

Article

Wide-Field Electromagnetic Monitoring of Multi-Cluster Fracture Propagation in Conglomerate Reservoirs: A Field Case from the Baikouquan Formation, Mahu Sag

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Abstract

Multi-stage multi-cluster hydraulic fracturing in conglomerate reservoirs is often characterized by strong cluster-to-cluster variability in fluid distribution, which can reduce stimulation efficiency. However, field-scale observations that constrain how injected fluid is partitioned among clusters remain limited, especially in strongly heterogeneous formations. In this study, wide-field electromagnetic (WFEM) monitoring was applied to a horizontal well completed in the Baikouquan Formation sandstone–conglomerate reservoir of the Mahu Sag, Junggar Basin. The monitored treatment consisted of 13 fracturing stages, each containing six perforation clusters. Time-lapse electromagnetic data acquired during pumping were inverted to reconstruct the spatiotemporal evolution of the effective conductive fluid-swept region. Based on the inversion results, we introduce a set of quantitative proxy indicators (swept area, swept length, cluster-specific sweep, and an asymmetric index) to support relative comparison of fluid distribution patterns at both stage and cluster scales. Results show pronounced non-uniformity within and between stages, even under similar pumping conditions. A limited number of clusters exhibit stronger and farther-reaching WFEM-inferred conductive-fluid responses, whereas other clusters show weaker or more localized responses. Asymmetric sweep patterns on opposite sides of the wellbore are also commonly observed. These patterns are consistent with the combined influences of reservoir heterogeneity, local structural/stress disturbances, and operational factors, although WFEM alone does not uniquely validate causal mechanisms of fracture growth. Overall, this study demonstrates that WFEM monitoring provides a field-scale proxy tool for delineating effective conductive fluid-swept regions and for evaluating cluster-to-cluster variability under consistent acquisition and inversion settings. The findings offer practical guidance for interpreting fluid distribution and optimizing multi-cluster fracturing in strongly heterogeneous unconventional reservoirs.

Keywords: wide-field electromagnetic monitoring; hydraulic fracturing; multi-cluster fracture propagation; conglomerate reservoir; fracture competition



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1. Introduction

Multi-stage, multi-cluster hydraulic fracturing in horizontal wells is a key technology for developing low-permeability unconventional reservoirs [1–3]. In practice, injected

fluid is often unevenly distributed among perforation clusters within a stage, resulting in strong cluster-to-cluster variability in effective stimulation and uncertain post-fracturing performance [4–6]. This challenge is particularly acute in sandstone–conglomerate and gravel-rich tight reservoirs, where rapid lateral lithologic transitions, strong contrasts in mechanical properties, and complex pore–fracture systems can amplify flow competition and spatially heterogeneous responses during pumping [7–9].

A central difficulty is the lack of field-scale observations that constrain fluid distribution and effective swept regions during fracturing [8–12]. Microseismic monitoring provides indirect information on rock failure but does not directly constrain conductive-fluid migration and is sensitive to velocity heterogeneity, detection thresholds, and location uncertainty [13–15]. Fiber-optic sensing offers high temporal resolution near the wellbore, yet its sensitivity typically decays away from the borehole and may not represent far-field sweep or cluster-to-cluster partitioning—limitations that can be amplified in highly heterogeneous conglomerate settings [16–19]. Therefore, complementary diagnostics that are directly sensitive to fluid distribution are valuable for evaluating multi-cluster stimulation.

Electromagnetic (EM) monitoring leverages conductivity contrasts introduced by conductive fracturing fluids, enabling time-lapse inversion of subsurface electrical responses to delineate effective conductive fluid-swept regions [20–23]. In this work, we use a wide-field electromagnetic (WFEM) framework that treats near-, transition-, and far-field responses in a unified manner, supporting continuous monitoring under complex source–receiver geometries [24–27]. Importantly, WFEM inversion results are interpreted in this paper as proxies for the effective conductive fluid-swept region and its evolution, rather than as deterministic measurements of discrete fracture-plane geometry (e.g., individual fracture length/height/aperture).

This study presents a field case from the Baikouquan Formation in the Mahu Sag, where WFEM monitoring was applied throughout a 13-stage, 6-cluster-per-stage hydraulic fracturing operation. The objectives are: (i) to characterize stage- and cluster-scale variability in WFEM-inferred conductive-fluid sweep patterns; (ii) to define proxy indicators for relative comparison across stages and clusters under consistent acquisition/inversion settings; and (iii) to discuss plausible geological and operational factors that are consistent with the observed proxy patterns while maintaining a clear separation between observations and mechanistic interpretations.

2. Geological Background and Fracturing Operations Overview

2.1. Regional Tectonic Background and Reservoir Development Overview

The Mahu Depression, situated at the northwestern margin of the Junggar Basin, is one of the basin's significant Mesozoic–Cenozoic superimposed oil and gas-bearing depressions. The study area lies within the central tectonic unit of the Mahu Depression, where the overall tectonic morphology is controlled by the superimposition of multiple tectonic episodes, resulting in complex fracture development and an intricate tectonic stress field. Influenced by tectonic evolution and differential sedimentary filling, reservoirs exhibit significant heterogeneity both horizontally and vertically, providing natural uneven conditions conducive to fracture initiation and propagation during hydraulic fracturing.

The Baikouquan Formation serves as the primary target reservoir for development in the study area. Its depositional environment predominantly consists of a proximal braided delta system, with sandstone and conglomerate bodies showing rapid lateral facies transitions. The reservoir exhibits substantial thickness variations and complex lithological assemblages. Significant differences in gravel content, grain-size sorting, and cementation modes exist within different stratigraphic sections, causing abrupt changes in mechanical properties and flow characteristics over short distances (Figure 1; All spatial

distributions shown represent EM-derived conductivity anomalies associated with fluid response rather than direct representations of fracture geometry). These characteristics provide the geological background for interpreting spatial variability observed during hydraulic fracturing.

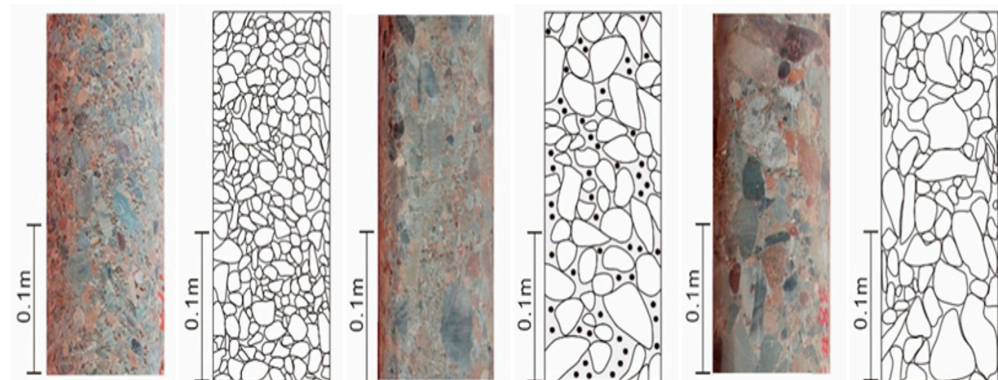


Figure 1. Photograph of core sampling in the Mahu Baikouquan Formation.

At the micro-scale (Figure 2), the primary pore types in the reservoir include intergranular pores, intergranular dissolution pores, and microfractures. The throat structures exhibit high complexity and a discrete distribution of throat radii, reflecting strong micro-scale heterogeneity in flow pathways. At the macroscale, geological properties and in situ conditions can vary along the horizontal section, which motivates the use of field diagnostics to assess spatial variability during stimulation.

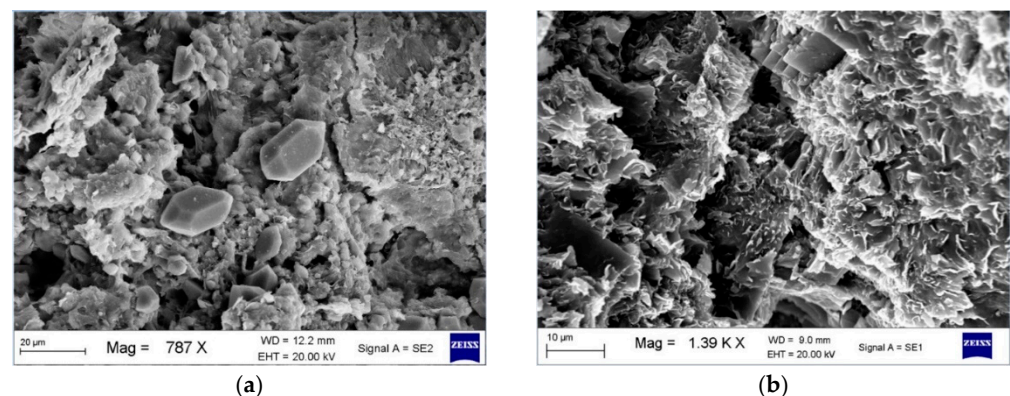


Figure 2. Microstructure of the dense conglomerate from Mahu. (a) Matrix microscopic scan image. (b) Microcrack scan image.

These multi-scale heterogeneous features may contribute to spatial variability in hydraulic connectivity and flow resistance during fracturing. In this section, we present them as background context; detailed interpretation of stage/cluster variability is discussed later based on WFEM-inferred proxy observations.

The current in situ stress field in the study area is dominated by horizontal stresses, with stress orientations influenced by both regional tectonic stresses and fracture distribution. Variations in minimum horizontal principal stresses exist across different well sections and stratigraphic levels, with overall horizontal stress differences ranging from 9.6 to 11 MPa (Figure 3). Macroscopically, these stress conditions favor the formation of a fracture system dominated by a single preferred orientation. However, at the local scale, the system remains susceptible to disturbances from lithological heterogeneity and the development of natural weak surfaces.

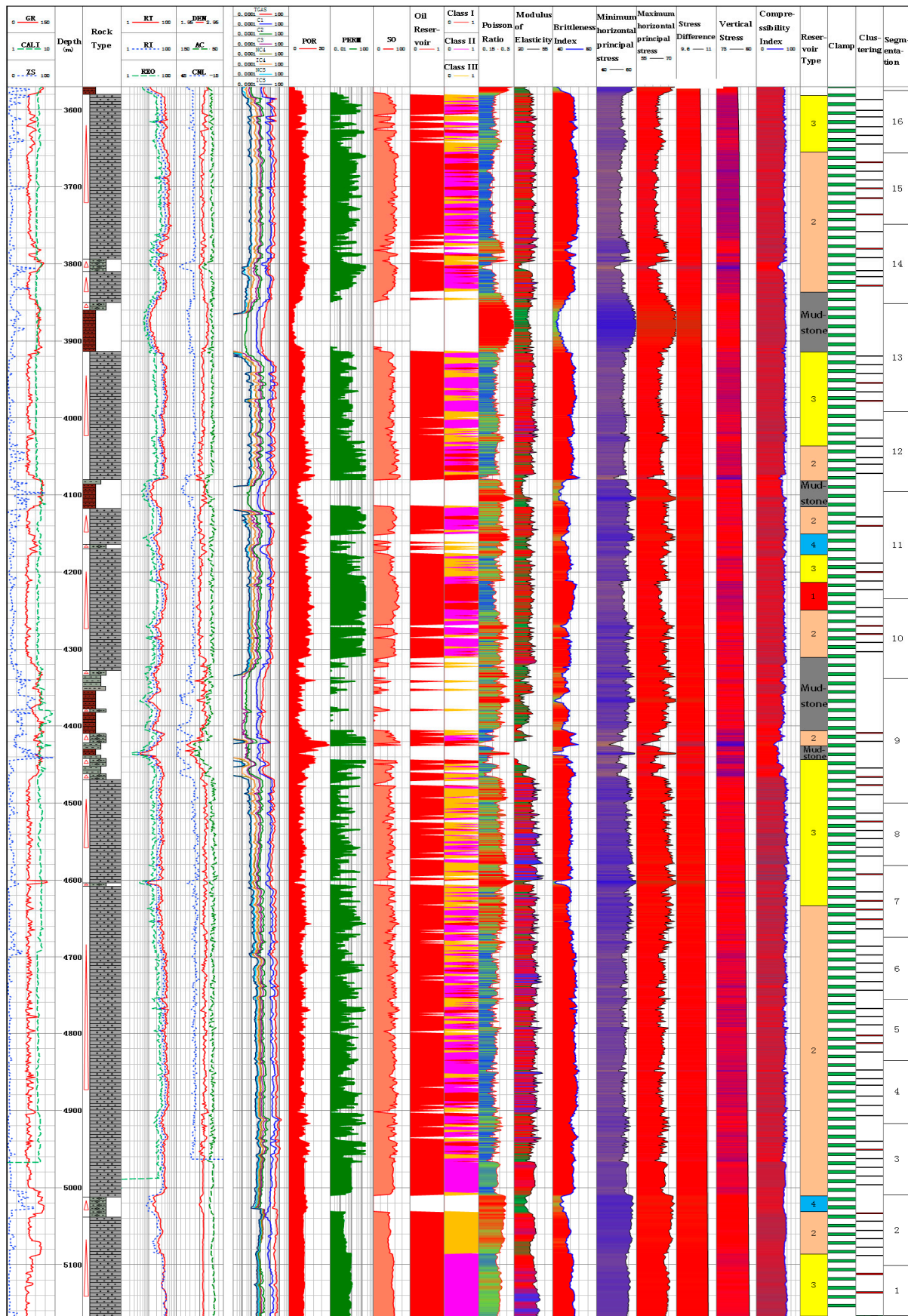


Figure 3. Composite well log and interpreted geomechanical context for the target well.

Within the Baikouquan Formation, locally developed natural fractures and weak bedding surfaces may not align perfectly with the regional principal stress direction. During stimulation, such structures may interact with fluid migration and influence hydraulic connectivity at different locations. Here we report these features as part of the geological background; their possible relationship to asymmetric WFEM-inferred sweep patterns is discussed later as an interpretation consistent with the proxy observations, rather than as a confirmed causal mechanism.

Tracks include GR, RT, DEN, and DT (with units shown on the axes) plotted against measured depth, together with the interpreted minimum horizontal stress (σ_{hmin}) (or stress-related parameter) and its along-well variation where available. The figure documents background geological/geomechanical variability along the horizontal section; mechanistic interpretations are discussed later based on WFEM-inferred proxy observations.

2.2. Design Characteristics of Horizontal Wells and Staged Multi-Cluster Fracturing Operations

This study focuses on a horizontal well targeting a sandstone reservoir within the research area (hereinafter referred to as the target well). The horizontal section of the target well is generally oriented nearly perpendicular to the direction of the maximum horizontal principal stress to promote full vertical and lateral fracture propagation. With a horizontal length of approximately 1200 m and an overall straight wellbore trajectory, the section provides favorable conditions for staged multi-cluster fracturing operations and monitoring interpretation.

The target well employed a bridge plug-segmented, multi-cluster perforation fracturing process. Thirteen fracturing stages were delineated along the horizontal section, each containing six perforation clusters. Within each cluster, the number of perforations, hole diameter, and phase were kept consistent to minimize the impact of perforation process variations on fracture initiation behavior. The perforated section lengths varied across different fracturing stages, generally ranging from 56 to 95 m, with corresponding cluster spacings of approximately 12 to 16 m. This provided favorable comparative conditions for analyzing the impact of perforation parameter variations on fracture propagation and fracturing-fluid distribution behavior.

During fracturing operations, a primary pumping method of alternating clean water and sand-carrying fluid was employed. Single-stage fluid consumption, fluid intensity, and sand injection scale varied across different fracturing stages. Temporary plugging and diversion measures were implemented in some fracturing stages to improve flow distribution within the stage and activate potentially under-fractured perforation clusters. Overall, the target well exhibits a range of variations in perforation parameters, fluid usage scale, and sand injection intensity, making it an ideal case study for investigating the variability of multi-cluster fracture propagation and the response patterns of these parameters.

2.3. Background of Electromagnetic Monitoring Implementation and Key Research Focus

Under the above geological and operational conditions, the initiation and within-stage interaction among multiple clusters are highly uncertain. Conventional diagnostics (e.g., pressure response alone or a single monitoring method) are insufficient to robustly quantify how injected fluid is partitioned among clusters and how the conductive-fluid sweep evolves in space and time at the field scale. Therefore, WFEM monitoring was implemented during the stimulation of the target well to provide continuous, full-process observations of the WFEM-inferred conductive-fluid sweep patterns across stages and clusters.

It should be noted that the objective of WFEM monitoring here is not to directly image deterministic fracture-plane geometry or to uniquely validate causal mechanisms. Instead, WFEM provides proxy observations of the spatiotemporal evolution of conductive-fluid-

related conductivity perturbations, which can support hypothesis-driven interpretation of cluster interaction and flow competition when combined with geological and operational context:

- (1) The actual propagation patterns of multiple fracture clusters within a stage, with a particular emphasis on identifying whether finger-like propagation behavior caused by flow concentration exists;
- (2) Asymmetric propagation characteristics on opposite sides of the wellbore, quantitatively characterizing the degree of propagation imbalance;
- (3) Perforation-cluster-scale variability in WFEM-inferred sweep, highlighting within-stage fluid partitioning contrasts among clusters;
- (4) Associations between completion/operational parameters and the proxy sweep extent, providing an empirical basis for relative comparison and design discussion within the limits of WFEM resolution.

By integrating geological context, operational parameters, and WFEM proxy observations, this study aims to document field-scale non-uniformity and sweep imbalance patterns during multi-cluster stimulation and to discuss plausible geological and operational contributors. The implications for completion and pumping design are therefore framed as case-based guidance rather than deterministic mechanistic validation.

3. Electromagnetic Fracturing Monitoring Methods and Data Processing

3.1. Physical Basis of Electromagnetic Response Induced by Fracturing Fluid Injection

During hydraulic fracturing, the dominant contributor to the WFEM response is typically the conductivity contrast introduced by the injected (often saline) fracturing fluid invading fractures and the near-fracture matrix (Figure 4). This invasion produces a measurable perturbation in apparent resistivity relative to the pre-fracturing background. Other processes (e.g., changes in saturation, temperature, or rock–fluid interactions) may also influence bulk conductivity, but WFEM observations alone generally cannot separate these effects uniquely. Therefore, in this study, we interpret WFEM anomalies primarily as proxies for conductive-fluid sweep, rather than as direct evidence of pore-structure reconstruction or deterministic fracture-plane growth.

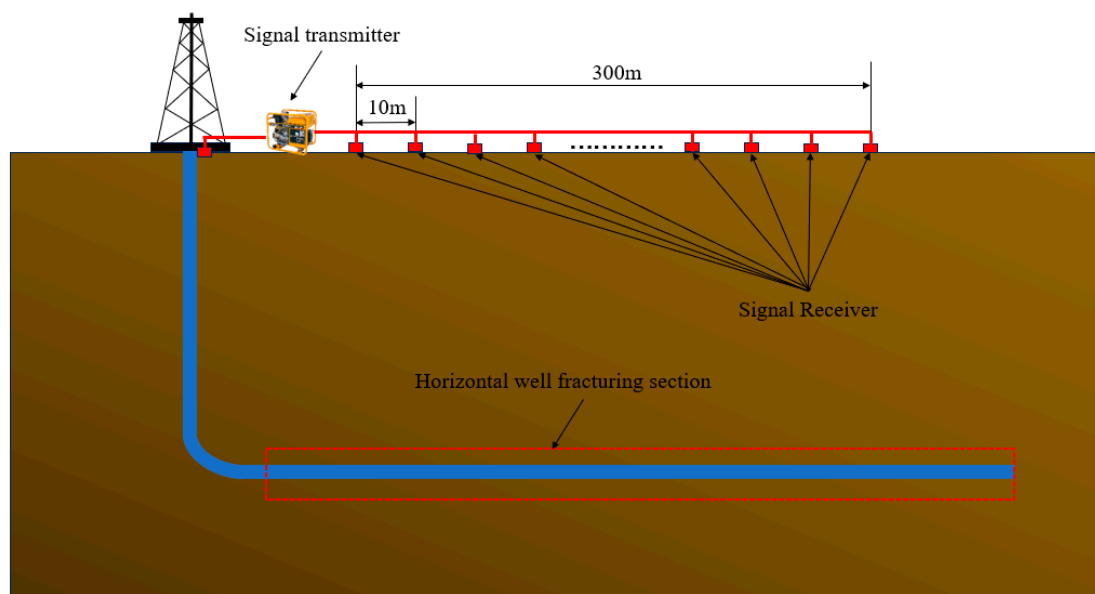


Figure 4. Schematic diagram of wide-field electromagnetic monitoring principle.

Accordingly, WFEM monitoring reflects the combined electrical response of the wellbore–fluid–fracture–near-matrix system, and is best interpreted as a field-scale proxy that delineates the effective conductive fluid-swept region, rather than the exact geometry of individual fracture planes or a uniquely defined “stimulated reservoir volume”.

3.2. Principles of Wide-Field Electromagnetic Methods and Their Applicability in Fracturing Monitoring

Traditional controlled-source electromagnetic methods in engineering applications typically rely on the near-field approximation, simplifying electromagnetic fields into plane wave forms. This approach limits their ability to identify anomalies in the near-field and transition zones. In fracturing monitoring scenarios, however, fractures are limited in scale, and the monitoring area is relatively close to the source. Electromagnetic responses often exist simultaneously in a hybrid state spanning the near-field, transition, and far-field zones, making a single approximation condition insufficient for interpretation needs.

Wide-field electromagnetic methods, grounded in unified electromagnetic field theory, avoid artificially partitioning the observation area. Instead, they introduce the concept of wide-field apparent resistivity to uniformly describe electromagnetic responses at different spatial locations. This method enables stable inversion of subsurface electrical structures without constraints from distant-zone conditions, significantly enhancing interpretation reliability in complex scenarios.

In fracturing monitoring applications, the wide-field electromagnetic method offers the following advantages:

(1) Requires observation of only a single electromagnetic field component, ensuring high data acquisition efficiency and suitability for continuous monitoring during fracturing operations; (2) Sensitivity to near-field electrical changes enables effective capture of fracturing fluid migration characteristics within fractures and near-fracture zones; (3) Greater effective detection depth under identical transmitter-receiver distances, suitable for monitoring fracturing operations in deep, tight reservoirs. Consequently, the wide-field electromagnetic method provides a reliable technical foundation for characterizing multi-cluster fracture propagation and fracturing fluid reach.

3.3. Electromagnetic Monitoring System Deployment and Data Acquisition Process

Considering the fracturing characteristics of the target well, this paper implements a combined well-surface electromagnetic monitoring scheme during fracturing. The field source employs a wellbore power supply, with Pole A connected to the wellbore and Pole B deployed at a surface location distant from the monitoring zone to form a stable current loop. The spacing between Poles A and B is approximately 1.2 km to mitigate interference from the field source geometry on near-field responses in the monitoring zone (Figure 5). This spacing was selected based on pre-job sensitivity checks (forward-response evaluation and field SNR tests), aiming to keep Pole B effectively remote relative to the monitoring grid so that source-geometry effects do not dominate the near-field apparent-resistivity changes during pumping.

Surface measurement points are arranged in a regular traverse pattern. Parallel traverses are deployed on both sides of the horizontal well, with perpendicular traverses positioned at both ends of the well section, forming an overall “well” pattern. Survey line lengths and point spacing are designed based on the anticipated fracture propagation scale, ensuring the monitoring network fully covers areas potentially affected by fracturing fluid. This configuration effectively enhances anomaly boundary identification and improves resolution for detecting asymmetric fracture propagation characteristics.

During data acquisition, pre-fracturing system consistency checks and signal-to-noise ratio tests are conducted to determine optimal transmission current intensity and signal

format. Throughout fracturing operations, electromagnetic data is continuously collected at fixed intervals while synchronously recording fracturing parameters (e.g., flow rate, pressure, proppant injection volume), providing foundational data support for subsequent integrated interpretation.

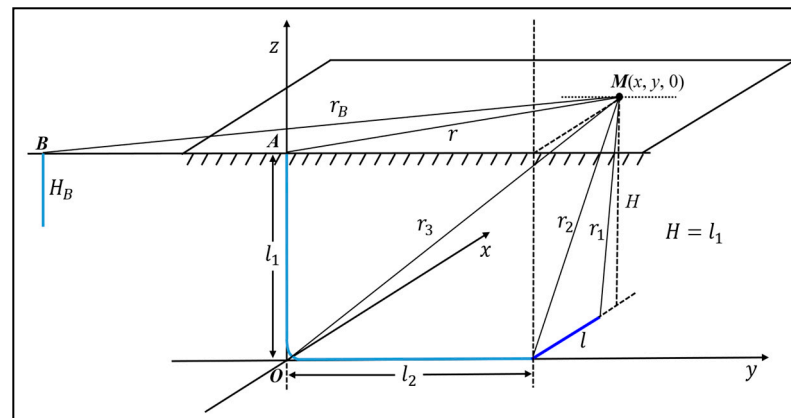


Figure 5. Monitoring mechanism of wide-field electromagnetic methods.

3.4. Data Processing Methods and Time-Differential Anomaly Extraction

After transmission to the data processing platform, raw electromagnetic monitoring data undergoes normalization to eliminate the impact of fluctuating excitation currents and instrument response variations on observational results. Subsequently, using background field data acquired prior to fracturing as the reference field, time-differential calculations are performed on electromagnetic responses during the fracturing process to extract anomalies caused by fracturing fluid injection and fracture propagation.

Time-differential anomalies effectively suppress the influence of stable formation electrical structures and field source geometry, enabling anomaly responses to more directly reflect the dynamic characteristics of the fracturing process. At the planar scale, analyzing the spatial distribution patterns of differential anomalies allows for the qualitative identification of anomaly trends and preferential conductive-response corridors (i.e., WFEM-inferred conductive-fluid sweep directionality), rather than deterministic fracture-plane orientation or uniquely resolved flow pathways. At the temporal scale, comparing consecutive differential results enables tracking of the evolution of the fracturing fluid's reach and extent.

Building upon this, quantitative interpretation of differential anomalies is performed in conjunction with a wide-field electromagnetic inversion model to obtain planar distributions of fracturing fluid reach at different time points. This study outputs fracturing fluid reach maps at 10 min intervals, providing a unified data foundation for subsequent proxy-based analysis of conductive-fluid sweep patterns at the stage and cluster scales.

3.5. Quantitative Characterization Metrics for Fracture-Fracturing Fluid Response Features

To facilitate comparative analysis of fracture propagation behavior across multiple fracturing stages and different perforation clusters within a stage, this paper establishes a set of fracture–fracturing fluid response characterization metrics based on electromagnetic inversion results.

- (1) Fluid Reach Area. This refers to the planar area covered by electromagnetic anomalies within a specific fracturing stage at a given time, characterizing the overall reach scale of fracturing fluid within the reservoir.
- (2) Fluid reach length (proxy sweep length). Defined as the maximum distance of the WFEM-inferred conductive-fluid sweep extent on either side of the wellbore along the

principal anomaly axis. This metric does not represent fracture half-length, but provides a relative proxy for the farthest extent of conductive-fluid-related perturbation under consistent acquisition and inversion settings.

- (3) Perforation-cluster sweep length (proxy). For a given perforation cluster, this metric extracts the corresponding local WFEM anomaly-extent along the principal axis to quantify the relative conductive-fluid sweep scale attributable to that cluster under consistent acquisition and inversion settings. This metric does not represent deterministic fracture length, but serves as a cluster-level proxy for fluid partitioning and effective sweep contrast.
- (4) Asymmetric sweep index (proxy). Defined as the ratio of the longer to the shorter WFEM-inferred conductive-fluid sweep length on the two opposite sides of the wellbore for the same cluster. This index quantifies the imbalance of proxy sweep rather than the geometric asymmetry of an individual fracture plane.

These metrics do not directly equate to actual fracture-related behavior parameters but reflect the combined response characteristics of the fracture–fluid–near-matrix system. When comparing relative differences between stages and clusters within the same well under consistent settings, they can highlight non-uniformity, proxy sweep imbalance, and cluster-to-cluster fluid partitioning, while quantitative conclusions remain subject to inversion resolution, smoothing, and threshold dependence.

3.6. Proxy Interpretation, Uncertainty, and Resolution Limits of WFEM Inversion

WFEM monitoring in this study provides a field-scale electromagnetic response to conductive-fluid migration and related conductivity perturbations. It does not directly image the deterministic geometry of individual hydraulic fracture planes (e.g., discrete fracture length, height, or aperture). Accordingly, throughout this manuscript, we interpret WFEM inversion results primarily as proxies for the effective conductive fluid-swept region and its spatiotemporal evolution, rather than as direct measurements of fracture-plane geometry.

The mapping from WFEM anomalies to “fluid reach” is non-unique and depends on inversion assumptions (e.g., model parametrization, regularization strength, and background conductivity), acquisition geometry, and measurement noise. Inversion smoothing and spatial sensitivity decay can broaden anomalies and influence apparent lateral extent. Therefore, the quantitative indicators defined in Section 3.5 are intended for relative comparison across stages and clusters within the same well under consistent acquisition and inversion settings, rather than for absolute recovery of fracture-related behavior.

Because the inferred sweep extent depends on the anomaly cutoff used in time-differential interpretation, we treat the threshold parameter as empirical. Where relevant, we report results using a baseline threshold and interpret small percentage differences cautiously. The robustness of qualitative patterns (e.g., within-stage strong/weak response contrast and prevalent asymmetry) is discussed in Section 4 in the context of threshold dependence and engineering cross-checks.

It should be emphasized that the conductivity anomalies derived from WFEM monitoring represent electromagnetic responses to fracturing-fluid migration rather than direct observations of physical fracture-related behavior. In this study, all fracture-related interpretations are inferred from the spatial and temporal evolution of EM anomalies and should therefore be understood as interpretations consistent with observed fluid-response patterns, rather than as validated representations of fracture-related behavior or propagation mechanisms.

4. Reliability and Quantitative Validation of Electromagnetic Monitoring Results

In this study, “validation” is used in the sense of internal consistency checks and operational cross-comparisons under fixed acquisition and inversion settings, rather than an absolute verification of deterministic fracture-plane geometry.

Whether electromagnetic monitoring inversion results accurately reflect fracturing fluid migration and fracture propagation behavior is a prerequisite for subsequent proxy-based interpretation of conductive-fluid sweep patterns and the discussion of plausible mechanisms under WFEM non-uniqueness. This chapter systematically provides indirect support for the reliability of electromagnetic monitoring results through quantitative characterization of electromagnetic responses, criteria for extracting fracturing fluid reach and extent, definition of WFEM-inferred proxy sweep indicators, and verification of temporary plugging responses.

4.1. Quantitative Characterization of Electromagnetic Responses Induced by Fluid Entry into Formations

During hydraulic fracturing, fracturing fluid entering fractures and near-fracture matrix significantly alters the equivalent electrical properties of target formations. To highlight electromagnetic response changes caused by fracturing operations while mitigating background formation electrical properties and instrument system influences, this study employs a time-differential approach for quantitative characterization of electromagnetic monitoring results. The fundamental form is:

$$\Delta\rho_a(t) = \rho_a(t) - \rho_a(t_0) \quad (1)$$

In the equation, $\rho_a(t)$ represents the apparent resistivity response at a given moment during fracturing, while $\rho_a(t_0)$ denotes the background apparent resistivity prior to fracturing.

Based on this, a normalized apparent resistivity change rate is introduced to characterize the electromagnetic anomaly intensity:

$$R_\rho(t) = \frac{\rho_a(t) - \rho_a(t_0)}{\rho_a(t_0)} \quad (2)$$

This indicator effectively reflects the degree of electrical property changes induced by fracturing fluid injection into the formation. It facilitates cross-sectional comparisons across different measurement points, time intervals, and fractured zones, providing quantitative evidence for subsequent identification of fracturing fluid propagation ranges.

4.2. Criteria for Extracting Fracturing Fluid Reach and Area Calculation

Based on differential electromagnetic response results, this paper defines areas where the normalized apparent resistivity change rate exceeds a given threshold as the effective reach zone of fracturing fluid. The criteria are defined as follows:

$$R_\rho(t) \leq -\eta \quad (3)$$

In the formula, η is an empirical threshold parameter determined by comprehensively considering the on-site noise level and background fluctuation amplitude, typically set at 5–10%. The threshold η is kept constant across all fracturing stages to ensure comparability of the derived indicators.

Subject to the aforementioned constraints, the plane wave and area $A_f(t)$ of the fracturing fluid at a given moment are expressed as:

$$A_f(t) = \sum_{i=1}^N S_i \quad (4)$$

Among these, S_i denotes the area of the i -th grid cell satisfying the anomaly criterion, and N represents the number of anomalous cells.

This method provides an operationally consistent proxy for delineating the effective conductive fluid-swept region from time-differential WFEM responses, enabling relative comparison of sweep patterns across stages and clusters under comparable acquisition and inversion settings.

4.3. Definition of WFEM-Inferred Sweep Length and Asymmetric Index (Proxy Metrics)

To quantify the lateral extent of the WFEM-inferred conductive-fluid sweep on both sides of the wellbore, the maximum proxy reach lengths on the left and right sides are defined as LL and LR , respectively. Based on these proxy lengths, an asymmetric index is defined as:

$$I_{asym} = \frac{\max(L_L, L_R)}{\min(L_L, L_R)} \quad (5)$$

When $I_{asym} = 1$, the inferred sweep extent is symmetric; when $I_{asym} > 1$, the inferred sweep exhibits increasing asymmetry. We emphasize that LL , LR , and I_{asym} are proxy metrics derived from WFEM responses and are used to support relative comparison of fluid distribution patterns, not to deterministically quantify discrete fracture-plane geometry.

4.4. Correspondence Verification Between Electromagnetic Response and Fracturing Construction Pressure Characteristics

Fracturing pressure curves provide an operational context for interpreting time-lapse WFEM responses. In general, periods of sustained pumping and stable proppant transport often coincide with growth in the magnitude and spatial extent of time-differential WFEM anomalies, whereas operational transitions (e.g., pumping mode changes or shutdown) are commonly associated with corresponding adjustments in the EM response. These observations support that WFEM is responsive to the fracturing operation at the field scale.

Across stages, segments with longer effective pumping duration and higher cumulative injected volume tend to exhibit larger WFEM-inferred swept areas and proxy reach lengths, while stages with shorter pumping time or lower cumulative volume show comparatively smaller anomaly extents. We interpret these relationships as engineering cross-checks that the EM-derived indicators are internally consistent with operational forcing, while acknowledging that such correlations do not constitute independent physical validation of discrete fracture-related behavior.

4.5. Quantitative Criteria and Validation for Temporary Plugging Fracturing Response

Temporary plugging fracturing alters flow distribution patterns within a section by sealing dominant flow pathways, thereby promoting new fracture initiation or expansion of previously suppressed fractures. To quantitatively evaluate the effectiveness of temporary plugging measures, this study introduces the rate of change in fracturing fluid coverage area before and after temporary plugging:

$$\Delta A_f = \frac{A_{f,after} - A_{f,before}}{A_{f,before}} \quad (6)$$

When $\Delta A_f > 0$ and the electromagnetic anomaly distribution shows significant migration, it can be determined that the temporary plugging measures have effectively promoted

the transfer of fracturing fluid to new fracture zones. If $\Delta A_f \leq 0$, it suggests that the temporary plugging effect is limited, and the original dominant flow channels still prevail within the section. Here, “before” and “after” refer to the EM responses immediately preceding and following the corresponding fracturing stage.

By analyzing the pressure changes before and after temporary plugging during construction, the effectiveness of temporary plugging and fracturing can be verified through a combined qualitative and quantitative approach, thereby enhancing the reliability of interpreting electromagnetic monitoring results.

Temporary plugging was implemented in multiple stages in this operation; in this paper, we focus on selected representative events that exhibit clear pre-/post-plugging EM and pressure signatures to demonstrate the applicability of the proposed interpretation criteria.

4.6. Sensitivity and Uncertainty

WFEM time-lapse anomalies and the derived indicators in this work are proxy measures of conductive-fluid-related perturbations rather than direct fracture-plane geometry. As discussed in Section 3.6, the mapping from anomaly patterns to “fluid reach” is non-unique and affected by (i) acquisition geometry and signal-to-noise ratio, (ii) inversion parametrization and regularization (smoothing), and (iii) the empirical anomaly cutoff used to extract the effective sweep zone. Therefore, we emphasize that the indicators are primarily intended for within-well, relative comparison across stages and clusters processed using the same workflow, rather than absolute recovery of fracture length/height/aperture.

The anomaly threshold η (Section 4.2) is chosen within a practical range (typically 5–10%) according to background fluctuation amplitude and field noise. Changing η will predictably alter the absolute inferred sweep area/extent; however, the main conclusions of this paper rely on robust qualitative contrasts (e.g., pronounced non-uniformity, persistent asymmetry, and strong cluster-to-cluster sweep imbalance) and on consistent ranking-level comparisons among stages/clusters under identical settings. Accordingly, we interpret small percentage differences cautiously and avoid over-precise mechanistic claims that exceed WFEM resolution.

Regarding spatial resolution, WFEM sensitivity decreases with distance and is effectively band-limited by electrode configuration, conductivity contrast, and inversion regularization. As a result, WFEM inversion products are best interpreted at the field scale as smoothed distributions of conductive-fluid sweep, and fine-scale fracture features (e.g., individual branches or aperture variations) cannot be uniquely resolved.

Finally, this study is based on a single-well case, and independent diagnostics (e.g., microseismic, tracers, production allocation logs) were not available for direct cross-validation. We therefore frame engineering implications as case-based and method-limited, and we highlight future work on multi-well validation and joint interpretation with independent monitoring and uncertainty quantification.

5. WFEM-Inferred Conductive-Fluid Sweep Patterns and Fracturing-Fluid Distribution Characteristics

Based on WFEM inversion results, this section analyzes stage- and cluster-scale variability in the EM-inferred conductive-fluid sweep patterns during the multi-stage operation. The analysis focuses on relative differences between stages and among clusters within a stage, using proxy indicators (swept area, proxy reach length, cluster-specific sweep, and an asymmetry index). Throughout this section, the reported spatial extents are interpreted as WFEM-inferred effective-conductive-fluid-swept regions rather than deterministic measurements of individual fracture-plane geometry.

Uncertainty in the EM inversion results arises from data noise, model regularization, and limited spatial resolution. While a formal resolution or uncertainty quantification analysis is beyond the scope of this study, all comparative analyses are conducted under consistent inversion settings, allowing reliable assessment of relative spatial and temporal trends.

5.1. Inter-Stage Variations in Fracturing Fluid Wave Reach and Coverage

By statistically analyzing WFEM-inferred swept area and proxy reach length across stages, this section compares stage-to-stage variability in the effective-conductive-fluid-swept region. As shown in Figure 6, the inferred swept area and proxy reach length vary across stages on both sides of the wellbore. The east–west differences are reported here as observed proxy patterns in the EM-inferred sweep; however, small percentage differences should be interpreted cautiously because the inferred extents are influenced by inversion resolution and threshold selection (Sections 3.6 and 4). The primary purpose of these metrics is relative comparison under consistent processing settings.

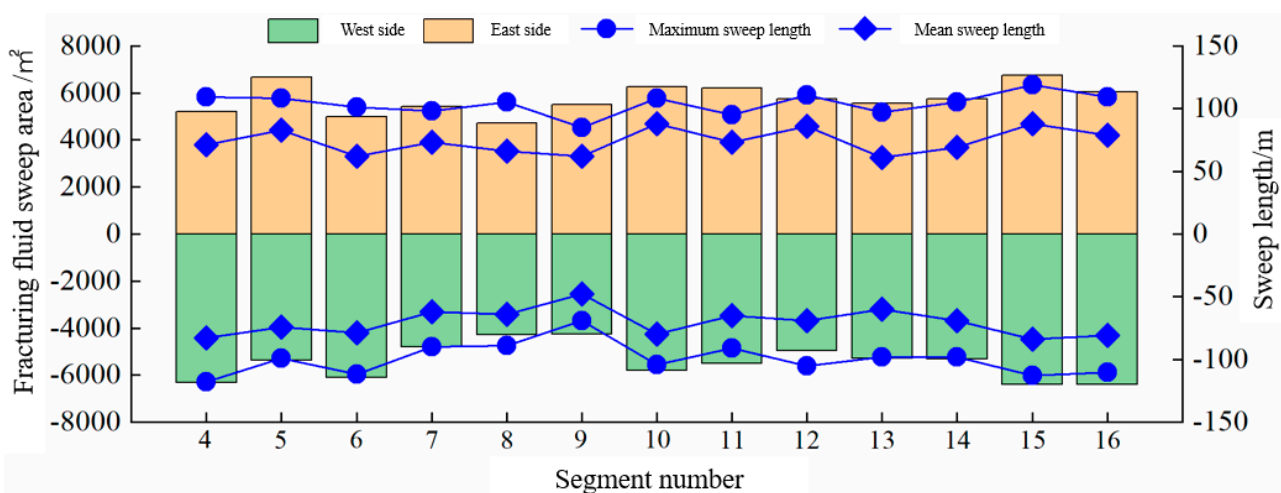


Figure 6. Monitoring results of fracturing fluid coverage area and length.

Along the horizontal wellbore direction, the total affected area (sum of affected areas on both sides of the wellbore) and total affected length (sum of maximum affected lengths on both sides) of each fracturing segment exhibit significant variations. Taking Well No. 1 as an example, the total affected area and total affected length of Fracturing Segments 7–9 are generally smaller, averaging 9652 m² and 179 m, respectively; while Fracturing Segments 5, 10, 11 and 15 exhibited significantly larger total propagation areas and lengths, averaging 12,231 m² and 209 m respectively—representing increases of 26.7% and 16.8% compared to Segments 7–9.

Further analysis shows an alternation between larger and smaller WFEM-inferred sweep extents along the horizontal direction. One plausible interpretation is interaction between adjacent stages (e.g., stress-shadow-like effects and/or pressure communication through heterogeneous pathways), whereby earlier stimulation may modify the local stress/pressure environment and influence subsequent fluid distribution. Because WFEM provides proxy constraints on conductive-fluid sweep rather than direct stress measurements, we report this alternation primarily as an empirical pattern and treat mechanistic explanations as hypotheses consistent with the proxy observations.

5.2. Finger-like Expansion Patterns of In-Segment Fractures

5.2.1. Prevalence of Finger-like Expansion Phenomena

Each fracturing stage of the target well was equipped with six perforation clusters. Figure 7 summarizes the WFEM-inferred conductive-fluid sweep extent (proxy reach area and proxy sweep length) for each cluster. A clear “finger-like” proxy response pattern is commonly observed on both sides of the wellbore: a few clusters exhibit strong and long proxy sweep signals, while others show weaker and shorter proxy responses. In this paper, we refer to these as dominant-proxy clusters and suppressed-proxy clusters, respectively. Importantly, this classification describes fluid-response proxies inferred from WFEM rather than deterministic fracture-plane geometry.

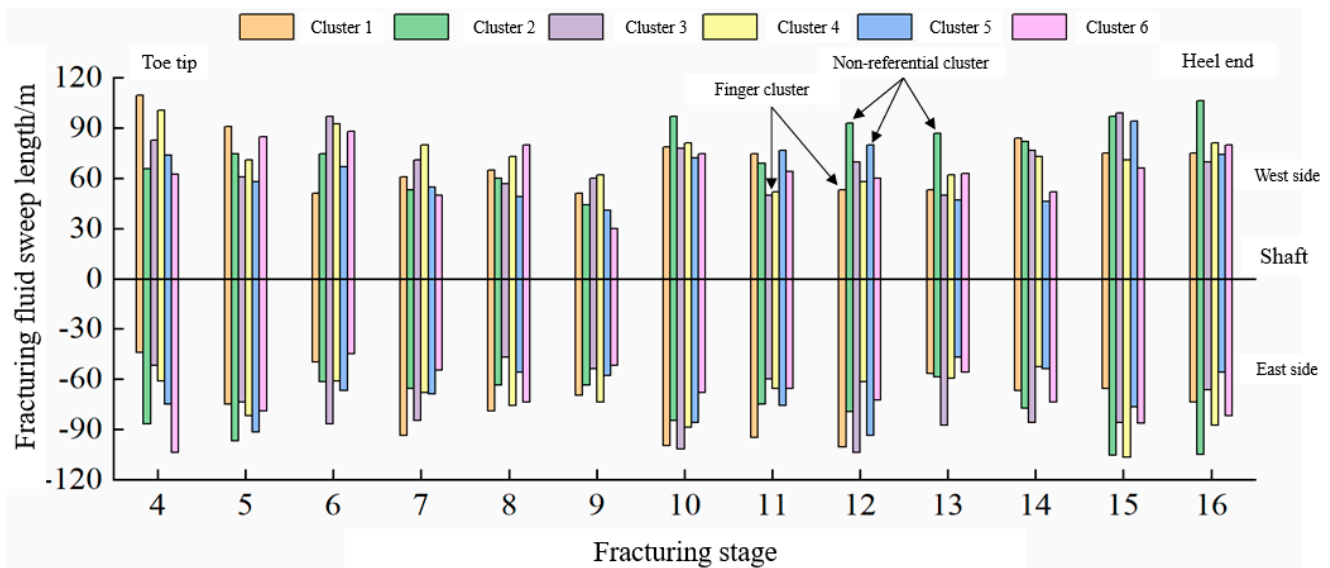


Figure 7. Fracturing fluid propagation and length monitoring results for each perforation cluster in the fractured section.

Taking the local fracturing section as an example, Clusters 2 and 5 (west side) in fracturing section-12 exhibit dominant-proxy sweep responses, while Clusters 3 and 4 (west side) in fracturing section-11 represent suppressed-proxy responses.

These observations indicate that preferential expansion is not solely determined by perforation location but is more likely closely related to formation heterogeneity. Spatially heterogeneous distributions of in situ stress and physical properties within sandstone reservoirs influence flow pressure patterns within fractures. This, in turn, alters the flow distribution among clusters within a stage, ultimately shaping the preferential expansion morphology.

5.2.2. Differences in WFEM-Inferred Proxy Sweep Length Between Dominant-Proxy and Suppressed-Proxy Clusters

To quantitatively characterize finger expansion features, the flow lengths of fracturing fluid in finger clusters and non-finger clusters on both sides of the wellbore were statistically analyzed (Figure 8). The flow length for each finger cluster (or non-finger cluster) is defined as the average value across all corresponding clusters within the fracturing section.

Statistical results indicate a significant positive correlation between the reach lengths of the target cluster and the non-target cluster. Specifically, when the reach length of the target cluster is larger, the reach length of the non-target cluster also increases accordingly. The reach length of the target cluster on the western side of the wellbore ranged from 60.9 to 106.1 m, with an average of 86.5 m, while the non-finger-in-cluster propagation length ranged from 41.4 to 76.9 m, averaging 61.2 m. On the eastern side of the shaft, the

finger-in-cluster propagation length ranged from 69.1 to 106.2 m, averaging 90.0 m; the non-finger-in-cluster propagation length ranged from 54.6 to 81.8 m, averaging 65.0 m.

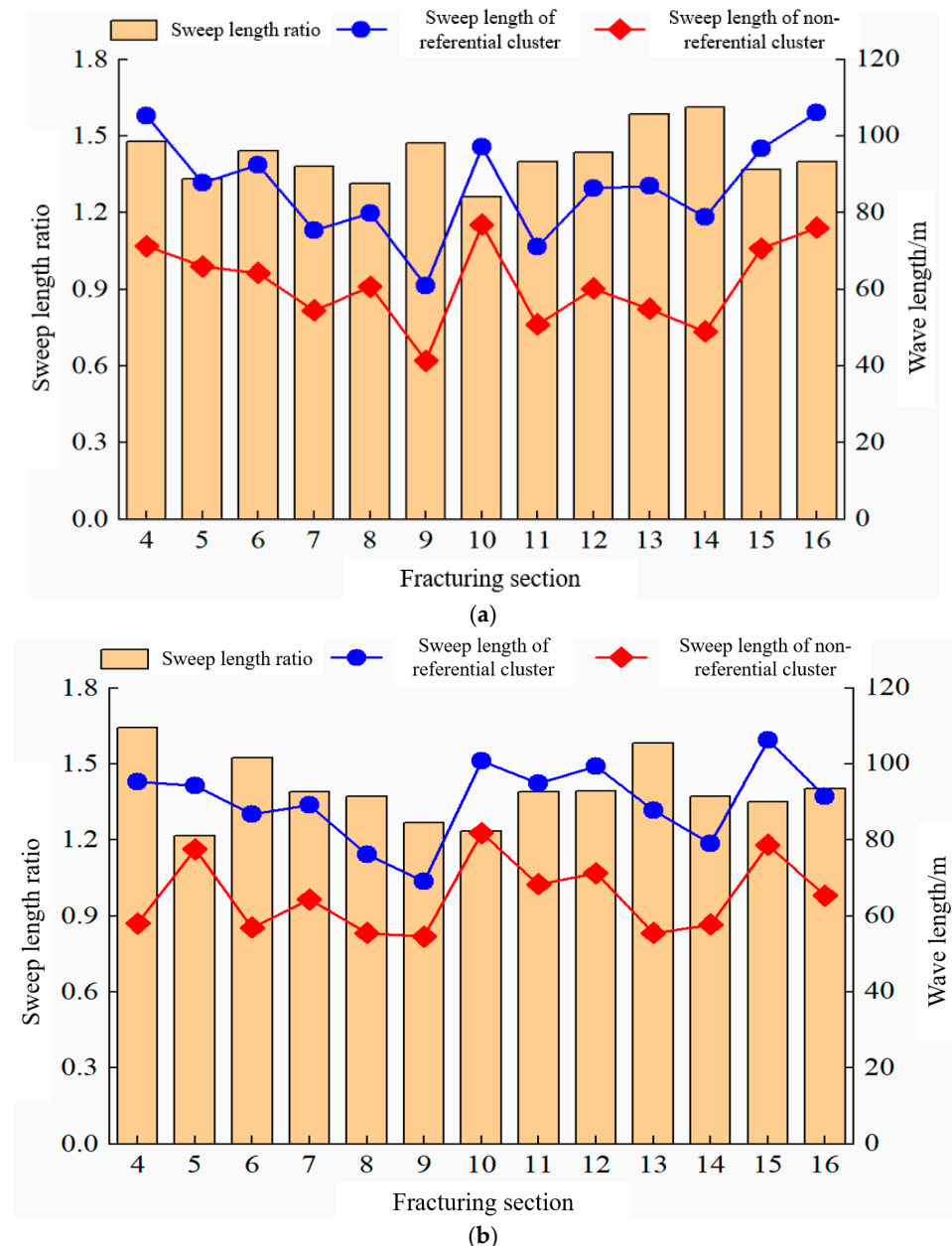


Figure 8. Difference in ripple length between finger-in-clusters and non-finger-in-clusters. (a) West side of the shaft. (b) East side of the shaft.

Overall, dominant-proxy clusters exhibit a consistently larger WFEM-inferred proxy sweep extent than suppressed-proxy clusters, indicating a stable scale contrast in conductive-fluid sweep within this dataset rather than a directly measured fracture-geometry difference.

5.3. Characteristics of Within-Stage Competition Reflected by WFEM-Inferred Proxy Sweep Patterns

Previous numerical simulations (Wu et al., Chen et al.) have indicated that under conditions of competitive propagation among multiple fracture clusters, the central cluster fractures are often more susceptible to inhibition. However, the electromagnetic monitoring

results in Figure 9 reveal that clusters exhibiting suppressed proxy sweep responses are not confined to the central cluster.

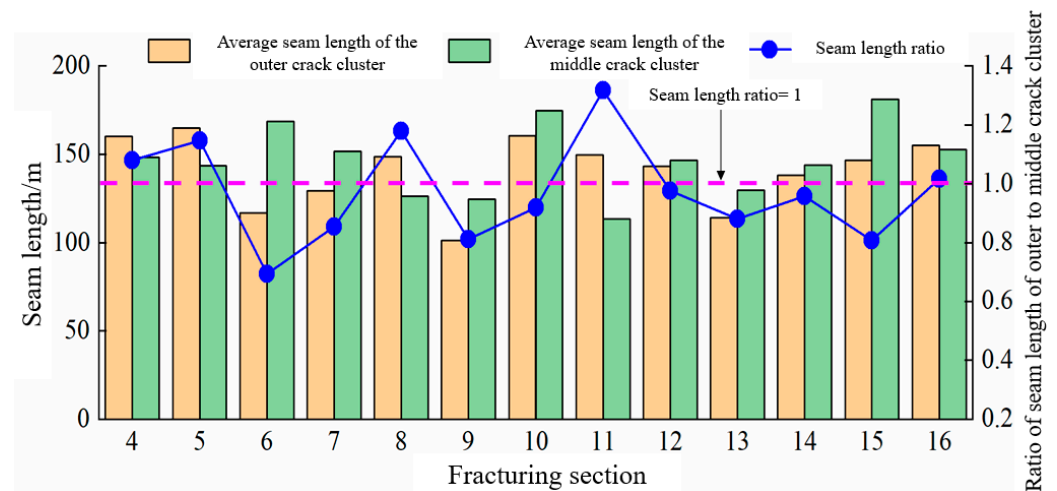


Figure 9. Differences in WFEM-inferred cluster-level proxy sweep length between outer clusters (Clusters 1 and 6) and central clusters (Clusters 3 and 4).

Figure 9 compares the average WFEM-inferred proxy sweep lengths between the outer clusters (Clusters 1 and 6) and the central clusters (Clusters 3 and 4) across stages. Results indicate that only four fracturing stages (Stages 4, 5, 8, and 11) exhibit outer clusters with larger average WFEM-inferred proxy sweep lengths than the central clusters. In all other fracturing stages, the average fracture lengths of the central clusters are greater than or comparable to those of the outer clusters.

For these stages, the average cluster-level proxy sweep length of the central clusters is 0.98–1.44 times that of the outer clusters (mean ≈ 1.15). This difference is interpreted as a proxy-level fluid-partitioning contrast under strong heterogeneity, rather than a deterministic reversal of fracture-geometry dominance.

5.4. Asymmetric Crack Propagation Characteristics

Figure 10 further demonstrates that pronounced asymmetric WFEM-inferred conductive-fluid sweeps are prevalent across clusters. To quantify the imbalance of proxy sweep on the two sides of the wellbore, we introduce an asymmetric sweep index defined as the ratio of the longer to the shorter WFEM-inferred proxy sweep length for the same cluster on opposite sides of the wellbore. The statistics are shown in Figure 10.

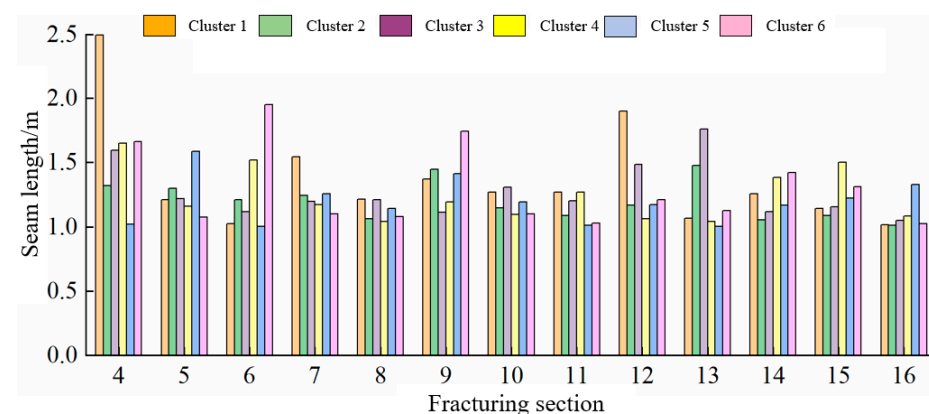


Figure 10. Asymmetric expansion indices of crack clusters within the segment.

Overall, the asymmetry expansion indices of fracture clusters ranged from 1.00 to 2.49, with an average of 1.26, indicating that the larger half of the fracture length was on

average 1.26 times the length of the smaller half. Significant variations in fracture cluster asymmetry expansion were observed across different fracturing stages. For instance, the asymmetry expansion index of Cluster 1 in Stage 4 was 2.44 times that of Cluster 5, with a standard deviation of 0.45 across clusters. In contrast, clusters within Stage 8 exhibited relatively concentrated indices, with the maximum value only 1.17 times the minimum, and a standard deviation of just 0.07.

These results indicate that asymmetric WFEM-inferred sweep patterns are prevalent, with pronounced heterogeneity in the degree of asymmetry among clusters within the same stage. A plausible interpretation is that stress redistribution and/or local geological disturbances may contribute to this proxy-level asymmetry; however, WFEM alone cannot uniquely validate the causal mechanism. Practically, such asymmetry may be associated with uneven effective sweep and non-uniform utilization of injected fluid between the two sides of the wellbore.

From an engineering perspective, a higher asymmetric propagation index implies a stronger directional bias of effective sweep, which may lead to uneven drainage, increased inter-well interference risk on the dominant wing, and under-stimulated rock volume on the opposite side. Therefore, AI can be used as a diagnostic metric to (i) identify stages/clusters requiring diversion or redistribution measures, and (ii) inform stage spacing and completion design in heterogeneous intervals where unilateral growth is recurrent.

5.5. Perforating Cluster Cracking Efficiency Characteristics

The thresholds (40 m and 80 m) are selected as data-driven breakpoints for this field case. As shown by the cluster-length statistics, suppressed (non-finger) clusters typically reach ~60–65 m, whereas dominant (finger) clusters commonly reach ~80–90 m. Therefore, 80 m is used to separate clusters that achieve the dominant sweep scale, while 40 m represents the lower-tail cutoff corresponding to clearly insufficient sweep in this dataset. To check robustness, we perturbed the thresholds by ± 10 m and found that the qualitative classification (insufficient/moderate/high) and the stage/cluster ranking trends remained unchanged, indicating that the main conclusions are not sensitive to small threshold shifts within this range.

Figure 11 presents the statistical results of perforation cluster fracturing efficiency on both sides of the wellbore. This paper characterizes perforation cluster fracturing efficiency using the fracturing fluid reach length: when $d < 40$ m, the perforation cluster is considered insufficiently fractured; when $40 \leq d < 80$ m, the perforation cluster is considered moderately fractured; and when $d \geq 80$ m, the perforation cluster is considered fully fractured.

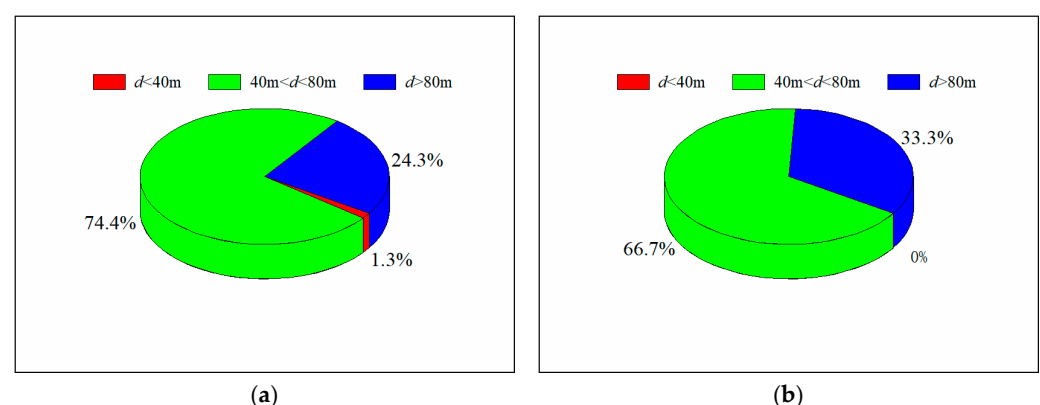


Figure 11. Monitoring results of cluster perforation fracturing efficiency. (a) West side of the shaft. (b) East side of the shaft.

Statistical results indicate that on the western side of the wellbore, 74.4% of perforation clusters (58 clusters) exhibited moderate activation, 24.3% (19 clusters) showed high activation, and only 1.3% (1 cluster) failed to achieve adequate fracturing. On the eastern side of the wellbore, 66.7% of perforating clusters (52 clusters) exhibited moderate activation, while 33.3% (26 clusters) showed high activation.

Overall, nearly all perforating clusters achieved cracking, but only 28.8% on average achieved full cracking. Most clusters (70.6% on average) exhibited moderate activation levels. This variation primarily stems from differences in the number of fractured perforation holes within each cluster: clusters with high utilization exhibited a larger proportion of fractured holes, while those with low utilization had relatively fewer fractured holes. Additionally, differences in fracture development between perforation clusters on opposite sides of the wellbore further exacerbate the asymmetric fracture propagation characteristics.

5.6. Control of Fracturing Fluid Reach by Perforation Section Length

The perforation section length is defined as the distance between the outermost perforation clusters on both sides within a section. The perforation section length in Well 1 ranged from 56.1 to 94.5 m, with an average of 65.7 m. To eliminate the geometric amplification effect of varying section lengths on fracture scale, the unit section length coverage area (the ratio of total fracturing fluid coverage area to perforation section length) was introduced as an indicator of longitudinal fracture propagation capability.

Results indicate a significant linear negative correlation between the coverage area per unit perforation length and the perforation section length ($R^2 = 0.6741$, see Figure 12). This demonstrates that under similar conditions of single-stage fluid volume (1800–2000 m³) and perforation parameters (six clusters per stage), the perforation section length is the key geometric parameter controlling whether fractures can effectively propagate to distant wellbore areas.

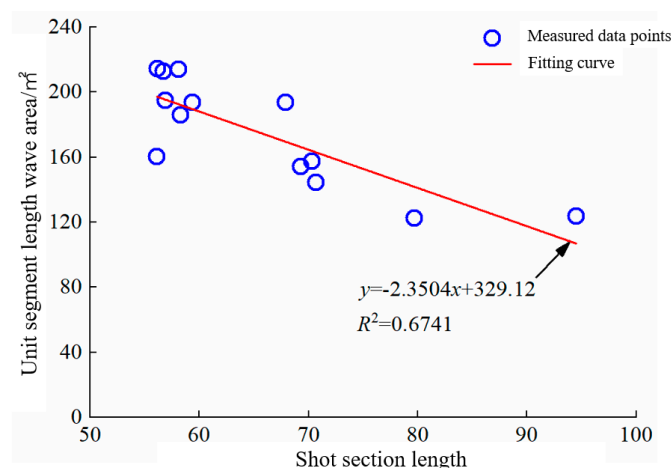


Figure 12. Effect of perforation gap length on fracturing fluid coverage.

When the perforation section length is large, the cluster spacing increases, leading to a corresponding rise in inter-cluster matrix volume. Under pressure differential drive, fracturing fluid more readily undergoes free flow into the inter-cluster matrix near the wellbore, thereby weakening the effective net pressure at fracture tips. This manifests as an expanded lateral mobilization range of fractures while their longitudinal extension capability is constrained—i.e., the modified zone “widens but does not lengthen.” Conversely, when the perforated section length decreases, cluster spacing narrows, restricting free flow space between clusters. This facilitates flow pressure connectivity within the sec-

tion, promoting sustained fracturing fluid delivery to the downhole region and enhancing longitudinal fracture propagation.

Further optimization of perforation section length was conducted using total fluid coverage area as the objective function. Multiplying the fitted function for coverage area per unit section length by perforation section length L yielded the expression for total fluid coverage area S (Equation (1)). Results indicate that S reaches its maximum value when $L \approx 70$ m. Concurrently, field data suggest that the coverage area per unit length remains high under conditions where $L = 56.1\text{--}59.4$ m. Considering both the longitudinal extension capability of fractures and the lateral mobilization efficiency, the recommended optimized perforation section length range is 60–70 m. For a single-stage configuration with six perforation clusters, the corresponding optimal cluster spacing is 12–14 m.

These results indicate that perforation section length fundamentally governs the trade-off between “fracture propagation capability and lateral mobilization capability,” serving as a primary controlling factor influencing the reach of fracturing fluid.

5.7. Effect of Single-Stage Fluid Volume on Fracture Propagation Capacity

Well No. 1's single-stage fluid volume ranged from 1463 to 3113 m^3 , averaging 2017 m^3 , and fluid intensity ranged from 20 to 55 m^3/m , averaging 31.5 m^3/m . Monitoring results indicate that the total fluid reach area and average reach length exhibit distinct phased characteristics with variations in single-stage fluid volume (Figure 13).

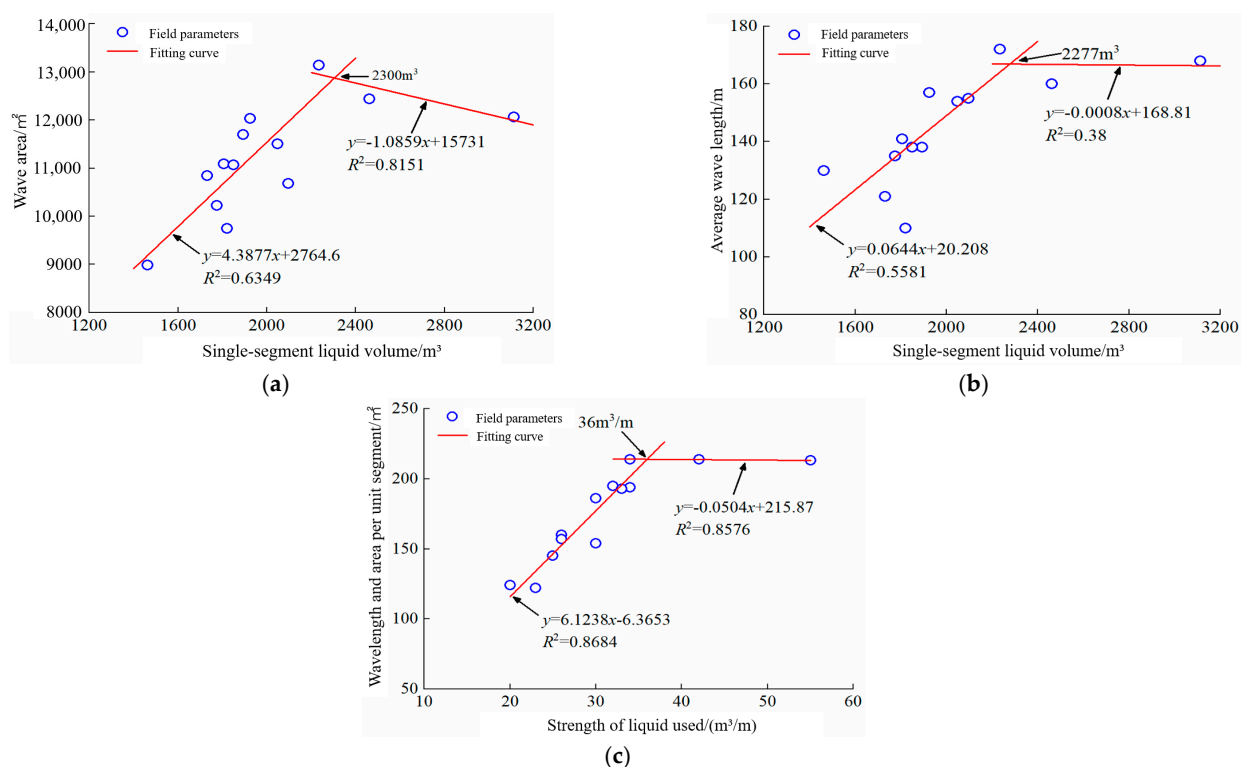


Figure 13. Effect of single-stage fluid volume on fracturing fluid propagation range. (a) Coverage area—single-pass liquid volume. (b) Average coverage length—single-pass liquid volume. (c) Unit segment length, wave propagation distance, and area coverage—liquid usage intensity.

When the single-stage fluid volume falls within the range of 1400–2400 m^3 , the total fracture coverage area exhibits a significant linear positive correlation with the single-stage fluid volume ($R^2 = 0.6349$). Within this phase, increasing the single-stage fluid volume effectively enhances the net fracture pressure, driving fracture propagation toward distant wellbore areas while simultaneously increasing the average fracture coverage length.

When the single-stage fluid volume exceeds approximately 2400 m^3 , the total coverage area of the fracturing fluid actually decreases with increasing single-stage fluid volume. At this point, as the fracture scale increases, fluid loss within the fractures and friction losses along the fracture path significantly rise. The net pressure at the fracture tip rapidly decays, markedly reducing the efficiency of further fracture propagation. The additional fracturing fluid injected is primarily consumed in the near-wellbore zone and within the already formed fracture network.

Based on the intersection of positive and negative correlation fitting curves, and considering field operational conditions, the optimal range for single-stage fluid volume is determined to be $2200\text{--}2300 \text{ m}^3$, corresponding to a fluid intensity of $34\text{--}36 \text{ m}^3/\text{m}$. Within this range, the total coverage area, average coverage length, and coverage area per unit length all achieve relatively optimal levels.

This demonstrates that single-stage fluid volume primarily controls whether fractures receive “sufficient energy supply for effective propagation,” but its efficiency-enhancing effect exhibits a clear upper limit.

5.8. Reinforcement Effect of Single-Stage Sand Injection Volume on Fracture Effective Support and Propagation

Well No. 1 employed two single-stage sand injection volumes of 110 m^3 and 130 m^3 , with sand injection intensity ranging from 1.17 to $2.33 \text{ m}^3/\text{m}$ and averaging $1.9 \text{ m}^3/\text{m}$. Monitoring results indicate that the total coverage area and average coverage length of the fracturing fluid exhibit a positive correlation with the single-stage sand injection volume. Furthermore, the coverage area per unit length shows a highly linear positive correlation with the sand injection intensity ($R^2 = 0.8601$; see Figure 14).

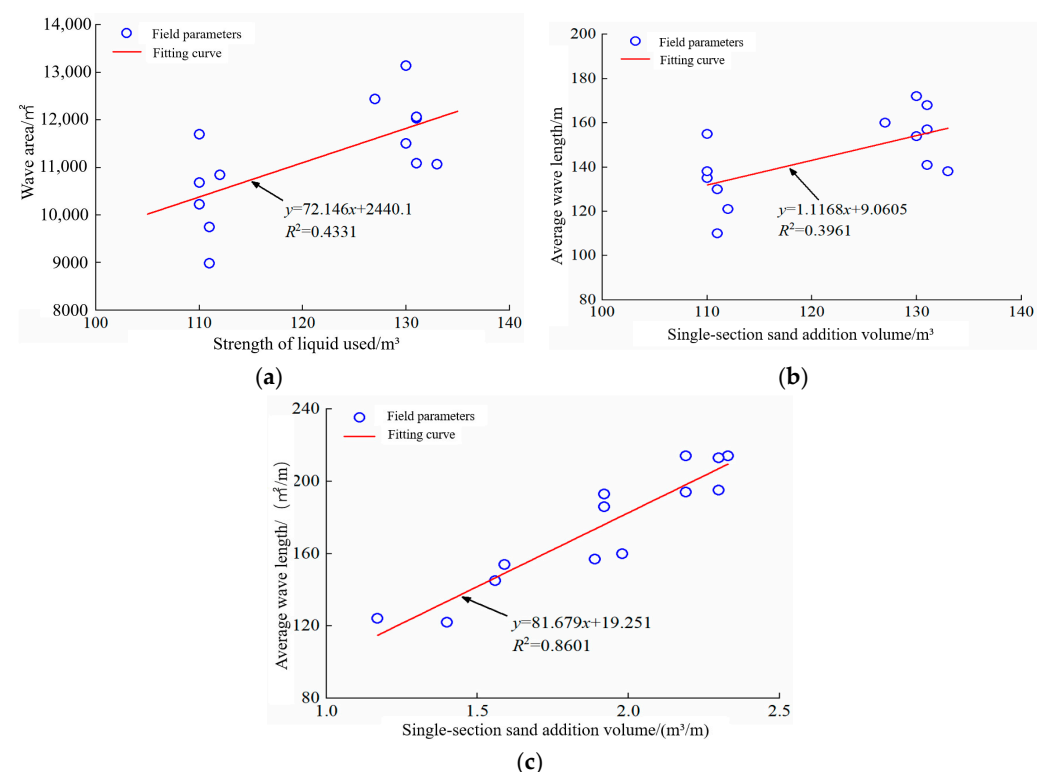


Figure 14. Effect of single-stage sand addition rate on fracturing fluid propagation range. (a) Area affected per sand addition segment. (b) Average affected length per sand addition segment. (c) Affected area per unit segment length per sand addition segment.

As the single-stage sand injection volume and injection intensity increase, the proppant packing density within fractures significantly improves. This not only enhances the effective proppant packing capacity of the fractures but also intensifies the abrasive effect of the high-sand-concentration slurry on perforation openings and near-wellbore tortuous fractures. Consequently, the diameter of perforation openings increases, and near-wellbore friction resistance decreases. The enhanced flow capacity of perforation openings facilitates increased fluid influx into fractures, thereby promoting their sustained extension.

Under current operational conditions, increased sand injection volumes did not exhibit noticeable adverse effects, indicating that within the studied range, single-stage sand injection primarily functions as an “amplifier of expansion capacity.” Based on monitoring results, a recommended single-stage sand injection volume of 130 m³ and injection intensity of 2.3 m³/m are proposed.

5.9. Hierarchical Classification of Primary Controlling Factors

Comprehensive analysis suggests that during multi-cluster fracturing in complex sandstone reservoirs, different engineering parameters exhibit distinct hierarchical control characteristics over fracture propagation behavior. Among these, the perforation section length determines the overall morphology of fracture propagation patterns and fluid reach by regulating inter-fracture competition and fluid distribution patterns within sections, serving as a primary controlling factor at the first level. Single-stage fluid volume primarily influences whether fractures can overcome initiation and propagation resistance to achieve effective expansion, exhibiting distinct threshold characteristics and thus constituting a secondary primary factor. Single-stage proppant charge, meanwhile, primarily enhances the extension and stability of existing fractures by improving fracture support conditions and near-wellbore flow capacity. This hierarchical control relationship elucidates the differentiated impact of engineering parameters on fracture propagation at the physical mechanism level, providing clear and actionable theoretical guidance for targeted optimization of fracturing parameters in complex sandstone reservoirs.

6. Mechanism Analysis and Controlling Factors of Multi-Cluster Fracture Propagation and Fracturing Fluid Reach Characteristics

6.1. Overall Characteristics of Non-Uniform Fracture Propagation During Multi-Cluster Fracturing

Based on WFEM inversion results, the EM-inferred conductive-fluid sweep exhibits substantial variability within and between stages. Even under broadly similar stage-level pumping parameters, the inferred swept area and proxy reach length can differ across clusters within the same stage. Some clusters show stronger and farther-reaching conductive-fluid responses, while others exhibit weaker responses.

These observations indicate that stage-scale operational parameters alone are insufficient to explain the variability of WFEM-inferred sweep patterns. A plausible interpretation is that the observed non-uniformity reflects the coupled effects of reservoir heterogeneity, local structural/stress disturbances, and dynamic fluid redistribution among clusters during pumping. Because WFEM provides proxy constraints on conductive-fluid sweep rather than direct fracture-plane geometry, mechanistic statements in this section are presented as interpretations consistent with the proxy observations rather than as independently validated causes.

6.2. Dominant Role of Reservoir Heterogeneity in Fracture Initiation and Propagation

The Baikouquan Formation sandstone–conglomerate reservoir exhibits complex lithological assemblages with spatially variable mechanical and physical properties. Such

variability can lead to differences in near-wellbore hydraulic connectivity and effective flow resistance among perforation clusters. A plausible interpretation is that, once a hydraulically efficient pathway is established early in a stage, subsequent injected fluid may preferentially follow that pathway, reinforcing a stronger WFEM-inferred conductive-fluid response while other clusters show weaker responses. This behavior is consistent with commonly discussed competition and flow-localization concepts, but WFEM alone does not uniquely validate the underlying fracture-growth mechanism. Therefore, we treat this explanation as a hypothesis consistent with the proxy observations.

6.3. Mechanism of Asymmetric Fracture Propagation Driven by In Situ Stress Variations

Electromagnetic inversion data reveal that most perforation cluster fractures exhibit distinct asymmetric propagation patterns on opposite sides of the wellbore. Specifically, fracturing fluid achieves greater propagation lengths on one side while encountering propagation limitations on the other. This phenomenon suggests a clear directional bias during fracture development.

The WFEM inversion results indicate that many clusters exhibit asymmetric conductive-fluid sweep on opposite sides of the wellbore, i.e., a longer or stronger proxy response on one wing and a more limited response on the other. A plausible interpretation is that the asymmetry reflects combined influences of the regional stress field and local heterogeneity (e.g., lithological contrasts, natural fractures, weak interfaces, or small-scale disturbances) that alter hydraulic connectivity and effective flow resistance. Nevertheless, WFEM alone does not uniquely resolve stress perturbations or fracture-plane morphology; thus, the above interpretation is presented as a hypothesis consistent with the observed proxy asymmetry rather than a confirmed causal mechanism.

The asymmetric index is therefore used here as a practical descriptor of EM-inferred sweep imbalance. Its repeatability across stages suggests that asymmetric sweep patterns are not rare in this case study, but the physical causes require additional independent diagnostics or coupled modeling for rigorous validation.

6.4. Competitive Fracture Propagation Among Multiple Clusters and Hydraulic Fracture Fluid Distribution Mechanisms

During multi-cluster fracturing, fluid distribution among perforation clusters within a section is not a static equilibrium but a dynamic process evolving with fracture propagation. Electromagnetic monitoring revealed that within some fracturing stages, the fluid-reached area rapidly concentrated over time in regions corresponding to a few perforation clusters, while responses from other perforation clusters gradually weakened.

A consistent interpretation of the observed WFEM response evolution is that, once a connected flow pathway becomes more hydraulically efficient early in a stage, subsequent injected fluid may preferentially follow that pathway, leading to further reinforcement of the associated conductive-fluid response while other clusters show weaker responses. This behavior is compatible with a positive-feedback-type redistribution of flow among clusters. However, because WFEM constrains the conductive-fluid sweep rather than directly resolving fracture initiation or discrete fracture dominance, we present this as a hypothesis consistent with the proxy observations, not as definitive proof of the underlying fracture-growth mechanism.

In the Baikouquan Formation sandstone reservoir, this competitive mechanism is significantly amplified due to reservoir heterogeneity, resulting in fracture numbers and sizes within sections far below predictions from ideal symmetric models. This is also a key reason why traditional design methods based on uniform fracture assumptions often fail in such reservoirs.

6.5. Amplification and Modulation Effects of Engineering Parameters on Fracture Propagation Characteristics

While geological conditions primarily govern fracture propagation behavior, engineering parameters exert significant amplification and modulation effects on the competitive fracture process. Comparative electromagnetic results indicate that, under conditions of similar single-stage fluid injection volumes, variations in perforation section length significantly affect the fracturing fluid coverage area per unit length. When perforation sections are longer, competition between perforation clusters within the section intensifies, reducing the effective fluid volume per cluster and limiting fracture propagation.

Operational parameters can amplify or mitigate within-stage variability in the WFEM-inferred sweep patterns by modulating flow distribution and competitive intensity among clusters. However, the available WFEM evidence does not allow us to claim deterministic changes in underlying fracture-growth mechanisms. We therefore interpret operational effects primarily as changes in how injected fluid is partitioned among clusters under the same geological context.

7. Conclusions and Engineering Implications

Based on wide-field electromagnetic monitoring data from a multi-stage, multi-cluster horizontal-well stimulation in the Baikouquan Formation, this study documents the spatiotemporal evolution of the WFEM-inferred conductive-fluid sweep at the stage and cluster scales. The results provide field-scale evidence of non-uniformity, asymmetry, and competition in proxy sweep patterns, and support discussion of plausible geological and operational contributors under the limitations of WFEM resolution and non-uniqueness.

- (1) Fracture propagation during multi-cluster fracturing in the Baikouquan Formation sandstone reservoir exhibits significant non-uniformity.

Even under conditions where engineering parameters such as fluid volume per stage, flow rate, and number of perforation clusters were essentially consistent, the fluid reach area and reach length varied markedly between different fracturing stages and perforation clusters within the same stage. This suggests that fracture propagation behavior is not solely governed by engineering parameters but is highly sensitive to reservoir heterogeneity.

- (2) Reservoir heterogeneity is a plausible contributor to cluster-to-cluster variability in WFEM-inferred sweep patterns. The Baikouquan Formation sandstone–conglomerate reservoirs exhibit strong spatial variability in mechanical and flow-related properties, which may create differences in effective hydraulic connectivity and flow resistance among clusters. This interpretation is consistent with the observed proxy patterns, but WFEM alone does not uniquely validate the causal mechanism.
- (3) The observed asymmetric WFEM-inferred sweep patterns are consistent with combined influences of regional stress orientation and local geological disturbances. WFEM inversion suggests that many clusters exhibit unequal proxy sweep extents on opposite sides of the wellbore. Because WFEM does not directly measure stress perturbations or fracture-plane morphology, mechanistic explanations are framed as hypotheses consistent with the proxy observations.
- (4) Engineering parameters modulate the intensity of within-stage variability in WFEM-inferred sweep patterns. Parameters such as perforation section length and cluster density are associated with measurable changes in the distribution of proxy sweep metrics. We interpret these effects primarily as modulation of flow distribution and competitive intensity among clusters, rather than deterministic changes in fracture-growth mechanisms.

- (5) Wide-area electromagnetic monitoring provides a field-scale proxy to delineate effective conductive fluid-swept regions and to support relative comparison of within-well stage/cluster variability; it does not directly resolve deterministic fracture-plane geometry or uniquely validate propagation mechanisms.
- (6) The research findings offer significant engineering implications for fracturing design in the Baikouquan Formation and similar sandstone/conglomerate tight oil reservoirs.

In highly heterogeneous reservoirs, the design assumption of “fracture geometric symmetry” should be deemphasized, with focus shifted to intra-stage fracture competition and effective fluid distribution. Optimizing perforation section length, perforation cluster configuration, and operational sequencing can mitigate fracture propagation imbalance, thereby enhancing the effectiveness and stability of hydraulic fracturing operations.

Limitations and future work: WFEM inversions primarily delineate the effective conductive fluid-swept region rather than the exact geometry of individual fracture planes; the spatial resolution is influenced by conductivity contrast, noise level, and inversion assumptions. The proposed WFEM-based indicators are intended for relative comparison across stages and clusters within the same operation under comparable acquisition and inversion settings, rather than for directly retrieving absolute fracture-plane geometry. In addition, this study is based on a single-well field case, and independent cross-validation with other diagnostics (e.g., tracers, production allocation, or joint interpretation with microseismic/fiber) is still limited. Their transferability to other lithologies or completion designs should be validated with additional field cases and independent diagnostics.

Practical considerations: The WFEM response and its signal-to-noise ratio are influenced by operational and geological factors, including formation and fluid temperature (seasonal effects), proppant size distribution and electrical conductivity, transmitter frequency selection, and inter-well electromagnetic coupling in densely developed pads (depending on well spacing). In addition, well depth and completion geometry can affect current pathways and effective investigation depth. Future work will systematically evaluate these sensitivities and explore alternative acquisition configurations (e.g., placing the transmitter and receivers in separate boreholes) to further improve SNR and interpretation robustness.

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