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Review and Outlook on Simulation Studies of Fracture Propagation in Segmented Multi-Cluster Fracturing of Coal Seam Roofs

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Abstract

As a clean and efficient unconventional natural gas resource, coalbed methane serves as a vital safeguard for China's energy transition and coal mine safety. Over 95% of China's high-gas mines face technical bottlenecks in low-permeability coalbed methane extraction efficiency, where conventional underground extraction technologies struggle to meet development demands in deep, fragmented, and soft coal seams. The horizontal top-wall multi-cluster fracturing technology for coal seams-involving horizontal well placement in the roof and multi-cluster segmented fracturing-induces fractures to penetrate and extend into the coal seam, forming complex fracture networks that enhance gas migration pathways. This has become one of the core technologies for efficient development of low-permeability coalbed methane. The fracture propagation patterns-including initiation locations, propagation paths, fracture network morphology, and interlayer penetration capabilities-directly determine fracturing effectiveness. Numerical simulation has become a core research tool in this field due to its ability to quantify coupled geological-engineering factors and dynamically reproduce fracture propagation processes.

Keywords

Coal Seam Roof; Staged Multi-Cluster Fracturing; Fracture Propagation; Numerical Simulation.

1. Introduction

Under current economic and technological conditions, surface extraction of coalbed methane from low-permeability coal seams has long been regarded as a development challenge. The primary extraction technology employed is vertical fracturing wells, which yield poor development results. There is an urgent need to explore new approaches and efficient extraction technologies that can rapidly and effectively reduce both the methane content and pressure within coal seams. Horizontal well staged fracturing has emerged as a key approach for efficiently developing low-permeability oil and gas reservoirs, unconventional natural gas, and coalbed methane. This technique significantly increases the controlled flow area per well, enhances formation flow capacity, and thereby boosts production rates, making it a vital technological tool for efficient unconventional reservoir development.

To systematically review the current state of research in this field, this paper focuses on cutting-edge directions such as multi-field coupled simulation, artificial intelligence prediction, and field engineering validation. The research content covers dimensions including geological factor constraints, engineering parameter control, and methodological innovation, providing reliable academic support for the review. This review will unfold in three aspects: geological factor influences, engineering parameter control, and research method advances. It summarizes existing research achievements and shortcomings, offering references for subsequent numerical simulation model optimization and engineering applications.

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2. Constraints of Geological Factors on Fracture Propagation in Horizontal Coal Seam Roof Multi-Cluster Fracturing

Geological factors constitute the intrinsic controlling conditions for fracture propagation, primarily encompassing the in-situ stress field, natural fractures and joints, lithological interfaces, and coal-rock mechanical properties. Their coupled effects directly determine the initial morphology, propagation path, and inter-layer penetration capability of fractures, making them core parameters requiring priority consideration in numerical simulations.

The in-situ stress field dominates both fracture propagation direction and initiation pressure. Pang Tao [1] studied the roof of a coal roadway under excavation, constructing five typical fracturing models based on roof structure and the relationship between perforations and coal seams. Numerical simulations revealed that after initial fracture initiation at the perforation base, secondary fractures readily occur at lithological interfaces and within coal seams. The in-situ stress field influences fracture morphology by controlling the initiation sequence at coal seams and structural planes. Differences in tensile strength are the primary factor governing the disparity in initiation pressures between coal seams and surrounding rock: when horizontal stress exceeds vertical stress and perforations traverse multiple structural planes, fractures tend to form horizontally along planes near coal seams, making it difficult to penetrate into the coal seam. Conversely, when vertical stress dominates, the vertical propagation capacity of fractures increases, raising the probability of layer penetration by over 30%. Lin Junqi [2] quantified the influence of the stress ratio K (vertical stress/horizontal stress) through orthogonal experiments. Results indicate K contributes 32.7% to fracture initiation pressure with a range of 3.55 MPa, significantly exceeding contributions from interface angle (18.2%) and water injection rate (15.5%). When K=1.8, the stress concentration effect at the interface was pronounced, increasing the fracture initiation pressure by 15.1% compared to K=1.2. Optimal fracture penetration efficiency was achieved when the interface angle ≤45°, with a fractal dimension of 2.4. At a critical pore spacing of 5 mm, synergistic optimization of fracture network complexity and permeability was realized, achieving 83% damage coverage. Additionally, variations in in-situ stress gradients significantly influence fracture propagation in steeply dipping reservoirs. Based on field data from the Fukan West area of the Qunnan Basin, Kang Junqiang et al. [3] classified steeply dipping reservoirs into three stress states: shallow zones with vertical stress < horizontal stress, middle zones with upward-dipping vertical stress < horizontal stress and downward-dipping vertical stress > horizontal stress, and deep zones with vertical stress > horizontal stress. Numerical simulations revealed that fracture propagation in shallow reservoirs occurs in three stages: "upward-dipping expansion - halt - downward expansion." In the middle zone, fractures initially expand upward before redirecting along zones of dominant vertical stress. Deep-zone fractures propagate perpendicular to the dip direction. As reservoir dip angle increases, the upward expansion rate in the shallow zone rises by 20%, and the redirection angle in the middle zone increases by 15°. These findings provide a basis for designing horizontal wellbore trajectories in steeply dipping reservoirs.

Natural fractures and joint planes are key conditions for forming complex fracture networks, with their density and orientation directly influencing the propagation patterns of hydraulic fractures. Peng Yuesheng et al. [4] derived fluid-solid coupled finite element equations based on the volume expansion-stress perturbation theory, establishing a coupled seepage-stress-damage model. They simulated fracture propagation in reservoirs with three fracture density configurations, identifying three typical interaction patterns between hydraulic fractures and natural joints: Direct penetration when the angle between the hydraulic fracture and principal stress exceeds 60°; termination after propagation along natural fractures when fracture density is low and strength is high; or initial propagation along natural fractures followed by the principal stress direction when the fracture-principal stress angle is <30°. In high-fracture-

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density reservoirs with fracture spacing < 5 cm, hydraulic fractures rapidly interconnected more fractures, reducing fracturing time by over 30% and increasing reservoir transformation area by 25%. The fracture network exhibited greater complexity, with fractal dimension values 0.3–0.5 higher than in medium-to-low fracture-density reservoirs. Lv Shuaifeng et al. [5] conducted detailed downhole dissections of 21 coalbed methane wells at Sihé and Chengzhuang mines in the Qinshui Basin. They classified natural fractures into six categories based on origin-including bedding fractures, exogenous joints, and gas-expansion joints—and further categorized them into four levels according to scale and flow capacity. Results indicate: Primary fractures are predominantly controlled by first-order natural fractures (bedding fractures) and exogenous joints, with secondary fractures having minimal influence on fracture propagation; The propagation direction of vertical fractures is jointly constrained by the maximum principal stress and the dominant orientation of natural fractures. When the angle between these two is less than a critical value of approximately 35°, fractures extend along synclinal joints, forming “T”-shaped or “H”-shaped composite patterns. Conversely, when the angle exceeds the critical value, fractures break free from natural fracture constraints and propagate along the direction of maximum principal stress. This pattern provides quantitative basis for setting natural fracture parameters in numerical simulations.

The difference in mechanical properties between lithological interfaces and coal strata constitutes the core obstacle restricting interlayer fracture propagation. Coal-bearing strata typically comprise layered combinations of coal, mudstone, and sandstone, where strength variations at lithological interfaces readily cause fracture propagation to “stall” or “deflect.” Ma Junqiang et al. [6] employed the finite-discrete element method to simulate fracture propagation in coal-bearing strata, identifying 12 primary propagation patterns categorized into four types: propagation through stratigraphic interfaces, propagation across and along interfaces, propagation along interfaces, and propagation halting at interfaces. The study found: When fractures initiate in soft rocks (e.g., mudstone with Young's modulus < 10 GPa) and propagate toward lithological interfaces, over 80% of fractures propagate along or halt at the interface, while only 20% penetrate the layer under high stress differentials (>5 MPa). Conversely, when fractures initiate from hard rocks like sandstone (Young's modulus > 30 GPa), the probability of layer penetration increases with the rock strength difference ΔS (the ratio of Young's modulus between hard and soft rocks). When ΔS > 3, the penetration probability exceeds 75%. Chen Ruijie et al. [7] conducted true triaxial fracturing tests using coal-rock analog materials. Comparing three lithological combinations-“hard roof - hard coal,” “soft roof - hard coal,” and “hard roof - soft coal”-results showed that fractures in sandstone roofs penetrated 40% farther than those in mudstone roofs. hard cap - soft coal,“ and ”soft cap - hard coal." Results showed: in hard cap combinations with sandstone cap rock, fracture propagation distances were 40%-60% longer than in soft cap combinations with mudstone cap rock, exhibiting more complex morphology and achieving interlayer expansion. Fractures in soft cap combinations were constrained by interface strength, predominantly propagating within the cap rock with interlayer penetration probability below 15%. Concurrently, greater mechanical disparity between coal and overburden/subgrade (Young's modulus difference > 20 GPa) resulted in larger fracture height and width, expanding modification coverage. However, this also increased susceptibility to uncontrolled fracture height and penetration into non-target strata. Jiang Changbao et al. [8] further validated through true triaxial fluid-solid coupling tests: the smaller the coal-rock Poisson's ratio (<0.3), the shorter the fracture length but the greater the width; the lower the Young's modulus (<5 GPa), the easier fractures propagate along interfaces, weakening interlayer penetration capability. This mechanical characteristic requires precise characterization through constitutive models in numerical simulations.

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3. Mechanism of Engineering Parameters in Controlling Fracture Propagation During Multi-Cluster Fracturing in Horizontal Coalbed Tops

Engineering parameters serve as the core means of artificial intervention in fracture propagation, primarily encompassing: - Flow rate (construction parameter) - Fracturing fluid viscosity - Cluster spacing and number - Perforation parameters (perforation location, depth, diameter) - Fracturing techniques (temporary plug diversion, pulsed fracturing) Optimizing these parameters significantly enhances fracture penetration capability and fracture network complexity, making them critical targets for numerical simulation optimization.

Construction parameters directly influence the dynamics and morphology of fracture propagation, with flow rate, fracturing fluid viscosity, and cluster spacing exhibiting the most pronounced regulatory effects. Yang Peng et al. [9] developed a fully coupled "wellbore-borehole-fracture" numerical model to simulate the entire process of sand-carrying fluid migration. They found that flow rate significantly impacts proppant distribution and borehole erosion: higher flow rates (>15 m^3/min) the weaker the particle settling effect in the wellbore, and the less pronounced the phase tendency for sand ingress and erosion in the open hole. However, sand ingress efficiency near the wellbore bottom hole assembly (BHA) cluster is low (<30%), causing proppant accumulation toward the toe end and resulting in uneven sand distribution between clusters. Conversely, at lower flow rates (<8 m^3/min), gravitational forces dominate, enhancing the phase tendency for fluid and sand ingress and erosion within the fractures. Sand ingress rates in toe-end fracture clusters exceeded 70%, but sand packing uniformity within the fractures deteriorated. The regulatory effect of fracturing fluid viscosity manifests in sand suspension capacity and fracture propagation rate: higher viscosity (>50 mPa·s) enhances sand suspension, resulting in more uniform sand distribution within the wellbore and fracture, and more stable fracture propagation. However, numerical simulations by Xia et al. [10] on Longmaxi Formation shale in the Sichuan Basin showed that increasing viscosity from 1 mPa·s to 6 mPa·s reduced fracture initiation pressure from 20.08 MPa to 12.14 MPa, and the acoustic emission energy decreased from 13.06 kJ to 7.18 kJ. The fracture propagation area shrank and the morphology tended toward circularity, indicating that although high viscosity reduces the fracture initiation pressure, it may suppress fracture branching. The cluster spacing and number determine the interference level among multiple clusters; When the number of clusters was 7 and viscosity was 1 mPa·s, increasing the cluster spacing from 6 m to 12 m linearly increased the crack initiation pressure from 16.47 MPa to 22.14 MPa. and the acoustic emission energy increased from 10.27 kJ to 13.98 kJ. The crack propagation areas on horizontal and vertical surfaces increased by 45% and 38%, respectively. This occurred because the increased cluster spacing weakened stress interference between cracks, allowing them to propagate more independently. When the cluster count increased from 3 to 9 with a 10 m spacing, the cracking pressure rose from 10.65 MPa to 25.36 MPa, and the fracture propagation area simultaneously increased by 60%. However, beyond 7 clusters, inter-fracture interference intensified, causing some fractures to halt propagation due to stress shadow effects. Zhu Suyang et al. [11] targeted deep coalbed methane production capacity and reserve control. Through integrated numerical simulation and dynamic analysis, they optimized the following parameter combination: section length 90–100 m, 5–6 clusters per section, flow rate 18–20 m^3/min, and average sand ratio 16%–20%. Field application demonstrated that under these parameters, the pure gas extraction flow rate reached 1.36 m^3/min, representing a 30% increase over traditional parameters. Furthermore, the combined influence of liquid volume and sand ratio on production capacity accounted for 40% of the total weighting, making them the most critical control parameters.

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Perforation parameters determine the initiation location and initial direction of fractures, guiding their ability to penetrate through strata. Huang Shuxin et al. [12] employed a three-dimensional discrete lattice simulation algorithm to study directional perforation and fracturing in deep coalbed horizontal wells. Results indicate that increasing perforation depth from 5 cm to 15 cm significantly reduces fracture pressure drop by 25% and substantially increases the enhanced area by 60%. This occurs because deeper perforations approach the coalbed more closely, reducing the distance fractures must traverse through the formation. Increasing perforation diameter from 10 mm to 20 mm reduced the enhanced area by 15%-20% and increased the coefficient of variation in enhanced area, indicating that larger-diameter perforations tend to cause fracturing fluid to concentrate in a single hole, leading to uneven fracture propagation. Perforation density exhibits a positive correlation with enhanced area. Increasing density from 10 holes/m to 20 holes/m boosts enhanced area by 35%, but gains plateau beyond 20 holes/m. The impact of perforation location proves more critical. Pang Tao et al. categorized perforation positions into three types: entirely within the coal seam, entirely within the roof strata, and partially within both roof and coal seam. Numerical simulations reveal: When all perforations are within the coal seam, fractures are “blocked” by the roof interface and propagate only within the coal seam, limiting transformation scope; When all perforations are in the roof, under developed roof bedding conditions, a vertical stress difference exceeding 2 MPa relative to the minimum horizontal principal stress is required for interlayer penetration. However, with intact roof, a stress difference exceeding -2 MPa suffices for interlayer penetration. When perforations partially penetrate the coal seam, they induce the formation of horizontal fractures along the interface and vertical fractures into the coal seam. Regardless of roof integrity, an effective fracture network is formed, achieving a cross-seam penetration probability exceeding 90%. Based on this, optimizing perforation locations at the Hancheng Coal Mine in Shaanxi Province-where 20–30% of perforations penetrate the coal seam-achieved a net gas extraction rate of 1,559 m^3/d, representing a 45% increase compared to full roof perforation.

Innovative fracturing techniques represent a key approach to overcoming constraints imposed by complex geological conditions. Methods such as temporary plug diversion and pulse fracturing enhance fracture network complexity by altering fracture propagation dynamics or pathways. Zhang Yuhao et al. [13] employed an extended finite element method to simulate different fracturing sequences, revealing that the initiation sequence significantly impacts multi-fracture interlayer propagation: When the sequence was “left-side - right-side - center,” the length and area of fractures formed in the coal seam doubled compared to the “center-left-right” sequence, with minimal stress interference between fractures. Simultaneous initiation increased stress interference by 30%, raised initiation pressure by 15%, and reduced coal seam fracture area by 25%. Therefore, the sequence “side-first, center-later” is recommended. Yin Zhongshan applied temporary plugging to fracturing in thin coal seams of southern Sichuan. Through numerical simulation, he optimized the timing and dosage of plug ball deployment. At Well LC1, he employed combined fracturing of “coal seam + bottom mudstone,” utilizing a high-volume single-stage fluid volume > 1000 m^3 and and a single-stage sand volume exceeding 50 m^3. This created a complex “rose-shaped” fracture network, achieving a post-fracturing daily gas production exceeding 4000 m^3, representing a 580% increase over conventional fracturing. Pulse fracturing enhances fracture network complexity through fatigue damage. Yang Ruiyue et al. [14] integrated laboratory physical models with machine learning, revealing that pulse fracturing induces coal fatigue failure, reducing fracture pressure by 30%-40% while increasing fracture network volume by over 50%. Dominant mechanisms vary across coal ranks: low-rank coal primarily degrades matrix strength, high-rank coal activates natural fractures and bedding planes, while medium-rank coal exhibits both. Consequently, numerical simulations require rank-specific damage constitutive models—emphasizing plastic strain

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accumulation for low-rank coal and natural fracture opening/closing simulation for high-rank coal.

4. Research Methods and Technological Advances in Fracture Propagation for Horizontal Multi-Cluster Fracturing in Coal Seam Roof Strata

Research methodologies for fracture propagation patterns have evolved into a three-pronged system: “numerical simulation - physical simulation - field validation.” Numerical simulation has advanced from single fluid-solid coupling to multi-field coupling and intelligent prediction. Physical simulation, combined with high-precision monitoring techniques, enhances understanding of underlying mechanisms. Field validation provides practical evidence for model optimization. The synergy among these three approaches drives deeper research.

Numerical simulation methods continue to evolve, with multi-field coupling and intelligent algorithms emerging as mainstream development directions. Early numerical simulations primarily focused on single fluid-solid coupling. Based on the theory of flow-stress-damage coupling, finite element models were established to validate the influence of reservoir fractures on fracture propagation. However, these models did not account for gas adsorption/desorption effects, limiting their applicability to coalbed methane development. In recent years, multi-field coupling models have gained widespread adoption. Liang Yu et al. [15] proposed an integrated fluid-solid-damage HMD gas-water two-phase flow model for deep coalbed methane wells in the Shenfu block, incorporating adsorption/desorption effects. Simulation results demonstrated a 167-fold increase in coalbed permeability post-fracturing and a 5.18-fold rise in cumulative gas production. Furthermore, the model revealed that the control weighting of geological -engineering parameters controlling fractures were weighted as follows: stress ratio 35% > Poisson's ratio 25% > elastic modulus 20% > cluster spacing 20%. This model first quantified the influence weights of multiple factors, providing quantitative basis for parameter optimization. The integration of artificial intelligence algorithms further enhances simulation efficiency and accuracy. Ma Junqiang et al. combined BP neural networks, differential evolution (DE) algorithms, and grey wolf optimization (GWO) to establish a hybrid AI model for predicting fracture propagation trajectories. After training with 12 sets of physical test data, the prediction error was <8%, achieving over 10 times the efficiency of traditional numerical simulations. The technical optimization method derived from this model, when applied in the Qinshui Basin, improved fracturing effectiveness by 30% compared to empirical design, demonstrating that AI-assisted numerical simulation represents a future development trend. Furthermore, the application of extended finite element method (XFEM) and discrete element method (DEM) enhanced the refined characterization of fracture propagation. XFEM simulations of interlayer fracture propagation, without requiring predefined fracture paths, dynamically captured the “stagnation-deflection-throughbreak” process, achieving over 85% agreement between simulated and physical test fracture morphologies.

Physical simulation techniques combined with high-precision monitoring have deepened understanding of fracture propagation mechanisms. True triaxial fracturing tests serve as the core method for physical simulation. Tang et al. [16] conducted multi-level, three-dimensional fracturing tests in a multi-well system, simultaneously monitoring pumping pressure and post-fracturing in-fracture pressure changes. Through three-dimensional reconstruction of 12 primary fractures across three wells, revealed that prior fractured wells exerted an “attraction effect” on hydraulic fractures in subsequent wells, causing asymmetric propagation in later wells. Branch fracture formation correlated with local stress field reversals induced by the main fracture, while main-branch fracture connectivity remained strong. This finding corrected the traditional perception that “inter-fracture interference only inhibits propagation.” The application of monitoring technologies such as acoustic emission (AE), CT scanning, and DC

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resistivity inversion enabled dynamic visualization of fracture propagation. Combined with AE monitoring in triaxial tests, a “three-stage” characteristic of fracture propagation was identified: Low-stress stage: Few AE events, slow crack initiation; High-stress stage: Surge in AE events, rapid crack propagation; Stable stage: Decrease in AE events, stable crack morphology. AE energy in each stage positively correlates with crack complexity. Ma Junqiang et al., using DC resistivity inversion, identified seven fracture patterns in coal-bearing strata-single, intersecting, “T”-shaped, etc.-and observed four distinct phases in pressure curves: rapid pressure rise to initiation pressure, abrupt pressure drop, stable fluctuation, and pump-off pressure decay. The abrupt pressure drop value showed a negative correlation with fracture complexity (correlation coefficient -0.82), providing a basis for fitting pressure curves in numerical simulations.

Field testing and monitoring are crucial for validating theoretical models and guiding engineering practices. Microseismic monitoring and geopotential detection serve as primary methods for characterizing fracture morphology in the field. Statistical analysis of monitoring data from 87 fractures across 51 wells in the southern Qinshui Basin reveals: with lengths ranging from 108 to 452 m and an average of 224.76 m. However, microseismic monitoring lengths exceeded geopotential method lengths by more than double, indicating microseismic monitoring may overestimate fracture extent and requires multi-method calibration. Field parameter optimization trials achieved significant results. At the Danning Coal Mine's No. 3 coal seam, directional long-hole staged fracturing was implemented in the roof zone. By adjusting the drilling layout to target the principal stress zone and employing multi-stage cyclic fracturing, post-fracturing gas recovery increased by an average of 30%, with a maximum increase of 21 times, and the influence zone reached 15-20 m. Shen Penglei [17] developed conventional tubing pressure fracturing technology in the northern Changzhi area of the Qinshui Basin. By controlling pressure conditions via wellhead stabilizing devices, fracturing curves in test wells predominantly exhibited stable pressure profiles. Microseismic monitoring revealed fracture wings extending up to 70 m, daily gas production exceeded 4000 m^3, achieving 20% cost savings and 35% efficiency gains compared to conventional tubing fracturing. Furthermore, differentiated development models for distinct blocks are emerging. For instance, Zhang Cong et al. [18-20] applied a strategy to the Zhengzhuang block in the Qinshui Basin based on rock mechanical parameter distributions: static Young's modulus ranging from 0.28 to 1.45 GPa, and Poisson's ratio ranging from 0.31 to 0.34. This approach proposed differentiated well spacing: 320 m for large-scale, high-volume fracturing in the northern well area, 300 m for medium-scale fracturing in the central-northern area, and 260 m for medium-scale fracturing in the southwestern area. Field application demonstrated a 580% improvement in enhancement efficiency, validating the rationality of “geology-engineering integrated” design.

5. Conclusion and Outlook

5.1. Key Characteristics and Trends in Existing Research

Existing studies on fracture propagation patterns in horizontal coalbed horizontal wells with staged multi-cluster fracturing have established a relatively comprehensive theoretical framework and technical system. Key characteristics are reflected in three aspects: First, the focus on the coupled effects of geological and engineering factors clarifies the dominant role of geological factors such as in-situ stress, natural fractures, and lithological interfaces, as well as the regulatory mechanisms of engineering factors including injection volume, cluster spacing, and perforation parameters. - engineering factors, clarifying the dominant roles of geological elements such as in-situ stress, natural fractures, and lithological interfaces, alongside the regulatory mechanisms of engineering parameters like fluid volume, cluster spacing, and perforation parameters. This has fostered a qualitative understanding of multi-factor

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influences, with some studies achieving quantitative weighting of these factors. Second, research methodologies have diversified. Numerical simulations have evolved from single fluid-solid coupling to multi-field seepage - stress-damage-adsorption coupling and AI-assisted prediction. Physical simulations integrate techniques like acoustic emission and CT scanning to enhance accuracy, while field trials emphasize multi-method monitoring and differentiated design approaches, with all three mutually validated and synergistically supported. Third, research exhibits clear application orientation. Most studies integrate specific geological conditions of blocks like the Qinshui Basin, Shenfu Block, and Linxing Block to propose targeted fracturing solutions. Field applications of techniques such as temporary plug diversion and pressurized fracturing have significantly enhanced gas extraction efficiency and coalbed methane production capacity.

Future research exhibits three major trends: First, refinement of multi-field fully coupled models requires further integration of factors like gas adsorption/desorption and temperature fields to enhance adaptability to deep, complex geological conditions. Second, deep integration of artificial intelligence and numerical simulation will optimize model parameters through machine learning, predict long-term fracture stability, and reduce simulation errors and computational costs. Third, integrated development of "theory - simulation - testing - engineering" integrated development, strengthening feedback calibration between field monitoring data and simulation models to accelerate the translation of research outcomes into engineering technologies.

5.2. Shortcomings and Gaps in Existing Research

Despite significant progress, four key deficiencies and gaps remain: First, insufficient quantitative research on multi-factor coupling. Existing studies predominantly analyze the impact of individual geological or engineering factors in isolation, lacking quantitative characterization of their interactions. For instance, the combined influence of in-situ stress and perforation parameters on fracture penetration weighting, or the coupled effect of natural fractures and fracturing fluid viscosity on fracture network complexity, remains unquantified. This absence of unified quantitative models leads to parameter settings in numerical simulations often relying on empirical values. Second, model applicability is limited. Most numerical models target horizontal, shallow-to-medium-depth reservoirs, with few universal models for complex conditions like steeply dipping reservoirs or fractured soft coal seams. Furthermore, models inadequately account for coal-rock anisotropy-such as variations in mechanical parameters along bedding planes-resulting in simulation discrepancies from field observations. Third, long-term stability studies are lacking. Existing research primarily focuses on instantaneous fracture morphology and short-term gas production effects following fracturing, with limited investigation into failure processes under sustained production-such as proppant settlement, fracture closure, and coal-rock creep-making it difficult to optimize long-term development plans for coalbed methane wells. Fourth, insufficient integration between monitoring techniques and simulation. Field methods like microseismic monitoring and geopotential detection yield fracture parameters (length, width) that diverge from numerical simulations, lacking unified calibration methods that undermine model reliability.

5.3. Research Expansion Directions

Addressing these limitations, this study will expand in three areas: First, constructing a "geology- - engineering - multi-field" fully coupled numerical model, accounting for randomly distributed natural fractures, lithological interface heterogeneity, gas adsorption/desorption, and coal-rock anisotropy. Machine learning algorithms like the BP-DEGWO hybrid model will quantify the coupled influence weights of multiple factors-including in-situ stress, perforation parameters, and fracturing fluid viscosity-to address quantitative challenges. Second, optimize the integration method between the model and field monitoring. Establish a dynamic

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calibration mechanism for simulation parameters targeting fracture orientation from microseismic monitoring and enhanced area from geopotential detection, reducing simulation errors to within 10% and enhancing the model's adaptability to complex geological conditions such as steeply dipping and friable coal seams. Third, incorporate a long-term production module to simulate proppant settling, fracture closure, and coal-rock creep processes. Analyze changes in long-term flow capacity of fracture networks under varying engineering parameters. By integrating field-long gas production data, propose fracturing schemes balancing short-term enhancement effects with long-term stability, providing theoretical support for efficient application of multi-cluster fracturing technology in horizontal coalbed top-hole wells.

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