

Productivity Prediction of Fractured Horizontal Wells in Shale Gas Reservoirs: A Comparative Study of Analytical Models

Ammad Ali

State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Chengdu University of Technology. ammad4337@gmail.com

Fawad Ahmed*

State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Chengdu University of Technology. Corresponding Author Email: fahmedgeoscientist@gmail.com

Behroz Jan Jamaldini

College of Geography and Planning, Chengdu University of Technology. behrozjamaldini@yahoo.com

Asad Ullah

College of Humanities & Law, Chengdu University of Technology. advasadk@gmail.com

Abdul Basir

Department of Environmental Sciences and Engineering College of Ecology and Environment. qais.abdulbasir@gmail.com

ABSTRACT

Accurate productivity prediction of multi-stage fractured horizontal wells in shale gas reservoirs remains a critical challenge in petroleum engineering. Due to ultra-low permeability and complex storage mechanisms, conventional gas well analysis methods require significant revision for shale gas extraction. Traditional evaluations assign constant fracture conductivity values and overlook time-dependent diversion capacity changes, causing substantial forecasting errors. This study presents a comparative assessment of analytical productivity prediction models for fractured horizontal wells in shale gas reservoirs. Based on the classical Guo Genliang model, an improved productivity equation is derived by introducing pseudo pressure functions for gas-phase behavior. Additionally, a novel productivity equation is established using a capsule flow model that conceptualizes drainage area as two hemispheroids connected by a cylinder, explicitly accounting for matrix-to-fracture transport, linear flow, radial flow, and spherical centripetal flow through equivalent seepage resistance methodology. Both models are validated against field data from a Sichuan Basin horizontal shale gas well. Comparative analysis confirms the capsule

flow model delivers superior accuracy, attributed to fewer restrictive assumptions and realistic stimulated reservoir volume representation. Comprehensive sensitivity analysis evaluates effects of formation parameters, well geometry, fracturing design, and desorbed gas steady diffusion rate. Results demonstrate that wellbore radius, fracture half-length, and desorbed gas diffusion rate dominate productivity control, while horizontal well length and fracture number show diminishing returns beyond optimal thresholds. The derived formulas provide practical guidance for predicting fractured horizontal well productivity and optimizing completion strategies in shale gas reservoirs.

Keywords: Shale gas reservoirs; fractured horizontal wells; productivity prediction; capsule flow model; Guo Genliang model; desorbed gas diffusion; pseudo pressure; equivalent seepage resistance

1. Introduction

Unconventional resource development has emerged as a dominant theme in global energy strategy, with shale gas progressively becoming an indispensable component of worldwide energy supply. The commercialization of shale gas reservoirs in North American basins including Barnett, Marcellus, Eagle Ford, and Haynesville has transformed the natural gas industry and stimulated global exploration activities (Wang et al., 2017; Zhang et al., 2018; Cai et al., 2019; Yu et al., 2019). Shale gas reservoirs exhibit extremely low matrix permeability, typically ranging from 10^{-2} to 10^{-6} millidarcies (Cipolla et al., 2009), rendering primary production from vertical wells economically unviable without stimulation. Consequently, horizontal well drilling combined with multi-stage hydraulic fracturing has proven to be the definitive technical solution for unlocking hydrocarbon potential within these ultra-low permeability formations (Mayerhofer et al., 2010; Brown et al., 2011; Xie et al., 2015).

The economic feasibility of tight shale development depends intimately on created fracture network effectiveness and fracture conductivity near the wellbore. Multi-stage fracturing of horizontal wells represents the cornerstone technology for enhancing shale gas production (Pan et al., 2022). However, fundamental differences between shale and conventional reservoirs—including multi-scale pore structures, significant gas adsorption on organic matter, Knudsen diffusion in nano pores, and stress-sensitive fracture conductivity—render accurate productivity prediction an active research frontier. Traditional gas well dynamic analyses focus predominantly on bulk reservoir physical properties while assigning constant fracture conductivity values. In actual production, diversion capacity evolves continuously due to proppant crushing, embedment, and fracture closure under effective stress (Pan et al., 2022). Its impact on long-term production capacity cannot be disregarded, necessitating substantial revision of conventional production analysis methodologies for shale gas applications.

Forecasting oil and gas production has constituted a major pillar of petroleum engineering practice. Reliable forecasts enable operators to estimate remaining asset value, optimize existing operations, and design future drilling programs. Despite mature reservoir engineering principles and extensive historical datasets, forecasting errors remain persistently high due to reservoir heterogeneity, complex natural and induced fracture networks, limited subsurface observability, and dynamically evolving properties during pressure depletion (Liu et al., 2018).

These challenges are magnified in shale gas systems where nanoscale flow physics, adsorption-desorption kinetics, and multi-mechanism transport processes govern production behavior.

The production analysis framework for conventional natural gas reservoirs requires fundamental restructuring for shale gas extraction. Production-decline analysis, pressure-transient analysis, and nanoscale pore transport mechanisms must be modified according to distinct shale flow patterns (Liu et al., 2018). Hydraulic fracture networks, natural and induced micro-fractures, and shale matrix simultaneously influence gas production rates, creating multi-continuum flow systems that defy simple analytical treatment. Performance evaluation of multiple fractured horizontal wells has identified distinct flow regimes including early linear flow, bilinear flow, compound linear flow, and boundary-dominated flow (Zhao et al., 2018). Rigorous analytical solutions must comprehensively account for gas diffusion mechanisms within shale matrix, where transport follows viscous flow with slip boundaries, molecular diffusion, Knudsen diffusion, and surface diffusion within adsorption layers (Liu et al., 2018).

Hydraulic fracture conductivity depends on fracturing fluid properties, proppant mechanical characteristics, and rock-proppant interactions under varying stress conditions. As production progresses, proppant particles experience crushing and embedment into fracture faces, fractures gradually close under increasing effective stress, and conductivity diminishes progressively (Pan et al., 2022). Research demonstrates that proppant embedment becomes particularly severe when rock is exposed to water-softened conditions, potentially resulting in conductivity losses up to 88 percent (Pan et al., 2022). Despite these documented phenomena, time-dependent fracture conductivity has not received adequate attention in many current simulation workflows.

Mainstream yield forecasting methodologies divide into three categories: analytical and semi-analytical methods, numerical simulation, and machine learning approaches (Pan et al., 2022). Analytical models offer computational efficiency and physical transparency but are frequently over-simplified, yielding limited accuracy under complex conditions. Machine learning methods function essentially as black-box models with poor interpretability, requiring extensive training datasets often unavailable for newly developed shale plays. Numerical simulation accommodates complex flow states, geological heterogeneity, and coupled geomechanical effects but demands substantial computational resources and high-quality input data (Pan et al., 2022). Against this backdrop, the present study develops improved analytical productivity models that better capture essential shale gas physics while remaining computationally tractable for engineering applications.

The specific objectives are fourfold. First, to review and critically evaluate existing productivity prediction theories for fractured horizontal wells in shale gas reservoirs. Second, to improve the classical Guo Genliang model by introducing gas pseudo pressure functions and adapting the formulation for shale gas conditions (Guo and Evans, 1993). Third, to derive an alternative productivity equation based on a capsule flow model representing composite drainage geometry and multi-stage flow resistance. Fourth, to validate both models against field data from the Sichuan shale gas reservoir and conduct systematic sensitivity analysis. The derived formulas and parametric insights provide practical guidance for predicting productivity and

optimizing completion and stimulation designs.

2. Methodology

2.1 Physical Model and Basic Assumptions

The analytical productivity models are founded upon physical assumptions reflecting essential shale gas reservoir characteristics. The reservoir is conceptualized as a dual-porosity medium comprising shale matrix with nanometer-to-micrometer scale pores and natural fractures providing primary flow pathways (Warren and Root, 1963). Upper and lower boundaries are impermeable and closed, while the outer boundary is infinite-acting, representative of early-to-intermediate production before inter-well pressure interference. Both adsorbed and free gas are stored within spherical matrix blocks dispersed throughout the reservoir volume. Matrix permeability is sufficiently low that pressure-driven Darcy flow within the matrix is negligible; gas transport from matrix to natural fractures occurs primarily through concentration-driven diffusion following desorption from pore surfaces. Desorption follows the Langmuir isothermal adsorption equation, providing thermodynamically consistent relationships between adsorbed gas volume and pressure at constant temperature (Bumb and McKee, 1988). Gas is treated as single-phase isothermal compressible fluid, with gravitational and capillary effects considered negligible relative to viscous and diffusive transport mechanisms.

2.2 Shale Gas Storage and Transport Mechanisms

Understanding gas storage and transport mechanisms is prerequisite to developing accurate productivity models. Natural gas within shale reservoirs exists in three principal states: free gas occupying pore spaces within matrix and fracture networks, adsorbed gas physically bonded to surfaces of organic matter and clay minerals, and minor dissolved gas within kerogen and formation water (Schein and Mack, 2007). The adsorbed gas component is particularly significant, typically accounting for 20 to 85 percent of total gas initially in place, depending on reservoir temperature, pressure, organic content, and thermal maturity (Curtis, 2002). Adsorbed gas volume is quantified using the Langmuir isothermal adsorption equation through Langmuir volume and Langmuir pressure parameters. As reservoir pressure declines, adsorption equilibrium shifts, causing desorbed gas to enter pore spaces and contribute to the mobile gas phase. This desorption process fundamentally differentiates shale gas production from conventional reservoirs.

Gas transport occurs through multiple mechanisms across different length scales. Within natural fractures and macro pores, flow follows continuous Darcy flow with modifications for gas compressibility and stress-dependent permeability. In matrix nano pores, the continuum assumption breaks down and transport involves viscous flow with slip boundaries, Knudsen diffusion, molecular diffusion, and surface diffusion along adsorbed layers (Javadpour et al., 2007). The Knudsen number classifies flow regimes: viscous flow below 0.001, slip flow from 0.001 to 0.1, transition flow from 0.1 to 10, and Knudsen diffusion above 10 (Swami et al., 2012). Matrix transport is treated as unsteady-state diffusion from spherical elements into surrounding fracture network, with diffusion coefficient representing effective matrix permeability to concentration-driven transport (Ertekin et al., 1986).

2.3 Improved Guo Genliang Productivity Model

The classical Guo Genliang model, originally developed for oil-phase flow in fractured horizontal wells, provides foundational framework for productivity

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estimation by dividing total production into fracture-system and matrix-system contributions (Guo and Evans, 1993). The model incorporates effects of formation anisotropy, skin factor, and shape factor through conformal transformation techniques. However, the original formulation for incompressible liquid flow cannot be directly applied to compressible gas in shale reservoirs. To adapt it for shale gas, pseudo pressure is introduced to linearize the nonlinear gas flow equation. Pseudopressure, defined as the integral of pressure divided by gas viscosity and compressibility factor, transforms the compressible flow problem into a form analogous to incompressible liquid flow. Substituting pseudo pressure for pressure and replacing oil-phase mobility with gas-phase properties reformulates the deliverability equation to account for gas compressibility, variable viscosity, and non-Darcy effects.

The improved formulation maintains structural division of fracture and matrix flow contributions. The fracture contribution uses conformal transformation for flow into finite-conductivity vertical fractures, with pseudopressure drop replacing pressure drop. The matrix contribution considers flow from bulk reservoir into wellbore sections between fractures, again employing pseudopressure for gas-phase consistency. A weighted average combines fracture and matrix contributions into a single deliverability equation. While this extends applicability to gas reservoirs, it retains limitations including rectangular drainage geometry representation and constant fracture conductivity assumption. Additionally, the model does not explicitly distinguish between different flow regimes that sequentially dominate production over the well life.

2.4 Capsule Flow Model

The capsule flow model represents drainage area surrounding a fractured horizontal well as a composite capsule-shaped region comprising two hemispheroidal end caps connected by a cylindrical central section. This geometry reflects the three-dimensional stimulated reservoir volume created by multi-stage fracturing, where fractures enhance flow capacity both laterally and vertically. Steady flow is divided into four sequential regimes. First, gas flows from matrix to hydraulic fractures through free gas expansion and desorption from organic surfaces, then along fracture planes toward the wellbore. Second, far-field gas flows linearly toward the near-wellbore stimulated region. Third, near-wellbore gas flows radially into the horizontal wellbore. Fourth, gas from well tips flows spherically toward the wellbore, accounting for end effects neglected in simpler two-dimensional models.

Mathematical derivation proceeds through mirror reflection theory for fracture interference, followed by equivalent seepage resistance methodology combining four flow regimes into total flow resistance. Mirror reflection treats each fracture as a plane source, calculating composite pressure response by superposing individual contributions while accounting for no-flow boundaries between adjacent fractures. Internal resistance includes fracture flow pressure drop and near-wellbore radial flow resistance. External resistance encompasses far-field linear flow and spherical centripetal flow from drainage boundaries. Total equivalent resistance is obtained by summing internal and external resistances in series. Applying the relationship between flow rate, pseudopressure drop, and total resistance yields the final productivity equation, explicitly incorporating desorbed gas diffusion rate as a source term enhancing total gas flux beyond free gas expansion alone.

2.5 Field Validation Approach

Validation is performed using production data from a horizontal shale gas well in the Sichuan Basin, characterized by high thermal maturity, significant tectonic deformation, complex natural fractures, and variable organic content. The dataset includes formation thickness, porosity, permeability, initial pressure, and temperature; completion parameters including well length, radius, stage count, fracture half-length, and conductivity; and production data including initial rate, flowing bottomhole pressure, and cumulative production. Two equations are solved numerically: the Improved Guo Genliang equation (IGLG) and Enhanced Capsule Flow equation (EFP). Calculated rates are compared against demonstrated reservoir capacity. Systematic sensitivity analysis varies individual parameters while holding others constant to quantify relative influence. Parameters investigated include horizontal well length, wellbore radius, fracture half-length, fracture number, and desorbed gas steady diffusion rate.

3. Results and Discussion

3.1 Model Validation and Comparative Assessment

Field validation demonstrates that both the Improved Guo Genliang model and the Capsule Flow model produce estimates approaching demonstrated reservoir capacity. However, quantitative comparison reveals the Enhanced Capsule Flow model consistently yields predictions with smaller deviation from actual field performance. The IGLG model tends to overestimate early-time production while underestimating late-time decline, attributable to simplified drainage geometry and failure to explicitly account for sequential flow regime transitions as the pressure depletion front propagates outward. In contrast, the EFP model captures transitions from fracture-dominated linear flow to compound linear flow and boundary-influenced flow through its structured resistance network, resulting in profiles closely matching observed field behavior across the entire evaluation period. The quantitative agreement between EFP predictions and field data validates the capsule geometry conceptualization and equivalent seepage resistance methodology as reliable tools for shale gas productivity forecasting.

The superior accuracy of the capsule model stems from fundamental improvements in physical conceptualization. The Guo Genliang model was derived for conventional oil reservoirs with homogeneous permeability and simple vertical fracture geometries; its adaptation through pseudopressure substitution does not address underlying geometric simplifications. The model assumes drainage area can be represented by a rectangular prism with uniform properties, employing weighted averaging that obscures actual flow path topology. Furthermore, it does not explicitly incorporate desorbed gas diffusion, representing a substantial fraction of total recovery in organic-rich shales. The capsule model represents drainage volume as a three-dimensional composite body with hemispheroidal end caps capturing elliptical pressure propagation patterns. Explicit treatment of four sequential flow regimes ensures each transport stage is governed by appropriate equations. The equivalent seepage resistance methodology provides an intuitive framework for combining sequential resistances without empirical weighting factors. The explicit incorporation of desorbed gas diffusion as a concentration-dependent source term further distinguishes the capsule model by acknowledging the substantial contribution of adsorbed gas to total production, particularly during later stages of

reservoir depletion.

3.2 Sensitivity Analysis of Productivity Controlling Parameters

Comprehensive sensitivity analysis elucidates the relative importance of reservoir, wellbore, and completion parameters in controlling productivity, revealing distinct relationships between parameter variations and production response.

The effect of horizontal well length on ultimate cumulative production is less pronounced than the effect of wellbore radius. While increasing lateral length extends contact area, incremental gain diminishes beyond a critical threshold due to increased frictional pressure drop, complex flow distribution among distant fractures, and interference between adjacent well depletion zones. This suggests maximizing length without regard to optimal spacing may not yield proportional returns. Increasing wellbore radius produces more immediate production enhancement by reducing near-wellbore flow resistance. However, larger radius accelerates formation pressure depletion, potentially compromising long-term recovery efficiency against principles of rational exploitation balancing early rates with sustainable recovery. The optimal wellbore radius represents a compromise between immediate productivity enhancement and reservoir management objectives.

Fracture geometry parameters exhibit complex nonlinear relationships with productivity. Production maximizes when fracture half-length approaches reservoir thickness, ensuring stimulated volume extends through full vertical pay zone while minimizing unproduced volume between fracture tips and boundaries. When length is significantly less than thickness, substantial reservoir remains unstimulated. Conversely, length substantially exceeding thickness contributes little additional production while increasing costs. Regarding fracture number, increasing stages generally enhances production but incremental benefit per fracture decreases with rising count. Diminishing returns are caused by intensifying inter-fracture interference, where adjacent depletion zones overlap, reducing effective pressure driving force and creating competitive rather than complementary drainage. Consequently, optimal fracture density balances production enhancement against operational cost and complexity. Operators must carefully evaluate stage spacing to maximize stimulated reservoir volume while minimizing destructive interference.

The desorbed gas steady diffusion rate emerges as a particularly influential parameter in controlling long-term behavior. The diffusion rate, governed by gas concentration differential between matrix and fracture systems and matrix porosity, exhibits a nearly linear relationship with production rate. As the diffusion rate increases, supplemental gas supply from the adsorbed phase augments free gas production, yielding higher flow rates and improved recovery. This underscores the critical importance of accurately characterizing Langmuir parameters and the effective diffusion coefficient, as errors propagate directly into forecasting uncertainty. However, the concentration differential cannot be maintained at high values indefinitely. As production proceeds and fracture pressure declines, the gradient driving diffusion diminishes, causing the desorbed gas contribution to decrease over time. This implies that the benefit of high desorption capacity is most pronounced during early-to-middle well life, with long-term sustainability depending more strongly on free gas volume and fracture conductivity maintenance.

3.3 Discussion

Comparative analysis highlights important trade-offs between analytical complexity,

computational requirements, and predictive fidelity relevant for practical applications. The Improved Guo Genliang model retains value as a rapid screening tool due to its simple algebraic structure and minimal input requirements. For preliminary assessments with limited fracture geometry data, the IGLG model provides order-of-magnitude estimates supporting initial decisions. However, for detailed completion optimization and reserves certification, the Capsule Flow model offers demonstrably superior accuracy justifying its moderately increased complexity. Explicit flow regime representation provides diagnostic capability, as deviations between predictions and actual data can be attributed to specific mechanisms, enabling targeted characterization and refinement. The ability to diagnose which flow regime dominates at different production stages offers valuable insights for production optimization and artificial lift design.

Sensitivity results are consistent with broader shale gas literature while providing additional quantitative specificity. Wellbore radius exerting stronger influence than horizontal length aligns with theoretical understanding that near-wellbore resistance dominates in high-conductivity fracture systems. Optimal fracture half-length equal to thickness confirms practical design rules, while quantification of diminishing returns from excessive density provides rational basis for stage spacing optimization. The dominant role of desorbed gas diffusion rate in long-term production reinforces the importance of laboratory core analysis for Langmuir determination, particularly in high-organic-content shales. These findings support an integrated approach to shale gas development combining geological characterization, petrophysical analysis, and analytical modeling.

Several limitations should be acknowledged. Both models assume single-phase flow and neglect multiphase effects significant in formations with mobile water or condensate. Constant bottomhole pressure simplifies wellbore hydraulics without capturing variable surface conditions or wellbore storage transients. Constant fracture conductivity treatment, while improved over conventional assumptions, still does not fully capture time-dependent degradation including proppant crushing, embedment, and gel damage. Future extensions could incorporate time-dependent conductivity into the capsule model framework, couple with geomechanical deformation, or integrate with machine learning to leverage physical transparency while improving accuracy through data-driven calibration. Combining quantitative characterization models with neural networks represents a promising direction, preserving parameter interpretability while exploiting adaptive learning for small-sample databases.

4. Conclusion

This study presents a comprehensive comparative assessment of analytical productivity prediction models for fractured horizontal wells in shale gas reservoirs, with particular emphasis on the development and validation of an improved Guo Genliang formulation and a novel capsule flow model. The following conclusions are drawn from the theoretical development, field validation, and sensitivity analysis conducted in this research.

First, production forecasting for fractured horizontal wells in shale gas reservoirs can be substantially improved by incorporating shale-specific physical mechanisms including gas desorption from organic matter surfaces, Knudsen diffusion in nanopores, and stress-sensitive fracture conductivity into analytical

productivity models. Traditional methods including decline curve analysis, semi-analytical solutions, and numerical simulation remain widely applied in industry practice; however, each approach exhibits limitations in fully capturing the complex, multi-physics production behavior characteristic of shale gas systems. Decline curve methods are restricted to late-life reserve estimation and cannot predict early-time transient behavior or parameter-dependent effects. Semi-analytical methods offer improved physical representation but require detailed fracture characterization that is frequently unavailable. Numerical simulation provides the most comprehensive treatment of coupled processes but demands extensive computational resources and high-quality input data.

Second, the improved Guo Genliang model successfully extends the classical oil-phase formulation to shale gas reservoirs through the introduction of pseudopressure functions and gas-phase property substitutions. While this adaptation enables gas reservoir application, the model retains inherent limitations associated with its original geometric simplifications and weighted-average flow combination approach. The model tends to overestimate early production and underestimate late-time decline, rendering it suitable for preliminary screening but insufficient for detailed completion optimization or reserves certification.

Third, the capsule flow model demonstrates superior predictive accuracy compared to the improved Guo Genliang formulation when validated against field data from the Sichuan shale gas reservoir. The capsule model's enhanced performance stems from its realistic three-dimensional representation of the stimulated drainage volume as a composite body with hemispheroidal end caps and cylindrical central section, its explicit treatment of four sequential flow regimes through equivalent seepage resistance methodology, and its direct incorporation of desorbed gas diffusion as a supplemental source term. The fewer restrictive assumptions employed in the capsule model's derivation result in production profiles that closely match observed field behavior across the entire production evaluation period.

Fourth, sensitivity analysis reveals that wellbore radius, fracture half-length, and desorbed gas steady diffusion rate are the dominant controlling parameters affecting fractured horizontal well productivity in shale gas reservoirs. Horizontal well length and fracture number exhibit diminishing returns beyond optimal thresholds, with excessive lateral length increasing frictional losses and excessive fracture density intensifying inter-fracture interference. Production is maximized when fracture half-length approximates formation thickness, ensuring complete vertical stimulation while avoiding unnecessary proppant expenditure. The linear relationship between desorbed gas diffusion rate and production rate underscores the economic significance of accurately characterizing adsorption isotherm parameters during reservoir evaluation.

Fifth, the quantitative characterization model and artificial neural network approaches represent promising complementary methodologies for shale gas productivity prediction. The quantitative characterization model offers the advantage of predicting production increases using physically meaningful parameters, though it remains inapplicable to new wells lacking production history. Artificial neural networks demonstrate strong adaptive and self-learning capabilities but require substantial training datasets that are often unavailable in emerging shale

plays. The integration of quantitative characterization models with neural network architectures may provide a robust hybrid approach that leverages physical transparency with data-driven adaptability, particularly for small-sample databases characteristic of early-stage field development.

The derived production formulas and comprehensive parametric analysis presented in this study provide a practical analytical framework for predicting the productivity of fractured horizontal wells in shale gas reservoirs. These tools offer valuable guidance for optimizing horizontal well trajectory, completion design, and stimulation strategies, ultimately contributing to improved economic outcomes and more efficient recovery of unconventional gas resources. Future research directions include the incorporation of time-dependent fracture conductivity degradation, coupling with geomechanical deformation models, and integration with machine learning algorithms to enhance predictive accuracy under data-limited conditions.

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Author Contributions

A.A. and F.A. conceived and designed the study. A.A. developed the methodology, performed the formal analysis, and, together with F.A., conducted the software implementation and validation. F.A. carried out the investigation, while B.J.J. and A.A. managed the data curation. A.U. and A.B. prepared the original manuscript draft, and all authors contributed to the review and editing of the manuscript. All authors have read and approved the final published version of the manuscript.

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Data Availability

Since no new data were generated or analyzed in this study, data sharing is not relevant to this article.

Competing interests

The authors have no conflicts of interest.

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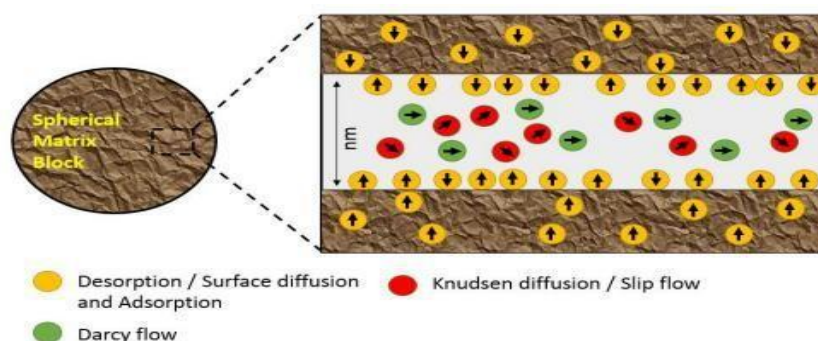


Figure 1.1 Schematic of gas flow in matrix nanopores (Zheng, 2017)

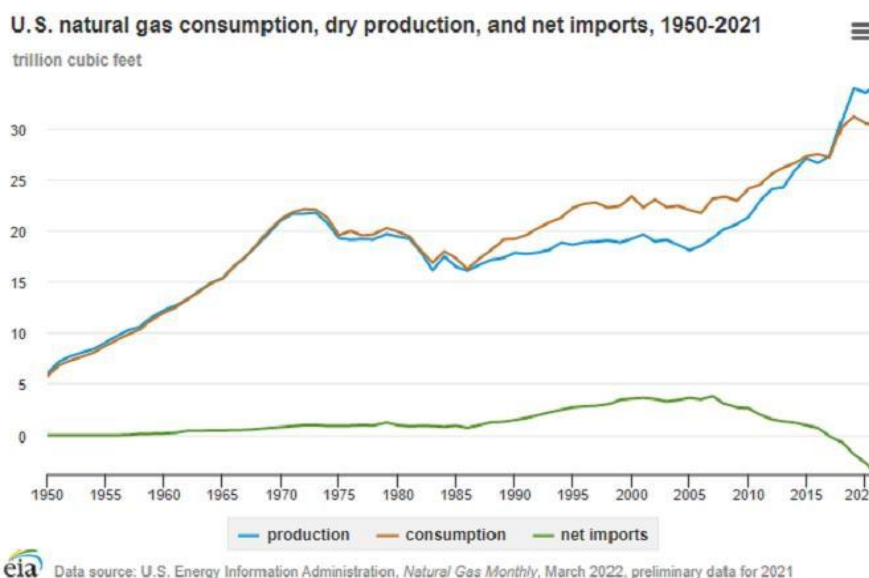


Figure 1.2 U.S natural gas consumption, production, and net imports 1950-2021

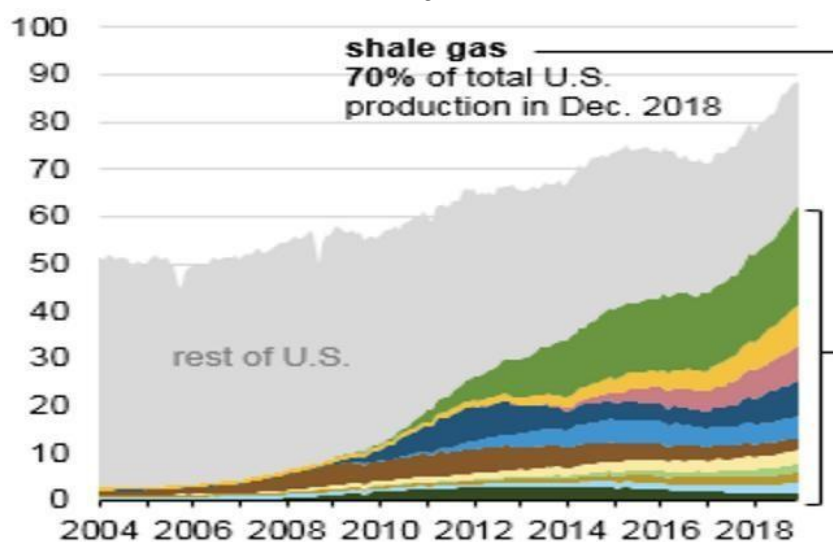


Figure 1.3 The production of shale gas in the U.S (EIA reports, 2019)

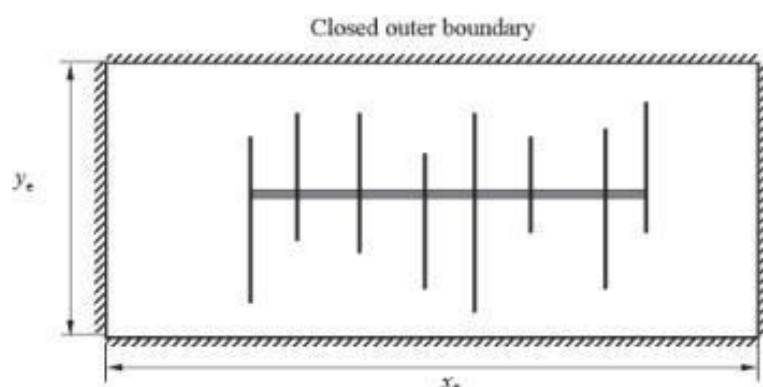


Figure 1.4 Schematic of a fractured horizontal well in a shale gas reservoir (Zhao et al. 2016).

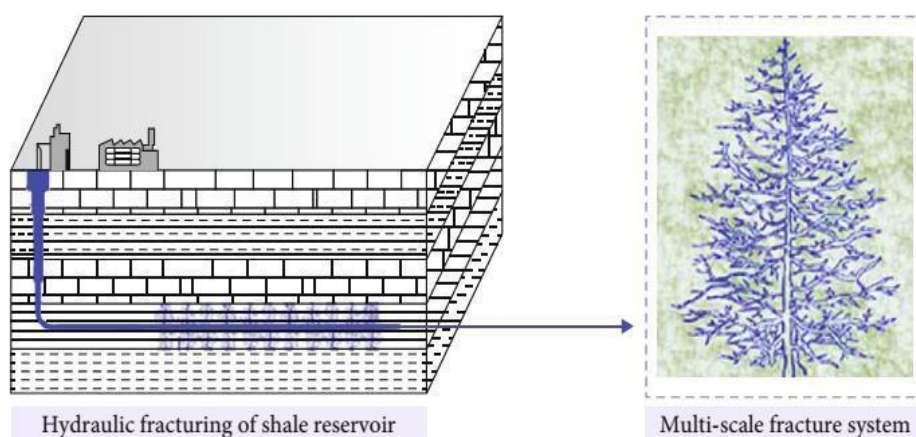


Figure 1.5 Multistage stimulation horizontal wells in unconventional reservoirs (Feng et al. 2019).

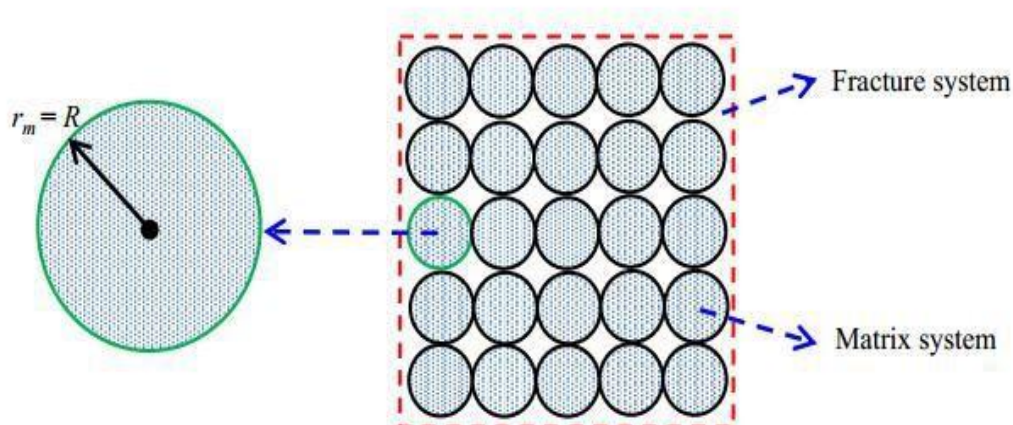


Figure 1.6 Schematic of fracture and matrix system (after Yuan et al., 2018).

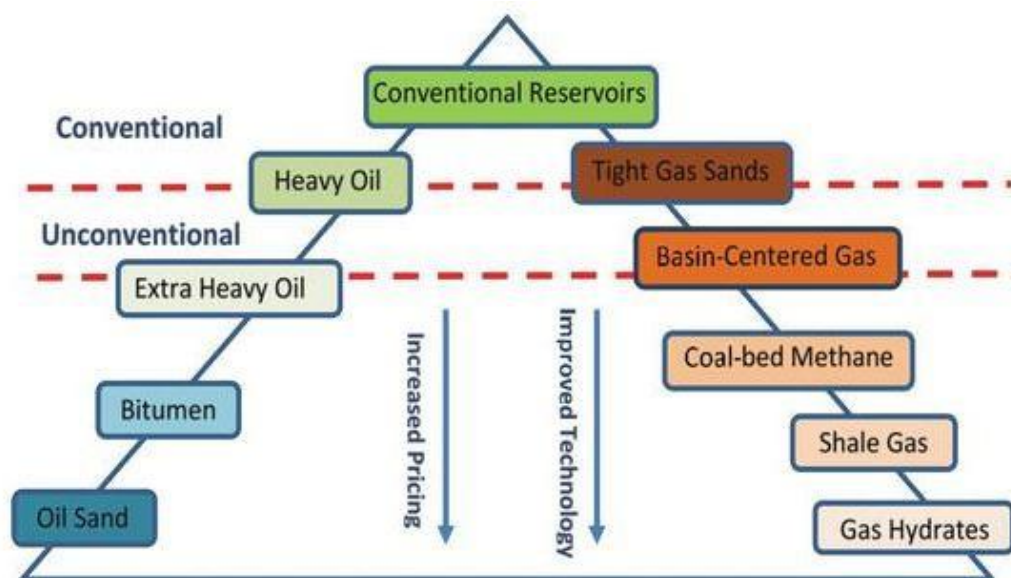


Figure 2.1 Petroleum resources triangle.

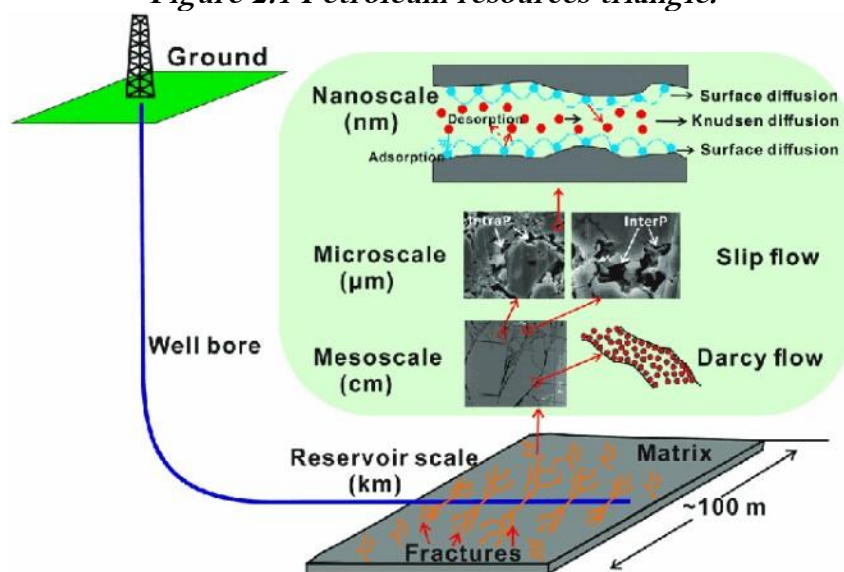


Figure 2.2 Gas storage and migration in shale reservoirs occurs at multiple pore scales with at least four distinct flow and gas movement mechanisms involved.

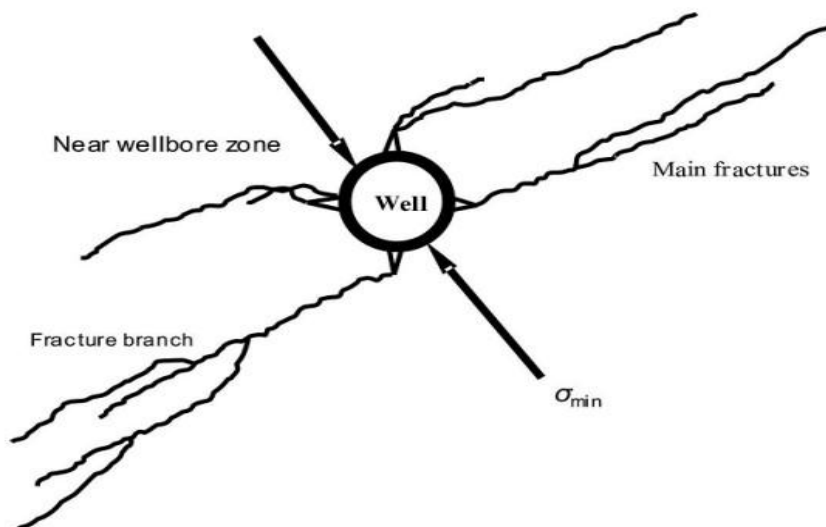


Figure 2.3 Hydraulic fractures.

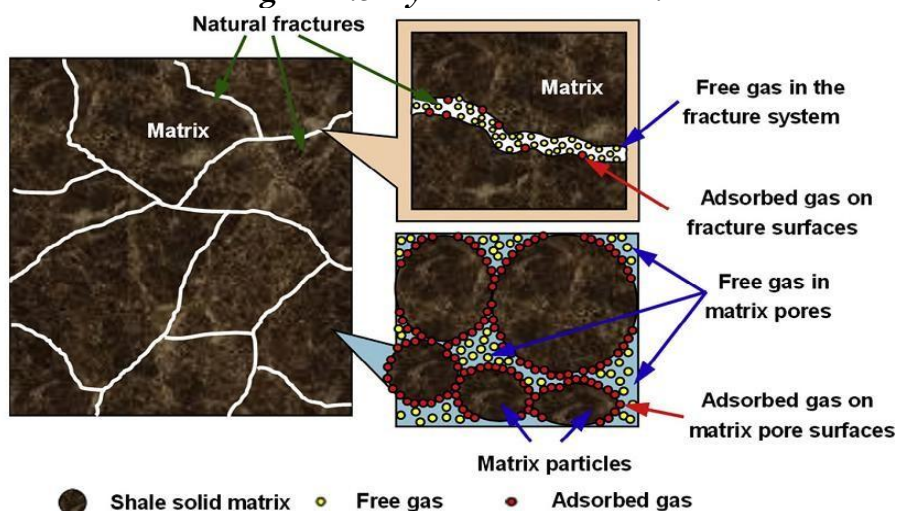


Figure 2.4 Existence characteristics of adsorbed gas and free gas in a shale gas reservoir.

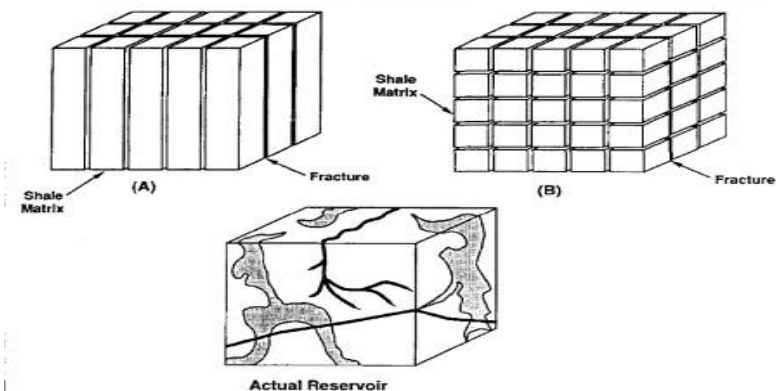


Figure 2.5 Explanation of dual-porosity model (Carlson et al. 1991)

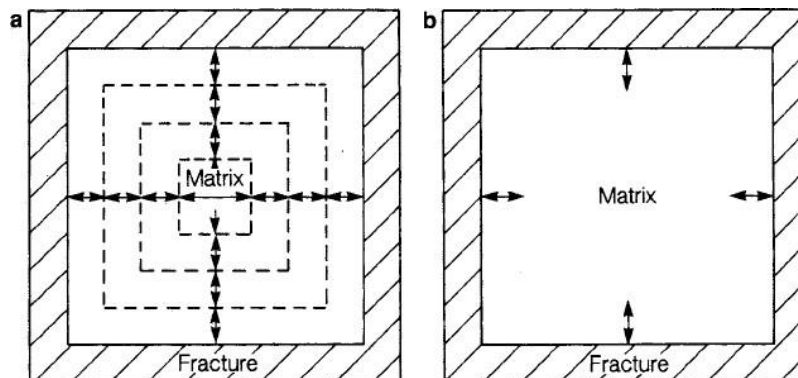


Figure 2.6 Discretization of matrix blocks; *a. MINC, b. dual-porosity model* (Yu-Shu Wu et al. 1998)

2.4.4 Dual permeability model

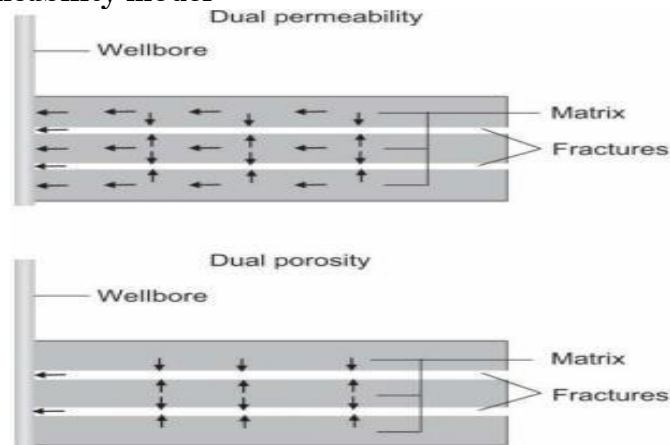


Figure 2.7 Illustration of flow in dual porosity model and dual permeability model (Pereira et.al. 2006)

Table 2.1: Flow regimes based on Knudsen number (Javadpour et al. 2007).

Navier-stokes	Equation
No-slip ($K_n < 0.001$)	Slip ($0.001 < K_n < 0.1$)
Continuum flow	Slip flow
Darcy flow	Knudsen diffusion

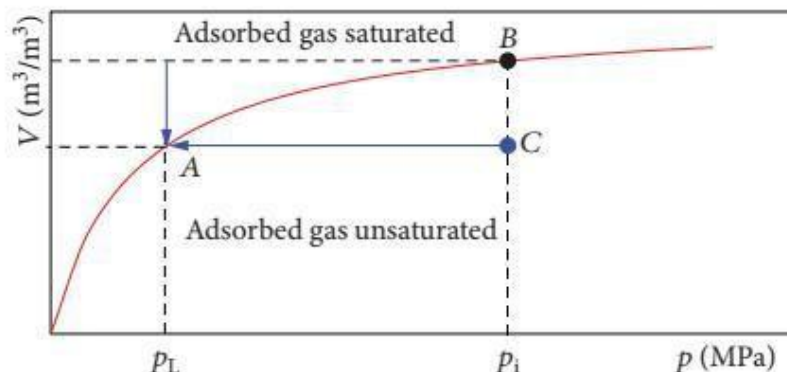


Figure 3.2 Shale gas isothermal adsorption curve and desorption process diagram

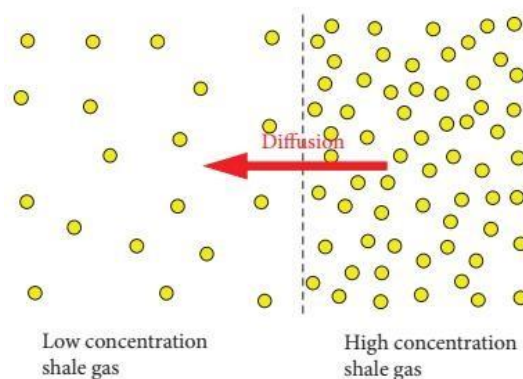


Figure 3.3 Diagram of Fick diffusion

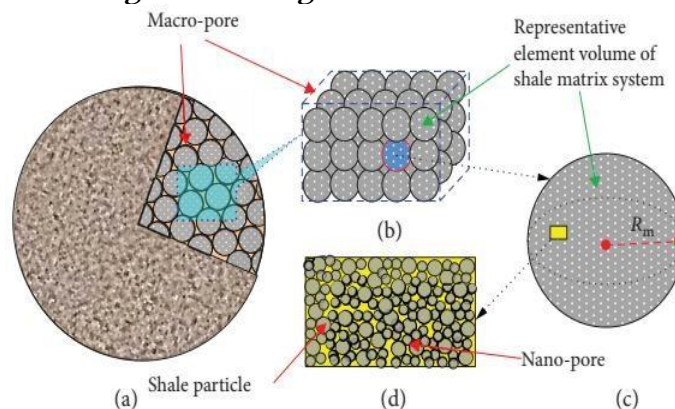


Figure 3.4 Conceptual model used in this study

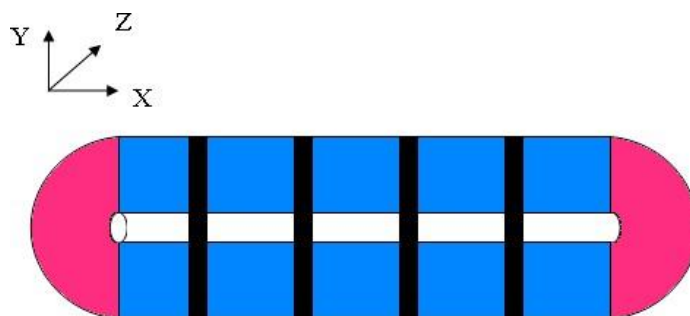


Figure 4.1 Capsule flow region of fractured horizontal well in shale gas.

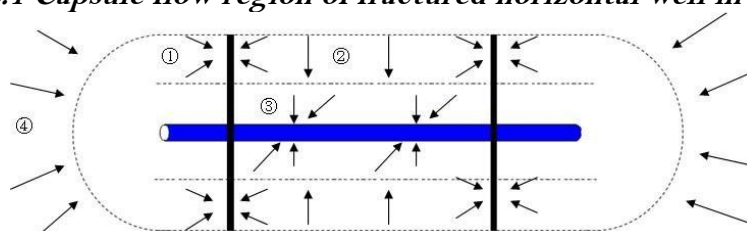


Figure 4.2 Fractured horizontal well flow in shale gas reservoir.

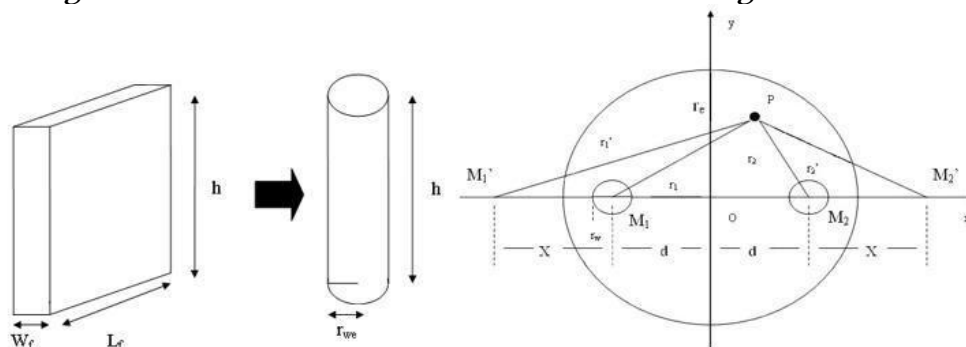


Figure 4.3 Identical area method and mirror reflection model.

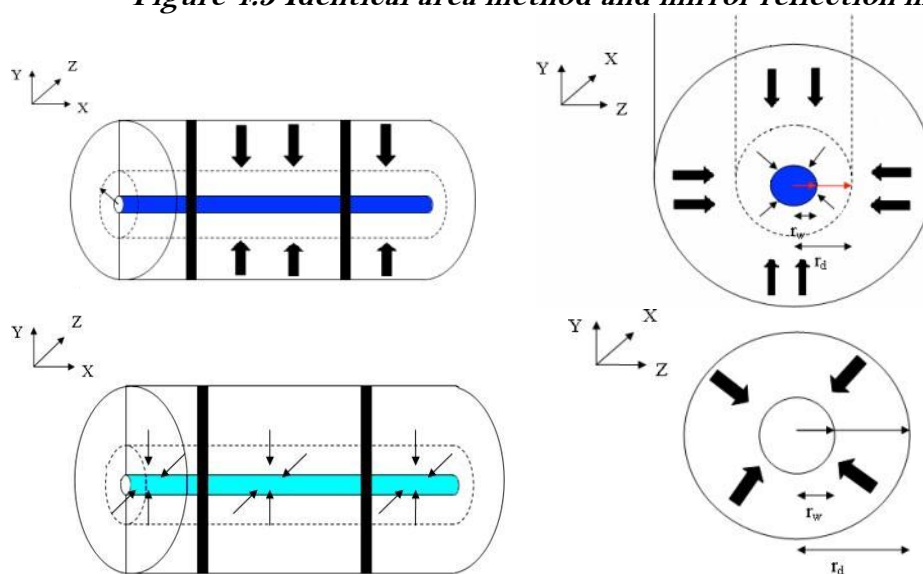


Figure 4.5 Horizontal well near side radial flow.

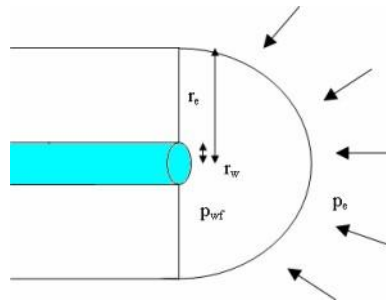


Figure 4.6 Spherical centripetal flow.

Table 4.1: Parameters of shale gas reservoir and fractures

Parameter	Data	Parameter	Data
Gas thickness(m)	20.16	Horizontal well length(m)	609.76
Vertical permeability(μm^2)	1.54×10^{-3}	Formation temperature($^{\circ}\text{C}$)	80
Horizontal permeability(μm^2)	2.54×10^{-3}	Has viscosity($\text{MPa} \cdot \text{s}$)	0.02
Seepage region(m^3)	4.8583×10^5	Deviation factor	0.9555
Initial reservoir pressure(MPa)	23.287	Half of fracture length(m)	5.75
Bottomhole pressure(MPa)	19.875	Fracture number	6
Horizontal well radius(m)	0.1	Fracture interval(m)	110

Table 4.2: Contrast of two equations and demonstrated capacity.

	IGLG	EFR	Demonstrated capacity
Production(m^3/d)	9289.6	9724.4	10247.8
Error	9.35%	5.1%	/

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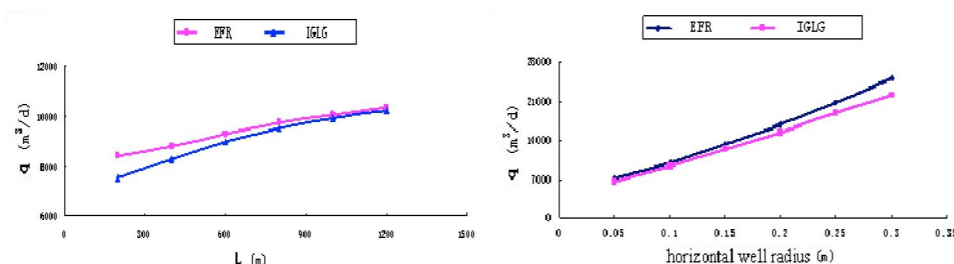


Figure 4.7 Production influence by horizontal well parameters.

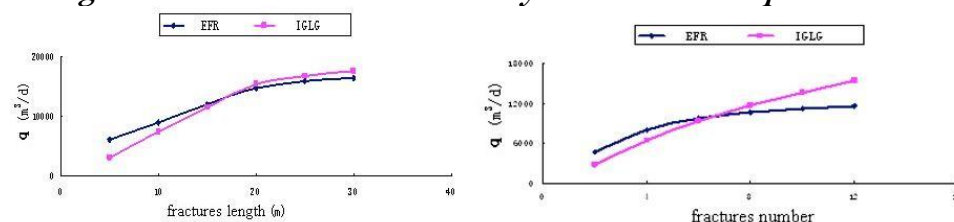


Figure 4.8 Production influence by hydraulic fracture parameters.

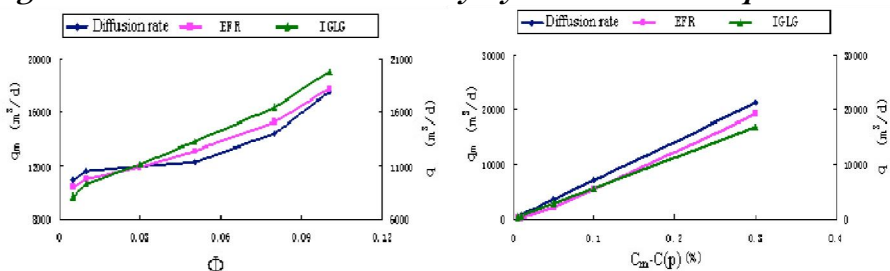


Figure 4.9 Production influence by desorbed gas diffusion rate.