in 2008 and suggested a calculation method with orderly iteration and decoupling. The method not only can shorten calculation duration, but also can enhance the stability of calculation, being still used to this day. A lot of experts and scholars investigated theories related to temperature monitoring since 1970s, and they paid more attention to the influence of heat exchange between wellbores and formations on the temperature and phase of fluids within wellbores back then. Thus, models in this period emphasize the research on flow-heat transfer models within wellbores, but heat transfer models and heat conduction effect are only noticed in the research on oil reservoirs.

2.2 A coupled heat transfer model of wellbores and oil reservoirs

Temperature monitoring has become one of the important links during the development and production of oil and gas fields with the rapid advancement and wide application of permanent temperature sensor technology since the 21st century. Temperature well testing or transient temperature analysis method gradually turns into the latest application of underground temperature monitoring. With regard to the research on theoretical models, researchers also begin to focus on the heat transfer process of fluids within reservoirs and bring forward a coupled heat transfer model of wellbores and oil reservoirs.

YOSHIOKA et al. [33] discussed Joule-Thomson effect among multiphase flow, convection heat transfer and conductive heat transfer in horizontal wells in 2005. Then, they advanced a model to predict the temperature distribution in horizontal wells with steady-state flow and deduced a coupled equation of wellbores and oil reservoirs.

$$\frac{\mathrm{d}T}{\mathrm{d}x} = \frac{2U_1}{R\left(\rho v c_p\right)_T}\left(T_1 - T\right) + \frac{(\rho v c_p K_{JT})_T}{(\rho v c_p)_T}\frac{\mathrm{d}p}{\mathrm{d}x} + \frac{(\rho v)_T}{(\rho v c_p)_T} g \sin\theta \tag{6}$$

$$\left(\rho v\right)_T = \sum_i \rho_i v_i y_i \tag{7}$$

$$\left(\rho v c_p\right)_T = \sum_i \rho_i v_i y_i c_{p,i} \tag{8}$$

$$\left(\rho v c_p K_{JT}\right)_T = \sum_i \rho_i v_i y_i c_{p,i} K_{JT,i} \tag{9}$$

wherein U_I is a comprehensive heat transfer coefficient of convection heat transfer and conductive heat transfer and is defined as

$$U_I = \gamma(\rho v c_p)_{T,I} + (1 - \gamma)U \tag{10}$$

In Eq. (6) to Eq. (10), T is temperature in K; x is the direction of wellbore axis; R is inner diameter in m; ρ is formation density in kg/m^3; v is the velocity of fluids in m/s; c_p is specific heat capacity in J/(kg·K); T_I is the temperature of fluids entering wellbores in K; K_{JT} refers to Joule-Thomson coefficient; p is pressure in Pa; g is the acceleration of gravity in m/s^2; θ is used as a certain angle, (°); i is a certain phase; ρ_i is the density of the phase in kg/m^3; v_i is the velocity of the phase in m/s; y_i is the hold-up rate of the phase; I is the fluids flowing in; γ is the aperture ratio of pipes; U is the total heat transfer coefficient in W/(m^2·K).

It is found after the acquisition of numerical solution about the coupling equation of wellbores and oil reservoirs that a smaller change will exist in temperature distribution when the flow velocity of fluids is lower or pressure drop along wellbores is smaller during gas production. GAO et al. [34] set up a mathematical model with temperature changing as the length of horizontal wells during the water injection process in those wells on the basis of mass and heat transfer between horizontal wells and reservoirs in 2008. A numerical algorithm to calculate reservoir temperature is advised through the one-dimensional linear processing on wellbores and the one-dimensional radial processing on oil reservoirs, and an analytical solution is deduced based on actual assumptions.

Temperature well testing or transient temperature analysis method is connected with rapid development depending on the coupling heat transfer model of wellbores and oil reservoirs. Their technical principle is that permanent temperature sensors are arranged to monitor underground and obtain real-time data of temperature sensing. Then, those data are combined with pressure monitoring data to attain reservoir permeability, formation coefficient and other reservoir parameters through inversion. DADA et al. [35] investigated reservoir temperature distribution in a vertical well in 2016 and grasped the temperature of gas flowing from production layers into wellbores by means of an analytical method. Meanwhile, pressure transient analysis technology was implemented to determine the radius and permeability of permeability-decreased areas near wellbores. MAO et al. [36] unveiled the deliberation about the quasi-linear behavior of the Joule-Thomson effect on a semi-logarithmic graph, and clarified the changes of fluid properties in the temperature transient analysis in 2018. Moreover, they took the correction of a value from fluid properties as an analytical solution to input, and then modeled the transient temperature signals of reservoirs with different production and various fluids in reservoirs by this method. In addition, the influence of parameter changes in fluid physical properties on interpretation results is explored and it is indicated that four primary fluid parameters affect temperature signals, including fluid density, specific heat, Joule-Thomson coefficient and viscosity.

2.3 A theoretical interpretation model of DTS

The influence of fluid temperature changes on fracturing fluid properties in wellbores and fractures during the operation attracts more attention when hydraulic fracturing is configured for production enhancement at the earlier oil and gas field development. It is discovered that temperature changes closely correlate with fracture propagation and the distribution of liquid production profiles during the hydraulic fracturing process with the large-scale application of DTS monitoring technology in oil fields. Hence, real-time hydraulic fracturing monitoring technology is significant for the evaluation of fracturing effects, and related theoretical models also progress rapidly. Many scholars have introduced several theoretical models regarding fracturing temperature changes matching temperature monitoring technology since the 1990s.

They conduct relative theoretical research on the explanation and analysis of liquid production profile distribution after fracturing. KAMPHUIS et al. [37] came up with the earliest theoretical model pertinent to the temperature monitoring of hydraulic fracturing in 1993. This model made a precise calculation on temperature in fracture propagation and fluid temperature in horizontal fractures was proved to be lower than that in vertical plane fractures. YOSHIOKA et al. [38–39] formed an inversion model of DTS monitoring data during the hydraulic fracturing process in horizontal wells according to Levenberg-Marquardt (L-M) algorithm in 2007. This model could deal with the evaluation of production profiles in single-phase oil extraction. LI et al. [40–41] built up a prediction model for temperature in a horizontal well in 2010 and imposed it on water flooding reservoirs, which could detect water position and water output. Additionally, Markov Chain & Monte Carlo (MCMC) algorithm was also utilized to generate an inversion model and the liquid production profile of the horizontal well was provided through the data inversion of DTS.

Furthermore, many scholars arrive at liquid production profiles after fracturing and fracture morphologies when establishing forward and inverse modeling interpretation models of DTS. ZHANG et al. [42] combined forward and inverse modeling models to interpret DTS data from a fracturing horizontal well in 2017 and knew fracture morphologies as well as production profiles. It was witnessed that the half-length and conductivity of fractures played the greatest role in temperature interpretation. Luo et al. [43] created an inversion model based on the L-M algorithm in 2019. This model gave a quantitative interpretation of fracture parameters in a fracturing horizontal well at a low-permeability gas reservoir and issued data on production profiles. Apart from that, they also exerted MCMC artificial intelligence and Simulated Annealing (SA) algorithms to foster an inversion model, which resolved a more complicated quantitative interpretation problem of fracture parameters in the fracturing horizontal well at shale gas reservoirs. DTS data can be set to analyze the quantitative interpretation of fracture parameters and production profiles, and the result can be regarded as the most direct basis for the effect evaluation of fracturing modification in horizontal wells and repeated fracturing.

3 Research progress about theoretical models of DAS

DAS technology now has been extensively applied in the hydraulic fracturing monitoring field of unconventional reservoirs. Scholars have begun to explore its theoretical models for the past few years.

SHERMAN et al. [44–45] simulated low-frequency DAS signals through a multi-physics coupling simulator in 2017. Those signals were recorded when hydraulic fracturing was conducted on a reservoir with heterogeneity and discrete fracture network, but a vertical well was taken as the monitoring well in this application, not a typical well from unconventional reservoirs. The mentioned model is a fully coupled three-dimensional thermal fluid mechanics (THM) model in the open source library (GEOS) developed by the National Laboratory Lawrence Livermore. THM model takes advantage of linear elastic fracture mechanics to solve fracture propagation and uses a finite volume scheme to address the flow of fluids in the rock matrix and fracture networks.

It is assumed that optical fibers are completely coupled with rock bodies and are insensitive to shear motion, and then the response of DAS is proportioned to the tangential component of finite element grid displacement on DAS path. Therefore, it is allowed to exercise a first-order finite-difference operator in time and space to connect the recorded displacement of optical fibers with strain or strain rate. This is the first understanding of Low-Frequency Distributed Acoustic Sensing (LF-DAS) signals by geomechanical modeling. It is suggested in the studies that these data and signals can be applied to the identification of hydraulic fractures and calculate the strain changes of a displacement-monitoring well in the vertical direction. The mechanism of strain-rate characteristics has not been discussed deeply yet. SHERMAN et al. [46] drew on data calculation monitored by DAS with the same model in 2018. That not only presented the initiation location of fractures, but also supplied their geometric morphologies. Furthermore, the influence of proppant distribution on DAS signals was seized, and then those signals could be further exerted on the diagnosis of screening the proppant top.

LIU et al. [47] employed a complicated fracture propagation model developed by WU in 2014 to simulate fracture propagation in 2020. The model was able to calculate the stress deformation of optical fibers in a horizontal monitoring well during the propagation of multiple fractures and provided a typical waterfall plot about strain rate when linear elastic rock deformation was coupled with fluids within fractures and horizontal wellbores in the manner of flow. Subsequently, this study lends a crucial basis to the strain and strain rate response of the monitoring well during the hydraulic fracturing process. GURJAO et al. [48] unveiled a DAS numerical model with the interaction of hydraulic fractures and natural fractures in 2021. This numerical model is a combination of rock mechanics and fluid mechanics, which are both related to the hydraulic fracturing process, and promotes a displacement discontinuity method (DDM) to calculate the strain field in media. It has application value for hydraulic fracturing monitoring in unconventional reservoirs with the development of natural fractures. Chen et al. [49] initiated a calculation model for the strain and strain rate of optical fibers in a fracturing-monitoring well on the basis of a plane three-dimensional multiple fracture propagation model in 2022. They also put forward a forward modeling method for strain of optical fibers induced by multiple fracture propagation in a horizontal well with fracturing. According to this method, a numerical simulation analysis is launched into the strain and strain rate of optical fibers induced by multiple fracture propagation in a horizontal well with fracturing.

DAS technology has been the latest technical means for monitoring during the hydraulic fracturing process in oil and gas development, but the investigation into its theoretical models remains in the initial stage. Accordingly, in order to give a better interpretation of DAS monitoring data, researchers are required to combine the monitoring of optical fibers with the fracturing diagnosis of horizontal wells to shape an inversion interpretation model for DAS data. This model can “translate” underground acoustic wave signals to improve the effect of fracturing.

4 Application of distributed optical fiber sensing technology

4.1 Application of DTS technology in hydraulic fracturing

1) Injection monitoring of fracturing fluid during the fracturing process

Optical fibers are fixed on the outside walls of casings or the inside walls of tubing (casings) before hydraulic fracturing to achieve continuous monitoring for temperature profiles in the whole fracturing operation [50]. The formation temperature passed by fracturing fluid gradually decreases as the fluid continues to be pumped into formations during the fracturing operation. This temperature is distinct from that of formations without fracturing fluid passing. The distribution of fracturing fluid can be analyzed through the real-time monitoring of formation temperature by DTS technology [51].

Halliburton Company determined the changes in fluid influx profiles after the initiation of formations during the hydraulic fracturing process of a vertical well by transient DTS temperature curves in 2008 [50]. HOLLEY et al. [52] engaged DTS technology in an open-hole packer and fracturing casing completion in 2012. They first decided the running depth of the packer in a target reservoir with reference to logging data, and then set packers with different intervals to separate distinct production layers so as to increase production. Then, distributed optical fibers were fixed at the production casings outside along the wellbore length. The temperature profile during the hydraulic fracturing process was obtained through the demodulation of DTS signals due to the injection of fracturing fluid would decrease reservoir temperature. The injection conditions of fracturing fluid within each fracturing section were observed and shown in Fig. 2. This waterfall plot displays a DTS color map from seven fracturing sections, wherein the light gray one (maximum cooling) refers to 37℃, the black shows no less than 75℃, and the light gray indicates the direct connection of fracturing fluid on optical fiber cables. The flow positions of most fluids at any time point during the production enhancement are in line with the above. Each fracturing section witnesses a significant decrease in temperature (light blue), which can be seen in Fig. 2. It implies that fracturing fluid is pumped into each fracturing section, but the injected fracturing fluid leaks to the second section during the fracturing operation at the third section [52]. Therefore, it is not completely accurate to quantify the injection volume of fracturing fluid at each fracturing point through DTS data entirely.

2) Initiation and propagation monitoring of fractures during the fracturing process

Staged multi-cluster fracturing technology for horizontal wells is mostly adopted when hydraulic fracturing technology is deployed on the fracturing of unconventional oil and gas reservoirs. Nonetheless, uneven fracture propagation and fluid influx often happen during the fracturing process, decreasing the formation of effective fractures and seriously impacting the fracturing simulation effect [53–56]. DTS technology can practice the whole-process and real-time monitoring on the initiation and propagation of fractures in each section during the hydraulic fracturing process and lays an important foundation for the improvement of operation technologies.

Halliburton company made use of DTS technology for the real-time monitoring of temperature profile changes during the small hydraulic fracturing operation in 2006 within the development of oil fields in the middle of the northern Sumatra Island of Indonesia. Further, the real-time monitoring of the increase in fracturing height was achieved [57]. TARRAHI et al. [58] examined DTS data by an integrated Kalman filter (EnKF) in 2014. EnKF is capable of quantitative fracture characterization and automatic history matching, and then precisely recognizes the half-length and permeability of fractures with temperature inversion. CUI et al. [59] put a two-dimensional semi-analytical model into effect at field cases in 2015. They determined fracture position and estimated fracture half-length based on the matching of measured temperature data, but did not build up a quantitative interpretation model. CUI et al. [60] explored and found that the temperature at the intersection point of fractures and wellbores was correlated with the flow quantity and volume of fractures. Besides, the fracture position could be determined through the temperature measurement along horizontal wellbores. This is favorable to assess the efficiency of hydraulic fracturing and provides a reference to repeated fracturing design in an applicable condition.

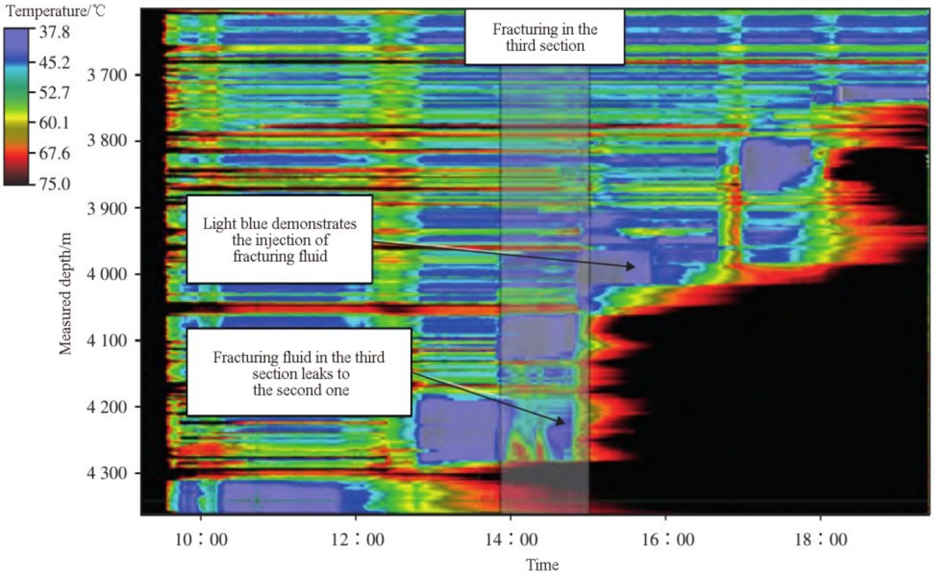

Fig. 2 DTS waterfall plot for monitoring horizontal well staged fracturing [52]

4.2 Application of DAS technology in hydraulic fracturing

1) Distribution profile monitoring of fracturing fluid during the fracturing process

DAS technology typically refers to the use of flow noise generated by fluids passing through tubing to monitor fracture fluid distribution profiles. The generation of flow noise can be attributed to two main factors. First, as fluids pass through pores, passive acceleration leads to the formation of vortices, which in turn generate sound energy. Second, when fluids experience large pressure differences or flow through constrictions, cavitation can occur, leading to the formation of small bubbles. The collapse of these bubbles also produces sound energy[61].

In 2011, MOLENAAR et al. [62–63] created a waterfall plot illustrating changes in acoustic waves over time along the wellbore (Fig. 3), enabling intuitive detection of fluid influx at perforation clusters during hydraulic fracturing. Flow restriction fracturing technology, mainly applied in horizontal wells to achieve uniform fluid distribution, typically involves four fracturing stages. Figure 3 presents DAS measurements following hydraulic fracturing, showing the amplitude of acoustic signals along the wellbore throughout the production enhancement process. In the plot, color variations represent acoustic energy levels (high in red, low in blue) within a high-frequency band, where selected frequency ranges can be correlated with injection rates. Initially, perforation cluster 3 exhibited the highest activity. Over time, as proppant was introduced, fluid influx increased in clusters 2 and 3, while cluster 1 absorbed more proppant. These results demonstrated a direct relationship between fluid influx and acoustic wave energy, with stronger acoustic signals indicating better fracture propagation. In 2017, SOMANCHI et al. [64] applied DAS technology to monitor fluid influx at individual perforation clusters during a horizontal well flow restriction fracturing operation. Their analysis showed that, although all three clusters initially opened and admitted fluid, the toe-end cluster eventually ceased absorbing fracturing fluid, as indicated by the disappearance of acoustic signals. Moreover, fluid distribution among the clusters became increasingly uneven as fracturing continued. In 2019, CERRAHOGLU et al. [65] utilized DAS technology during multi-stage fracturing of a horizontal gas well in an unconventional Canadian reservoir. Their assessment revealed a positive, though nonlinear, correlation between gas production at the wellhead and the number of active perforation clusters. Overall, DAS monitoring technology plays a critical role in understanding the fluid influx behavior of perforation clusters and detecting proppant sand-out during hydraulic fracturing operations. This insight enables real-time optimization and adjustment of fracturing strategies to enhance overall effectiveness.

2) Strain monitoring during the fracturing process

As discussed above, the fundamental principle of DAS technology is to leverage the high strain sensitivity of optical fibers to achieve real-time monitoring of environmental vibrations and acoustic fields. In earlier studies, DAS technology for hydraulic fracturing monitoring primarily focused on the high-frequency components of DAS data (above 1 Hz). However, with continuous technological advancements, it has been discovered that the low-frequency components of DAS data (below 0.05 Hz) also provide valuable information related to fracture development during the hydraulic fracturing process.

JIN et al. [66] first came up with the analysis of low-frequency (lower than 0.05 Hz) DAS signals in 2017. DAS data document micro strain disturbance in formations owing to fracture propagation and the geometric morphology information of hydraulic fractures can be grasped from that. A monitoring well is constructed around a fracturing well, optical fibers are laid outside the monitoring well and DAS data can be collected. Then, collected data are filtered to

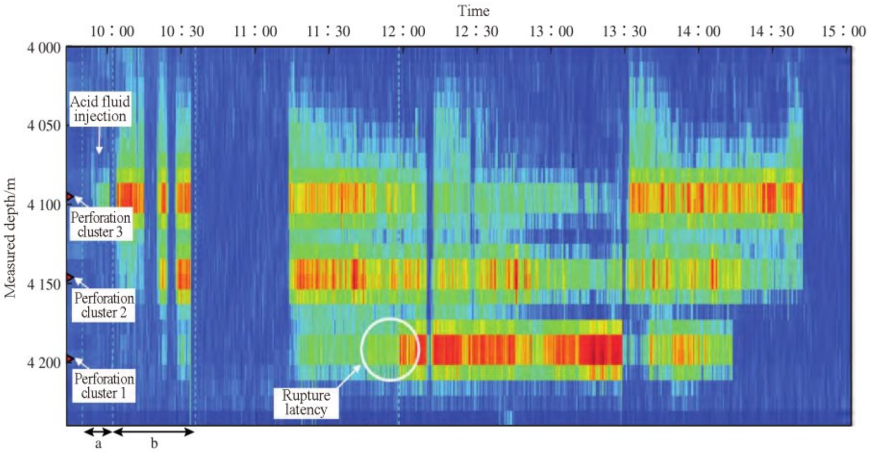

Fig. 3 DAS waterfall plot for monitoring flow limited fracturing in horizontal wells [63]

Note: a stage is the injection of acid fluid before hydraulic fracturing, and b refers to the starting of hydraulic fracturing.

remove any peak noise and then bear filtering again by a low pass filter with another angular frequency of 0.05 Hz. The low-frequency processing improves both the signal-to-noise ratio of signals and the accuracy of strain rate, which is important for the interpretation of DAS data. Optical fibers outside casings are able to measure strain caused by fracture spreading in the monitoring well when they are perfectly coupled with ambient formations. Generally speaking, the monitoring is parallel to the fracturing well, and the latter forms a high angle with fault planes, thereby maximizing the strain response along optical fibers. Hydraulic fractures constitute a “heart-shape” extension area in Fig. 4 before arriving at the monitoring well with optical fibers. It can be explained by the narrow extension in the front of tips of propagation fractures. Next, tension (red parts) occurs at fiber cross-sections within fracture paths after hydraulic fractures reach to the monitoring well, but fiber cross-sections at the sides of fracture paths are compressed (blue parts). UGUETO et al. [67] showed a field application example of low-frequency DAS monitoring technology in a production enhancement well from various completion systems and estimated the geometric morphology of fractures in 2019. Additionally, they explored the influence of the completion operation on the geometry of hydraulic fractures, and thus issued a suggestion for production enhancement efficiency, fracture geometry and borehole structural defects. LI et al. [68] put low-frequency DAS monitoring technology on a field example in 2020, obtaining one group of real-time DAS strain measurement data. 10 new fractures were found and continued to extend after data analysis, and those new fractures met a certain degree of closure after the end of pumping. DAS strain monitoring technology is the cutting-edge method of DAS technology during the hydraulic fracturing process. Research on the interpretation software and theoretical models for this technology now is still inadequate and requires vigorous development.

4.3 Joint application of DTS and DAS technologies in hydraulic fracturing

Both DTS and DAS have unique technical advantages during the hydraulic fracturing monitoring process. For example, both of them can perform long-distance and whole-process real-time monitoring; they are free of the influence from fluid flow states and of electromagnetic interference; and they can be played in a high-temperature and high-pressure environment, etc. However, they are difficult to ensure the integrity of optical fibers during the fracturing operation. The damage to optical fibers may lead to inaccurate or failed monitoring, and the large volume, fast growth as well as huge data amount of distributed optical fiber monitoring data size pose greater challenges to their storage, transmission and interpretation.

There is a condition of insufficient monitoring accuracy when DTS or DAS technologies are utilized individually according to the mentioned above. In the case that DTS primarily monitors fracturing fluid injection and fracture propagation from the angle of temperature, its essence is the involvement of temperature difference generated by fluid injection into reservoirs. The test data of DTS is not precise enough when fracturing fluid leaks or said fluid does not enter micro fractures in reservoirs. At the moment, DAS data are demanded to be verified to improve the accuracy of data analysis results. Hence, the joint monitoring technology of DTS and DAS is beneficial to improve the accuracy of data analysis results, and some oil field companies have implemented it in the field.

Maersk company first applied the joint monitoring technology of DTS and DAS to the fracturing operation of one horizontal well at Halfdan oil field in the North Sea of Denmark in 2014, achieving the whole-process underground monitoring of fracturing operation. This application corroborated the advantage of this joint monitoring technology and visual processing was presented in the monitoring data of DTS and DAS, providing a comprehensive tool for real-time monitoring and dynamic well condition analysis [69]. WHEATON et al. [70] carried out the joint monitoring technology of DTS and DAS for the fracturing operation of one horizontal well from a shale gas reservoir of Eagle Ford in the USA. They first collected monitoring data, and then made a three-dimensional fracture

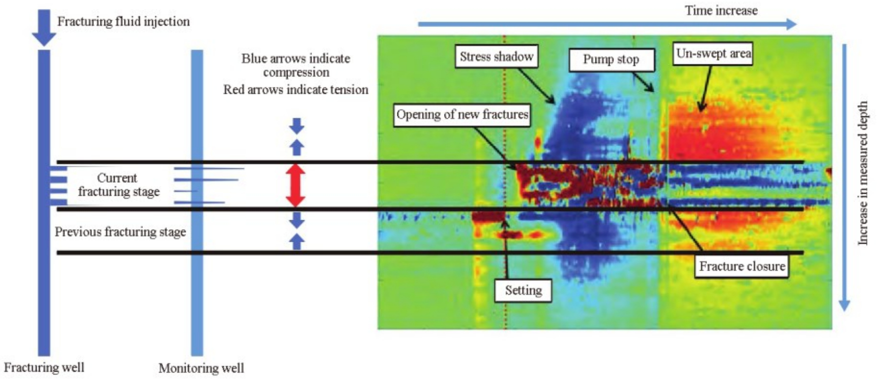

Fig. 4 Strain response of low-frequency DAS monitoring in adjacent wells during hydraulic fracturing [66]

modeling on detected fracture distribution to intuitively observe the geometric morphologies of fractures. Finally, they revealed the influence of adjacent fractures on fracture distribution, fracture geometric morphologies and completion effect within fracturing sections. In 2016, UGUETO et al. [71] employed this technique to evaluate perforation cluster efficiency during the hydraulic fracturing process. Their analysis revealed that all perforation clusters underwent a certain degree of hydraulic fracturing. However, the efficiency of the clusters gradually decreased during the later stages of fracturing or during proppant injection. Furthermore, a lower number of clusters was associated with higher completion efficiency.

Lots of studies have proved that the joint monitoring technology of DTS and DAS can capture the temperature and acoustic wave signals of formations at the same time and complements DTS and DAS. It also can perform better assessment and analysis of the fracturing fluid influx for each level of fractures, the propagation of hydraulic fractures, etc. This technology at present has been gradually included in the field application, but its matching theoretical models remain undeveloped, whose research will become a breakthrough core for the growth of this technology.

5 Conclusions and foresight

Distributed optical fiber sensing technology has become the latest approach for staged fracturing monitoring at horizontal wells in unconventional reservoirs. This technology can fulfill real-time and high-accuracy monitoring of stress, temperature, pressure and other parameters at each position during the hydraulic fracturing process, so that the condition of hydraulic fracturing operation can be better understood to identify problems and improve techniques. Distributed optical fiber sensing technology currently has been introduced to the monitoring of fracturing fluid distribution profiles, fracture initiation, fracture propagation and other aspects during the hydraulic fracturing process. Some progress is also brought into its corresponding theoretical models. Among them, the theoretical models related to DTS are relatively mature and can manage the relevant calculation of liquid production profiles and fracture morphologies. Instead, research on DAS technology is started later, and inquiry into its theoretical models still stays at the beginning stage with a lack of corresponding inversion models. Thus, it only can accomplish the relevant calculation of formation stress and strain.

The advancement of DAS theoretical models should be emphasized in future research. The fracture morphologies of hydraulic fracturing can be solved by the establishment of forward and inverse modeling models of DAS, which is important to conclude the real-time monitoring of fracture morphologies during the hydraulic fracturing process. Besides, the novelty of distributed optical fiber sensing technology also needs to be further promoted, such as the limitation of optical fiber transmission property, the accuracy of monitoring data processing, etc. These problems require to be addressed by technical innovation as well as research and development in the future in order to improve the reliability of the technology and the accuracy of monitoring. The application of distributed optical fiber sensing technology displays the trend of growing maturity in terms of hydraulic fracturing monitoring. It strongly supports the improvement of the effective development of unconventional reservoirs and possesses a bright prospect for the exploration and application of unconventional reservoirs.

References

[1] HOLLEY E H, KALIA N. Fiber-optic monitoring: Stimulation results from unconventional reservoirs [C]// Paper URTEC-2151906-MS presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, San Antonio, Texas, USA, July 2015.

[2] KAPRON F P, MAURER R D, TETER M P. Theory of back scattering effects in wave guides [J]. Applied Optics, 1972, 11(6): 1352–1356.

[3] SOOKPRASONG P A, GILL C C, HURT R S. Lessons learned from DAS and DTS in multicluster, multistage horizontal well fracturing: Interpretation of hydraulic fracture initiation and propagation through diagnostics [C]// Paper SPE-170512-MS presented at the IADC/SPE Asia Pacific Drilling Technology Conference, Bangkok, Thailand, August 2014.

[4] PATEL D, WEE K, GORGI S, et al. Success story: 64 wells with hybrid real time DTS/DAS monitoring and permanent downhole gauges installed in the United Arab Emirates [C]// Paper SPE-202681-MS presented at the Abu Dhabi International Petroleum Exhibition & Conference, Abu Dhabi, UAE, November 2020.

[5] ZHANG Chunchi, PENG Wenquan, GAO Bingyan, et al. Favorable exploration strata and resource evaluation of shale gas in Shandong Province [J]. Petroleum Geology and Recovery Efficiency, 2019, 26(2): 7–13. (in Chinese)

[6] YANG Zhaozhong, CHEN Qian, LI Xiaogang, et al. Optimization of multi-cluster staged fracturing for horizontal well in low-permeability tight sandstone gas reservoir, Ordos Basin [J]. Petroleum Geology and Recovery Efficiency, 2019, 26(2): 120–126. (in Chinese)

[7] LI Yahui. Production profile interpretation model and its software development based on DTS data for horizontal well in bottom water gas reservoir [D]. Chengdu: Southwest Petroleum University, 2018. (in Chinese)

[8] DALEY T M, FREIFELD B M, AJO-FRANKLIN J, et al. Field testing of fiber-optic distributed acoustic sensing (DAS) for subsurface seismic monitoring [J]. The Leading Edge, 2013, 32(6): 936–942.

[9] HARTOG A, FRIGNET B, MACKIE D, et al. Vertical seismic optical profiling on wireline logging cable [J]. Geophysical Prospecting, 2014, 62(4): 693–701.

[10] JIANG T, ZHAN G, HANCE T, et al. Valhall dual-well 3D DAS VSP field trial and imaging for active wells [C]// Paper SEG-2016-13871754 presented at the 2016 SEG International Exposition and Annual Meeting, Dallas, Texas, October 2016.

[11] SUI Weibo, ZHANG Di, WANG Mengyu, et al. Review on application and theoretical models for temperature monitoring technology under intelligent well completion conditions in oil and gas field development [J]. Petroleum Geology and Recovery Efficiency, 2020, 27(3): 129–138. (in Chinese)

[12] ROGERS A J. Polarization-optical time domain reflectometry: A technique for the measurement of field distributions [J]. Applied Optics, 1981, 20(6): 1060–1074.

[13] BARNOSKI M K, ROURKE M D, JENSEN S M, et al. Optical time domain reflectometer [J]. Applied Optics, 1977, 16(9): 2375–2379.

[14] SHANG Junhui. Principle and technical characteristics of optical fiber temperature measurement technology [J]. China Petroleum and Chemical Standard and Quality, 2012, 32(suppl. 1): 61. (in Chinese)

[15] SUN Guoshan, HOU Sizu, CHEN Chao. Raman optical fiber temperature measurement principle and application in power system [J]. Electric Power Science and Engineering, 2010, 26(3): 26–29. (in Chinese)

[16] HUANG Jian. Optimization of distributed optical fiber temperature measurement system based on Raman scattering [D]. Guilin: Guangxi Normal University, 2022. (in Chinese)

[17] HAN Yongwen, HAO Wenjie, ZHANG Linxing, et al. Research of distributed optical fiber temperature measurement system based on Raman scattering principle [J]. Semiconductor Optoelectronics, 2013, 34(2): 342–345. (in Chinese)

[18] JUSKAITIS R, MAMEDOV A M, POTAPOV V T, et al. Distributed interferometric fiber sensor system [J]. Optics Letters, 1992, 17(22): 1623–1625.

[19] JUSKAITIS R, MAMEDOV A M, POTAPOV V T, et al. Interferometry with Rayleigh back scattering in a single-mode optical fiber [J]. Optics Letters, 1994, 19(3): 225–227.

[20] SHATALIN S V, TRESCHIKOV V N, Rogers A J. Interferometric optical time domain reflectometry for distributed optical fiber sensing [J]. Applied Optics, 1998, 37(24): 5600–5604.

[21] LI Kang. Research on signal enhancement and processing of fiber distributed acoustic sensor system [D]. Chengdu: University of Electronic Science and Technology of China, 2019. (in Chinese)

[22] JIN G, UGUETO G, WOJTASZEK M, et al. Novel near-wellbore fracture diagnosis for unconventional wells using high-resolution distributed strain sensing during production [J]. SPE Journal, 2021, 26(5): 3255–3264.

[23] SAMUELSON M, HARRIS S, SCHRADER K. Successful installation of a down-hole fiber optic wetmate connection system [C]// Paper SPE-201349-MS presented at the SPE Annual Technical Conference and Exhibition, Virtual, October 2020.

[24] SANNI M, HVEDING F, KOKAL S. Lessons learned from in-well fiber-optic DAS/DTS deployment [C]// Paper SPE-191470-MS presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, USA, September 2018.

[25] AL SHOAIBI S S, FLOREZ J C, AL FARSI S. The first behind-casing fiber-optic installation in a high-pressure high-temperature deep gas well in Oman [C]// Paper SPE-205275-MS presented at the SPE International Hydraulic Fracturing Technology Conference & Exhibition, Muscat, Oman, January 2022.

[26] RAMEY H J. Wellbore heat transmission [J]. Journal of Petroleum Technology, 1962, 14(4): 427–435.

[27] SATTER A. Heat losses during flow of steam down a wellbore [J]. Journal of Petroleum Technology, 1965, 17(7): 845–851.

[28] SHIU K C, BEGGS H D. Predicting temperatures in flowing oil wells [J]. Journal of Energy Resources Technology, 1980, 102(1): 2–11.

[29] WILHITE G P. Over-all heat transfer coefficients in steam and hot water injection wells [J]. Journal of Petroleum Technology, 1967, 19(5): 607–615.

[30] SAGAR R, DOTY D R, SCHMIDT Z. Predicting temperature profiles in a flowing well [J]. SPE Production Engineering, 1991, 6(4): 441–448.

[31] HAGOORT J. Ramey’s wellbore heat transmission revisited [J]. SPE Journal, 2004, 9(4): 465–474.

[32] LIVESCU S, DURLOFSKY L J, AZIZ K. Application of a new fully-coupled thermal multiphase wellbore flow model [C]// Paper SPE-113215-MS presented at the SPE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, USA, April 2008.

[33] YOSHIOKA K, ZHU D, HILL A D, et al. A comprehensive model of temperature behavior in a horizontal well [C]// Paper SPE-95656-MS presented at the SPE Annual Technical Conference and Exhibition, Dallas, Texas, October 2005.

[34] GAO G H, JALALI Y. Prediction of temperature propagation along a horizontal well during injection period [J]. SPE Reservoir Evaluation & Engineering, 2008, 11(1): 131–140.

[35] DADA A O, MURADOV K M, DAVIES D R. Novel solutions and interpretation methods for transient, sandface temperature in vertical, dry gas producing wells [C]// Paper SPE-181057-MS presented at the SPE Intelligent Energy International Conference and Exhibition, Aberdeen, Scotland, UK, September 2016.

[36] MAO Y L, ZEIDOUNI M. Accounting for fluid-property variations in temperature-transient analysis [J]. SPE Journal, 2018, 23(3): 868–884.

[37] KAMPHUIS H, DAVIES D R, ROODHART L P. A new simulator for the calculation of the in situ temperature profile during well stimulation fracturing treatments [J]. Journal of Canadian Petroleum Technology, 1993, 32(5): 38–47.

[38] YOSHIOKA K. Detection of water or gas entry into horizontal wells by using permanent downhole monitoring systems [D]. Texas: Texas A&M University, 2007.

[39] YOSHIOKA 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 [J]. SPE Production & Operations, 2009, 24(4): 510–521.

[40] LI Z Y, ZHU D. Predicting flow profile of horizontal well by downhole pressure and distributed-temperature data for water drive reservoir [J]. SPE Production & Operations, 2010, 25(3): 296–304.

[41] LI Z Y. Interpreting horizontal well flow profiles and optimizing well performance by downhole temperature and pressure data [D]. Texas: Texas A&M University, 2010.

[42] ZHANG S, ZHU D. Inversion of downhole temperature measurements in multistage fracture stimulation in horizontal wells [C]// Paper SPE-187322-MS presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 2017.

[43] LUO Hongwen, LI Haitao, JIANG Beibei, et al. A novel method to interpret production profiles of fractured horizontal well in low-permeability gas reservoir by inversing DTS data [J]. Natural Gas Geoscience, 2019, 30(11): 1639–1645. (in Chinese)

[44] SHERMAN C S, MORRIS J P, MELLORS R J, et al. Simulating fracture-induced strain signals measured by a distributed fiber-optic sensor [C]// Paper SEG-2017-17678887 presented at the 2017 SEG International Exposition and Annual Meeting, Houston, Texas, September 2017.

[45] SHERMAN C S, MELLORS R J, MORRIS J P, et al. Geomechanical modeling of distributed fiber-optic sensor measurements [J]. Interpretation, 2019, 7(1): SA21–SA27.

[46] SHERMAN C S, MELLORS R J, MORRIS J P, et al. Modeling distributed fiber optic sensor signals using computational rock mechanics [C]// Paper URTEC-2900760-MS presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Houston, Texas, USA, July 2018.

[47] LIU Y Z, WU K, JIN G, et al. Hydraulic fracture modeling of fracture-induced strain variation measured by low-frequency distributed acoustic sensing(LF-DAS)along offset wells [C]// Paper ARMA-2020-1426 presented at the 54th U. S. Rock Mechanics/Geomechanics Symposium, physical event cancelled, June 2020.

[48] GURJAO K G R, GILDIN E, GIBSON R, et al. Modeling of distributed strain sensing(DSS)and distributed acoustic sensing (DAS)incorporating hydraulic and natural fractures interaction [C]// Paper URTEC-2021-5414-MS presented at the SPE/AAPG/SEG Unconventional Resources Technology Conference, Houston, Texas, USA, July 2021.

[49] CHEN Ming, GUO Tiankui, XU Yun, et al. Evolution mechanism of optical fiber strain induced by multi-fracture growth during fracturing in horizontal wells [J]. Petroleum Exploration and Development, 2022, 49(1): 183–193. (in Chinese)

[50] SIERRA J, KAURA J, UALTIERI D, et al. DTS monitoring of hydraulic fracturing: Experiences and lessons learned [C]// Paper SPE-116182-MS presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA, September 2008.

[51] LI X Y, ZHU D. Temperature behavior of multi-stage fracture treatments in horizontal wells [C]// Paper SPE-181876-MS presented at the SPE Asia Pacific Hydraulic Fracturing Conference, Beijing, China, August 2016.

[52] HOLLEY E H, MOLENAAR M M, FIDAN E, et al. Interpreting uncemented multistage hydraulic-fracturing completion effectiveness using fiber-optic DTS injection data [C]// Paper SPE-153131-MS presented at the SPE Middle East Unconventional Gas Conference and Exhibition, Abu Dhabi, UAE, January 2012.

[53] SU Liangyin, CHANG Du, YANG Hai ’en, et al. Segmented multicluster fracturing technology for sidetrack horizontal well with slim holes in low permeability reservoir well with slim holes in low permeability reservoir [J]. Petroleum Drilling Techniques, 2020, 48(6): 94–98. (in Chinese)

[54] XIE Nanxing, CAI Daogang, YE Changqing, et al. New production pressure drop calculation model for shale gas horizontal well [J]. Drilling & Production Technology, 2022, 45(1): 75–80. (in Chinese)

[55] XIAO Jianfeng, HU Pengjie, HAN Liexiang, et al. Mechanical properties and compressibility evaluation of Qiongzhusi Shale in Weiyuan Area in Southern Sichuan [J]. Drilling & Production Technology, 2022, 45(2): 61–66. (in Chinese)

[56] YAO Hongsheng, WANG Wei, HE Xipeng, et al. Development practices of geology-engineering integration in complex structural area of Nanchuan normal pressure shale gas field [J]. Petroleum Reservoir Evaluation and Development, 2023, 13(5): 537–547. (in Chinese)

[57] NATH D K, FINLEY D B, KAURA J D, et al. Real-time fiber-optic distributed temperature sensing(DTS)new applications in the oil field [C]// Paper SPE-103069-MS presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 2006.

[58] TARRAHI M, GILDIN E, MORENO J, et al. Dynamic integration of DTS data for hydraulically fractured reservoir characterization with the ensemble Kalman filter [C]// Paper SPE-169990-MS presented at the SPE Energy Resources Conference, Port of Spain, Trinidad and Tobago, June 2014.

[59] CUI J Y, ZHU D, JIN M Q. Diagnosis of multi-stage fracture stimulation in horizontal wells by downhole temperature measurements [C]// Paper SPE-170874-MS presented at the SPE Annual Technical Conference and Exhibition, Amsterdam, The Netherlands, October 2014.

[60] CUI J Y, YANG C D, ZHU D, et al. Fracture diagnosis in multiple stage stimulated horizontal well by temperature measurements with fast marching method [J]. SPE Journal, 2016, 21(6): 2289–2300.

[61] SUI Weibo, LIU Rongquan, CUI Kai. Application and research progress of distributed optical fiber acoustic sensing monitoring for hydraulic fracturing [J]. SCIENTIA SINICA Technologica, 2021, 51(4): 371–387. (in Chinese)

[62] MOLENAAR M M, COX B E. Field cases of hydraulic fracture stimulation diagnostics using fiber optic distributed acoustic sensing (DAS) measurements and analyses [C]// Paper SPE-164030-MS presented at the SPE Unconventional Gas Conference and Exhibition, Muscat, Oman, January 2013.

[63] MOLENAAR M M, HILL D, WEBSTER P, et al. First downhole application of distributed acoustic sensing(DAS) for hydraulic fracturing monitoring and diagnostics [C]// Paper SPE-140561-MS presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, January 2011.

[64] SOMANCHI K, BREWER J, REYNOLDS A. Extreme limited-entry design improves distribution efficiency in plug-and-perforate completions: Insights from fiber-optic diagnostics [J]. SPE Drilling & Completion, 2018, 33(4): 298–306.

[65] CERRAHOGLU C, NALDRETT G, VIGRASS A, et al. Cluster flow identification during multi-rate testing using a wireline tractor conveyed distributed fiber optic sensing system with engineered fiber on a HPHT horizontal unconventional gas producer in the Liard Basin [C]// Paper SPE-196120-MS presented at the SPE Annual Technical Conference and Exhibition, Calgary, Alberta, Canada, September 2019.

[66] JIN G, ROY B. Hydraulic-fracture geometry characterization using low-frequency DAS signal [J]. The Leading Edge, 2017, 36(12): 975–980.

[67] UGUETO G A, TODEA F, DAREDIA T, et al. Can you feel the strain? DAS strain fronts for fracture geometry in the BC Montney, Groundbirch [C]// Paper SPE-195943-MS presented at the SPE Annual Technical Conference and Exhibition, Calgary, Alberta, Canada, September 2019.

[68] LI X Y, ZHANG J, GRUBERT M, et al. Distributed acoustic and temperature sensing applications for hydraulic fracture diagnostics [C]// Paper SPE-199759-MS presented at the SPE Hydraulic Fracturing Technology Conference and Exhibition, The Woodlands, Texas, USA.

[69] DANARDATU H, GREGERSEN S, ALTERN E, et al. Data acquisition and processing of carbon rod conveyed DTS and DAS in very long horizontal wells: First trial in North Sea Danish Sector [C]// Paper SPE-170663-MS presented at the SPE Annual Technical Conference and Exhibition, Amsterdam, The Netherlands, October 2014.

[70] WHEATON B, HAUSTVEIT K, DEEG W, et al. A case study of completion effectiveness in the eagle ford shale using DAS/DTS observations and hydraulic fracture modeling [C]// Paper SPE-179149-MS presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, February 2016.

[71] UGUETO C G A, HUCKABEE P T, MOLENAAR M M, et al. Perforation cluster efficiency of cemented plug and perf limited entry completions; Insights from fiber optics diagnostics [C]// Paper SPE-179124-MS presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, February 2016.