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[1]Nurtashev A.T.,
Master's student, ORCID ID: 0009-0006-5532-5808,
e-mail: as.nurtashev@gmail.com

[1]Kazakh-British Technical University, Almaty, Kazakhstan

FEATURES OF THE NEAR-WELLBORE ZONE TEMPERATURE REGIME DURING HYDRAULIC FRACTURING AND ITS IMPACT ON BREAKER SELECTION

Abstract

In the development of oil and gas fields with elevated and high formation temperatures, the effectiveness of hydraulic fracturing (HF) operations is largely determined by the correct selection of the breaker system, which ensures controlled degradation of the polysaccharide gel after pumping and proppant placement. In conventional HF design practice, breaker type and concentration are typically selected based on a static formation temperature, while variations in the near-wellbore thermal regime during pumping are only partially considered. This study presents the results of an analysis of formation temperature dynamics recorded in real time using an autonomous downhole pressure–temperature gauge during an HF operation, including the injection test, mini-frac, and main fracturing stages. It was established that injection of fracturing fluid at a surface temperature of approximately 20 °C leads to a rapid reduction of near-wellbore temperature by several tens of degrees relative to the initial formation temperature. Operational pauses result in partial temperature recovery; however, the original thermal state is not restored before subsequent stages. The results demonstrate that the effective temperature governing HF fluid performance during a significant portion of the operation differs substantially from the static formation temperature. This discrepancy affects gel degradation kinetics and the efficiency of persulfate-type oxidative breakers. Comparison of field temperature data with laboratory rheological test results obtained using a Chandler 5550 viscometer confirms the necessity of accounting for dynamic temperature conditions when selecting breaker systems. Incorporating actual thermal history into breaker design improves selection reliability and enhances fracture cleanup efficiency in high-temperature reservoirs.

Keywords: hydraulic fracturing, fracturing fluid, reservoir temperature, near-wellbore, breaker, rheological properties.

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Introduction

Hydraulic fracturing (HF) is one of the key technologies for hydrocarbon production stimulation and is widely applied in the development of low-permeability and heterogeneous reservoirs, including fields with elevated and high formation temperatures [1, 2]. Over more than half a century of development, HF technology has undergone significant evolution; however, the fundamental principles of operation design remain closely associated with the proper selection of fracturing fluid properties [2].

The effectiveness of HF operations is largely determined by the rheological and filtration properties of the applied fluid, which must ensure stable fracture opening, efficient proppant transport, and subsequent controlled degradation of the polymer gel with minimal residual damage to fracture conductivity [3–6]. Under high formation temperature conditions, the requirements for HF fluid formulation increase substantially, since elevated temperature accelerates thermal degradation of the polymer structure, alters the viscosity characteristics of crosslinked gels, and directly affects breaker reaction kinetics [7–9].

In engineering practice, the selection of HF fluid formulation is typically based on a static formation temperature determined from geological and geophysical data. Laboratory evaluation of fluid rheological properties and gel-breaking kinetics is usually performed at a fixed temperature assumed to be equal to the formation temperature or at a reduced value. This approach is reflected in current methodological guidelines and regulatory documents, including the international standard ISO 13503-1, which governs methods for measuring the viscosity characteristics of completion and HF fluids [10].

At the same time, the results of experimental and field studies indicate that the actual temperature conditions in the near-wellbore zone during HF may differ significantly from the initial formation temperature [11–13]. The injection of large fluid volumes, whose temperature is generally lower than the formation temperature, leads to intensive cooling of the HF zone. The magnitude and nature of this cooling depend on the pumping regime, injected fluid volume, and operation duration, as confirmed by both analytical assessments and field observations [13, 14].

Variations in the temperature regime during pumping have a direct impact on the rheological behavior of HF fluids and the efficiency of gel degradation. As temperature decreases, breaker reaction rates may be significantly reduced, resulting in delayed fracture cleanup and retention of polymer residues within the proppant pack [15, 16]. Consequently, selecting breaker concentration solely based on static formation temperature without accounting for actual thermal transients may lead to a mismatch between laboratory-designed fluid formulations and real reservoir conditions.

Despite the recognized importance of temperature effects, most existing HF fluid design methodologies implicitly assume quasi-stationary thermal conditions and do not incorporate real-time temperature evolution during pumping. In this regard, optimization of HF fluid formulation with consideration of dynamic formation temperature represents an important scientific and practical challenge.

The objective of this study is to substantiate an adaptive approach to HF fluid formulation selection based on real-time downhole pressure-temperature monitoring and laboratory investigations of the rheological properties of crosslinked gels. By integrating field-measured thermal histories with controlled laboratory testing, the proposed approach enables improved design reliability and enhanced effectiveness of HF fluids under high formation temperature conditions.

Materials and methods

Object of study and initial reservoir conditions

The study is based on field and laboratory data obtained during an HF operation conducted in a terrigenous reservoir characterized by elevated formation temperature. In order to comply with confidentiality requirements, the field name, well number, and stratigraphic designation of the productive interval are not disclosed in this paper. The considered object represents a typical oil field with low-permeability porous reservoirs, for which HF is the primary method of production stimulation.

The main geological, physical, and thermobaric reservoir parameters are summarized in Table 1. The reservoir conditions are characterized by significant burial depth, high formation temperature, and moderate reservoir pressure, which impose increased requirements on the thermal stability and gel-breaking kinetics of the HF fluid.

Table 1 – Main Initial Reservoir Parameters

Parameter	Value
Average reservoir depth, m	2,640
Reservoir type	Porous
Average effective thickness, m	9
Porosity, %	14
Permeability, mD	2
Formation temperature, °C	108
Initial reservoir pressure, atm	285

Brief description of the HF operation

The HF operation was performed in several consecutive stages and included an injection test, a mini-frac, and the main HF treatment. The total pumping duration, including operational pauses between individual stages, was approximately eight hours.

HF fluid injection was carried out in a staged manner and was accompanied by periodic pump shutdowns between operation stages. The presence of operational pauses was dictated by the specifics of the field execution and had a significant impact on the thermal regime of the near-wellbore zone. During active pumping periods, intensive cooling of the formation occurred due to the injection of fluid with a temperature substantially lower than the formation temperature, whereas during pump shutdown periods partial temperature recovery was observed.

Within the scope of the present study, pressure parameters, pumping schedules, injected fluid and proppant volumes, as well as fracture geometry characteristics were not analyzed. The HF operation was considered exclusively as a controlled hydrothermal process, allowing investigation of formation temperature dynamics and its influence on HF fluid rheological properties and gel-breaking kinetics.

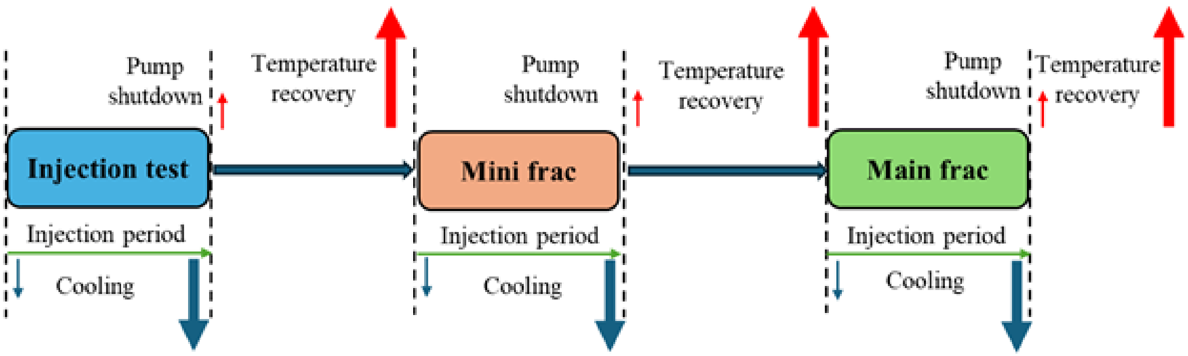

Figure 1 – Schematic representation of HF operation stages

Downhole Temperature Monitoring Methodology

To record the temperature regime in the near-wellbore zone during the HF operation, an autonomous downhole pressure–temperature gauge AMT-10 was installed within the HF treatment interval. The gauge provided continuous recording of temperature and pressure throughout all pumping stages and the subsequent recovery period.

Pressure and temperature data were recorded with a time step of 1 second, ensuring sufficient temporal resolution to capture both rapid temperature changes during active pumping and gradual temperature recovery after pump shutdown. The obtained data were used for a detailed analysis of temperature dynamics during the injection test, mini-frac, and main HF stages.

The main technical specifications of the applied measuring equipment are presented in Table 2.

Table 2 – Main technical specifications of the downhole pressure–temperature gauge

Parameter	Value
Type	Autonomous pressure–temperature gauge
Model	AMT-10
Temperature measurement range	up to 150 °C
Pressure measurement range	up to 100 MPa
Temperature measurement accuracy	±0.5 °C
Data recording type	Internal memory
Logging frequency	Programmable

HF Fluid System

The studied HF operation employed a water-based HF fluid formulated with a crosslinked polysaccharide gel. Guar gum derivatives were used as the gelling agent, providing the formation of a three-dimensional crosslinked structure with rheological properties suitable for efficient proppant transport.

Viscosity enhancement and thermal stability of the system were achieved through the application of a borate-based crosslinking agent, providing reversible crosslinking of polysaccharide chains. Such fluid systems are widely used in field practice for HF operations under moderate and elevated temperature conditions.

Controlled degradation of the gel structure after pumping completion was achieved using an oxidative breaker based on inorganic persulfate-type oxidizers. Its mechanism of action is associated with oxidative destruction of polysaccharide chains, resulting in viscosity reduction and facilitating subsequent removal of degradation products from the fracture.

Special attention was paid to the selection of breaker concentration, as the rate and efficiency of breaker action are largely governed by the temperature regime. The base fluid formulation was initially designed using the static formation temperature, after which its applicability was evaluated considering the actual temperature dynamics during pumping.

Laboratory Rheological Testing Methodology

Laboratory investigations of HF fluid rheological properties were conducted using a high-pressure, high-temperature rotational viscometer Chandler 5550, designed to simulate HF fluid flow conditions at elevated temperatures and pressures. The testing methodology complied with the requirements of the international standard ISO 13503-1 [10].

The rheological testing program consisted of three consecutive stages performed to simulate temperature conditions characteristic of the main HF treatment. At the first stage, the stability of the crosslinked gel was evaluated at formation temperature for a duration exceeding the calculated main HF pumping time by 20%, corresponding to pad-stage conditions within the main treatment. At the second stage, tests were conducted at a temperature reduced to approximately 85% of the formation temperature, simulating intermediate thermal conditions during the main HF pumping process. At the third stage, gel breaking and structural degradation were investigated at a temperature defined as the arithmetic mean between the formation temperature and the surface-injected fluid temperature. This temperature level was used to simulate the conditions of the final stages of the main HF treatment and the initial post-pumping period, when a mixed thermal regime forms in the near-wellbore zone due to heat exchange between the injected fluid and the formation.

All tests were performed at a constant shear rate representative of fluid flow conditions within the fracture. During testing, viscosity evolution over time was recorded, allowing evaluation of gel stability, degradation kinetics, and system sensitivity to temperature variations.

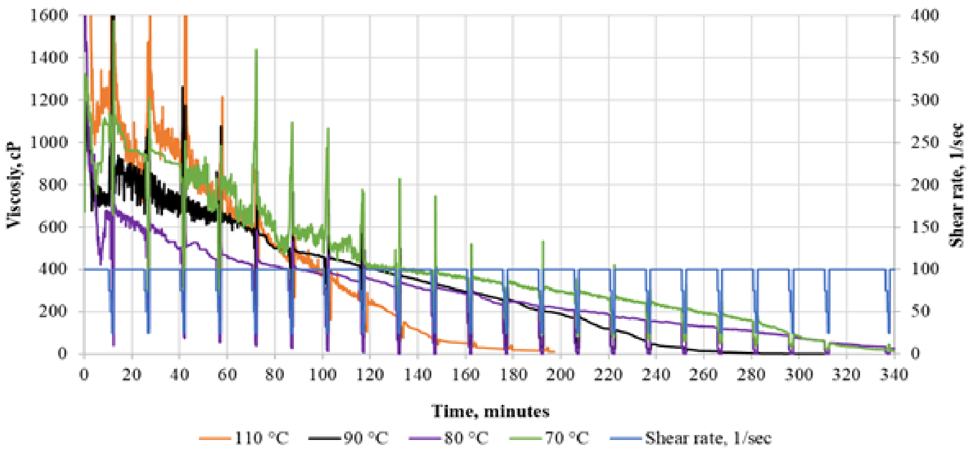

Figure 2 – Example of a rheological test of a crosslinked gel under different temperature regimes

Data Processing and Analysis

Downhole temperature data and laboratory rheological test results were analyzed jointly. Temperature curves were segmented according to HF operation stages, and characteristic temperature ranges were identified for each stage. Laboratory results were interpreted with consideration of these temperature ranges, which enabled evaluation of the adequacy of the conventional static-temperature-based fluid design approach and substantiation of the need for HF fluid formulation optimization accounting for dynamic formation temperature behavior.

Results and discussion

Formation temperature dynamics during the HF operation

The results of downhole pressure–temperature monitoring provided a continuous temperature history of the near-wellbore zone throughout all stages of the HF operation. The overall dynamics of temperature, pressure, and operational parameters are presented in Figure 3.

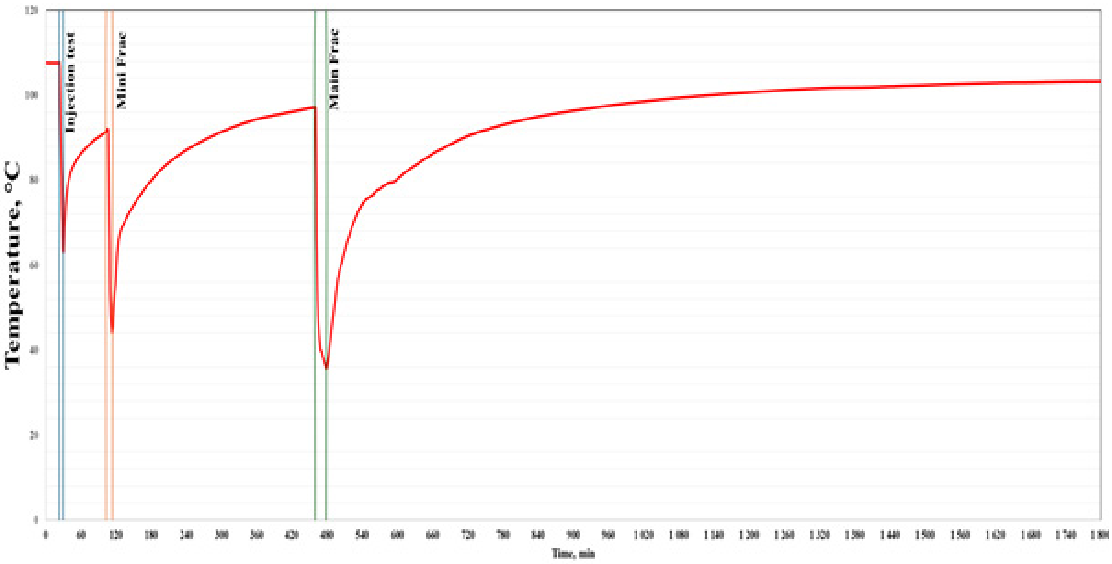

Figure 3 – Overall dynamics of temperature, pressure, and operational parameters in the near-wellbore zone during the hydraulic fracturing operation

Analysis of the temperature curve indicates that the thermal regime in the near-wellbore zone is distinctly non-stationary and differs significantly from the static formation temperature assumed during HF design. Already at the injection test stage, a sharp temperature decrease is observed due to the injection of HF fluid at approximately 20 °C, which is substantially lower than the initial formation temperature of 108 °C (Table 1). This rapid cooling develops within the first minutes of pumping, indicating intense heat exchange between the injected fluid and the surrounding formation.

After pump shutdown, partial temperature recovery occurs as a result of conductive heat transfer from the surrounding rock; however, the temperature does not return to the initial formation level before the onset of subsequent operation stages. As a result, a reduced thermal background is established in the near-wellbore zone early in the treatment and persists throughout the operation.

A more detailed view of temperature evolution during the injection test stage is presented in Figure 4. Even short-term injection of cold fluid leads to a pronounced temperature reduction, forming the initial thermal conditions for subsequent stages.

Temperature dynamics during the mini-fracturing stage are shown in Figure 5. Compared with the injection test, the mini-frac results in deeper and more prolonged cooling of the formation. The minimum temperatures recorded at this stage are significantly lower than the formation temperature, indicating an accumulated cooling effect from preceding pumping activities. After pump shutdown, partial thermal recovery is observed; however, by the start of the main HF stage the temperature remains noticeably below the initial formation value.

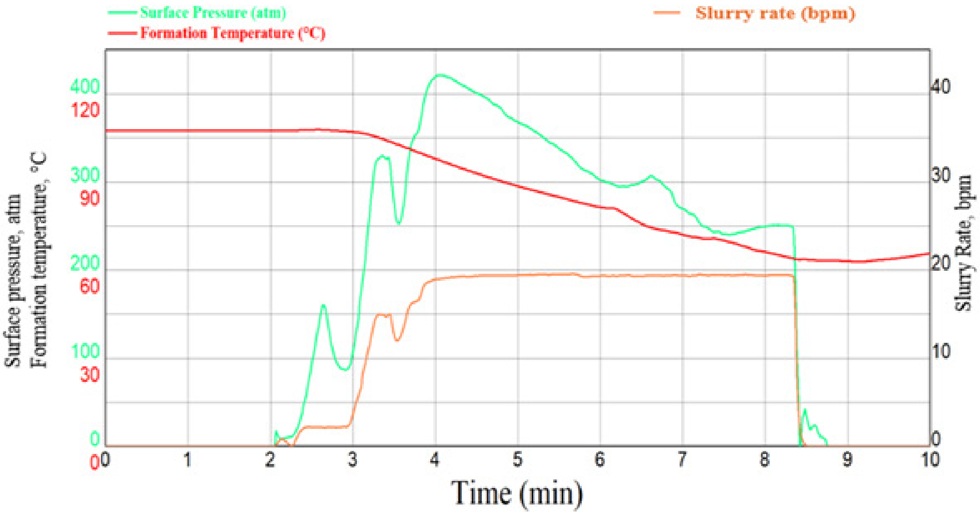

Figure 4 – Temperature dynamics in the near-wellbore zone during the injection test stage

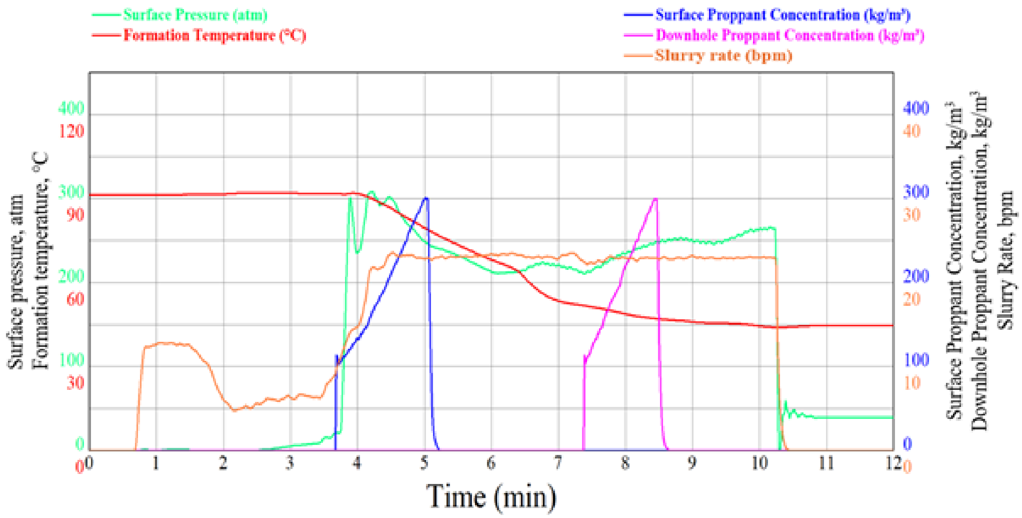

Figure 5 – Temperature variation during the mini-hydraulic fracturing stage

The most pronounced and long-lasting cooling of the near-wellbore zone occurs during the main HF stage (Figure 6). During this period, temperature decreases by several tens of degrees relative to the initial formation temperature and remains at a reduced level throughout the entire active pumping interval. Consequently, the HF fluid system operates under thermal conditions that differ substantially from those assumed in conventional laboratory-based fluid design.

The characteristic temperature parameters for each operation stage are summarized in Table 3. These data clearly demonstrate that the effective operating temperature range of the HF fluid is shifted toward significantly lower values relative to the formation temperature, particularly during the mini-frac and main HF stages.

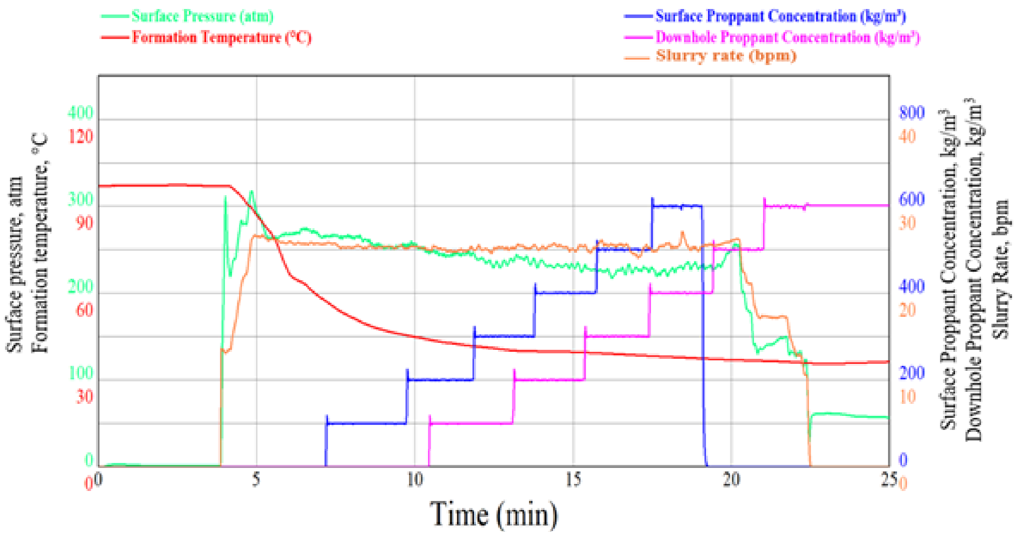

Figure 6 – Temperature dynamics in the near-wellbore zone during the main hydraulic fracturing stage

Table 3 – Characteristic temperature parameters during different stages of the HF operation

Operation stage	Stage duration, min	Temperature before injection, °C	Minimum temperature during injection, °C	Average temperature during injection, °C	Deviation of average temperature from formation temperature, °C
Injection test	7	108	63	83	-25
Mini-fracturing	10	92	44	70	-38
Main hydraulic fracturing	23	97	36	56	-52

Comparison of field temperature data and laboratory rheological tests

The results of laboratory rheological tests of the crosslinked gel conducted in accordance with ISO 13503-1 [10]. The experiments demonstrate that both viscosity stability and gel-breaking kinetics are highly sensitive to temperature conditions. A decrease in temperature relative to the formation value results in a slowdown of oxidative breaker action and prolonged retention of elevated viscosity.

Comparison of the downhole temperature history obtained in the field (Figures 3–6) with laboratory test results reveals that the conventional approach to breaker selection does not adequately represent the actual operating conditions of the HF fluid during pumping. Effective cooling of the near-wellbore zone leads to a reduced rate of gel degradation, which may delay fracture cleanup and negatively affect proppant pack conductivity. These observations are consistent with findings reported in previous studies [15, 16].

Comparison of conventional and optimized temperature selection approaches

To quantitatively assess the discrepancy between calculated and actual temperature conditions used for breaker selection, a comparison between the conventional and optimized approaches is presented in Table 4.

As shown in Table 4, the temperatures applied within the optimized approach are systematically lower than those assumed in traditional design. The most significant deviations are observed at the intermediate and final stages of the main HF treatment, where the actual operating temperature of the fluid is tens of degrees lower than the formation temperature. This explains the reduced efficiency of breaker action when using fluid formulations designed without consideration of dynamic temperature conditions.

Table 4 – Comparison of calculated and actual temperatures

Parameter	Conventional approach	Optimized approach (based on study results)
Initial stage, °C	108	97
Intermediate stage, °C	92	60
Final stage, °C	64	40

Justification for optimizing HF fluid formulation

The obtained results confirm that a HF operation should be considered not only as a hydrodynamic process but also as a pronounced hydrothermal process. The temperature regime in the near-wellbore zone is governed by the injected fluid temperature, pumping rates and stage durations, as well as the presence of operational pauses between stages.

Under such conditions, optimization of fracturing fluid formulation should be performed with consideration of the actual thermal history of the operation rather than relying exclusively on static formation temperature. Selection of breaker type and concentration accounting for reduced temperature conditions allows maintaining viscosity stability during pumping stages and ensuring effective gel degradation after fracturing completion, which is critically important for improving efficiency and repeatability of HF results in high-temperature reservoirs [7–9, 15].

Conclusion

Within the framework of the present study, the influence of dynamic formation temperature behavior on HF fluid performance under high-temperature reservoir conditions was systematically analyzed. Based on downhole pressure–temperature monitoring data, it was demonstrated that the thermal regime in the near-wellbore zone during HF operations is highly non-stationary and is governed by the sequence of pumping stages, the temperature of the injected fluid, and the presence of operational pauses between treatment stages.

It was established that a significant temperature reduction occurs already during the injection test stage, while subsequent temperature recovery is limited and incomplete. During the mini-fracturing and main HF stages, an accumulated cooling effect develops, resulting in an effective operating temperature of the HF fluid that remains several tens of degrees lower than the initial formation temperature for a substantial portion of the treatment duration.

Comparison of downhole thermometry data with laboratory rheological test results showed that the conventional HF fluid design approach based on static formation temperature does not adequately reflect the actual operating conditions of the gel system during pumping. In particular, reduced temperature conditions lead to a pronounced slowdown in polysaccharide gel degradation kinetics and a corresponding decrease in the efficiency of oxidative breakers, potentially impairing fracture cleanup and proppant pack conductivity.

Based on the obtained results, the necessity of optimizing HF fluid formulation with consideration of the actual thermal history of the operation is substantiated. Adaptation of breaker concentration and fluid formulation parameters to the dynamically evolving temperature regime enables the simultaneous achievement of viscosity stability during pumping stages and effective gel degradation after HF completion.

The proposed approach can be readily implemented in HF design workflows without additional operational complexity, relying on the interpretation of downhole temperature data and adjusted laboratory testing protocols. The conclusions obtained have practical significance and may be applied in the design of HF operations in high-temperature reservoirs to enhance the reliability of engineering decisions, improve fracture cleanup efficiency, and increase the repeatability of field results.

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[1]Нурташев А.Т.,
магистрант, ORCID ID: 0009-0006-5532-5808,
e-mail: as.nurtashev@gmail.com
[1]Қазақстан-Британ техникалық университеті,
Алматы қ., Қазақстан

ҚАБАТТЫ ГИДРАВЛИКАЛЫҚ ЖАРУ КЕЗІНДЕГІ КЕНЖАР МАҢЫНДАҒЫ АЙМАҚТЫҢ ТЕМПЕРАТУРАЛЫҚ РЕЖИМІНІҢ ЕРЕКШЕЛІКТЕРІ ЖӘНЕ ОЛАРДЫҢ ЫДЫРАТУШЫНЫ ТАҢДАУҒА ӘСЕРІ

Аңдатпа

Қабат температурасы жоғары мұнай және газ кен орындарын игеру жағдайында қабатты гидравликалық жару (ҚГЖ) операцияларының тиімділігі көбінесе ыдыратушы жүйесін дұрыс таңдаумен анықталады. Бұл жүйе проппантты айдау және орналастыру аяқталғаннан кейін полисахаридті гельдің бақылаулы түрде бұзылуын қамтамасыз етуі тиіс. ҚГЖ жобалаудың дәстүрлі тәжірибесінде ыдыратушының түрі мен концентрациясы, әдетте, қабат температурасының статикалық мәніне негізделіп таңдалады, ал айдау процесіндегі оқпан маңы аймағындағы температуралық режимнің өзгеруі шектеулі деңгейде ғана ескеріледі. Жұмыста айдау сынағы, мини-ҚГЖ және негізгі гидравликалық жаруды қамтитын ҚГЖ операциясы кезінде автономды тереңдік термобарикалық датчигінің көмегімен нақты уақыт режимінде тіркелген қабат температурасының динамикасын талдау нәтижелері ұсынылған. Беткі температурасы шамамен 20 °C болатын жұмыс сұйықтығын айдау оқпан маңы аймағындағы температураның бастапқы қабат температурасымен салыстырғанда ондаған градусқа тез төмендеуіне әкелетіні анықталды. Технологиялық үзілістер кезінде температура ішінара қалпына келеді, алайда қабаттың бастапқы жылу күйі келесі кезеңдер басталғанға дейін толық қалпына келіп үлгермейді. Алынған нәтижелер көрсеткендей, операцияның едәуір бөлігінде ҚГЖ сұйықтығының қасиеттерін анықтайтын тиімді температура статикалық қабат мәнінен айтарлықтай ерекшеленеді. Бұл сәйкессіздік гельдің ыдырау кинетикасына және персульфатты типтегі тотықтырғыш ыдыратушылардың тиімділігіне әсер етеді. Кен орнындағы температуралық деректерді Chandler 5550 вискозиметрінде жүргізілген зертханалық реологиялық сынақтардың нәтижелерімен салыстыру ыдыратушы жүйелерді таңдау кезінде динамикалық температуралық режимді ескеру қажеттілігін растайды. Операцияның нақты температуралық тарихын есепке алу ыдыратушыны таңдау сенімділігін арттырады және жоғары температуралы ұжымдық қабаттар жағдайында жарықшақтың тазаруын жақсартуға әрі ҚГЖ нәтижелерінің қайталануын қамтамасыз етуге мүмкіндік береді.

Тірек сөздер: қабатты гидравликалық жару, қабатты гидравликалық жару сұйықтығы, кенжар маңындағы аймақ, ыдыратушы, реологиялық қасиеттер.

[1]**Нурташев А.Т.,**
магистрант, ORCID ID: 0009-0006-5532-5808,
e-mail: as.nurtashev@gmail.com
[1]Казахстанско-Британский технический университет,
г. Алматы, Казахстан

ОСОБЕННОСТИ ТЕМПЕРАТУРНОГО РЕЖИМА ПРИЗАБОЙНОЙ ЗОНЫ ПРИ ГИДРОРАЗРЫВЕ ПЛАСТА И ИХ ВЛИЯНИЕ НА ПОДБОР БРЕЙКЕРА

Аннотация

В условиях разработки нефтяных и газовых месторождений с повышенными и высокими пластовыми температурами эффективность операций гидроразрыва пласта (ГРП) в значительной степени определяется корректным выбором брейкерной системы, обеспечивающей контролируемое разрушение полисахаридного геля после завершения закачки и размещения проппанта. В традиционной практике проектирования ГРП тип и концентрация брейкера, как правило, подбираются исходя из статического значения пластовой температуры, тогда как изменения температурного режима в призабойной зоне в процессе закачки учитываются лишь в ограниченной степени. В работе представлены результаты анализа динамики пластовой температуры, зарегистрированной в режиме реального времени с использованием автономного глубинного термобарического датчика в ходе проведения операции ГРП, включающей нагнетательный тест, мини-ГРП и основной гидроразрыв. Установлено, что закачка жидкости гидроразрыва с поверхностной температурой порядка 20 °C приводит к быстрому снижению температуры в призабойной зоне на десятки градусов по сравнению с исходной пластовой температурой. Наличие технологических пауз сопровождается частичным восстановлением температуры, однако исходное тепловое состояние пласта не восстанавливается до начала последующих стадий. Полученные результаты показывают, что эффективная температура, определяющая поведение жидкости ГРП в течение значительной части операции, существенно отличается от статического пластового значения. Это расхождение оказывает влияние на кинетику разрушения геля и эффективность окислительных брейкеров персульфатного типа. Сопоставление промысловых температурных данных с результатами лабораторных реологических испытаний, выполненных на вискозиметре Chandler 5550, подтверждает необходимость учёта динамического температурного режима при подборе брейкерных систем. Учет фактической температурной истории операции повышает надежность выбора брейкера и способствует улучшению очистки трещины и повторяемости результатов ГРП в условиях высокотемпературных коллекторов.

Ключевые слова: гидроразрыв пласта, жидкость гидроразрыв пласта, призабойная зона, брейкер, реологические свойства.