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Dual-porosity-Permeability Modeling in Carbonate Reservoirs: A Review on Characterization Techniques, Modeling Approaches, and CCS Applications

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ABSTRACT - Carbonate reservoirs are extremely heterogeneous owing to fractures, vugs, micropores, and karst features. This heterogeneity complicates fluid-flow prediction, characterisation, and simulation in both naturally fractured reservoirs and carbon capture and storage (CCS). Dual-porosity modeling remains the dominant approach for capturing matrix–fracture interactions in these systems. This review critically assesses geological, petrophysical, geophysical, and dynamic characterization techniques alongside conventional dual-porosity, dual-permeability, MINC, DFN, and hybrid continuum–discrete methods for carbonate reservoirs, with emphasis on CCS applications. Case studies from Central Luconia and Abu Dhabi demonstrate that dual-porosity workflows outperform single-porosity approaches in multiscale pore-system characterization, permeability prediction, and dynamic behavior forecasting. Nevertheless, significant uncertainties persist regarding fracture connectivity, multimodal pore networks, interporosity transfer functions, and history-matching non-uniqueness, directly impacting CO₂ injectivity, plume migration, and long-term containment security. The review further examines advances in digital rock physics, machine-learning-assisted workflows, uncertainty-aware simulation, and coupled thermal–hydraulic–mechanical–chemical modeling. Though no single framework is universally applicable, future progress depends on improved multiscale characterization, rigorous uncertainty quantification, coupled multiphysics simulation, and computationally efficient workflows that balance geological realism with practical field-scale implementation.

Keywords: dual-porosity modeling, carbonate reservoirs, carbon capture and storage (CCS)

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1. Introduction

Carbonate reservoirs store more than 50% of the world's proven hydrocarbon reserves and remain essential to global energy production and subsurface resource development (Garland et al., 2012; Malki et al., 2023). However, characterization and simulation of carbonate reservoirs are highly challenging due to complex geological heterogeneity related to depositional variability, diagenesis, dissolution, dolomitization, and fracturing (Janjuhah et al., 2019; Malki et al., 2023; Xiong et al., 2025). These processes generate multiscale pore systems in which low-permeability matrix microporosity coexists with highly conductive fractures and vugs, creating strong contrasts in storage and flow behavior (Pruess & Narasimhan 1985; Janjuhah et al., 2019).

A key feature of many carbonate reservoirs is dual-porosity behavior, in which the matrix primarily provides fluid storage while fractures and vugs dominate fluid flow (Wu et al., 1998; Berkowitz 2002; Cordero et al., 2019). This results in rapid early-time fracture flow followed by slower matrix-controlled drainage at later stages of production (Wu et al., 1998; Maulindani et al., 2021). In the classic dual-porosity model, fractures transport fluids that were initially stored in the matrix to the wellbore, emphasizing a non-direct flow pathway from the matrix to the wellbore. However, when matrix permeability is non-negligible, as in vuggy or intercrystalline carbonates, fluid can migrate directly from the matrix to the wellbore, a condition represented by dual-permeability models. The duration and extent of matrix support for fluid flow are governed by several critical parameters: 1) matrix permeability relative to fracture permeability, 2) fracture spacing or matrix block size, 3) capillary pressure and wettability characteristics, 4) fluid viscosity ratios, and 5) the prevailing pressure gradient between matrix and fracture domains. In highly fractured systems with small matrix blocks and low matrix permeability, matrix drainage may persist for months to years. Conversely, in moderately fractured systems with larger matrix blocks and higher matrix permeability, direct matrix flow can sustain production over decades.

To address these limitations, dual-porosity and dual-permeability models were developed to represent matrix and fracture systems as interacting continua. Since the pioneering work of Warren and Root (1963) and Barenblatt et al. (1960), these approaches have evolved into more advanced formulations such as Multiple Interacting Continua (MINC), Discrete Fracture Network (DFN), and hybrid models (Pruess & Narasimhan 1985; Cordero et al., 2019; Moldabayeva et al., 2025). Although these methods improve the representation of multiscale heterogeneity and fracture connectivity, significant challenges remain in parameter estimation, scale dependency, uncertainty quantification, and integration of geological and petrophysical datasets (De Boever et al., 2016; Wei et al., 2021).

The importance of dual-porosity modeling has also expanded into carbon capture and storage (CCS) applications. In naturally fractured carbonate reservoirs, fractures control CO₂ injectivity and migration, while the matrix contributes to long-term trapping through capillary and diffusion-driven processes (Janjuhah & Alansari 2020; Xiong et al., 2025). Accurate modeling of these systems therefore requires reliable representation of coupled multiphase flow, matrix–fracture exchange, and reservoir heterogeneity (Zampetti et al., 2004; Janjuhah & Alansari 2020; Yerima et al., 2024). The duration of matrix support in CCS is particularly important: during injection, fractures provide rapid conduits for CO₂, while matrix diffusion and capillary trapping operate over decades to centuries. The extent of matrix involvement depends on fracture-matrix contact area, matrix pore-throat size distribution, and the CO₂-brine interfacial tension.

Despite considerable progress, existing studies remain fragmented, often focusing on specific modeling techniques or isolated case studies without critically integrating geological characterization, modeling approaches, and CCS applications (De Boever et al., 2016; Wei et al., 2021). In addition, the strengths, limitations, and applicability of different dual-porosity frameworks are rarely evaluated systematically across varying carbonate reservoir conditions.

This review critically examines current dual-porosity modeling approaches in carbonate reservoirs by synthesising advances in characterization techniques, modeling frameworks, and CCS applications. Carbonate reservoirs in the Central Luconia Province, offshore Sarawak, are of particular interest because of their pronounced multiscale heterogeneity and dual-porosity behavior (Janjuhah et al., 2019). This area is also selected as a focus study because it has been the largest gas-producing province in Southeast Asia from the 1960s to the present day.

In addition, this paper includes a global analogue from the Abu Dhabi carbonate reservoir. It also identifies major research gaps in multimodal pore systems, parameter uncertainty, data integration, and computational limitations, while highlighting emerging directions in digital rock physics, machine learning, and coupled geomechanical reactive transport modeling.

2. Methodology

2.1 Critical review of modeling approaches

2.1.1 Single porosity model

Single porosity models treat the reservoir as a single, homogeneous continuum where all pore spaces are interconnected and contribute equally to fluid storage and flow (Warren & Root 1963; Ding 2022). This approach, governed by the classical Darcy equation for a single medium, is computationally efficient and mathematically straightforward, making it widely adopted for conventional sandstone and clastic reservoirs. However, in carbonate reservoirs characterized by bimodal pore systems comprising low-permeability matrix and high-permeability fractures, the single porosity assumption proves fundamentally inadequate (Jones & Xiao 2005). The absence of fracture-dominated flow pathways in these models leads to systematic underestimation of reserves by up to 30% in some complex carbonate buildups and poor history matching against observed production data (Malki et al., 2023). Recent comparative studies show that single porosity simulations consistently underpredict early-time production rates and overestimate late-time recovery because they cannot capture rapid, fracture-dominated flow followed by slow matrix drainage (De Boever et al., 2016; March et al., 2018).

2.1.2 Dual-porosity model

The conceptualization of fluid flow in naturally fractured carbonate reservoirs has evolved significantly over the past six decades, driven by the need to reconcile idealised mathematical representations with the complex reality of multiscale pore systems. This section traces the development of dual-porosity and dual-permeability models, emphasising the evolving assumptions regarding matrix-fracture flow pathways and domain coupling mechanisms that distinguish these approaches.

The classic dual-porosity model, pioneered by Warren and Root (1963) and Barenblatt et al. (1960), was predicated on a strict functional separation between matrix and fracture domains: the matrix served exclusively as a storage medium (characterized by high porosity but negligible permeability), while fractures provided the sole conduits for fluid flow to the wellbore (Bai et al., 1994; March et al., 2018). Figure 1a presents this conceptualization, where flow pathways (indicated by red arrows) show unidirectional transfer from matrix blocks to the fracture network, with no direct matrix-wellbore connection permitted.

Although mathematically tractable, the classic dual-porosity assumption proved overly restrictive for many real-world carbonate reservoirs, particularly when the matrix possessed non-negligible permeability or when fracture networks were sparse. This limitation became especially apparent in carbonates, where matrix permeability arises from interconnected vugs, molds, or intercrystalline porosity. Dual-permeability models (DPM) addressed this constraint by allowing simultaneous and coupled flow in both matrix and fracture domains. In these formulations, fluid can migrate directly from matrix blocks to the wellbore, independent of the fracture network, capturing scenarios where both domains contribute meaningfully to production and pressure support (Egya et al., 2019; Matsushima et al., 2021).

The distinction between these modeling frameworks fundamentally rests on assumptions about flow-domain connectivity. Figure 2 shows a schematic of pore-scale flow pathways within a representative elementary volume (REV) of carbonate rock, highlighting four critical assumptions underpinning dual-porosity/permeability formulations.

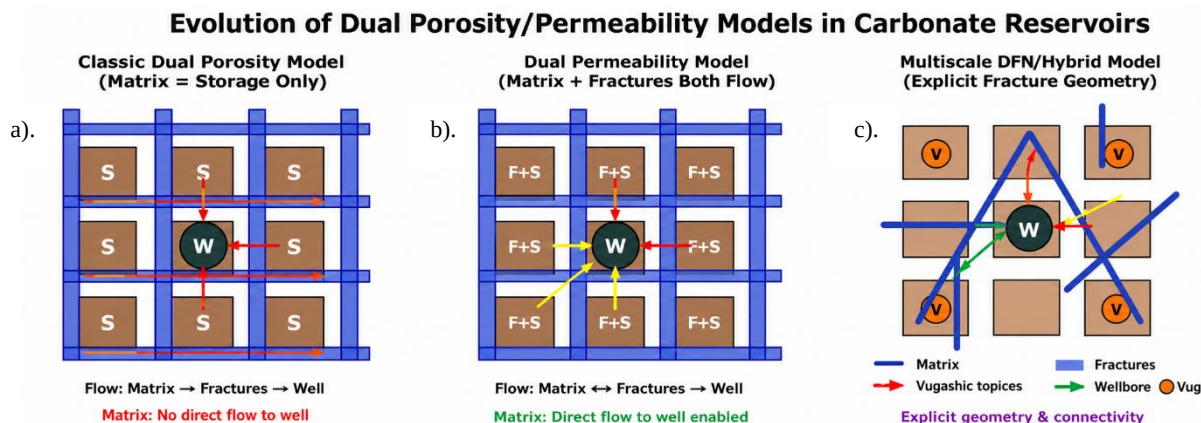
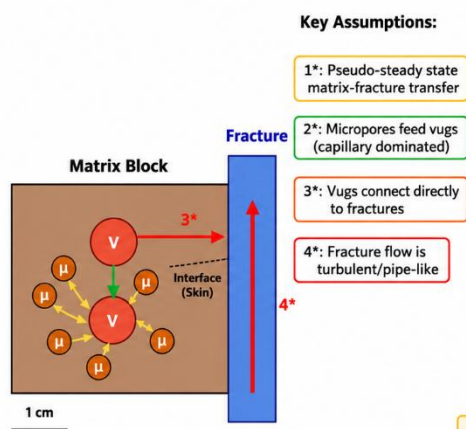


Figure 1.

Evolution of dual-porosity modeling frameworks illustrating the progressive relaxation of domain-coupling assumptions from left to right. (a) The classic dual-porosity model is where the matrix acts solely as a storage medium with negligible permeability, and fractures provide the only flow pathways to the wellbore. (b) The dual-permeability model demonstrates both matrix and fractures contributing to fluid flow and storage, permitting direct matrix-wellbore communication. (c) The multiscale hybrid model incorporates explicit fracture geometry and discrete fracture networks for improved geological realism.

Fluid Flow Mechanisms and Assumptions in Multiscale Carbonate Pore Systems

(a) Pore-Scale Flow Pathways and Domain Coupling



(b) Comparison of Modeling Approaches and Their Assumptions

Model Type	Matrix Flow	Transfer Function	Best Application
Warren-Root (1963)	No flow (Pure storage)	Pseudo-steady state Shape factor ω , λ	Highly fractured $k_m \ll k_f$
Kazemi (1969)	No flow (Gravity only)	Transient Numerical coupling	Anisotropic fractures
DPM (Dual Perm)	Darcy flow ($k_m > 0$)	Coupled PDEs Two permeabilities	Moderate contrast $k_m \approx 0.01-0.1 k_f$
MNC (Pruess)	Multiple continua	Nested subdomains For matrix heterogeneity	Tight matrix With micropores
DFN (Explicit)	3D Darcy + Navier-Stokes	Geometric connectivity	Complex fracture networks

Note: Selection depends on permeability contrast ($\kappa = k_f/k_m$) and matrix heterogeneity. Classical models assume $\kappa > 100$; DPM valid for $\kappa < 100$.

Figure 2.

Pore-scale flow pathways and domain coupling assumptions within a representative elementary volume (REV) of carbonate rock. (a) Schematic illustration of four critical assumptions underpinning dual-porosity/dual-permeability formulations: matrix block geometry, fracture connectivity, interporosity transfer mechanisms, and flow domain coupling. (b) Comparative schematic of dual-porosity and dual-permeability modeling approaches showing differences in matrix-fracture flow connectivity and wellbore communication pathways.

2.1.3 Dual-permeability model

This paper compares five major modeling approaches and their underlying assumptions. These include the Warren-Root model, the Kazemi model, the Dual-Permeability Model, the Multiple Interacting Continua (MINC), and the Discrete Fracture Network (DFN). The Warren-Root model assumes no matrix flow and pseudo-steady-state transfer, appropriate for highly fractured systems where matrix permeability is orders of magnitude lower than fracture permeability. Meanwhile, the dual-permeability model relaxes the "no matrix flow" constraint, permitting Darcy flow in both domains when the permeability contrast is moderate. The Kazemi (1969) model

significantly advanced this framework by introducing a numerical formulation for naturally fractured reservoirs. Unlike earlier analytical solutions, the Kazemi approach enabled simulation of more complex matrix-fracture geometries and transient flow behaviors, providing a critical foundation for modern dual-porosity simulators. For extreme matrix heterogeneity common in carbonates with separate vuggy porosity, the Multiple Interacting Continua (MINC) method subdivides the matrix into nested continua (Rahman & Pierson 2011). This example addresses both porosity and permeability together.

2.1.4 Advanced models

- Multiple interacting continua (MINC) method

The Multiple Interacting Continua (MINC) method was developed by Pruess and Narasimhan (1985) to address the limitations of the classical dual-porosity formulation when matrix heterogeneity is extreme. Unlike the Warren and Root (1963) approach, which treats the entire matrix as a single continuum with a single interporosity transfer coefficient, MINC subdivides the matrix block into nested shells or layers, each with its own porosity, permeability, and exchange term. This nested structure captures the transient, spatially varying pressure gradients within the matrix that the pseudo-steady-state assumption of the classic model cannot resolve. In carbonate reservoirs with multimodal pore-throat distributions, such as those found in Central Luconia where microporosity, mesoporosity, and vuggy macroporosity coexist, MINC provides significantly more accurate representations of fluid exchange dynamics (Makhankova et al., 2021; Jiménez et al., 2024).

- Discrete fracture network (DFN) model

The Discrete Fracture Network (DFN) model represents an alternative paradigm that abandons the continuum approximation in favor of explicit, deterministic fracture geometry (Henglai et al., 2025). In DFN simulations, each fracture is mapped as a discrete planar feature with orientation, aperture, length, and connectivity derived from outcrop analogues, borehole image logs, or seismic attributes (Alabere et al., 2023). This explicit representation is essential for carbonate reservoirs where fracture corridors and karst conduits create localized high-permeability pathways that dominate flow. Because DFN models remain computationally demanding at the field scale, hybrid DFN–dual-porosity workflows have been increasingly adopted, in which DFN characterizes near-wellbore or critical flow paths while dual-porosity approximations represent the far-field matrix (Gerke & Van Genuchten 1993; Cordero et al., 2019).

- Hybrid models

Hybrid models combine the computational efficiency of continuum dual-porosity or dual-permeability formulations with the geometric fidelity of discrete fracture networks (Yerima et al., 2024). In a typical hybrid workflow, large-scale deterministic fractures (e.g., seismic-scale fault corridors) are embedded explicitly within a continuum matrix-fracture grid, while smaller background fractures are homogenized into effective dual-porosity properties (Nguyen et al., 2018; Zambrano et al., 2021). This approach balances accuracy and efficiency: explicit fractures capture near-wellbore dynamics, injectivity, and early-time breakthrough, while continuum approximations keep simulation times feasible for full-field forecasting. Hybrid models have shown promise for CCS applications, where accurately representing CO₂ migration along preferential pathways is critical for containment assessment (Nguyen et al., 2018; Zambrano et al., 2021).

Recent advances have moved beyond continuum approximations to represent multiscale heterogeneity explicitly. The Discrete Fracture Network (DFN) model and hybrid continuum-discrete approaches incorporate spatial variability in fracture orientation, intensity, and connectivity directly into the simulation grid. These methods are particularly relevant for carbonate reservoirs where fracture corridors, karst features, and diagenetic alterations create deterministic heterogeneity that stochastic models cannot adequately represent (Zambrano et al., 2021). Integrating machine learning and digital rock physics represents the current frontier in dual-porosity characterization. These techniques enable direct identification and parameterization of multiscale pore features from core samples, borehole images, and digital reconstructions, providing the geological foundation necessary to select appropriate modeling assumptions (Al Hameli et al., 2022).

2.1.5 Comparative evaluation of modeling approaches

The comparative assessment of modeling approaches highlights the evolution of reservoir simulation techniques from simplified homogeneous representations to increasingly sophisticated frameworks that capture the multiscale heterogeneity characteristic of carbonate reservoirs. The suitability of each modeling approach depends strongly on reservoir complexity, fracture connectivity, matrix permeability contribution, data availability, and computational constraints (Table 1).

Single porosity models remain the simplest and most computationally efficient approach for reservoir simulation because they treat the reservoir as a homogeneous continuum with uniformly distributed porosity and permeability (Warren & Root 1963; Ding 2022). These models are generally adequate for relatively homogeneous clastic reservoirs where pore connectivity is continuous, and fracture influence is limited. However, their application to carbonate reservoirs is fundamentally limited because they cannot represent bimodal pore systems and matrix–fracture interactions (Jones & Xiao 2005; Malki et al., 2023). In fractured carbonate systems, fluid flow is commonly dominated by highly conductive fractures and vugs, whereas the low-permeability matrix primarily controls hydrocarbon storage. Because single porosity models cannot separate these domains, they often underestimate reserves, misrepresent pressure behavior, and fail to reproduce characteristic production trends such as rapid early-time fracture flow followed by slower matrix drainage (De Boever et al., 2016; Malki et al., 2023).

Dual-porosity models were developed to overcome these limitations by representing the matrix and fracture systems as separate interacting continua (Bai et al., 1994; March et al., 2018). In this framework, fractures primarily control fluid flow, while the matrix acts as the dominant storage domain. The separation significantly improves the representation of naturally fractured carbonate reservoirs and allows more realistic simulation of matrix–fracture exchange processes (March et al., 2018; Maulindani et al., 2021). Dual-porosity models are particularly effective in highly fractured systems where fracture permeability exceeds matrix permeability by several orders of magnitude (De Boever et al., 2016; Wei et al., 2021). Their ability to reproduce both early-time fracture-dominated production and late-time matrix-controlled drainage explains their widespread adoption in carbonate reservoir simulation. Nevertheless, these models rely heavily on pseudo-steady-state assumptions and typically neglect direct matrix flow, which may oversimplify carbonate reservoirs containing connected vuggy or intercrystalline pore systems (Zampetti et al., 2004; De Boever et al., 2016). Furthermore, the interporosity transfer coefficient (α), matrix block size, and fracture spacing are difficult to constrain directly at reservoir scale, introducing significant calibration uncertainty and non-uniqueness during history matching (Rahman & Pierson 2011; Wei et al., 2021).

Dual-permeability models extend the dual-porosity concept by allowing simultaneous flow in both matrix and fracture domains (Zampetti et al., 2004; Moldabayeva et al., 2025). This provides a more physically realistic representation of carbonate reservoirs, where the matrix contributes meaningfully to fluid flow through connected vugs, interparticle pores, or intercrystalline permeability (Fuentes-Cruz & Valko 2015). Compared with classic dual-porosity models, dual-permeability formulations improve predictions of pressure propagation, sweep efficiency, and long-term recovery behavior in moderately fractured systems (Egya et al., 2019; Matsushima et al., 2021). However, this increased realism comes at the expense of greater model complexity. Dual permeability models require additional parameters, including separate permeability tensors and relative permeability functions for both continua, substantially increasing calibration difficulty and computational demand (Zampetti et al., 2004; Correia et al., 2011). As a result, parameter non-uniqueness becomes a major challenge, particularly when geological and petrophysical constraints are limited.

The Multiple Interacting Continua (MINC) method represents a further advancement designed to address transient matrix–fracture flow behavior and internal matrix heterogeneity (Jiménez et al., 2024; Trianto et al., 2026). Rather than treating the matrix as a single continuum, MINC subdivides matrix blocks into nested continua, enabling improved representation of diffusion-dominated flow and transient pressure equilibration processes (Makhankova et al., 2021). This approach is particularly beneficial in carbonate reservoirs with multimodal pore-throat distributions and strong microporosity development, where fluid transfer between fractures and matrix occurs gradually rather than instantaneously. MINC models provide improved physical realism but are also significantly more computationally intensive than conventional dual-porosity approaches (Fleury & Soualem 2009; Jabbari & Zeng 2011). In addition, defining representative nested continua and

upscaling pore-scale heterogeneity to reservoir-scale simulation remain major sources of uncertainty. Consequently, MINC methods are often restricted to detailed sector studies or research-oriented applications rather than routine full-field simulation.

Discrete Fracture Network (DFN) models provide the highest degree of geological realism by explicitly representing fracture geometry, orientation, aperture, spacing, and connectivity (Alabere et al., 2023; Henglai et al., 2025). Unlike continuum-based approaches, DFN models simulate fractures as discrete geological features, making them particularly effective for reservoirs dominated by fracture corridors, karst systems, and strongly anisotropic fracture networks (Zambrano et al., 2021). These models are highly valuable for evaluating near-wellbore flow behavior, fracture connectivity, and preferential fluid migration pathways. However, extreme computational demands and the scarcity of field-scale fracture characterization data severely limit their practical application (Moonen & Carmeliet 2013; Alabere et al., 2025). Fracture connectivity and scaling uncertainty remain major limitations because local fracture observations from cores or image logs may not accurately represent reservoir-scale fracture architecture.

Hybrid continuum–DFN models balance computational efficiency with geological realism by combining explicit representations of major fractures with continuum approximations for smaller-scale fracture systems and matrix flow (Barenblatt et al., 1960; Nguyen et al., 2018). These approaches are more relevant for complex carbonate reservoirs where deterministic fracture corridors coexist with diffuse background fracturing. Hybrid models improve simulation of localized, fracture-dominated transport while remaining computationally feasible for larger-scale forecasting. Hybrid models are also particularly relevant for CCS applications, where accurately represented preferential CO₂ migration pathways are essential for injectivity and containment assessment (Nguyen et al., 2018). Nevertheless, hybrid approaches remain more computationally demanding than classic models and require careful coupling between discrete and continuum domains. Additionally, uncertainty in fracture upscaling and interactions between explicit and homogenized fracture systems continue to pose significant modeling challenges (Alabere et al., 2025).

The comparative evaluation (Table 1) demonstrates that no single modeling approach is universally applicable to all carbonate reservoirs. Simpler continuum models offer computational efficiency but often oversimplify geological complexity; conversely, advanced methods improve physical realism at the expense of increased parameter uncertainty, stringent data requirements, and high computational costs. Model selection should therefore be guided by reservoir heterogeneity, fracture intensity, pore system connectivity, available datasets, and the specific objectives of the simulation study. In practice, the trade-off between geological realism and computational practicality remains a central challenge in dual-porosity reservoir modeling.

2.1.6 Key limitations and uncertainties in dual-porosity-permeability modeling

Despite their widespread application in carbonate reservoir simulation, models for dual porosity and dual permeability remain subject to several important limitations that affect predictive reliability and field-scale applicability. Although representations of matrix–fracture systems in dual-porosity and dual-permeability models are practical, they rely on simplified assumptions that may not adequately capture the extreme heterogeneity and multiscale pore complexity characteristic of carbonate reservoirs (De Boever et al., 2016; March et al., 2018). Consequently, uncertainty in model structure, parameter estimation, and scale integration remains a major challenge in both hydrocarbon production forecasting and CCS applications.

- Simplified matrix–fracture geometry

One of the primary limitations of conventional dual-porosity and dual-permeability formulations is the assumption of simplified and idealised matrix–fracture geometry. Classic dual-porosity and dual-permeability models typically represent the reservoir as regularly shaped matrix blocks surrounded by uniformly distributed fractures (Bai et al., 1994; March et al., 2018). However, natural carbonate reservoirs rarely exhibit such regular fracture distributions. Instead, fracture systems are commonly characterized by strong anisotropy, irregular spacing, fracture corridors, and localized karst features that create highly heterogeneous flow pathways (Correia et al., 2011; De Boever et al., 2016). This structural oversimplification can lead to an

inaccurate representation of fracture connectivity and pressure propagation, particularly in reservoirs where flow is strongly influenced by large vugs, dissolution channels, or fault-related fracture systems (Zambrano et al., 2021). In highly heterogeneous carbonate reservoirs, continuum-based assumptions may therefore oversimplify localized flow behavior and underestimate preferential transport pathways. Although DFN and hybrid continuum–discrete models improve geological realism, they also introduce substantially greater computational and data requirements (Barenblatt et al., 1960; Henglai et al., 2025).

- Uncertainty in matrix–fracture transfer parameters

The interporosity transfer coefficient (α) remains one of the most uncertain parameters in dual-porosity and dual-permeability simulations because it governs fluid exchange between the matrix and fracture domains (Rahman & Pierson 2011; Wei et al., 2021). Although α can be estimated from analytical relationships, laboratory experiments, or history matching, it cannot be measured directly at the reservoir scale in the subsurface. Consequently, multiple parameter combinations may produce equally acceptable history matches, leading to significant non-uniqueness in model calibration (Trianto et al., 2026). Furthermore, transfer behavior is strongly scale-dependent and influenced by fracture spacing, matrix block geometry, wettability, and pore connectivity (De Boever et al., 2016). Small variations in α may significantly alter production forecasts, pressure depletion behavior, and matrix drainage efficiency, particularly during late-time production (Barenblatt et al., 1960). This uncertainty becomes even more pronounced in carbonate reservoirs with multimodal pore systems, where matrix–fracture exchange often deviates substantially from the pseudo-steady-state assumptions used in classical dual-porosity models (Jiménez et al., 2024).

- Limitations in multimodal carbonate pore systems

Most dual-porosity models assume a binary separation between matrix storage and fracture flow. However, carbonate reservoirs commonly feature far more complex pore architectures where micropores, mesopores, vugs, fractures, and karst networks coexist within the same reservoir interval (De Boever et al., 2016; Jiménez et al., 2024). In many carbonate systems, connected vuggy or intercrystalline porosity contributes significantly to fluid flow, which violates the classical assumption that matrix permeability is negligible (Zampetti et al., 2004; Moldabayeva et al., 2025). As a result, conventional dual-porosity models may oversimplify pore connectivity and underestimate internal matrix flow dynamics. This limitation is particularly critical in reservoirs with strong microporous development, where fluid transfer occurs gradually through diffusion-dominated processes rather than through instantaneous pressure equilibration (Makhankova et al., 2021; Jiménez et al., 2024). Although advanced approaches such as the MINC method improve the representation of transient matrix behavior, they also increase computational complexity and require a detailed characterization of the internal pore structure (Fleury & Soualem 2009; Jabbari & Zeng 2011).

- Scale dependency and data integration challenges

Another major challenge in dual-porosity and dual-permeability modeling is integrating multiscale geological and petrophysical datasets into reservoir-scale simulation models. Parameters derived from core analysis, nuclear magnetic resonance (NMR), mercury injection capillary pressure (MICP), and petrographic observations often reflect pore-scale or laboratory-scale conditions that are not directly transferable to field-scale simulations (Omidpour et al., 2022; Rahman & Pierson 2011). Upscaling these measurements while preserving representative matrix–fracture interactions remains highly uncertain, particularly in heterogeneous carbonate reservoirs. Furthermore, fracture characterization introduces additional uncertainty because fracture orientation, connectivity, and aperture distribution are often inferred indirectly from image logs, seismic attributes, or outcrop analogues (Alabere et al., 2023; Henglai et al., 2025). These datasets often may inadequately represent reservoir-scale fracture networks, resulting in discrepancies between static geological models and dynamic simulation behavior (Zambrano et al., 2021). Consequently, extensive calibration and history matching are frequently required to reconcile geological observations with production performance (De Boever et al., 2016; March et al., 2018).

Table 1.
Comparative Assessment of Dual-Porosity Modeling Approaches

Model	Major Strength	Major Limitation	Best Reservoir Type	Main Uncertainty	References
Single Porosity Model	Computationally efficient, mathematically simple, and suitable for rapid simulation and preliminary reservoir evaluation.	Assumes homogeneous porosity and permeability, making it unable to represent fracture-dominated flow or matrix–fracture interactions in carbonate reservoirs.	Homogeneous clastic reservoirs and low-fracture formations with relatively uniform pore connectivity.	Reservoir heterogeneity and fracture connectivity are poorly represented, leading to uncertainty in production prediction.	(Warren & Root 1963; Jones & Xiao 2005; Ding 2022)
Dual-porosity Model	Separates matrix storage from fracture flow, allowing realistic representation of early-time fracture-dominated production and late-time matrix drainage.	Assumes negligible matrix permeability and pseudo-steady-state matrix–fracture transfer, which may oversimplify heterogeneous carbonate systems.	Highly fractured carbonate reservoirs where fracture permeability dominates flow and the matrix primarily acts as storage.	Interporosity transfer coefficient (α), matrix block size, and fracture spacing remain difficult to constrain at reservoir scale.	(Bai et al., 1994; De Boever et al., 2016; March et al., 2018; Maulindani et al., 2021; Wei et al., 2021)
Dual-Permeability Model	Allows simultaneous flow in both matrix and fracture domains, improving realism in reservoirs with connected matrix permeability or vuggy systems.	Requires additional parameters and calibration effort, increasing computational cost and numerical instability.	Carbonate reservoirs with moderate permeability contrast and partially conductive matrix systems.	Strong uncertainty in matrix–fracture permeability partitioning and relative permeability calibration.	(Zampetti et al., 2004; Fuentes-Cruz & Valko 2015; Egya et al., 2019; Matsushima et al., 2021; Moldabayeva et al., 2025)
MINC (Multiple Interacting Continua) Model	Captures transient matrix–fracture exchange more accurately by subdividing the matrix into nested continua.	Computationally intensive and difficult to implement efficiently at full-field scale.	Carbonate reservoirs with strong matrix heterogeneity and multimodal pore throat distributions.	Uncertainty in upscaling nested continua and defining representative matrix subdivisions.	(Makhankova et al., 2021; Jiménez et al., 2024; Trianto et al., 2026)
Discrete Fracture Network (DFN) Model	Explicitly represents fracture geometry, orientation, aperture, and connectivity, providing high geological realism.	Highly data-intensive and computationally demanding, particularly for field-scale simulation.	Reservoirs dominated by fracture corridors, karst systems, and strongly anisotropic fracture networks.	Fracture connectivity, spatial distribution, and scaling of fracture properties to reservoir-scale models.	(Gerke & Van Genuchten 1993; Moonen & Carmeliet 2013; Alabere et al., 2023; Henglai et al., 2025)
Hybrid Continuum–DFN Model	Combines continuum efficiency with explicit fracture representation, improving simulation of both matrix flow and localized fracture transport.	Complex model construction and coupling between continuum and discrete domains increase calibration difficulty.	Complex carbonate reservoirs containing both diffuse fractures and major deterministic fracture systems.	Coupling consistency between DFN and continuum domains and uncertainty in fracture upscaling.	(Barenblatt et al., 1960; Nguyen et al., 2018; Zambrano et al., 2021; Yerima et al., 2024)

- Computational and numerical limitations

Increasing geological realism generally comes at the expense of computational efficiency. While classical dual-porosity models remain relatively efficient for full-field simulation, advanced methods such as MINC, DFN, and hybrid continuum–discrete models require significantly greater computational resources (Jabbari & Zeng 2011; Alabere et al., 2025). Because explicit fracture representation substantially increases grid complexity, numerical coupling requirements, and simulation runtime, these computational constraints become more pronounced, particularly in reservoirs with multiscale fracture networks (Cordero et al., 2019; Alabere et al., 2025). Consequently, large-scale uncertainty quantification and probabilistic forecasting become less feasible since multiple simulation realisations are required. As a result, many field-scale studies continue to rely on simplified dual-porosity approximations despite their known geological limitations (Barenblatt et al., 1960; De Boever et al., 2016). Thus, balancing computational practicality with geological realism remains one of the central challenges in carbonate reservoir modeling.

- CCS-specific modeling limitations

Additional challenges arise when dual-porosity models are applied to CCS systems. In fractured carbonate reservoirs, fractures enhance CO₂ injectivity and plume migration but may also serve as potential leakage pathways if fracture connectivity and geomechanical behavior are not accurately represented (Tsakiroglou et al., 2009; Fuentes-Cruz & Valko 2015). Conventional dual-porosity models often neglect coupled geomechanical effects, stress-dependent fracture permeability, and fracture reactivation, potentially underestimating long-term containment risks (Koša 2015; Khalid et al., 2024). Likewise, because many formulations do not explicitly incorporate reactive transport processes between CO₂, formation brine, and carbonate minerals, they may miss effects on porosity evolution and long-term storage behavior (Fuentes-Cruz & Valko 2015; Nguyen et al., 2018). Capillary trapping and wet ability effects are also commonly simplified, introducing additional uncertainty in predictions of plume migration and storage efficiency (Berkowitz 2002; Koša 2015). Hence, reliable CCS forecasting in carbonate reservoirs increasingly requires coupled flow–geomechanical–reactive transport models capable of representing both fracture-controlled migration and long-term matrix trapping processes. These limitations demonstrate that no single dual-porosity modeling approach is universally applicable to all carbonate reservoirs. Model reliability depends strongly on reservoir heterogeneity, fracture architecture, pore connectivity, available datasets, and simulation objectives. Future developments should therefore focus on improving multiscale characterization, reducing parameter uncertainty, integrating coupled physical processes, and developing computationally efficient workflows that balance geological realism with practical field-scale applicability.

3. Result and discussion

3.1 Evaluation of characterization techniques for dual-porosity carbonate reservoirs

Accurate characterization of carbonate reservoirs is fundamental for reliable dual-porosity modeling because fluid storage and flow behavior are strongly controlled by multiscale heterogeneity, fracture connectivity, and complex pore architectures (De Boever et al., 2016; Janjuhah et al., 2019). In contrast to relatively homogeneous clastic systems, carbonate reservoirs commonly contain interconnected micropores, vugs, fractures, and karst features that coexist across multiple spatial scales (Pruess & Narasimhan 1985; Jiménez et al., 2024). As a result, these heterogeneities significantly influence permeability distribution, matrix–fracture interaction, and reservoir performance, making reservoir characterization critical and highly uncertain stage of dual-porosity simulation (Rahman & Pierson 2011; Wei et al., 2021). Because no single characterization technique can fully capture the complexity of carbonate pore systems and fracture networks, integrated workflows combining geological, petrophysical, geophysical, and dynamic datasets are required to constrain reservoir heterogeneity and improve simulation reliability (Barenblatt et al., 1960; De Boever et al., 2016). However, integrating multiscale datasets into reservoir-scale models remains highly challenging due to scale mismatch, data uncertainty, and incomplete fracture representation. Table 2 compares the various characterization techniques used in dual-porosity carbonate reservoir modeling.

3.2 Core-based and petrophysical characterization techniques

Core-based analyses remain among the most important methods for evaluating carbonate pore systems and matrix properties. Routine core analysis (RCAL), special core analysis (SCAL), petrographic analysis, and mercury injection capillary pressure (MICP) measurements are widely used to characterise porosity distribution, pore-throat geometry, wet ability, and capillary behavior (Egya et al., 2019; Omidpour et al., 2022). These techniques provide valuable pore-scale information that improves understanding of matrix storage capacity and fluid transport mechanisms. MICP and petrographic analyses are particularly useful for identifying microporosity development and pore throat distributions in carbonate reservoirs (Omidpour et al., 2022). Figure 3 shows the image processing workflow applied to thin-section data, demonstrating how original images are segmented and analyzed to extract pore geometry, spatial distribution, and quantitative pore-structure characteristics.

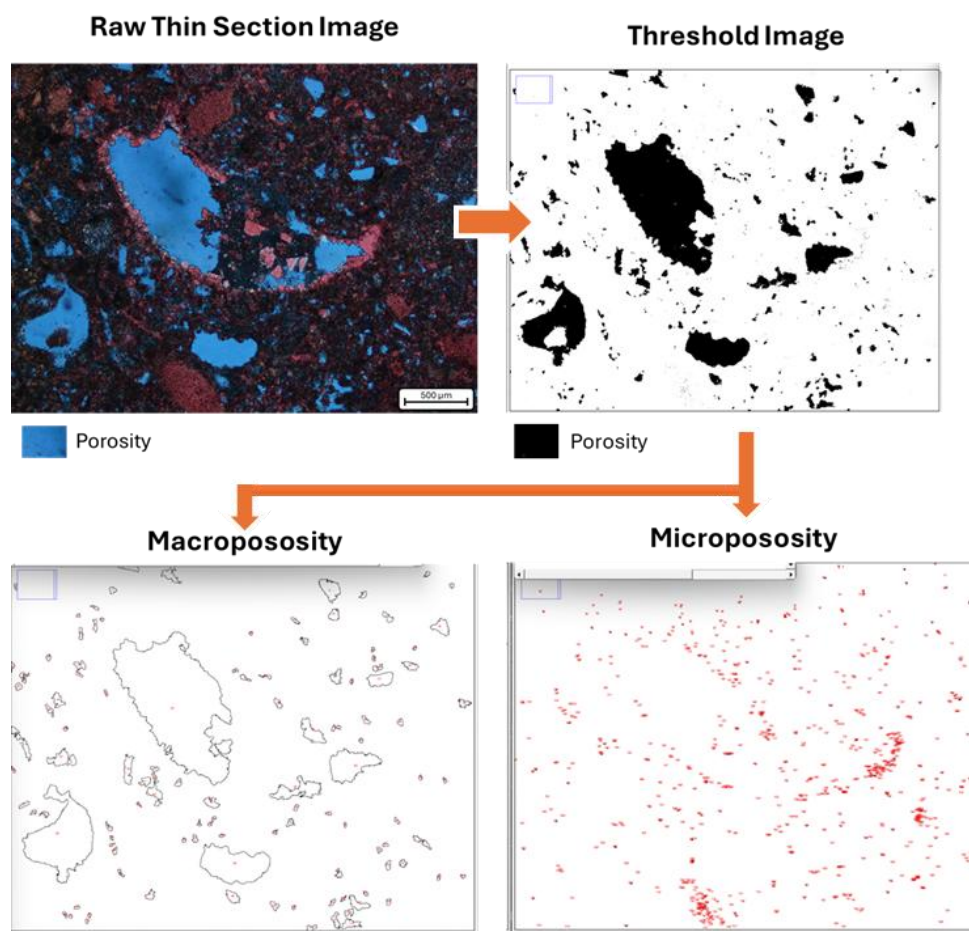


Figure 3.

Image processing workflow for pore structure identification and quantification in carbonate thin sections. (a) Original thin-section photomicrograph under plane-polarized light showing the heterogeneous distribution of pore types. (b) Binary segmentation mask highlighting porosity (white) versus solid matrix (black) after image thresholding. (c) Quantified pore network map showing individual pore boundaries, size classification, and connectivity indices used to derive dual-porosity parameters for reservoir simulation.

Carbonate reservoirs commonly exhibit strong spatial variability, which implies core-scale measurements may not accurately capture large-scale fracture connectivity or vug distribution (Figure 4). As a result, laboratory-derived petrophysical properties are often difficult to upscale into representative simulation parameters for dual-porosity models. Nuclear magnetic resonance (NMR) logging has become increasingly important for characterizing pore-size distribution and fluid mobility in carbonate reservoirs (Matsushima et al., 2021). Furthermore, NMR measurements can effectively differentiate between movable and immovable fluids and improve the identification of microporous intervals. Nevertheless, permeability estimation from NMR remains indirect and strongly dependent on calibration relationships that may vary significantly between carbonate facies (Rahman & Pierson 2011). Consequently, this uncertainty in pore-system interpretation may propagate directly into matrix permeability estimations and interporosity transfer calculations.

3.3 Well logging and borehole imaging techniques

Well logs and borehole imaging tools are essential for evaluating fracture distributions, lithofacies variations, and dynamic reservoir properties. Conventional logs, including density, neutron, sonic, and resistivity logs, are widely used to estimate porosity and fluid saturation (Egya et al., 2019). However, their ability to distinguish between matrix porosity, vugs, and fractures is often limited in highly heterogeneous carbonate systems (De Boever et al., 2016).

Formation microimager (FMI) logs and other borehole image logs provide improved fracture characterization by identifying fracture orientation, density, aperture, and dip (Henglai et al., 2025). These datasets are particularly valuable for constraining fracture networks in dual-porosity and DFN models. Additionally, sonic and acoustic logs also provide indirect indications of fracture intensity and mechanical heterogeneity (Alabere et al., 2023). Despite their importance, borehole imaging tools characterize fractures only near the wellbore and may not adequately represent reservoir-scale fracture connectivity (Zambrano et al., 2021). As a result, fracture interpretation often remains highly uncertain, particularly in reservoirs with anisotropic fracture systems or localized fracture corridors.

3.4 Seismic and dynamic characterization approaches

Seismic interpretation and dynamic reservoir data provide larger-scale constraints on carbonate reservoir heterogeneity and fracture distributions. Three-dimensional (3D) seismic data are commonly used to identify major structural features, faults, and fracture corridors that influence fluid flow behavior (Henglai et al., 2025). Additionally, time-lapse (4D) seismic techniques can provide insights into pressure depletion and fluid migration during production or CO₂ injection (Tsakiroglou et al., 2009). Pressure transient analysis and production history matching are also crucial in identifying fracture-dominated flow behavior and estimating matrix–fracture interaction (March et al., 2018). In many carbonate reservoirs, dual-porosity behavior is inferred primarily from dynamic production responses, such as early-time pressure decline and delayed matrix drainage (Maulindani et al., 2021). However, seismic methods are generally unable to resolve small-scale fractures and microporous heterogeneities that strongly influence local flow behavior (Alabere et al., 2023). Likewise, production data may produce non-unique interpretations because multiple fracture configurations can generate similar pressure responses (De Boever et al., 2016).

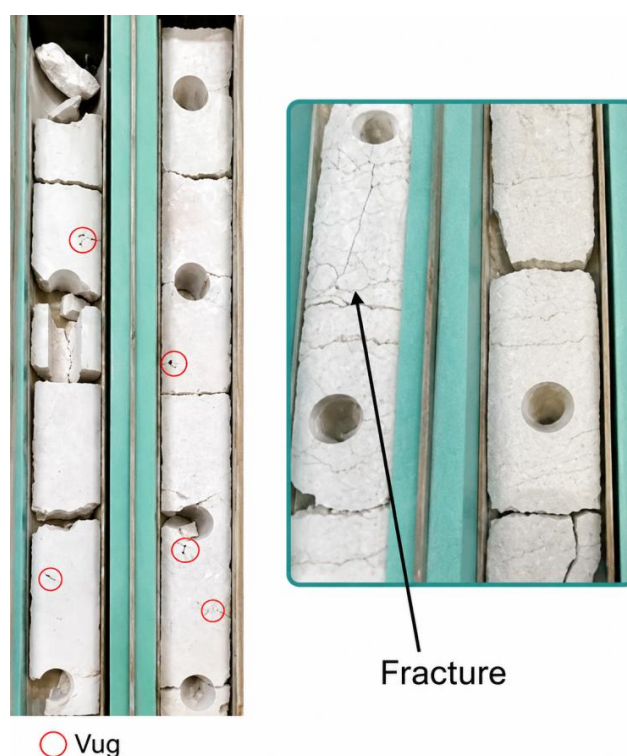


Figure 4.

Core sample photograph of a carbonate rock exhibiting multimodal pore architecture. Large vugs developed through dissolution processes, creating macroporosity that dominates fluid flow. Subvertical fractures cutting across the matrix, providing additional high-permeability pathways. Microporous matrix between vugs and fractures acting as the primary storage domain. This heterogeneous pore assemblage exemplifies the bimodal to multimodal pore systems that necessitate dual-porosity modeling approaches.

Table 2.
Comparative evaluation of characterization techniques used in dual-porosity carbonate reservoir modeling.

Technique	Main Application	Major Strength	Major Limitation	Scale
Neutron–Density Crossplot Logs	Porosity, lithology, and fluid-content evaluation.	Differentiates microporous matrix from macroporous fracture/vug zones.	Limited direct fracture characterization capability.	Wellbore scale
Sonic / Full Waveform Acoustic Logs	Fracture and vug detection through acoustic velocity anomalies.	Identifies fracture corridors and high-permeability zones.	Indirect interpretation is affected by lithological variability.	Wellbore scale
NMR Logs	Pore-size distribution and fluid mobility analysis.	Confirms bimodal pore systems and evaluates storage versus flow potential.	Strong dependence on calibration and interpretation models.	Wellbore scale
Electrical Image Logs (FMI)	Fracture density, orientation, aperture, and fracture-network characterisation.	Enables DFN calibration and fracture mapping near the wellbore.	Limited penetration depth and uncertain reservoir-scale connectivity.	Borehole scale
Gamma Ray Logs	Lithology and clay-content identification.	Useful for facies correlation and carbonate differentiation.	Limited capability for direct fracture or pore-network characterisation.	Wellbore scale
Routine Core Analysis (RCA)	Measurement of porosity, permeability, and grain density.	Provides baseline matrix reservoir properties and calibration data for well logs.	Limited representativeness in highly heterogeneous carbonate reservoirs.	Core scale
Special Core Analysis (SCAL)	Determination of capillary pressure, relative permeability, and wettability.	Essential for multiphase flow simulation and matrix–fracture interaction analysis.	Laboratory conditions may not fully represent in-situ reservoir behavior.	Core scale
Mercury Injection Capillary Pressure (MICP)	Pore throat size distribution and microporosity characterisation.	Effective for quantifying bimodal pore systems and capillary behavior.	Small sample size and uncertainty during reservoir-scale upscaling.	Pore/core scale
Core-Based NMR	Pore-size distribution, fluid typing, and fluid mobility evaluation.	Distinguishes bound and free fluids and confirms dual pore systems.	Indirect permeability estimation and calibration dependency.	Core/log scale
Tracer and Displacement Tests	Estimation of interporosity transfer coefficient (α) and matrix block size.	Provides empirical calibration of matrix–fracture exchange behavior.	Difficult to scale from laboratory conditions to field-scale simulations.	Core scale
Digital Rock Physics (DRP)	Pore-scale flow simulation and pore-network characterisation.	Direct visualization of pore connectivity and fluid-flow pathways.	Computationally intensive and difficult to upscale.	Pore scale
Micro-CT Imaging	Three-dimensional imaging of pore systems and fractures.	High-resolution visualization of pore networks and fracture distribution.	Limited sample size and high computational requirements.	Pore scale
Petrographic Analysis	Identification of pore types, diagenetic features, and pore connectivity.	Provides detailed understanding of carbonate pore architecture and dual-porosity behavior.	Qualitative interpretation and difficult quantitative upscaling.	Micron/core scale
Scanning Electron Microscopy (SEM)	Visualization of microporosity and nanoporosity.	High-resolution imaging of microstructural pore systems.	Limited sample coverage and expensive image processing.	Micron scale
Cathodoluminescence (CL)	Identification of diagenetic alteration and cementation patterns.	Improves understanding of pore evolution and diagenetic history.	Mainly qualitative and interpretation dependent.	Thin-section scale
Digital Image Analysis (DIA)	Quantification of pore geometry, pore size, and connectivity from thin sections.	Improves quantitative pore characterization and permeability correlations.	Image segmentation uncertainty and limited field-scale representation.	Pore/core scale
Seismic Attribute Analysis / 3D Seismic	Structural interpretation, fracture corridors, and reservoir architecture mapping.	Provides reservoir-scale structural characterisation.	Cannot resolve small-scale fractures and microporosity.	Reservoir scale
Pressure Transient Analysis (PTA)	Evaluation of fracture behavior and matrix–fracture interaction.	Provides dynamic evidence of dual-porosity flow behavior.	Non-unique interpretation of fracture connectivity.	Reservoir scale
Production History Matching	Calibration and validation of dual-porosity simulation models.	Integrates dynamic reservoir behavior into model calibration.	Strong parameter non-uniqueness and calibration uncertainty.	Field scale
Machine Learning Approaches	Prediction of porosity, permeability, and fracture-related properties from multiscale datasets.	Rapid integration and analysis of large geological and petrophysical datasets.	Dependent on training-data quality and limited physical interpretability.	Multiscale

3.5 Digital rock physics and emerging characterization technologies

Recent advances in digital rock physics (DRP), micro-computed tomography (micro-CT), and machine learning have significantly advanced pore-scale characterization of carbonate reservoirs (Yan et al., 2024). Digital rock workflows enable detailed visualization of pore geometry, fracture connectivity, and fluid-flow pathways at micron-scale resolution, thereby supporting the evaluation of multimodal pore systems and improving understanding of matrix–fracture interactions (Jiménez et al., 2024). Concurrently, machine learning methods are increasingly applied to lithofacies classification, permeability prediction, fracture detection, and pore-network analysis using integrated well log and seismic datasets (Shun et al., 2020). Although these techniques offer potential improvements in automated characterization and uncertainty reduction, digital rock physics and AI-assisted approaches remain computationally demanding and highly dependent on data quality and representativeness (Yan et al., 2024). In addition, translating pore-scale digital observations into field-scale simulation parameters remains a major unresolved challenge.

3.6 Digital challenges in multiscale data integration

A major limitation in carbonate reservoir characterization is the difficulty of integrating datasets acquired at different spatial scales into a consistent reservoir simulation framework (Barenblatt et al., 1960; De Boever et al., 2016). Core analyses provide detailed pore-scale information, whereas well logs and seismic data represent progressively larger spatial scales with lower resolution. Preserving representative matrix–fracture relationships during upscaling remains highly uncertain, particularly in reservoirs with strong heterogeneity and anisotropic fracture systems (Rahman & Pierson 2011). Furthermore, fracture characterization adds uncertainty because fracture orientation, aperture, and connectivity are often inferred indirectly from limited borehole observations and seismic interpretation (Alabere et al., 2023; Henglai et al., 2025). This structural uncertainty can result in inaccurate static and dynamic geological models, which misrepresent reservoir behavior during production or CO₂ injection (Zambrano et al., 2021). Extensive calibration and history matching are therefore commonly required to reconcile geological observations with reservoir simulation results (March et al., 2018). These uncertainties directly affect dual-porosity model reliability because matrix permeability, fracture connectivity, and interporosity transfer behavior are strongly dependent on characterization accuracy (Wei et al., 2021). Poor characterization may lead to the incorrect estimation of fracture conductivity, storage capacity, and sweep efficiency, ultimately reducing forecasting reliability and increasing uncertainty in CCS containment assessment (Fuentes-Cruz & Valko 2015; Koša 2015).

3.7 Implications for dual-porosity and CCS modeling

The effectiveness of dual-porosity modeling is fundamentally dependent on the quality of reservoir the ability to represent multiscale heterogeneity realistically. In hydrocarbon reservoirs, inaccurate fracture characterization can lead to unreliable production forecasts, poor sweep efficiency estimations, and incorrect pressure depletion behavior (De Boever et al., 2016). In CCS applications, this uncertainty becomes even more critical because fracture connectivity and caprock integrity directly influence CO₂ migration and long-term storage security (Tsakiroglou et al., 2009). Although integrated characterization work flows have considerably improved carbonate reservoir modeling considerably, substantial uncertainties remain in multiscale data integration, fracture representation, and pore-network upscaling. Future research should therefore focus on improving uncertainty-aware characterization work flows, integrating digital rock physics with reservoir-scale simulation, and applying machine learning approaches to automated fracture and pore-system characterization (Shun et al., 2020; Yan et al., 2024). Additionally, coupled geological–geomechanical–reactive transport characterization frameworks will likely become increasingly important for reliable CCS assessments in fractured carbonate reservoirs.

3.8 Implications of dual-porosity modeling for CCS and subsurface energy systems

Dual-porosity modeling has become increasingly important in carbon capture and storage (CCS) and subsurface energy applications because fractures and multiscale pore systems strongly influence fluid migration, injectivity, pressure propagation, and long-term storage behavior (Fuentes-Cruz & Valko 2015; Janjuhah & Alansari 2020). In carbonate reservoirs, fractures commonly provide highly conductive flow pathways, whereas

the matrix acts as the primary storage domain through capillary trapping, dissolution, and diffusion-controlled processes (Zampetti et al., 2004; Xiong et al., 2025). Accordingly, accurately representing matrix–fracture interaction is essential for predicting CO₂ plume evolution, containment security, and reservoir performance. Compared with relatively homogeneous saline aquifers, carbonate reservoirs present substantially greater uncertainty due to their strong heterogeneity, anisotropic fracture systems, connected vugs, and karst features (De Boever et al., 2016; Jiménez et al., 2024). These characteristics create complex flow pathways that can enhance injectivity while simultaneously increasing uncertainty in plume migration and long-term containment behavior (Fuentes-Cruz & Valko 2015). As a result, dual-porosity modeling constitutes a critical component of CCS assessment and subsurface energy system evaluation.

- Implications for CO₂ injectivity and storage efficiency

Fractures significantly influence CO₂ injectivity by increasing permeability and providing rapid flow pathways during injection (Fuentes-Cruz & Valko 2015; Janjuhah & Alansari 2020). In many carbonate reservoirs, fracture-dominated flow improves injectivity performance and facilitates pressure dissipation, making fractured carbonate formations attractive candidates for large-scale CO₂ storage (Tsakiroglou et al., 2009). At the same time, the matrix contributes to long-term storage through capillary trapping, dissolution trapping, and diffusion-driven transfer of CO₂ from fractures into lower-permeability pore systems (Zampetti et al., 2004). Dual-porosity and dual-permeability models are therefore widely used to evaluate the balance between rapid fracture flow and slower matrix-controlled storage processes (Zampetti et al., 2004; Wei et al., 2021). These models improve the prediction of multiphase flow behavior and pressure propagation compared with conventional single-porosity approaches (March et al., 2018). However, storage efficiency in fractured carbonate reservoirs remains highly uncertain because preferential fracture flow can lead to uneven sweep efficiency, rapid plume migration, and localized breakthrough behavior (De Boever et al., 2016). In reservoirs with connected vuggy porosity or karst systems, classical dual-porosity assumptions may oversimplify fluid migration pathways and underestimate internal matrix flow (Jiménez et al., 2024). Regardless, the prediction of long-term CO₂ distribution and storage efficiency remains strongly dependent on fracture characterization quality, matrix permeability estimation, and interporosity transfer behavior (Rahman & Pierson 2011).

- Fracture-controlled leakage and containment uncertainty

Although fractures improve injectivity, they can also create preferential leakage pathways that threaten long-term storage security (Tsakiroglou et al., 2009; Fuentes-Cruz & Valko 2015). Fracture connectivity, fault transmissibility, and caprock integrity are therefore among the primary uncertainties in carbonate CCS systems (Khalid et al., 2024). In highly fractured reservoirs, interconnected fracture corridors may facilitate rapid vertical CO₂ migration, particularly if fractures intersect sealing formations or fault systems (Koša 2015). Conventional dual-porosity models commonly simplify fracture geometry and connectivity using homogenised continuum representations (March et al., 2018). While computationally efficient, these assumptions may inadequately represent localized leakage pathways and anisotropic fracture behavior (Barenblatt et al., 1960). In addition, fracture permeability may evolve dynamically during CO₂ injection due to stress changes, geochemical reactions, and pressure buildup (Khalid et al., 2024). Many conventional dual-porosity formulations do not explicitly capture these coupled processes, potentially underestimating long-term leakage risk. Containment uncertainty is further complicated by the difficulty of accurately characterizing fracture networks at the reservoir scale (Alabere et al., 2023; Henglai et al., 2025). Fracture properties derived from borehole observations and seismic interpretation are often sparse and indirect, making reservoir-scale fracture predictions highly uncertain (Zambrano et al., 2021). Consequently, CO₂ plume migration forecasts frequently remain strongly non-unique even after extensive history matching and model calibration (De Boever et al., 2016).

- Limitations of conventional dual-porosity models for CCS applications

Despite their widespread use, conventional dual-porosity models exhibit several limitations that affect their applicability to CCS systems. One major limitation is the pseudo-steady-state assumption commonly used to represent matrix–fracture transfer behavior (Bai et al., 1994; March et al., 2018). During CO₂ injection, transient

multiphase flow conditions often dominate fluid exchange processes, particularly in reservoirs with strong microporosity development or complex pore connectivity (Jiménez et al., 2024).

Under these conditions, simplified transfer formulations may inadequately represent delayed diffusion and capillary trapping. Another important limitation is the neglect of coupled geomechanical effects. Injection-induced pressure changes can alter fracture aperture, permeability, and connectivity through stress-dependent deformation and fracture reactivation (Koša 2015; Khalid et al., 2024). Because conventional dual-porosity models frequently assume static fracture properties, they risk oversimplifying permeability evolution and containment behavior during long-term storage operations (Fuentes-Cruz & Valko 2015).

Reactive transport processes also introduce additional uncertainty. CO₂ interaction with carbonate minerals may lead to dissolution, precipitation, and porosity alteration that progressively modify flow behavior and storage capacity (Moonen & Carmeliet 2013). However, many conventional dual-porosity formulations do not explicitly incorporate these geochemical reactions or dynamically evolving pore structures (Koša 2015). As a result, long-term predictions of injectivity, plume migration, and storage security often remain uncertain.

Furthermore, in reservoirs containing multimodal pore systems, binary matrix–fracture representations may further oversimplify carbonate heterogeneity (De Boever et al., 2016; Jiménez et al., 2024). Micropores, vugs, fractures, and karst conduits often coexist within the same reservoir interval and may contribute differently to flow and storage processes (Moldabayeva et al., 2025). As a result, more advanced approaches such as MINC, DFN, and hybrid continuum–discrete models are increasingly needed to better represent complex carbonate systems (Barenblatt et al., 1960; Makhankova et al., 2021).

- Implications for other subsurface energy systems

Beyond CCS applications, dual-porosity modeling also plays an important role in geothermal energy systems, underground gas storage, hydrogen storage, and enhanced oil recovery (EOR) operations (Tsakiroglou et al., 2009; Janjuhah & Alansari 2020). In geothermal reservoirs, fractures commonly dominate heat transfer and fluid circulation, while matrix diffusion controls long-term thermal recovery behavior (Fuentes-Cruz & Valko 2015). Accurate representation of fracture connectivity is therefore essential for predicting thermal breakthrough and reservoir sustainability. Similarly, hydrogen storage in depleted carbonate reservoirs and saline formations requires reliable modeling of gas migration, containment behavior, and cyclic pressure effects (Tsakiroglou et al., 2009). Although fracture-controlled flow pathways can improve injectivity and deliverability, they can also simultaneously increase uncertainty in gas containment and caprock integrity (Khalid et al., 2024). Similar challenges occur in underground gas storage systems, where repeated injection and withdrawal cycles may alter stress conditions and fracture permeability over time. In CO₂-enhanced oil recovery (CO₂-EOR) operations, dual-porosity behavior strongly influences sweep efficiency, breakthrough timing, and matrix–fracture transfer processes (Zampetti et al., 2004). Fracture-dominated flow can improve injectivity but may also cause early gas breakthrough and reduced recovery efficiency if fracture connectivity is poorly characterized (De Boever et al., 2016). Ultimately, the reliable modeling of matrix–fracture interaction remains essential across a broad range of subsurface energy applications.

- Emerging directions and future challenges

Recent advances in machine learning, digital rock physics, and coupled multiphysics simulation have significantly enhanced the ability to model complex carbonate reservoirs and CCS systems (Shun et al., 2020; Yan et al., 2024). Machine learning approaches are increasingly used for fracture characterization, permeability prediction, uncertainty quantification, and surrogate modeling, offering substantial reductions in computational cost and simulation runtime (Shun et al., 2020).

Coupled thermal–hydraulic–mechanical–chemical (THMC) modeling frameworks are also becoming increasingly important for CCS applications because they simultaneously evaluate multiphase flow, geomechanical deformation, fracture evolution, and reactive transport processes (Chang et al., 2026). Although these approaches provide a more realistic representation of long-term reservoir behavior, they remain computationally demanding and highly dependent on data availability.

Concurrently, digital rock physics and micro-CT imaging are further improving pore-scale understanding of matrix–fracture interaction and multimodal pore connectivity (Jiménez et al., 2024; Yan et al., 2024).

Nevertheless, significant challenges remain when integrating these pore-scale observations into field-scale simulation workflows. Specifically, uncertainties in fracture characterization, scale dependency, and parameter non-uniqueness continue to limit predictive reliability in both carbonate CCS systems and broader subsurface energy applications. Ultimately, the reviewed literature demonstrates that dual-porosity modeling provides a foundational framework for evaluating fractured carbonate reservoirs in CCS and subsurface energy systems. However, substantial uncertainty remains regarding fracture connectivity, coupled physical processes, multiscale heterogeneity, and long-term storage behavior. Future developments must therefore prioritise a tighter integration of geological characterization, coupled multiphysics modeling, uncertainty quantification, and computationally efficient simulation workflows that can balance geological realism with field-scale practicality.

Table 3.
Critical Implications and Uncertainties of Dual-porosity Behavior in Carbonate CCS Systems.

CCS Aspect	Role of Dual-porosity Behavior	Major Challenge	Main Uncertainty
CO ₂ Injectivity	Fractures enhance injectivity and pressure dissipation, while the matrix contributes to storage capacity.	Preferential fracture flow may reduce sweep efficiency and create uneven plume distribution.	Fracture connectivity and permeability anisotropy.
CO ₂ Plume Migration	Matrix–fracture interaction controls short-term fracture flow and long-term matrix diffusion.	Rapid fracture-controlled migration may reduce predictability of plume evolution.	Interporosity transfer behavior and fracture-network continuity.
Storage Efficiency	Matrix porosity contributes to capillary trapping, dissolution trapping, and long-term CO ₂ retention.	Heterogeneous pore systems may produce inefficient sweep and bypassed storage zones.	Matrix permeability distribution and multimodal pore connectivity.
Containment Security	Fractures and faults strongly influence leakage potential and caprock integrity.	Connected fracture corridors may create preferential leakage pathways.	Fault transmissibility, fracture reactivation, and caprock integrity.
Pressure Evolution	Fracture systems control pressure propagation and dissipation during injection.	Pressure buildup may alter fracture permeability and induce geomechanical instability.	Stress-dependent fracture behavior and reservoir compressibility.
Reactive Transport Processes	CO ₂ –brine–rock interaction influences porosity evolution and long-term storage behavior.	Mineral dissolution and precipitation may alter permeability and flow pathways.	Geochemical reaction kinetics and coupled THMC behavior.
History Matching and Forecasting	Dual-porosity models improve simulation of fracture-dominated flow and delayed matrix drainage.	Multiple parameter combinations may produce similar simulation results.	Parameter non-uniqueness and multiscale heterogeneity.
Long-Term Storage Assessment	Matrix diffusion and residual trapping improve long-term containment potential.	Long-term prediction reliability decreases with increasing geological complexity.	Fracture evolution, uncertainty propagation, and coupled physical processes.

3.9 Comparative analysis of dual-porosity modeling applications in carbonate reservoirs

Field-scale case studies provide important validation for dual-porosity modeling approaches because they demonstrate how matrix–fracture interactions influence reservoir behavior under realistic geological conditions. In carbonate reservoirs, strong multiscale heterogeneity commonly involves fractures, vugs, microporosity, and karst systems that evolve through complex depositional and diagenetic processes (Janjubah et al., 2019; Malki et al., 2023). As such, field applications are essential for evaluating the practical reliability, uncertainty, and limitations of dual-porosity workflows in both hydrocarbon production and carbon capture and storage (CCS)

applications. The reviewed case studies from Central Luconia and Abu Dhabi collectively demonstrate that the interaction between matrix storage and fracture-dominated flow pathways strongly controls carbonate reservoir performance. They further show that successful modeling depends heavily on fracture characterization, pore-system evaluation, and appropriate model selection based on reservoir heterogeneity.

3.10 Central luconia carbonate reservoirs

The Central Luconia Province offshore Sarawak represents one of the most important carbonate provinces in Southeast Asia and serves as a major reference system for evaluating dual-porosity behavior in Miocene carbonate reservoirs (Koša 2015; Koša et al., 2015; Ismail et al., 2026). In this region, extensive carbonate build-ups are characterized by strong facies heterogeneity, microporosity development, fractures, dissolution features, and localized karst systems (Jamaludin et al., 2021; Jiménez et al., 2024; Henglai et al., 2025) (Figure 5). These geological characteristics create highly heterogeneous pore systems that strongly influence permeability distribution, storage behavior, and fluid-flow dynamics.

- Multimodal pore systems and matrix–fracture partitioning

Petrographic and petrophysical studies from Central Luconia demonstrate that microporosity contributes significantly to total reservoir storage, particularly within mud-dominated carbonate facies (Rahman & Pierson 2011; Janjuhah et al., 2019). Specifically, Janjuhah et al. (2019) conducted a detailed petrographic investigation using enhanced Digital Image Analysis (DIA) workflows to quantify microporosity development in Miocene carbonates from Central Luconia. Their results revealed that microporosity commonly accounts for 20% to 60% of total porosity, with moldic porosity representing the dominant pore type, followed by vuggy, intraparticle, interparticle, and fracture-related porosity. Furthermore, the study demonstrated that explicitly separating microporosity and macroporosity significantly improved prediction of acoustic velocity and permeability behavior compared with conventional total-porosity approaches (Janjuhah et al., 2019). These findings confirm that carbonate reservoirs in Central Luconia cannot be adequately represented using homogeneous single-porosity assumptions because storage and flow are controlled by fundamentally different pore domains. In addition, the coexistence of low-permeability matrix microporosity and highly conductive fracture–vug systems creates characteristic dual-porosity flow behavior: rapid early-stage fracture flow is followed by slower matrix drainage during later production stages (March et al., 2018; Egya et al., 2019). As a result, matrix–fracture partitioning plays a critical role in controlling production performance, pressure propagation, and reservoir forecasting reliability.

- Evaluation of modeling approaches in central luconia

Several studies from Central Luconia highlight the importance of selecting modeling approaches based on reservoir heterogeneity and fracture complexity. Conventional dual-porosity models generally perform reasonably well in fracture-dominated carbonate systems where fractures provide the primary flow pathways and the matrix mainly acts as a storage medium (Warren & Root 1963; March et al., 2018). However, in reservoirs with connected karst systems or highly heterogeneous vuggy porosity, classical dual-porosity assumptions become increasingly inadequate (Jiménez et al., 2024). To address these limitations, Trianto et al. (2026) applied a hybrid modeling workflow combining conventional carbonate matrix models with three-dimensional karst networks using Discrete Fracture Network (DFN) techniques in the JTN Carbonate Field, Central Luconia. Their workflow integrated seismic interpretation, core analysis, and petrophysical logs to construct a geological model that explicitly represents matrix–karst interactions and fluid-flow uncertainty under different karst-fill scenarios.

The study demonstrated that explicitly representing karst connectivity improved reproduction of production heterogeneity and dynamic flow behavior compared with simplified continuum approaches (Trianto et al., 2026). These findings indicate that model reliability decreases substantially when reservoirs contain deterministic heterogeneity, such as connected vugs, fracture corridors, or karst conduits, because simplified matrix–fracture assumptions cannot adequately represent them. Therefore, highly heterogeneous carbonate reservoirs require advanced workflows incorporating DFN or hybrid continuum–discrete approaches, despite their greater computational cost and calibration complexity (Cordero et al., 2019; Zambrano et al., 2021).

Figure 6 summarizes the key dual-porosity model results from Central Luconia, illustrating (a) the partitioning of porosity between matrix microporosity and fracture/vug macroporosity across multiple fields, (b) the distribution of pore types as quantified from detailed petrographic analyses, and (c–d) the improvements in velocity and permeability prediction correlations achieved through dual-porosity parameterisation. Collectively, these studies demonstrate that dual-porosity workflows significantly improve reservoir characterisation, permeability prediction, and history matching compared with conventional single-porosity approaches (Janjuhah et al., 2019; Jiménez et al., 2024; Trianto et al., 2026).

- Implications for CCS applications

The Central Luconia case studies also provide important implications for CCS because the same fracture systems that enhance hydrocarbon productivity may strongly influence CO₂ injectivity, migration, and containment behavior (March et al., 2018; Xiong et al., 2025). While fracture networks improve injectivity and pressure dissipation, matrix microporosity contributes to long-term CO₂ trapping through diffusion-controlled transfer and capillary storage processes. However, these studies also highlight substantial uncertainty related to fracture connectivity and interporosity transfer behavior (Egya et al., 2019). In reservoirs with highly conductive karst pathways or anisotropic fracture corridors, preferential CO₂ migration can reduce storage predictability and increase containment uncertainty. Consequently, these observations emphasize the importance of fracture characterization and uncertainty-aware modeling workflows for reliable CCS forecasting in fractured carbonate reservoirs.

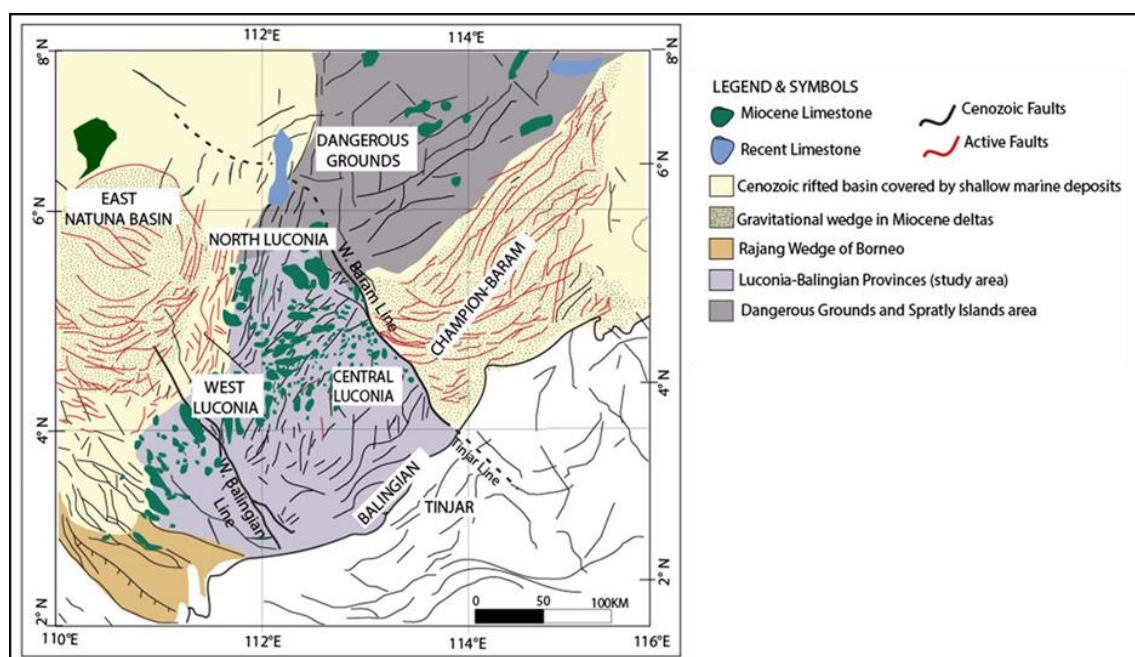


Figure 5.

Geographical location of the Central Luconia geological province and surrounding area in offshore Sarawak, Malaysia. The map shows the distribution of Miocene carbonate build-ups (shaded polygons) relative to major structural elements, shelf margins, and adjacent basinal areas. The study area represents the largest gas-producing carbonate province in Southeast Asia, providing an excellent natural laboratory for evaluating dual-porosity behavior in heterogeneous carbonate systems.

Modified from Jamaludin et al. (2021).

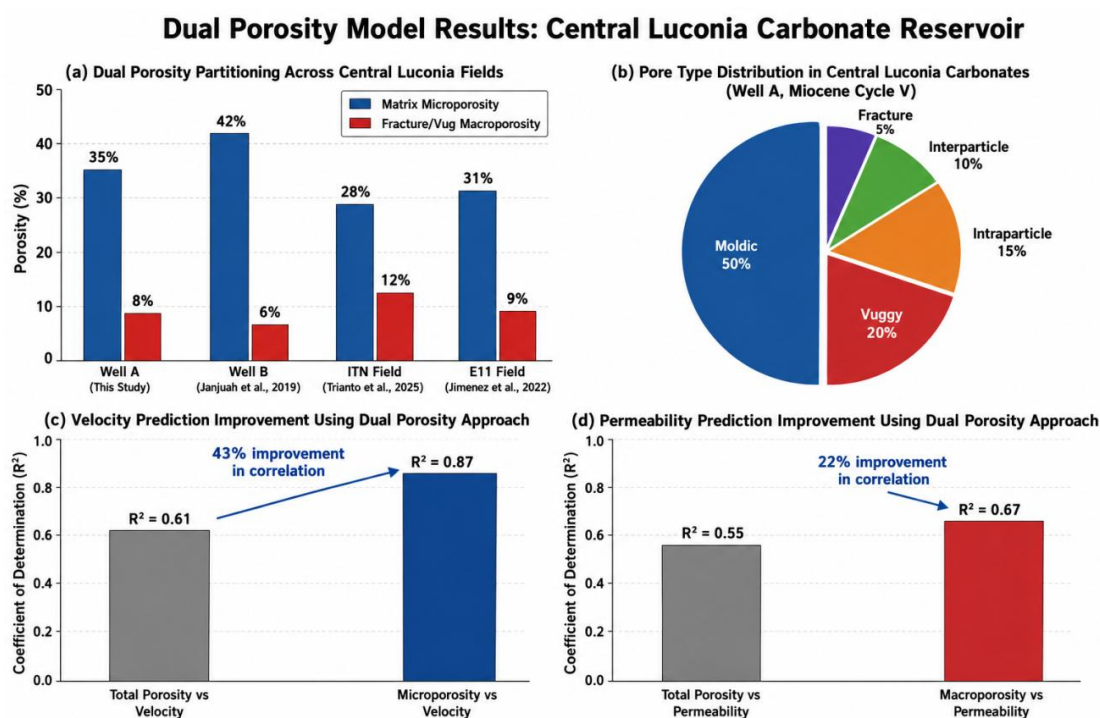


Figure 6.

Dual-porosity model results from Central Luconia carbonate reservoirs. (a) Porosity partitioning showing matrix microporosity versus fracture/vug macroporosity across different fields, illustrating the bimodal storage-flow architecture. (b) Pore type distribution from petrographic analysis of Well A (Miocene Cycle V), quantifying the relative abundance of moldic, vuggy, intraparticle, interparticle, and fracture porosity. (c) Velocity prediction improvement using microporosity-based dual-porosity approach (R^2 improved from 0.61 to 0.87), demonstrating the importance of separating microporous and macroporous domains for acoustic property estimation. (d) Permeability prediction improvement using macroporosity-based dual-porosity approach (R^2 improved from 0.55 to 0.67), confirming that explicit macroporosity characterization enhances flow property prediction. Data compiled from Janjua et al. (2019), Jiménez et al. (2024), and Trianto et al. (2026).

3.11 Global analogue: Abu Dhabi carbonate reservoirs

The Lower Cretaceous carbonate reservoirs of Abu Dhabi provide an important analogue for evaluating dual-porosity behavior in heterogeneous carbonate systems (Alabere et al., 2023; 2025). Like Central Luconia, these reservoirs exhibit strong multiscale heterogeneity controlled by depositional facies, micritisation, dissolution, stylolites, fractures, and vug development (Ehrenberg 2018; Alabere et al., 2023). Figure 7 illustrates the workflow for developing a dual-porosity model in an Abu Dhabi carbonate reservoir. Petrographic and digital rock studies from Abu Dhabi demonstrate that dual-porosity architecture is strongly facies-dependent (Alabere et al., 2023; 2025). Grain-dominated facies, such as grainstones and rudstones, commonly exhibit bimodal pore systems involving both intergranular macropores and microporosity, whereas mud-dominated facies are typically characterized by isolated micropores and fracture-dominated permeability (Alabere et al., 2023). These findings reinforce the conclusion that pore connectivity and flow behavior in carbonate reservoirs are highly sensitive to depositional textures and diagenetic evolution. Furthermore, imaging studies have revealed that pore-throat distributions become increasingly complex at higher imaging resolutions, highlighting the scale dependency of carbonate pore characterization (Jouini et al., 2023; Alabere et al., 2025).

Studies from Abu Dhabi also demonstrate that microporosity strongly influences resistivity behavior in low-resistivity carbonate intervals, whereas macroporosity exhibits a weaker correlation with the resistivity response (Alabere et al., 2023; 2025). This finding highlights a key challenge in carbonate reservoir characterization because conventional petrophysical interpretations may underestimate productive intervals if dual-porosity behavior is not explicitly considered. The Abu Dhabi analogue therefore reinforces observations from Central Luconia indicating that depositional fabrics, diagenetic overprinting, and multimodal pore systems must be explicitly integrated into dual-porosity workflows for reliable flow simulation and reservoir characterization.

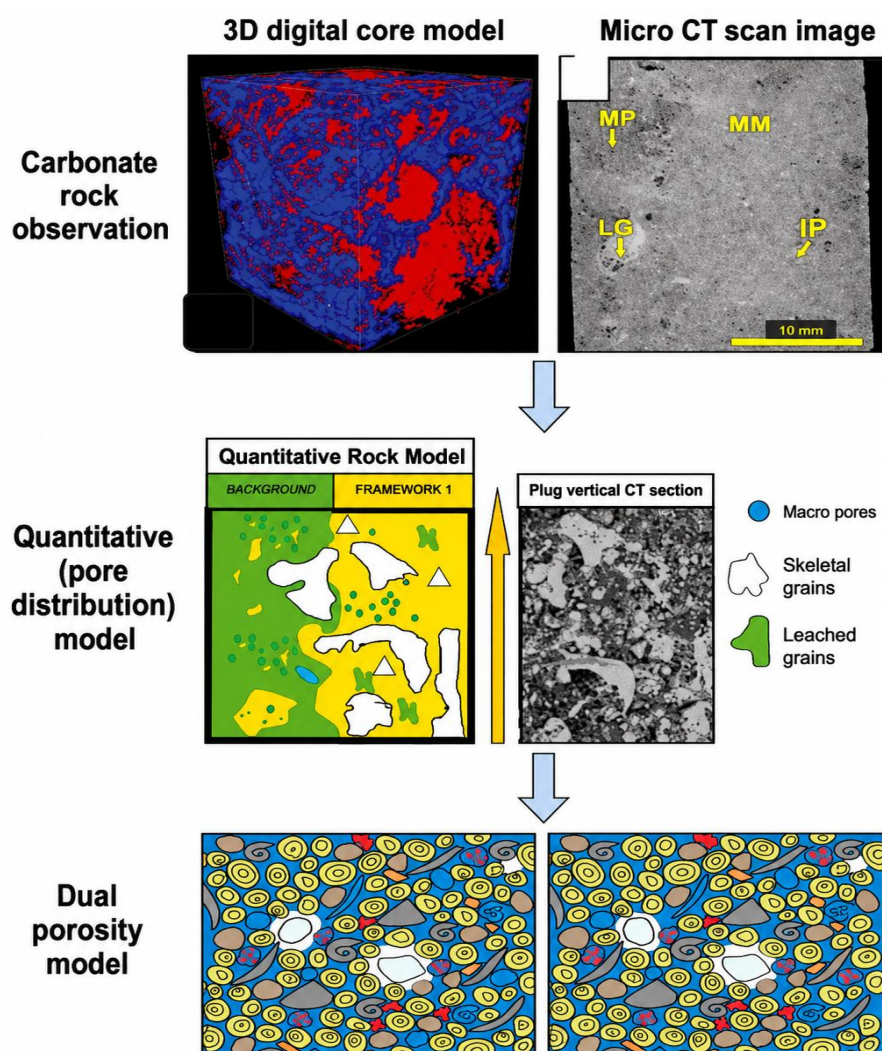


Figure 7.

Workflow for dual-porosity model development in Abu Dhabi Lower Cretaceous carbonate reservoirs. The workflow progresses from core plug selection and petrographic facies identification, through digital rock physics analysis and pore-network extraction, to upscaling of dual-porosity parameters for reservoir simulation. Key steps include thin-section petrography, SEM imaging, MICP analysis, micro-CT scanning, and permeability simulation, culminating in calibrated matrix–fracture transfer functions. Modified from Alabere et al. (2023).

3.12 Comparative evaluation of case study findings

The reviewed case studies collectively demonstrate that dual-porosity modelling substantially improves conventional single-porosity approaches for heterogeneous carbonate reservoirs. Across both the Central Luconia and Abu Dhabi systems, dual-porosity workflows improve the characterisation of multiscale pore systems, permeability prediction, and dynamic reservoir behaviour by explicitly separating matrix storage from fracture-dominated flow pathways (March et al., 2018; Janjuhah et al., 2019; Alabere et al., 2023). Nevertheless, the studies also reveal several recurring limitations. First, model reliability remains strongly dependent on fracture characterisation quality, as fracture connectivity exerts a major control on flow behaviour, pressure propagation, and injectivity (Berkowitz 2002; Egya et al., 2019). As such, sparse fracture observations and scale-dependent heterogeneity frequently produce non-unique interpretations during history-matching and uncertainty analysis. Second, conventional binary matrix–fracture representations often oversimplify multimodal carbonate pore systems (Zambrano et al., 2021; Jiménez et al., 2024). In reservoirs containing connected vugs, karst features, or extensive microporosity development, advanced approaches such as dual permeability, DFN, MINC, or hybrid

continuum–discrete workflows generally provide more realistic simulation behaviour than classical dual-porosity models (Nguyen et al., 2018; Cordero et al., 2019). Third, these reviewed case studies demonstrate a persistent trade-off between geological realism and computational practicality. Advanced workflows incorporating DFN and hybrid approaches improve the fracture-geometry representation and localised flow pathways but require significantly greater computational resources and more detailed characterisation datasets (Zambrano et al., 2021). Dual-porosity models are particularly effective in highly fractured carbonate reservoirs. For instance, Putra et al. (2026) demonstrated through seismic inversion in the Natuna Basin that separating matrix storage from fracture flow pathways provides more realistic reservoir characterization, directly supporting dual-porosity modelling assumptions. Therefore, selecting an appropriate modelling approach remains strongly dependent on reservoir complexity, data availability, and simulation objectives. The reviewed field applications demonstrate that no single modelling framework is universally applicable to all carbonate reservoirs. Instead, effective simulation requires workflows capable of integrating multiscale geological characterisation, petrophysical analysis, fracture-network evaluation, and uncertainty-aware dynamic calibration within reservoir-specific modelling frameworks.

3.13 Challenges and future research directions in dual-porosity modeling for carbonate reservoirs and CCS systems

Despite major advances in carbonate reservoir characterization and dual-porosity simulation, significant challenges remain in accurately representing the complex interactions among matrix storage, fracture-controlled flow, and multiscale heterogeneity (De Boever et al., 2016; Jiménez et al., 2024). Carbonate reservoirs commonly feature highly heterogeneous pore architectures involving fractures, vugs, micropores, and karst systems that evolve across multiple spatial scales and strongly influence fluid-flow behavior (Janjubah et al., 2019; Henglai et al., 2025). As a result, these complexities introduce substantial uncertainty into reservoir characterisation, permeability prediction, history matching, and long-term forecasting for both hydrocarbon production and CCS applications. The reviewed literature demonstrates that, although dual-porosity modeling remains a widely applied approach for fractured carbonate systems, no single modeling framework is universally applicable to all carbonate reservoirs. Instead, model performance depends strongly on fracture characterization quality, pore-system complexity, data integration strategy, and simulation objectives. Future research must therefore focus on reducing uncertainty, improving multiscale integration, and developing more physically realistic and computationally efficient simulation frameworks.

- Fracture characterization and connectivity uncertainty

One of the largest unresolved challenges in carbonate reservoir simulation is the accurate characterization of fracture networks and connectivity (Berkowitz 2002; Egya et al., 2019). Fractures commonly dominate permeability and fluid migration in carbonate reservoirs; however, fracture properties are typically inferred indirectly from limited datasets such as cores, borehole image logs, seismic interpretation, and production responses (Alabere et al., 2023; Henglai et al., 2025). Because these datasets often provide localized or low-resolution information, reservoir-scale prediction of fracture continuity and connectivity remains highly uncertain. In many carbonate reservoirs, fracture corridors, karst conduits, and fault-associated fracture systems create strongly anisotropic flow behavior that simplified continuum assumptions cannot adequately represent (Zambrano et al., 2021; Jiménez et al., 2024). Consequently, uncertainty in fracture geometry often propagates into pressure predictions, sweep efficiency estimations, and CO₂ plume migration forecasts (March et al., 2018). Although Discrete Fracture Network (DFN) and hybrid continuum–discrete approaches improve fracture realism, their computational expense and strong dependence on detailed fracture characterization datasets (Nguyen et al., 2018) remain a challenge. Future research should therefore focus on integrating multiscale fracture characterization techniques, combining seismic interpretation, digital rock analysis, high-resolution imaging, and uncertainty-aware modeling workflows. Automated fracture extraction and machine learning-assisted fracture identification may also improve characterization efficiency and reduce interpretation uncertainty in highly heterogeneous carbonate systems (Shun et al., 2020; Yan et al., 2024).

- Challenges in multiscale pore-system representation

Conventional dual-porosity models are fundamentally based on binary separation between matrix storage and fracture flow (Warren & Root 1963; March et al., 2018). However, many carbonate reservoirs exhibit far

more complex pore architectures with micropores, vugs, interparticle pores, fractures, and karst systems coexisting within the same reservoir interval (Janjuhah et al., 2019; Jiménez et al., 2024). These multimodal pore systems often display strong facies dependence and scale-dependent connectivity that simplified matrix–fracture assumptions cannot adequately represent. Microporosity presents a particularly important challenge because it contributes significantly to storage capacity while exhibiting extremely low permeability and delayed fluid-transfer behavior (Rahman & Pierson 2011; Janjuhah et al., 2019). Similarly, connected vuggy porosity and karst conduits may contribute directly to flow behavior rather than acting purely as storage domains (Jiménez et al., 2024). As a result, classical dual-porosity models may oversimplify internal matrix flow and underestimate preferential flow pathways in highly heterogeneous carbonate systems. Future developments should therefore focus on advanced multiscale modeling approaches capable of representing dynamically connected pore systems more realistically. Hybrid workflows combining dual-porosity, dual-permeability, MINC, DFN, and digital rock physics may provide improved representation of multiscale carbonate heterogeneity (Nguyen et al., 2018; Cordero et al., 2019; Makhankova et al., 2021). However, balancing geological realism with computational practicality remains a major challenge, especially for full-field applications with limited computational resources.

- Interporosity transfer and history matching uncertainty

The interporosity transfer coefficient (α) remains among the most uncertain parameters in dual-porosity simulation because it controls fluid exchange between the matrix and fracture domains (Rahman & Pierson 2011; Wei et al., 2021). Although α can be estimated using laboratory measurements, analytical solutions, or history matching, it cannot be directly measured at the reservoir scale. Consequently, multiple parameter combinations may reproduce similar production behavior, creating significant non-uniqueness during model calibration (De Boever et al., 2016). This uncertainty becomes particularly severe in reservoirs containing multimodal pore systems or complex fracture connectivity because matrix–fracture interaction may vary spatially and temporally throughout the reservoir (Jiménez et al., 2024). In addition, simplified pseudo-steady-state transfer assumptions commonly used in conventional dual-porosity formulations may also inadequately represent transient flow conditions during CO₂ injection and long-term matrix drainage (March et al., 2018). Future research may benefit from developing more physically representative transfer functions that incorporate pore geometry, wet ability, capillary forces, and dynamically evolving fracture behavior. Machine learning approaches may additionally improve history matching efficiency, surrogate modeling, and uncertainty quantification during large-scale reservoir calibration workflows (Shun et al., 2020).

Computational challenges and advanced simulation workflows increasing geological realism generally comes at the expense of computational efficiency. Advanced simulation approaches such as DFN, MINC, and coupled multiphysics models require high-resolution gridding, large computational resources, and complex numerical coupling schemes (Nguyen et al., 2018; Alabere et al., 2025). These requirements often limit the practical feasibility of uncertainty quantification, probabilistic forecasting, and large-scale field simulation in routine commercial workflows. Although hybrid continuum–discrete workflows better represent fracture-controlled flow behavior, they introduce additional challenges related to fracture upscaling, grid refinement, and numerical convergence (Zambrano et al., 2021). Furthermore, coupling geological characterization, geomechanics, reactive transport, and multiphase flow within a unified simulation framework remains computationally demanding, particularly for long-term CCS forecasting. Future developments should therefore prioritize reduced-order modeling, surrogate simulation methods, and high-performance computing techniques that improve simulation efficiency while preserving geological realism. Integration of machine learning approaches with conventional physics-based workflows may further improve computational scalability and reservoir forecasting capability, particularly for uncertainty quantification, history matching, and long-term CCS risk forecasting (Shun et al., 2020; Yan et al., 2024).

Challenges in CCS Forecasting and Long-Term Containment Assessment Carbon, capture, and storage (CCS) applications introduce additional complexities beyond conventional hydrocarbon reservoir simulation because long-term storage security depends strongly on fracture behavior, caprock integrity, reactive transport processes, and pressure evolution (Fuentes-Cruz & Valko 2015; Xiong et al., 2025). In fractured carbonate reservoirs, fractures improve CO₂ injectivity and pressure dissipation but may simultaneously create

preferential leakage pathways that are difficult to characterize and predict (Khalid et al., 2024). Many conventional dual-porosity workflows only partially incorporate coupled thermal–hydraulic–mechanical–chemical (THMC) processes, and even when THMC models are applied, their implementation is often limited to research-scale studies rather than routine field-scale commercial workflows (Chang et al., 2026). To improve practical CCS forecasting, these THMC models should be linked with 4D seismic monitoring, pressure data, tracer tests, and history-matched plume observations to validate long-term containment predictions. Future research should also focus on developing reduced- order THMC models that balance physical realism with computational tractability for probabilistic CCS risk assessment. Merging Research Directions Recent advances in digital rock physics, micro-CT imaging, artificial intelligence, and uncertainty-aware simulation workflows are significantly enhancing the future of carbonate reservoir modeling (Shun et al., 2020; Yan et al., 2024; Alabere et al., 2025). Three priority areas stand out for near-term research.

First, digital rock approaches now provide increasingly detailed visualisation of pore connectivity and fluid-flow pathways at micron-scale resolution, which improve the understanding of matrix–fracture interaction and multimodal pore behavior (Alabere et al., 2025). However, the primary unsolved challenge remains upscaling these pore-scale observations to field-scale dual-porosity parameters in a way that preserves representative connectivity, relative permeability functions, and flow behavior across scales. Bridging this gap requires the systematic development of upscaling workflows that integrate digital rock physics with reservoir-scale simulation grids while honoring geological heterogeneity.

Second, machine learning methods are increasingly applied to fracture detection, permeability prediction, lithofacies classification, automated history matching, and surrogate modeling (Shun et al., 2020). These approaches offer potential improvements in computational efficiency and uncertainty quantification, particularly when integrated with conventional physics-based simulation workflows. However, their success depends heavily on training-data quality, feature engineering, and the physical interpretability of the results. Future work should focus on hybrid physics-informed neural networks that embed conservation laws directly into the learning architecture, thereby improving generalisability beyond the training dataset.

Third, an important emerging direction involves the development of adaptive and continuously updated reservoir modeling workflows capable of incorporating newly acquired geological and dynamic reservoir data during production or CO₂ injection operations sometimes referred to as closed-loop reservoir modeling or data assimilation. In such workflows, static geological models are dynamically updated with real-time pressure, saturation, and 4D seismic data to reduce forecast uncertainty progressively. This approach is particularly promising for long-term CCS operations, where monitoring data accumulate over decades and can be used to refine containment risk assessments iteratively. Ultimately, future progress in dual-porosity modeling will likely depend on tighter integration of multiscale characterization, uncertainty-aware workflows, coupled multiphysics simulation, and computationally efficient modeling strategies capable of balancing geological realism with practical field-scale implementation.

4. Conclusion

This review critically evaluated the characterization techniques, modeling approaches, integrated workflows, and field-scale applications of dual-porosity modeling in carbonate reservoirs, with particular emphasis on carbon capture and storage (CCS). As a foundation, the synthesis confirms that carbonate reservoirs remain among the most difficult geological systems to characterize and simulate because they exhibit multiscale heterogeneity spanning from tiny micropores to large fractures, vugs, and karst conduits. This complex coexistence of variable pore and fracture geometries governs fluid exchange between the matrix and fracture domains, as well as permeability distributions, fluid migration pathways, and long-term reservoir behavior. Regarding the current state of knowledge, dual-porosity modeling remains the most widely adopted framework for fracture-dominated carbonate flow, yet the reviewed literature exposes several unresolved contradictions. Conventional dual-porosity and dual-permeability models are computationally efficient and reproduce fracture-controlled behavior in systems where the matrix acts mainly as a storage domain; however, they become physically inadequate in reservoirs with connected vugs, karst networks, or multimodal pore structures. Although advanced formulations such as dual-

permeability, MINC, DFN, and hybrid continuum–discrete workflows improve geological realism, the literature remains divided regarding the optimal balance among accuracy, data demands, and computational tractability. While the Warren-Root model has been successfully implemented in modern commercial fluid flow reservoir simulators, the implementation of DFN and MINC approaches in future commercial simulators remains an active area of development. Several commercial platforms have begun incorporating DFN modules, and MINC-type approaches are available in research simulators, suggesting a trajectory toward greater adoption as computational capabilities improve.

Because greater fracture explicitness raises computational costs and parameter non-uniqueness, no single framework is universally applicable, and this tension between representational fidelity and practical solvability remains the central unresolved debate in the field.

Several gaps consistently emerged across the reviewed studies and the Central Luconia and Abu Dhabi case analyses. Matrix–fracture transfer functions remain poorly constrained and are frequently calibrated non-uniquely through history-matching. Fracture connectivity and multimodal pore partitioning are also inconsistently characterized across scales, and workflows integrating static geological descriptions with dynamic simulations are still immature. For CCS specifically, the dual role of fractures—which enhance CO₂ injectivity but amplify uncertainty in plume migration and long-term containment—has not been resolved within conventional dual-porosity assumptions, and long-term coupled trapping mechanisms remain insufficiently validated against field-scale monitoring data.

Methodologically, the review identified core and petrophysical analyses, well-log and borehole-imaging interpretations, seismic and dynamic (pressure-transient) characterisation, and digital rock physics as the principal techniques underpinning dual-porosity workflows. Although each method resolves heterogeneity at a distinct scale, they are seldom integrated coherently. Future progress will therefore depend on a tighter multiscale integration of these techniques with digital rock physics, machine learning-assisted characterization and history matching, formal uncertainty quantification, and coupled thermal–hydraulic–mechanical–chemical (THMC) simulations capable of balancing geological realism with field-scale practicality. Ultimately, prioritising uncertainty-aware, data-integrated workflows over single-continuum idealisations offers the most promising path toward reliable forecasting for both hydrocarbon recovery and secure CO₂ storage in carbonate reservoirs.

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6. Declarations

6.1 Author contributions

Khalisha Shafa Yumnanisa: Conceptualization, methodology, investigation, writing – original draft, visualization. Siti Nur Fathiyah Jamaludin: Supervision, conceptualization, writing – review and editing, funding acquisition. Numair Ahmed Siddiqui: Writing – review and editing, validation. Jun Matsushima: Writing – review and editing, resources. Alidu Rashid: Writing – review and editing, resources. Jamaluddin: Writing – review and editing, resources. The authors declare that this manuscript is original, has not been published previously, and is not under consideration for publication elsewhere. All authors have approved the final version of this manuscript and agree to its submission to Scientific Contributions Oil and Gas (SCOG).

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6.3 Competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

6.4 The use of AI or AI-assisted technologies

During the preparation of this work, the authors used generative AI tools for language editing, grammar checking, and structural formatting assistance. After using these tools, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

7. Glossary of terms and symbols

Terms & Symbol	Definition	Unit
α (alpha)	Interporosity transfer coefficient governing fluid exchange between matrix and fracture domains [m^{-2}]	-
Bimodal pore system	Reservoir pore architecture characterized by two distinct populations of pore sizes (typically micropores and macropores/vugs)	-
Capillary trapping	Mechanism by which CO_2 is immobilized in pore spaces by capillary forces during multiphase flow	-
CCS	Carbon Capture and Storage; the process of capturing CO_2 emissions and storing them in subsurface geological formations	-
DFN	Discrete Fracture Network; a modeling approach representing individual fractures as explicit geometric features	-
Diagenesis	Post-depositional chemical and physical processes that modify sedimentary rocks, including dissolution, cementation, and dolomitization	-
DIA	Digital Image Analysis; computational technique for quantifying pore geometry and connectivity from thin-section images	-
Dissolution trapping	Long-term CO_2 storage mechanism involving dissolution of CO_2 into formation brine	-
DPM	Dual-Permeability Model; formulation allowing simultaneous Darcy flow in both matrix and fracture continua	-
DRP	Digital Rock Physics; computational methods simulating fluid flow and transport properties on digital representations of rock microstructure	-
EOR	Enhanced Oil Recovery; techniques used to increase the amount of crude oil extracted from reservoirs	-
FMI	Formation MicroImager; borehole logging tool providing high-resolution electrical images of the borehole wall	-
Full-field simulation	Reservoir simulation covering the entire producing area rather than a sector or pattern	-
History matching	Process of adjusting reservoir model parameters until simulated production behavior matches observed field data	-
Homogenization	Upscaling approach averaging small-scale heterogeneities into effective continuum properties	-
Hybrid model	Simulation framework combining continuum dual-porosity formulations with explicit discrete fracture representations	-
Interporosity flow	Fluid transfer between matrix and fracture pore systems	-
Karst	Terrain characterized by dissolution features such as caves, conduits, and vugs formed by chemical weathering of carbonate rocks	-
MICP	Mercury Injection Capillary Pressure; laboratory technique measuring pore throat size distribution	-
MICP	Mercury Injection Capillary Pressure; laboratory technique for measuring pore throat size distribution and capillary entry pressure	-
MINC	Multiple Interacting Continua; method subdividing matrix blocks into nested shells to capture transient exchange behavior	-
NMR	Nuclear Magnetic Resonance; logging and laboratory technique for evaluating pore-size distribution and fluid properties	-
Non-uniqueness	Condition where multiple combinations of model parameters produce equally acceptable simulation results	-
Pseudo-steady-state	Assumption that matrix–fracture transfer rate is proportional to the instantaneous pressure difference between domains	-
PTA	Pressure Transient Analysis; interpretation of pressure build-up or draw-down data to infer reservoir properties	-

RCAL / RCA	Routine Core Analysis; standard laboratory measurements of porosity, permeability, and grain density on core plugs	-
REV	Representative Elementary Volume; smallest volume over which a measurement can be made that yields a value representative of the whole	-
SCAL	Special Core Analysis; advanced laboratory measurements including relative permeability, capillary pressure, and wettability	-
THMC	Thermal–Hydraulic–Mechanical–Chemical; coupled multiphysics framework incorporating heat transfer, fluid flow, geomechanics, and geochemistry	-
Time-lapse (4D) seismic	Repeated 3D seismic surveys acquired at different times to monitor reservoir changes during production or injection	-
Transient flow	Flow regime where pressure and saturation distributions change with time, not yet reaching equilibrium	
Upscaling	Process of transferring measurements or simulation results from a fine scale to a coarser simulation grid	
Vug	Large dissolution pore in carbonate rocks, typically much larger than matrix interparticle pores	
Warren-Root model	Classical dual-porosity formulation assuming uniformly distributed fractures surrounding cubic matrix blocks with pseudo-steady-state transfer	
Wellbore	Drilled hole used for hydrocarbon production, fluid injection, or data acquisition	

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