

C0₂ STORAGE IN DEPLETED OIL RESERVOIRS USING CMG



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**A PROJECT SUBMITTED TO THE DEPARTMENT OF PETROLEUM
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CERTIFICATION

This is to certify that this research project was carried out by **ATAIRU ABDULBAQI DANESI** with matriculation number **ENG2002600** in the Department of Petroleum Engineering at the University of Benin, Benin city, Edo state Nigeria.

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DEDICATION

I dedicate this work to Almighty Allah, my source of inspiration, strength, wisdom, knowledge and understanding and to the two most significant women in my life, my mother and oldest sister. I don't say it or show it as I should but I really do mean it, Thank you.

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ABSTRACT

Worldwide efforts to reduce carbon emissions require technologies that can substantially decrease human-caused CO₂ releases while preserving energy reliability. Carbon Capture and Storage (CCS) presents an interim solution by capturing carbon dioxide from industrial facilities and storing it permanently underground in geological structures. This study examines the viability of storing CO₂ in a typical depleted oil field in Nigeria's Niger Delta Basin using sophisticated compositional modeling through Computer Modelling Group (CMG) software. A detailed three-dimensional reservoir model was constructed using geological, rock property, and production data to simulate extended-term CO₂ injection, plume movement, and entrapment patterns. The research assesses actual storage volumes, injection limitations, pressure changes, and the roles of various trapping methods—including structural containment, residual entrapment, dissolution, and mineralization—across a century-long timeframe. Findings show storage capacity ranging from 5.5 to 11.2 million tonnes of CO₂ with pressure remaining safely under fracture thresholds, confirming reliable containment with negligible escape potential. Parameter studies demonstrate that variations in rock permeability, remaining oil content, and injection speeds significantly affect storage performance and CO₂ distribution patterns. The results validate that Nigeria's depleted petroleum reservoirs offer suitable geological and technical conditions for secure, effective carbon sequestration. This research provides a simulation-driven methodology for nationwide CCS implementation, advancing Nigeria's progression toward reduced-carbon energy systems and adherence to global climate commitments.

CHAPTER ONE

INTRODUCTION

1.1 Background of the Study

Global climate change represents one of humanity's most pressing challenges, driven primarily by anthropogenic carbon dioxide (CO₂) emissions from fossil fuel combustion and industrial processes.

Carbon Capture and Storage (CCS) emerges as an essential bridging technology enabling continued fossil fuel utilization while constraining atmospheric emissions (Johnson & Lee, 2019). CCS encompasses capturing CO₂ from concentrated sources such as power plants and industrial facilities, transporting compressed gas via pipelines or ships, and permanently injecting it into deep geological formations (Ola et al., 2022) for millennial-scale storage. Without CCS, achieving climate targets becomes substantially more expensive or potentially infeasible, particularly for hard-to-abate sectors including cement production, steel manufacturing, and chemical processing where alternatives remain limited or economically prohibitive.

Among geological storage options—deep saline aquifers, unmineable coal seams, and depleted hydrocarbon reservoirs—the latter offers most practical near-term opportunities. Depleted oil and gas fields provide proven containment capability demonstrated by hydrocarbon retention over millions of years, extensive characterization from decades of production operations reducing uncertainty, existing infrastructure enabling cost-effective repurposing, and depleted pressure creating "buffer" for safe injection without exceeding formation fracture thresholds. Global storage capacity in depleted reservoirs is estimated at 675-900 gigatonnes, sufficient for several decades of large-scale CCS deployment. Economic advantages prove compelling: well conversion costs fraction of new drilling expenses, surface facilities require modest modifications, established land access and permits streamline development, and when combined with Enhanced Oil Recovery (Smith et al., 2020) (EOR), CO₂ injection can generate revenue offsetting storage costs.

Nigeria, Africa's largest petroleum producer with over six decades of hydrocarbon development, possesses substantial potential for CO₂ storage in depleted reservoirs. The Niger Delta Basin contains more than 300 oil and gas fields, many approaching or reaching economic depletion after

20-40 years of production. These mature assets represent both environmental liability—through continued low-productivity operations and eventual abandonment—and strategic opportunity for sustainable repurposing as carbon storage infrastructure.

The Niger Delta Basin exhibits highly favorable geological characteristics for CO₂ storage. Reservoir depths typically range 2,000-3,500 meters, ensuring supercritical CO₂ conditions (critical point: 31.1°C, 7.38 MPa) with appropriate temperatures (80-110°C) and pressures. Structural closures and stratigraphic traps throughout the basin prevent lateral migration, while extensive petroleum infrastructure including thousands of wells, pipeline networks, offshore platforms, and processing facilities offers potential for cost-effective repurposing.

Despite Nigeria having many depleted oil reservoirs, only a limited number of thorough studies have assessed their potential and capacity for CO₂ storage. Important uncertainties—such as reservoir heterogeneity, wellbore integrity, fault systems, and long-term geomechanical stability—remain inadequately explored, even though they are crucial for ensuring safe storage and reducing leakage risks. To address these challenges, advanced reservoir simulation tools like those from the Computer Modelling Group (CMG) are extremely valuable. CMG enables researchers to model CO₂ injection processes, estimate storage capacity, evaluate trapping mechanisms, and analyze risks including plume migration and potential leaks.

CMG-GEM simulator accurately captures complex phase behavior, multiphase flow with hysteresis effects, dissolution processes, and coupled geomechanical responses essential for predicting long-term storage performance and safety. Applying these proven methodologies to Nigerian depleted reservoirs addresses critical knowledge gaps while establishing technical foundation for commercial-scale implementation.

1.2 Statement of the Problem

Nigeria faces a dual challenge: meeting growing energy demands while fulfilling international climate commitments.

As numerous Niger Delta oil fields reach economic depletion after decades of production, strategic questions emerge regarding optimal management of these mature assets. Traditional approaches—

continued marginal production or permanent abandonment—represent missed opportunities for sustainable value creation. Depleted reservoirs could serve dual purposes: addressing climate obligations through carbon storage while potentially enhancing residual oil recovery, thereby extending economic life and employment while reducing emissions intensity.

However, critical uncertainties impede deployment. Actual storage capacity accounting for realistic operational and geological constraints remains poorly quantified—theoretical volumetric estimates provide insufficient basis for investment decisions or policy development. Long-term CO₂ behavior including plume migration patterns, pressure evolution, and containment security lacks rigorous modeling specific to Niger Delta geological conditions. Trapping mechanism evolution from mobile to permanently immobilized forms over decadal to centennial timescales requires quantification for demonstrating storage permanence to regulators and stakeholders. Geomechanical risks including caprock integrity, fault reactivation potential, and induced seismicity need systematic assessment given the tectonically active setting. Optimal injection strategies balancing storage efficiency with safety and economic considerations remain undefined.

Without comprehensive simulation-based assessment addressing these uncertainties, Nigeria cannot confidently advance CCS deployment, potentially missing strategic opportunities to leverage existing petroleum infrastructure and expertise for climate mitigation while international CCS markets and carbon credit mechanisms develop. This research gap constrains policy development, regulatory framework design, commercial strategy formulation, and stakeholder confidence—all prerequisites for successful implementation.

1.3 Aim and Objectives

1.3.1 Aim

The aim of this research is to comprehensively evaluate CO₂ storage potential in a representative Niger Delta depleted oil reservoir using advanced Computer Modelling Group (CMG) simulation, establishing technical feasibility, quantifying capacity and risks, and developing operational recommendations applicable to regional-scale deployment.

1.3.2 Specific Objectives

1. Construct a comprehensive CMG-based reservoir simulation model of a representative Niger Delta depleted oil field (Field X) incorporating geological structure from seismic interpretation, petrophysical heterogeneity from well logs and core data, fluid properties from laboratory analysis, and 20-year production history for calibration.
2. Evaluate dynamic CO₂ storage capacity through compositional simulation accounting for injectivity constraints from formation properties, pressure limitations from geomechanical considerations, residual hydrocarbon effects on available pore volume, and operational timeframes (30-50 year injection scenarios).
3. Predict long-term CO₂ plume migration and pressure evolution over 100-year simulation horizons, mapping spatial-temporal saturation distribution, identifying preferential flow pathways influenced by heterogeneity, and assessing arrival times at monitoring locations and reservoir boundaries.
4. Quantify contributions of multiple trapping mechanisms to storage security, including structural trapping (mobile CO₂ beneath caprock), residual capillary trapping (immobilized ganglia), solubility trapping (dissolved in brine), and mineral trapping (carbonate precipitation), as functions of time and operational strategy.
5. Assess geomechanical integrity and containment risks through integrated fluid flow-stress analysis, evaluating caprock breakthrough potential using CO₂-specific entry pressures, fault reactivation likelihood under injection-induced stress changes, and potential leakage pathways through abandoned wells or fracture networks.
6. Conduct comprehensive sensitivity analysis evaluating effects of uncertain parameters including permeability heterogeneity, residual oil saturation, relative permeability hysteresis, injection rates, well configurations, and caprock properties on storage performance, capacity, and safety metrics.
7. Develop operational recommendations for safe, efficient CO₂ storage in Nigerian depleted oil reservoirs, including optimal injection strategies (rates, well patterns, pressure management), monitoring protocols, risk mitigation measures, and economic considerations applicable to field-scale implementation and regional extrapolation.

1.4 Significance of the Study

This research delivers multiple contributions advancing scientific knowledge, technical practice, and policy development:

Scientific Contributions: This study provides the first comprehensive dynamic simulation assessment of CO₂ storage in Nigerian depleted oil reservoirs using industry-standard CMG compositional modeling. It extends understanding of trapping mechanism evolution in oil-bearing systems with residual hydrocarbons—an understudied configuration compared to saline aquifers and gas reservoirs dominating existing literature. The research demonstrates application of advanced hysteresis modeling, geomechanical coupling, and long-term prediction methodologies to African geological conditions, contributing methodological improvements transferable to similar basins globally.

Technical Applications: Results quantify storage capacity with realistic consideration of operational and geological constraints, informing national CCS deployment planning and site selection. The study establishes simulation workflows applicable to additional Niger Delta fields, enabling systematic regional assessment of 200+ potentially suitable reservoirs. Sensitivity analysis identifies critical parameters requiring detailed characterization, guiding data acquisition priorities for future projects. Operational recommendations on injection strategies, well configurations, and pressure management provide actionable guidance for pilot and commercial-scale implementation.

Policy and Regulatory Development: Findings support evidence-based policy formulation for Nigeria's climate commitments, demonstrating technical viability of leveraging existing petroleum infrastructure for emission reductions. The research informs regulatory framework design including site selection criteria, operational standards, monitoring requirements, and long-term stewardship protocols adapted to Nigerian context. Economic analysis of capacity versus infrastructure requirements guides investment planning and commercial strategy development. International comparisons benchmark Nigerian potential against established projects, supporting technology transfer and capacity building initiatives.

Regional and Economic Implications: Demonstrating 5.5-11.2 million tonnes capacity in a single representative field, with extrapolation suggesting 500-1,500 million tonnes aggregate Niger Delta potential, positions Nigeria as a significant West African carbon storage hub. This capacity could accommodate 15-45 years of national industrial emissions, supporting Just Energy Transition commitments while prolonging petroleum sector value and employment during renewable energy scaling. Potential revenue from carbon credits or storage services creates new economic opportunities for petroleum companies and communities. Infrastructure reuse delivers 40-60% cost advantages versus greenfield development, improving commercial viability.

Environmental and Social Benefits: Successful CCS deployment enables Nigeria to meet Paris Agreement targets while maintaining energy security and economic development. Reduced gas flaring directly improves air quality in petroleum-producing regions, delivering immediate health benefits to local communities. Demonstrated safe, permanent CO₂ storage addresses public concerns about climate technology deployment. Job creation through CCS operations, monitoring, and research provides economic opportunities in petroleum regions facing production decline. International carbon finance mechanisms could mobilize funding for broader sustainable development initiatives.

1.5 Scope and Limitations

1.5.1 Scope

This research focuses specifically on geological CO₂ storage in a representative Niger Delta depleted oil reservoir(Field X) characterized by: onshore/shallow offshore location at 2,450 meters depth, fluvial-deltaic sandstone lithology with marine shale caprock, 85 million stock tank barrels original oil in place with 42% recovery, and 20 years production history (1985-2005). The study employs CMG-GEM compositional simulation over 100-year horizons (30-year injection, 70-year post-injection monitoring) with geological model resolution of 50×50×15 grid cells (37,500 total) at 100-meter lateral dimensions.

Analysis encompasses dynamic capacity evaluation, plume migration prediction, pressure evolution modeling, multi-mechanism trapping quantification, and geomechanical risk assessment through integrated simulation . Sensitivity analysis examines ten parameters including injection

rates (250-1,000 tonnes/day), well configurations (1-4 wells), permeability variations (0.5-2.0× base case), residual oil saturations (0.20-0.35), and hysteresis effects. Results apply directly to Field X and by extension to similar depleted reservoirs in the Niger Delta Basin (2,000-3,500 meter depths, sandstone lithologies, analogous production histories).

1.5.2 Limitations

Geological Limitations: Heterogeneity captured only at 100-meter grid scale; sub-seismic features including small faults, fracture networks, and meter-scale property variations remain unresolved. Static properties assumed constant during injection; stress-dependent permeability, clay swelling, and fines migration (Ola et al., 2022) neglected. Diagenetic alterations from prolonged CO₂-rock interaction simplified to dissolution effects without detailed reactive transport modeling.

Fluid Modeling Constraints: Simplified five-component compositional model (CO₂, C1, C2-6, C7+, H₂O) balances accuracy with computational efficiency but loses detail on intermediate components. Geochemical reactions limited to CO₂ dissolution and basic mineral equilibrium; complex precipitation kinetics, secondary mineralization, and pH-dependent reactions treated conservatively. Salt precipitation near injection points neglected despite potential for localized permeability impairment.

Numerical Considerations: IMPES (implicit pressure, explicit saturation) formulation exhibits stability constraints at very high injection rates requiring timestep reduction. Grid-scale numerical dispersion artificially smears sharp saturation fronts, potentially affecting detailed plume geometry. Upscaling from fine-scale geological models to simulation grid introduces averaging errors that may underestimate connectivity or barrier effects.

Operational Assumptions: CO₂ purity maintained at 95% without contamination effects; actual captured streams contain 1-10% impurities (N₂, O₂, H₂S, SO_x) affecting density, viscosity, and corrosivity. Constant injection temperature (40°C) assumed; actual wellbore heat transfer and Joule-Thomson cooling neglected. Continuous operation without mechanical failures, shutdowns, or rate adjustments beyond planned scenarios. No wellbore mechanical issues including cement degradation or casing corrosion explicitly modeled despite recognized importance.

Uncertainty Limitations: Ranges for uncertain parameters based on limited local data supplemented by literature values; systematic calibration campaigns could refine distributions. Monte Carlo analysis computationally prohibitive; tornado diagram sensitivity approach identifies key parameters but doesn't fully quantify probabilistic outcomes. Long-term predictions (50-100 years) extend beyond validation timescales; confidence decreases with projection horizon despite model calibration to 20-year history.

Despite these limitations, the study provides robust technical assessment using industry-standard methodologies, conservative assumptions favoring safety, and comprehensive sensitivity analysis bounding outcomes. Results establish credible technical foundation for advancing Nigerian CCS deployment while identifying priorities for future refinement through field pilots, monitoring programs, and continued research.

CHAPTER TWO

LITERATURE REVIEW

2.1 Introduction

This chapter examines scholarly work on carbon dioxide sequestration in depleted petroleum reservoirs, focusing on climate mitigation strategies, containment mechanisms, and computational modeling techniques. The review establishes theoretical foundations for evaluating CO₂ storage in Nigerian depleted oil fields using Computer Modelling Group (CMG) simulation tools. Key topics include global climate imperatives, geological storage options, trapping mechanisms, caprock integrity, simulation methodologies, monitoring protocols, and international project experiences. The chapter concludes by identifying research gaps specific to the Nigerian context, justifying the current study's focus on CMG-based assessment of CO₂ storage potential in Niger Delta depleted reservoirs.

2.2 Global Climate Crisis and Carbon Sequestration Imperatives

2.2.1 Atmospheric CO₂ and Climate Change

Human industrial activities have fundamentally altered atmospheric composition since pre-industrial times. Contemporary measurements indicate CO₂ concentrations have increased from approximately 280 ppm to beyond 415 ppm, driven predominantly by fossil fuel combustion and industrial processes (IPCC, 2021). These elevated concentrations correlate strongly with observable environmental consequences including rising global temperatures, increasing ocean levels, marine acidification, and intensifying meteorological extremes (Metz et al., 2005). Climate modeling projects continued warming of 1.5-4.5°C by 2100 under various emission scenarios, with potentially catastrophic impacts on ecosystems, agriculture, water resources, and human settlements.

2.2.2 Fossil Fuel Dependence and Transition Challenges

Despite expanding renewable energy deployment, hydrocarbon resources remain fundamental to worldwide energy provision. The International Energy Agency forecasts fossil fuels maintaining 60-70% of global energy supply through 2040, particularly in developing

economies where energy demand escalates continuously (IEA, 2022). This persistent dependence reflects multiple factors including established infrastructure, energy density advantages, dispatchability requirements, and economic considerations. Complete transition to carbon-neutral energy systems requires decades, making interim emission reduction strategies essential for meeting climate targets.

2.2.3 CCS as Transitional Technology

Carbon Capture and Storage represents a critical bridging technology enabling continued fossil fuel utilization while constraining atmospheric emissions. CCS encompasses three integrated phases: capturing CO₂ from concentrated emission sources (power plants, industrial facilities), transporting compressed gas to storage sites, and permanently injecting it into deep geological formations (Benson & Cole, 2008). The IPCC identifies CCS as essential component of cost-effective climate mitigation portfolios, potentially contributing 15-20% of cumulative emission reductions required to limit warming below 2°C. Without CCS, achieving climate targets becomes substantially more expensive or potentially infeasible, particularly for hard-to-abate sectors including cement, steel, and chemical production.

2.3 Technical Framework of Carbon Capture and Storage

2.3.1 CCS Process Components

The CCS value chain integrates capture, transport, and storage operations. CO₂ capture technologies include post-combustion absorption using amine solvents (applicable to existing facilities), pre-combustion conversion producing hydrogen and concentrated CO₂, and oxyfuel combustion burning fuel in pure oxygen atmosphere. Capture efficiency typically achieves 85-95% removal, with energy penalties of 15-30% depending on technology and application. Transportation employs high-pressure pipelines (most economical for large volumes and distances), ships transporting liquefied CO₂ (suitable for offshore or international routes), or alternative modes. Storage involves injecting supercritical CO₂ (density 500-800 kg/m³) into formations exceeding 800 meters depth where pressure-temperature conditions maintain dense phase (Metz et al., 2005).

2.3.2 Strategic Advantages and Applications

CCS delivers multiple benefits toward climate objectives. It enables substantial emission reductions from large point sources including fossil-fueled power generation (accounting for 25% of global CO₂ emissions), industrial facilities (cement, steel, refineries contributing 20%), and enables low-carbon hydrogen production ("blue hydrogen") critical for transport and industrial decarbonization. CCS combined with bioenergy (BECCS) can achieve net-negative emissions, removing historical CO₂ from atmosphere. Economic benefits include prolonging petroleum asset value through CO₂-Enhanced Oil Recovery, leveraging existing infrastructure and workforce capabilities during energy transition (IEA, 2022).

2.3.3 Implementation Barriers

CCS faces significant deployment challenges. High costs (\$50-120 per tonne CO₂ for integrated systems) exceed current carbon prices in most jurisdictions, limiting commercial viability without subsidies. Public acceptance concerns regarding leakage risks, induced seismicity, and local environmental impacts require transparent engagement and demonstrated safety. Long-term liability extending decades or centuries beyond operations creates regulatory complexity and financial uncertainty. Policy frameworks remain incomplete in many regions, particularly developing nations, creating ambiguity for investors. Technical challenges include optimizing capture efficiency, ensuring geological containment security, and developing comprehensive monitoring protocols (Bachu, 2008).

2.4 Geological Storage Options for CO₂

2.4.1 Deep Saline Aquifers

Deep saline formations offer largest theoretical storage capacity globally, with estimates suggesting 1,000-10,000 gigatonnes potential—sufficient for centuries of industrial emissions (Bachu, 2008). These porous-permeable rock layers saturated with non-potable brine exist at suitable depths worldwide. However, saline aquifers generally lack comprehensive characterization compared to hydrocarbon reservoirs, requiring extensive geological investigation. Absence of pre-existing wells and infrastructure increases development costs substantially. Open aquifer systems may require pressure management through brine extraction to prevent

unacceptable pressure buildup. Storage efficiency typically ranges 1-4% of gross pore volume due to pressure constraints and heterogeneity effects.

2.4.2 Unmineable Coal Seams

Deep coal deposits economically impractical for mining present storage opportunities through CO₂ adsorption onto coal surfaces. This mechanism can enhance coalbed methane recovery (ECBM), potentially offsetting storage costs. However, coal seam storage faces significant limitations including low permeability restricting injection rates, uncertain long-term containment given coal's natural fracture systems, and limited storage capacity (typically <50 gigatonnes globally). Most studies indicate coal seams suitable only for niche applications rather than large-scale storage (White et al., 2005).

2.4.3 Depleted Oil and Gas Reservoirs

Exhausted hydrocarbon reservoirs constitute the most practical near-term storage option, offering multiple advantages: proven geological containment demonstrated by hydrocarbon retention over millions of years, comprehensive characterization from decades of production operations, existing infrastructure (wells, pipelines, facilities) enabling cost-effective repurposing, depleted pressure creating "buffer" for safe injection without fracturing, and established regulatory frameworks adaptable to CO₂ operations. Global storage capacity in depleted fields is estimated at 675-900 gigatonnes, sufficient for several decades of emissions from large point sources. Storage efficiency typically achieves 2-6% of original pore volume, higher than saline aquifers due to better understanding and existing infrastructure (Li et al., 2006).

Table 2.1: Comparison of Geological Storage Options

Storage Type	Global Capacity (Gt CO₂)	Advantages	Disadvantages	Readiness
Deep Saline Aquifers	1,000-10,000	Enormous capacity, widespread availability	Limited characterization, no infrastructure, high costs	Medium-term (5-15 years)
Depleted Oil/Gas Fields	675-900	Proven containment, well characterized, existing infrastructure	Limited capacity, well integrity concerns, heterogeneity	Near-term (0-5 years)
Coal Seams	15-200	ECBM revenue potential, distributed locations	Low permeability, uncertain containment, limited capacity	Experimental

2.5 CO₂ Storage in Depleted Oil Reservoirs

2.5.1 Technical Rationale

Depleted oil reservoirs offer optimal conditions for initial CCS deployment due to convergence of geological, technical, and economic factors. Geological integrity is demonstrated—reservoirs successfully trapped mobile hydrocarbons (lower viscosity, higher mobility than supercritical CO₂) for millions of years, validating both reservoir quality and caprock effectiveness. Comprehensive datasets from exploration (seismic surveys, well logs) and production (pressure-rate histories, fluid sampling) provide detailed characterization reducing uncertainty. The pressure advantage proves critical: following 30-50% pressure depletion during production, substantial "room" exists for CO₂ injection without exceeding original pressures or fracture thresholds, ensuring geomechanical stability (Benson & Cole, 2008).

Economic considerations strongly favor depleted reservoirs. Existing wells can be converted to injection or monitoring service at fraction of new well costs (\$2-5 million conversion versus \$8-15 million new drilling). Surface facilities (separators, compressors, pipelines) often require only modest modifications for CO₂ service. Established land access, permits, and stakeholder relationships streamline project development. When combined with Enhanced Oil Recovery, CO₂ injection generates revenue offsetting storage costs, potentially achieving economic viability without carbon credits (Li et al., 2006).

2.5.2 Nigerian Context and Potential

Nigeria ranks among Africa's leading petroleum producers with over 300 oil and gas fields in the Niger Delta Basin, many approaching or reaching economic depletion. These reservoirs present substantial CO₂ storage opportunities aligned with national climate commitments under the Paris Agreement (20% emission reduction by 2030, 45% with international support). The basin exhibits favorable characteristics: reservoir depths of 2,000-3,500 meters ensuring supercritical CO₂ conditions, high-quality sandstone reservoirs (porosity 20-30%, permeability 100-3,000 mD), thick shale caprocks with proven sealing over geological time, and structural closures preventing lateral migration (Ajidahun et al., 2025).

Technical expertise from five decades of petroleum operations provides skilled workforce familiar with subsurface engineering, drilling, reservoir management, and facilities operations—capabilities directly transferable to CCS. Extensive infrastructure including offshore platforms, pipeline networks, and processing facilities offers reuse potential substantially reducing capital requirements. Proximity to major emission sources (refineries, LNG facilities, power plants, cement factories) in Lagos, Port Harcourt, and Warri industrial zones minimizes transportation distances and costs.

2.5.3 Technical Challenges

Despite favorable conditions, several challenges require careful assessment. Reservoir heterogeneity—characteristic of fluvial-deltaic Niger Delta deposits—causes unpredictable plume migration and reduced storage efficiency compared to homogeneous models. Well integrity emerges as primary concern: legacy wells (often 20-40 years old) may exhibit cement degradation, casing corrosion, or inadequate abandonment creating potential leakage pathways (Bachu, 2017). Fault reactivation risks exist given the tectonically active setting and numerous growth faults; pressure increases from injection could trigger slip on critically stressed faults. Residual oil saturation (typically 25-35% after primary/secondary recovery) occupies pore space and affects multiphase flow, reducing available capacity and complicating displacement dynamics.

2.6 CO₂ Trapping and Containment Mechanisms

Long-term CO₂ storage security depends on multiple containment processes operating across different timescales, providing progressive enhancement of storage permanence. Understanding these mechanisms is essential for predicting performance and assessing reliability (IPCC, 2005).

2.6.1 Structural and Stratigraphic Trapping

Structural trapping constitutes the primary immediate mechanism, occurring when buoyant supercritical CO₂ (density 500-700 kg/m³ versus 1,000-1,100 kg/m³ for brine) rises until encountering impermeable caprock. The seal, typically shale, evaporite, or tight carbonate, prevents upward migration through low permeability (<0.001 mD) and high capillary entry pressure. Effectiveness depends on seal integrity, lateral continuity, and breakthrough pressure—

minimum differential pressure required for CO₂ penetration. Stratigraphic trapping occurs when CO₂ encounters permeability barriers from facies changes, unconformities, or pinch-outs, providing additional containment independent of structure (IPCC, 2005).

Critical research by Li et al. (2006) revealed that CO₂ capillary sealing capacity is substantially lower than for hydrocarbons due to reduced interfacial tension (20-30 mN/m for CO₂-brine versus 30-50 mN/m for oil-brine). Measurements on Weyburn caprock showed CO₂ breakthrough pressures of 9.2-21.4 MPa, significantly below values extrapolated from hydrocarbon sealing history. This implies caprocks adequate for oil/gas may risk CO₂ breakthrough if pressures approach original reservoir conditions, necessitating caprock re-evaluation and conservative pressure management for all storage projects.

2.6.2 Residual Capillary Trapping

Residual trapping immobilizes CO₂ as disconnected ganglia within pore networks through capillary forces during brine imbibition. Following injection cessation, brine progressively re-invades CO₂-saturated zones, fragmenting the continuous CO₂ phase into isolated clusters trapped by capillary snap-off mechanisms. This trapped CO₂ remains permanently immobile regardless of structural barrier integrity, providing high security. Trapping efficiency depends on pore structure, wettability, and drainage-imbibition history captured through relative permeability hysteresis (IPCC, 2005).

Raza et al. (2018) demonstrated residual trapping significance through simulation of depleted gas reservoirs, finding residually trapped CO₂ increases linearly with residual gas saturation. At 20-30% residual gas saturation, up to 30-35% of injected CO₂ can become residually trapped within decades post-injection. This suggests residual hydrocarbon presence may enhance capillary trapping, though mechanisms require further investigation. Hysteresis modeling proves critical for accurate simulation—non-hysteretic models underpredict residual trapping by 40-60%, substantially underestimating long-term security.

2.6.3 Solubility Trapping

Dissolution trapping proceeds through CO₂ dissolving into formation brine, creating denser CO₂-saturated brine (1,010-1,030 kg/m³) that sinks, eliminating buoyancy-driven migration. CO₂ solubility in brine ranges 3-6 wt% in freshwater at typical storage conditions (depth >800m, T=30-100°C, P=8-30 MPa), reduced 25-35% by salinity (Li et al., 2006). Dissolution initially occurs slowly via molecular diffusion at CO₂-brine interfaces but accelerates through convective mixing driven by density instabilities. As CO₂ dissolves, density increases create gravitational instabilities that expedite mass transfer—so-called "convective dissolution" operating over decades to centuries.

Long-term modeling suggests dissolution can sequester 20-40% of injected CO₂ within 1,000-10,000 years depending on reservoir properties and CO₂ distribution. While slower than structural or residual trapping, solubility provides significant security enhancement over project-relevant timescales (100-1,000 years). Importantly, Li et al. (2006) showed diffusive leakage through intact caprocks remains negligible (<0.01% over 10,000 years) compared to volume flow if breakthrough occurs, though ubiquitous diffusion may affect caprock geochemistry over geological time.

2.6.4 Mineral Trapping

Mineral trapping represents the ultimate storage form, involving geochemical reactions between dissolved CO₂ (forming carbonic acid, H₂CO₃) and reactive minerals, precipitating stable carbonates (calcite, dolomite, siderite, magnesite, ankerite). This process operates over longest timescales (centuries to millennia) but provides maximum permanence since CO₂ becomes chemically bound in solid phases. Extent depends on reactive mineral abundance (particularly Ca/Mg/Fe-bearing phases), surface area, temperature, and water chemistry (IPCC, 2005).

Reaction pathways include primary mineral dissolution (feldspars, mafic minerals) releasing divalent cations, followed by carbonate precipitation. Reaction rates prove highly variable: fast reactions (calcite dissolution/precipitation) equilibrate within years to decades, while slow reactions (silicate weathering) require millennia. Conservative estimates suggest 5-15% mineral trapping over 100 years in favorable lithologies (sandstones with 10-20% reactive

minerals), potentially reaching 40-70% over 10,000 years. However, slow kinetics mean substantial mineral trapping unlikely during operational and monitoring phases, limiting its practical relevance for project design though providing ultimate long-term assurance.

2.7 Caprock Integrity and Sealing Capacity

The caprock constitutes the most critical containment component, providing primary barrier against upward CO₂ migration. Essential properties include extremely low permeability (<1 μD preventing significant volume flow), high capillary entry pressure (exceeding maximum injection pressure differential to prevent breakthrough), adequate thickness (typically >20m, preferably >50m) providing redundancy, lateral continuity across injection area eliminating escape routes, mechanical stability withstanding pressure and thermal stresses, and chemical resistance to CO₂-induced alteration (Bachu, 2008).

2.7.1 Seal Rock Requirements

Typical seals include marine shales (most common, porosity <10%, clay-rich), evaporites (halite, anhydrite—excellent seals where present), and cemented tight carbonates or siltstones. Seal quality assessment requires multiple measurements: permeability via pressure pulse-decay or steady-state flow, capillary pressure curves determining entry pressure and pore throat distribution, mineralogy via XRD identifying reactive versus stable phases, and geomechanical properties (strength, brittleness) assessing fracture risk.

Caprock Integrity and CO₂ Leakage Risk Pathways

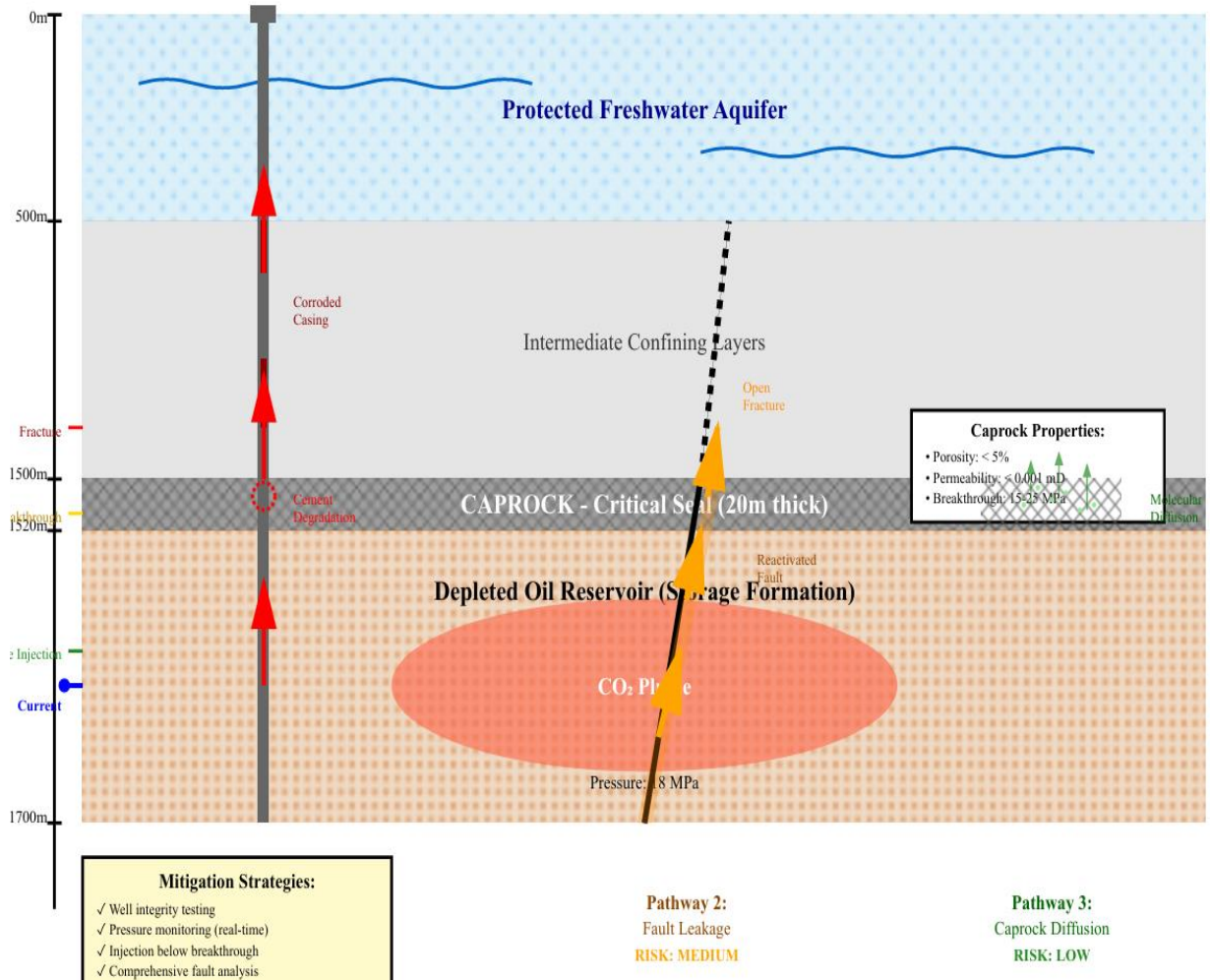


Figure 1: Caprock integrity and CO₂ leakage pathway

2.7.2 CO₂-Specific Breakthrough Pressure

Capillary breakthrough pressure—minimum differential pressure for CO₂ penetration through largest interconnected pore throats—follows Young-Laplace equation relating capillary pressure to interfacial tension (σ), pore throat radius (r), and contact angle (θ): $P_c = 2\sigma\cos\theta/r$. Critical research by Li et al. (2006) demonstrated CO₂ breakthrough pressure is 30-50% lower than for hydrocarbons due to reduced interfacial tension (20-30 mN/m CO₂-brine versus 30-50 mN/m oil-brine or 50-70 mN/m gas-brine).

Their measurements on Weyburn Midale Evaporite caprock yielded CO₂ breakthrough pressures of 9.2-21.4 MPa, substantially below pressures inferred from hydrocarbon seal capacity. This reduction has profound implications: caprocks successfully retaining oil/gas at original pressures may prove inadequate for CO₂ if injection restores reservoir pressure near original values. Consequently, caprock re-evaluation specifically for CO₂ is mandatory for all storage projects, and injection strategies must maintain pressure differentials below CO₂-specific breakthrough thresholds—often requiring injection at <80% of original reservoir pressure.

2.7.3 Volume Flow versus Diffusive Leakage

Two leakage modes through caprocks differ drastically in magnitude and implications. Volume flow (Darcy flow) occurs when injection pressure exceeds breakthrough pressure, establishing continuous CO₂ pathways through caprock pore network. Li et al. (2006) measured effective permeability to CO₂ in water-saturated Weyburn caprock after breakthrough as 3×10^{-5} to 6×10^{-4} mD—approximately 10× lower than absolute gas permeability but sufficient for catastrophic leakage. Their calculations showed that for 10m thick caprock, 1 km² area, and 10 MPa differential pressure, volume flow leakage rates reach 3,690-36,900 tonnes/km²/year, equivalent to 6-60% annual loss—completely defeating storage objectives.

Conversely, diffusive leakage via molecular diffusion through intact caprock (no volume flow) proceeds several orders of magnitude slower. Under identical conditions, diffusion yields <1 tonne/km²/year leakage—negligible compared to stored mass. While diffusion operates universally over geological time and may affect caprock mineralogy slowly, it poses minimal risk for project-relevant timescales (100-1,000 years). This stark contrast emphasizes absolute criticality of preventing volume flow breakthrough through conservative pressure management—breakthrough represents binary failure mode, while diffusion remains acceptable background process.

2.8 Residual Hydrocarbon Effects on Storage Performance

2.8.1 Remaining Hydrocarbon Saturation

Following primary and secondary recovery, substantial hydrocarbon volumes remain in depleted reservoirs. Typical oil recovery factors of 30-50% leave residual oil saturations of 20-35%, while gas recovery of 70-85% yields residual gas of 5-20%. These residual hydrocarbons occupy pore space and affect multiphase flow characteristics, yet their influence on CO₂ storage received limited attention until recent studies. Raza et al. (2018) systematically investigated residual gas effects in depleted gas reservoirs, revealing significant impacts on capacity, injectivity, and trapping mechanisms.

2.8.2 Storage Capacity Impact

Raza et al.'s simulations demonstrated storage capacity decreases proportionally with residual gas saturation. For a representative dry gas reservoir (1,068 BScf OGIP), calculated storage potential declined from 990 BScf at 5% residual saturation to 912 BScf at 30% residual saturation—7.9% reduction attributable to residual gas occupying pore volume. Over 10-year injection period, cumulative CO₂ injection ranged from 882 BScf (5% S_{gr}) to 730 BScf (30% S_{gr}) for optimal configurations, representing 17% capacity loss. This suggests secondary gas recovery operations (pressure maintenance, infill drilling) before CO₂ storage could substantially enhance capacity, though requiring economic justification.

2.8.3 Injectivity and Operational Constraints

Residual gas presence dramatically affects sustainable injection rates. At conservative rates (250 MMscf/day), injection could be maintained regardless of residual saturation level, though total injected volumes decreased proportionally. However, at aggressive rates (500-700 MMscf/day), injectivity problems emerged rapidly at high residual gas levels, with rates declining significantly within months of startup (Raza et al., 2018). This behavior indicates residual gas increases flow resistance and pressure accumulation through relative permeability reduction, potentially forcing operations at lower rates or requiring additional wells to achieve target storage within project timeframes. Optimal injection rate was found to decrease linearly with increasing residual gas saturation.

2.8.4 Trapping Mechanism Interactions

Residual gas exerts differential effects on various trapping mechanisms. Structural trapping (free-phase CO₂) showed inverse relationship with residual gas—less mobile CO₂ present at higher residual levels due to pore space occupation. Conversely, capillary trapping exhibited direct linear correlation: significantly more CO₂ became residually trapped at 20-30% residual gas compared to 5-10% levels (Raza et al., 2018). This suggests residual gas presence may enhance storage security by promoting immobilization at expense of total capacity—a beneficial trade-off from containment perspective. However, dissolution trapping decreased with residual gas saturation, being most effective at low residual levels. The interplay between these competing effects requires careful consideration in storage project design and optimization.

2.9 Reservoir Simulation for CO₂ Storage

2.9.1 Simulation Objectives

Reservoir simulation provides essential tools for predicting CO₂ behavior using mathematical models solving coupled equations describing multiphase fluid flow, mass transfer, and geochemical reactions in porous media. For storage applications, simulation enables: (1) estimating dynamic storage capacity accounting for injectivity limits and pressure constraints, (2) forecasting plume migration patterns, extent, and arrival times at monitoring points or boundaries, (3) evaluating trapping efficiency and distribution among structural, residual, solubility, and mineral forms, (4) assessing risks including pressure buildup, fault reactivation, and leakage pathways, (5) optimizing injection strategies (rates, well locations, operational controls) for safe, efficient storage (Li et al., 2015).

2.9.2 Critical Physical Processes

Accurate CO₂ storage simulation must capture several complex phenomena. Multiphase flow describes simultaneous movement of CO₂, oil, gas, and brine governed by relative permeability and capillary pressure functions—highly nonlinear relationships dependent on saturation history and wettability. Phase behavior modeling employs equations of state (typically Peng-Robinson) predicting CO₂ density, viscosity, and solubility as functions of pressure, temperature, and composition. Hysteresis effects represent irreversible changes in relative

permeability during drainage-imbibition cycles, critical for residual trapping accuracy. Gravitational segregation driven by density contrast (400-500 kg/m³ between CO₂ and brine) causes vertical migration and pooling beneath seals. Geochemical reactions including CO₂ dissolution, mineral dissolution/precipitation, and pH changes alter fluid and rock properties over time (Raza et al., 2018).

2.9.3 Simulation Workflow

Standard CO₂ storage simulation workflow comprises sequential phases. Data collection and QC assembles geological (seismic, well logs, core), engineering (production history, well tests), and fluid (PVT analysis, water chemistry) data, identifying uncertainties and gaps. Static geological model construction develops structural framework from seismic interpretation, populates petrophysical properties (porosity, permeability, saturation) using geostatistical methods honoring well control, and defines initial conditions (pressure, temperature, fluid contacts). Fluid characterization defines component properties for CO₂, hydrocarbons, and water, develops equation of state parameters tuned to laboratory PVT data, and generates tables for phase behavior calculations. Dynamic model building designs simulation grid (resolution, orientation, refinement), assigns rock properties via upscaling from geological model, and specifies wells, completions, and operational constraints. History matching calibrates uncertain parameters by minimizing mismatch between simulated and observed production data (rates, pressures, saturations), validating model predictive capability. CO₂ injection scenarios simulate various strategies (base case, sensitivities, optimizations) predicting plume behavior, pressure evolution, and trapping over decades to centuries (CMG, 2023).

2.10 Computer Modelling Group (CMG) Software

2.10.1 CMG Suite Overview

Computer Modelling Group provides industry-standard reservoir simulation software extensively utilized in petroleum engineering and increasingly applied to CO₂ storage studies worldwide. The CMG suite comprises integrated modules: GEM (compositional and unconventional simulator—primary tool for CO₂ storage), IMEX (black oil simulator), STARS (thermal and advanced processes), Builder (geological model construction and property distribution), WinProp (fluid characterization and equation of state development), and Results (3D

visualization and post-processing). For CO₂ storage applications, GEM serves as primary simulation engine due to compositional modeling capabilities essential for capturing CO₂ phase behavior, dissolution, and interactions with reservoir fluids (CMG, 2023).

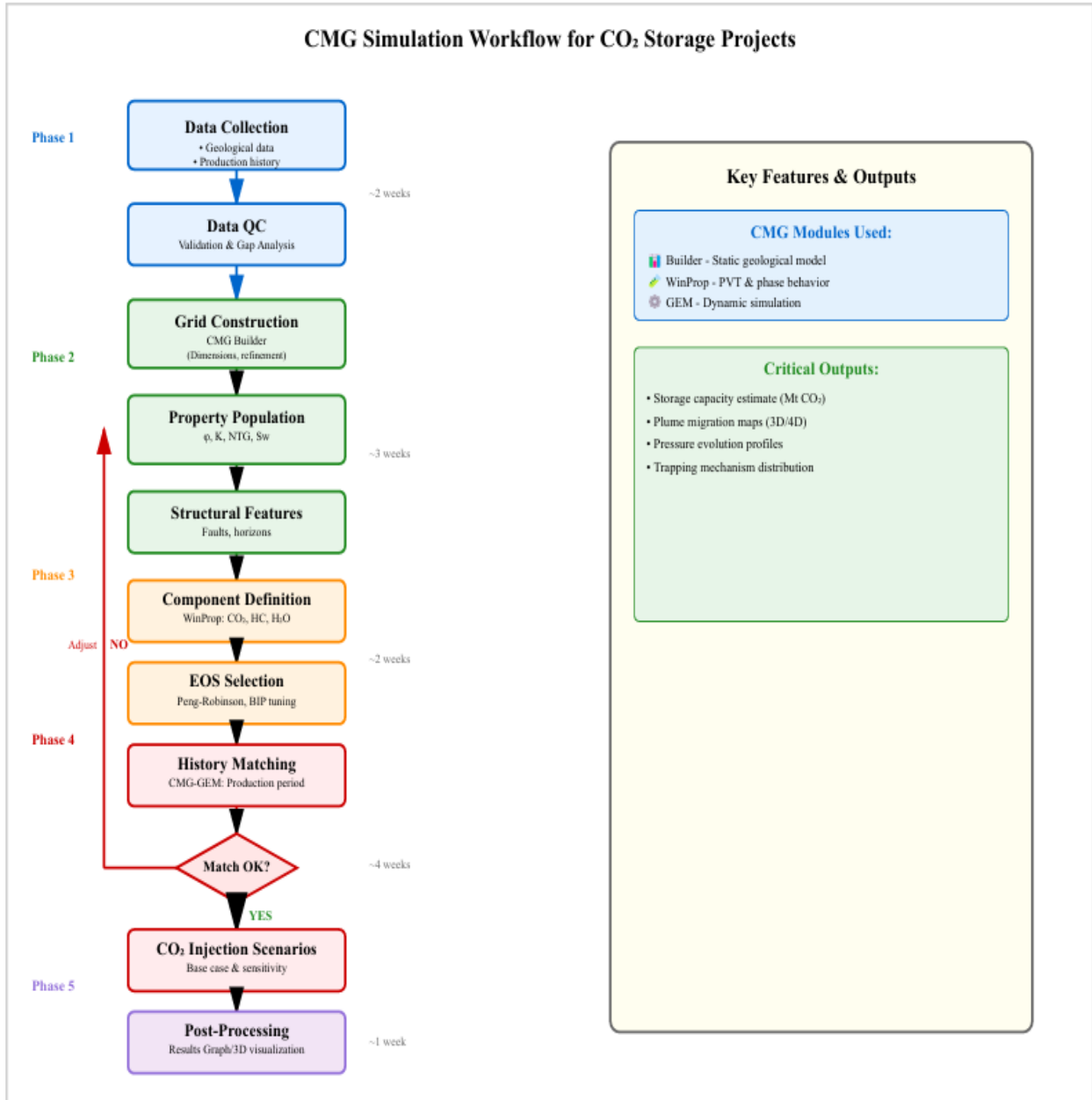


Figure 2: CMG simulation workflow

2.10.2 GEM Capabilities for CO₂ Storage

CMG-GEM offers specialized features particularly relevant for carbon sequestration. Equation of state compositional modeling accurately predicts CO₂ phase behavior and mixing with reservoir fluids using Peng-Robinson, Soave-Redlich-Kwong, or advanced cubic EOS with binary interaction parameters. The software handles supercritical CO₂ phase transitions, density and viscosity variations with pressure-temperature, and multi-component diffusion. Advanced relative permeability options include three-phase models (oil-gas-water), hysteresis modeling using Land's, Carlson's, or Killough's methods for residual trapping, and compositional-dependent functions. Aqueous phase reactions model CO₂ dissolution following Henry's Law, basic geochemical interactions (mineral dissolution/precipitation), and pH-dependent reactions. Optional geomechanical coupling enables assessment of stress changes, compaction/subsidence, and fault reactivation through linked simulation with CMG-GeoMech module (CMG, 2023).

2.10.3 Advantages for Nigerian Applications

CMG software offers particular benefits for evaluating Nigerian depleted reservoirs. The proven track record in petroleum engineering across 1,000+ companies globally provides confidence in numerical accuracy and reliability. Compositional capabilities properly handle complex fluid mixtures including CO₂, residual oil, solution gas, and high-salinity formation brines characteristic of Niger Delta. Ability to import seismic data, well logs, and production histories facilitates integration with extensive databases accumulated during decades of field operations. Built-in uncertainty analysis through CMOST (CMG optimization and uncertainty tool) enables probabilistic forecasting under data limitations typical of mature fields. Widespread industry adoption ensures availability of technical support, training programs, and experienced personnel familiar with workflows. Nigerian petroleum companies and universities increasingly utilize CMG for reservoir studies, providing foundation for CCS applications (CMG, 2023).

2.11 Geomechanical Considerations

2.11.1 Stress Changes and Rock Failure

CO₂ injection elevates pore pressure, reducing effective stress on rock matrix and fractures according to Terzaghi's principle: $\sigma' = \sigma - \alpha P_p$, where σ' is effective stress, σ is total stress, α is

Biot coefficient (~ 1 for most sediments), and P_p is pore pressure. Effective stress reduction can trigger multiple failure modes including hydraulic fracturing when injection pressure exceeds minimum principal stress plus tensile strength, shear failure on pre-existing faults or fractures when stress changes move Mohr circle to failure envelope, and compaction/subsidence of overlying formations as reservoir pressure declines post-injection. Geomechanical analysis requires determining in-situ stress state, rock mechanical properties (strength, elasticity, failure criteria), and coupled fluid-flow mechanical modeling (Rutqvist, 2012).

2.11.2 Fault Reactivation and Induced Seismicity

Pressure increases from CO₂ injection can reactivate critically stressed faults, potentially causing felt earthquakes and creating permeability pathways for CO₂ migration. Fault reactivation risk depends on stress state (normal, strike-slip, or reverse faulting regime), fault orientation relative to principal stresses, fault strength characterized by friction coefficient (typically 0.6-0.85) and cohesion, and pressure perturbation magnitude and spatial extent. Mohr-Coulomb analysis assesses proximity to failure: $\tau = c + \sigma' \tan \phi$, where τ is shear stress, c is cohesion, σ' is effective normal stress, and ϕ is friction angle. Most documented induced seismicity from fluid injection occurs in crystalline basement rocks with large critically stressed faults; sedimentary basin storage projects generally show minimal seismicity due to lower injection pressures, ductile rock behavior, and smaller fault dimensions. However, sites with large basement-penetrating faults require careful pressure management and seismic monitoring (Bachu, 2017).

2.11.3 Caprock Geomechanical Integrity

Caprock mechanical stability is as critical as hydraulic sealing capacity. Mechanical failure modes include tensile fracturing if pressure differential exceeds tensile strength (typically 2-5 MPa for shales), shear failure along pre-existing natural fractures or weakness planes, and reactivation of healed fractures or faults penetrating seal. Safe injection requires maintaining pressure below fracture propagation threshold, typically expressed as: $P_{inj} < \sigma_{h,min} + T - \alpha(P_{res} - P_{initial})$, where $\sigma_{h,min}$ is minimum horizontal stress, T is tensile strength, and the last term accounts for reservoir depletion effects. Conservative practice limits injection pressure to 90-95% of estimated fracture pressure, providing safety margin for uncertainties (Rutqvist, 2012).

2.12 Monitoring, Measurement, and Verification (MMV)

2.12.1 MMV Framework and Objectives

Monitoring programs serve multiple critical functions throughout CO₂ storage project lifecycle. Primary objectives include verifying CO₂ remains contained within storage complex according to predictions, detecting potential leakage at early stages enabling corrective action, demonstrating regulatory compliance and operational safety to stakeholders, building public confidence through transparent data disclosure, and providing feedback for updating predictive models and improving operations. Effective MMV integrates multiple complementary technologies, operates throughout injection and post-closure periods, and transitions from intensive operational monitoring to long-term stewardship surveillance (Benson & Cole, 2008).

2.12.2 Monitoring Technologies

Multiple surveillance methods comprise comprehensive MMV programs. Seismic monitoring including time-lapse 3D surveys (4D seismic) repeating baseline acquisitions to image CO₂ plume geometry, vertical seismic profiling (VSP) providing high-resolution near-well imaging, and passive seismic networks detecting microearthquakes from geomechanical responses. Pressure-temperature monitoring via permanent downhole gauges in injection and observation wells tracking spatial-temporal pressure evolution, identifying anomalies indicating unexpected behavior. Geochemical sampling of formation fluids from observation wells analyzing CO₂ concentration and isotopic signatures, soil gas surveys detecting near-surface CO₂ anomalies, and groundwater monitoring in overlying aquifers ensuring protection. Geophysical methods including electrical resistivity tomography sensitive to CO₂-brine substitution, gravity surveys detecting density changes from CO₂ accumulation, and electromagnetic methods. Remote sensing using satellite InSAR measuring ground surface deformation (uplift/subsidence) with millimeter precision, and atmospheric monitoring detecting potential surface seepage (Benson & Cole, 2008).

2.12.3 Monitoring Phases and Duration

MMV intensity varies across project phases. Pre-injection baseline monitoring (1-2 years before injection) establishes natural variability in monitored parameters, providing reference for detecting injection-induced changes. During active injection, intensive monitoring includes continuous pressure-temperature recording, annual to quarterly seismic surveys tracking plume development, frequent geochemical sampling, and real-time microseismic surveillance. Post-injection monitoring continues at reduced frequency as plume stabilizes, typically extending 20-50 years after cessation with focus on confirming predictions and detecting unexpected migration. Long-term stewardship involves periodic surveillance potentially spanning centuries at minimal intensity, focusing on critical indicators of containment integrity. Regulatory frameworks increasingly specify minimum monitoring requirements for each phase, with some jurisdictions allowing liability transfer to government after demonstrated storage performance over post-closure period (typically 20-50 years) (Benson & Cole, 2008).

2.13 Global Case Studies

2.13.1 Sleipner Project, Norway

Sleipner represents the world's first commercial-scale offshore CO₂ storage, operational since 1996. Located in Norwegian North Sea, the project injects ~1 Mt/year CO₂ separated from Sleipner gas field production into Utsira saline aquifer at 800-1,000m depth. Over 25 years, >20 Mt stored with no detected leakage. Time-lapse seismic surveys conducted every 2-4 years successfully track plume development, revealing complex migration influenced by thin intra-reservoir shale layers creating multiple accumulations. Key lessons include demonstrating long-term storage viability in saline aquifers, validating time-lapse seismic as plume monitoring tool, and confirming simulation predictions broadly match observations though detailed migration patterns show more complexity than initially modeled (Torp & Gale, 2004).

2.13.2 Weyburn-Midale Project, Canada

Weyburn-Midale combines CO₂-Enhanced Oil Recovery with geological storage in depleted Mississippian oil field (Saskatchewan, Canada). Since 2000, >30 Mt CO₂ injected from Dakota coal gasification plant via 330 km pipeline, enhancing recovery while storing CO₂.

Comprehensive monitoring includes baseline and repeat 3D seismic, microseismic networks, soil gas sampling, groundwater surveillance, and atmospheric monitoring. Research confirmed injected CO₂ remains contained, with significant residual and solubility trapping developing. Project demonstrated economic viability through oil revenue offsetting costs, and importance of integrated monitoring detecting unexpected pressure communication between reservoir units. Well integrity investigations following community concerns highlighted need for thorough legacy well assessment and remediation (Wilson & Monea, 2004).

2.13.3 In Salah Project, Algeria

In Salah project (central Algeria) injected CO₂ separated from gas production into Carboniferous sandstone at 1,800m depth from 2004-2011, storing ~3.8 Mt total. Advanced monitoring employed satellite InSAR detecting subtle surface uplift (5-10mm) corresponding to pressure increases. Analysis suggested possible CO₂ migration along fault zone, prompting operational modifications and eventual injection suspension. Project provided crucial lessons: InSAR valuable for detecting geomechanical responses and potential containment issues, fault characterization critical for site screening, and adaptive management essential for responding to monitoring observations. Though considered technical learning experience rather than failure, In Salah demonstrated challenges of storage in faulted systems and importance of conservative site selection (Rutqvist, 2012).

2.13.4 Lessons from International Experience

Collective insights from operational projects inform best practices. Comprehensive site characterization including detailed structural geology, fault mapping, stress measurements, and caprock assessment proves essential for success. Multiple monitoring technologies provide redundancy and cross-validation, building confidence and enabling early anomaly detection. Simulation models require continuous updating with monitoring data through history matching and ensemble methods, improving predictions and informing decisions. Stakeholder engagement and transparent communication build social license—public concerns must be addressed proactively through education, participation, and demonstrated safety. Regulatory frameworks balancing safety with commercial viability facilitate deployment while protecting environment and communities (Benson & Cole, 2008).

Global CO₂ Storage Projects - Key Features and Lessons Learned

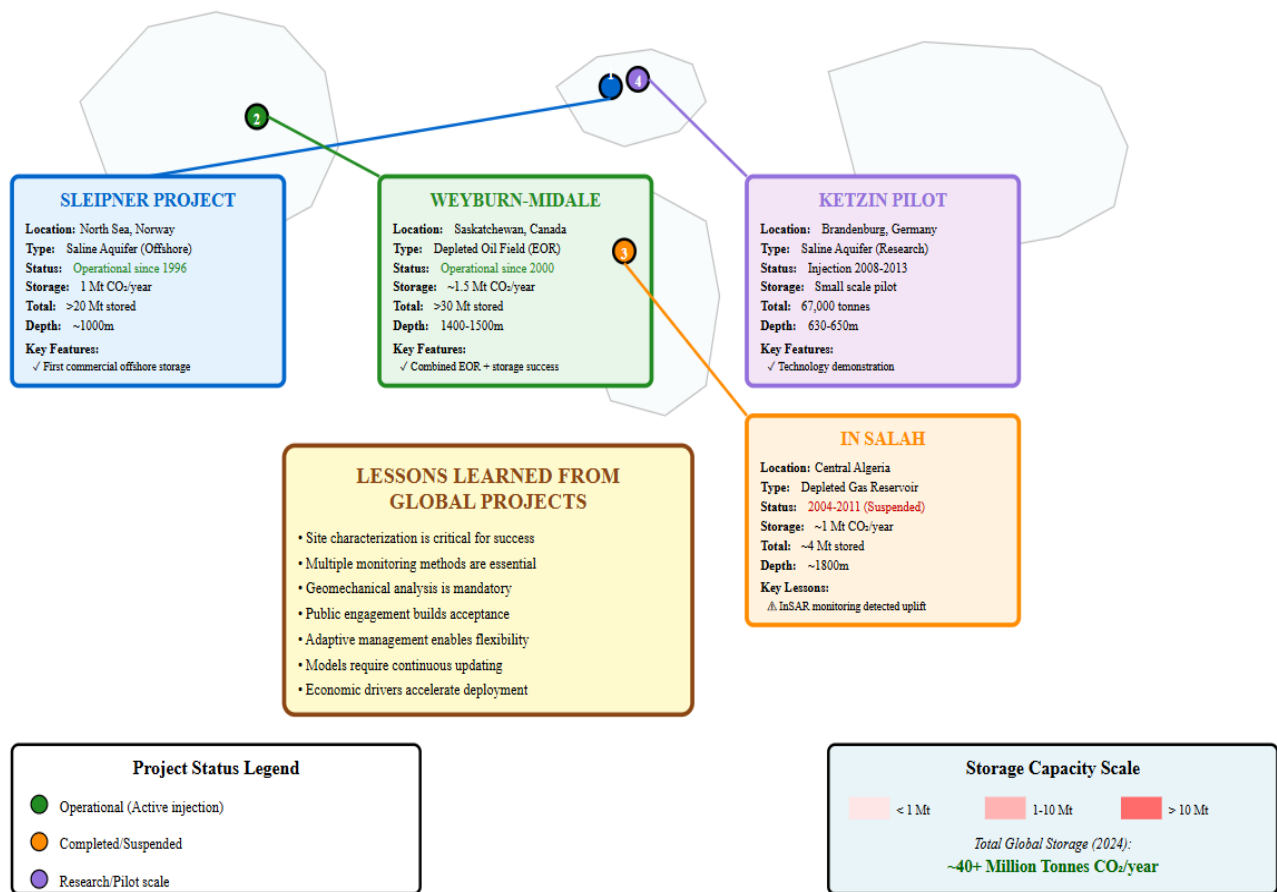


Figure 3: Global CO₂ storage project

2.14 Nigerian Context for CO₂ Storage

2.14.1 Niger Delta Basin Characteristics

Nigeria's Niger Delta Basin ranks among Africa's most prolific petroleum provinces, containing >300 oil and gas fields developed over six decades. The basin exhibits highly favorable characteristics for CO₂ storage. Numerous mature and depleted reservoirs provide proven containment, with cumulative production >40 billion barrels oil equivalent indicating vast pore space availability. Reservoir depths typically 2,000-3,500 meters ensure supercritical CO₂ conditions (critical point: 31.1°C, 7.38 MPa), with reservoir temperatures of 80-110°C and pressures of 20-35 MPa. Predominantly high-quality sandstone reservoirs characteristic of Agbada

Formation exhibit porosity 18-30% and permeability 100-3,000 mD, providing excellent injectivity. Thick marine shale caprocks (Akata Formation) with demonstrated sealing over geological time (preserving hydrocarbons since Tertiary), typically >50m thick with permeability <0.001 mD. Structural closures and stratigraphic traps throughout basin prevent lateral migration (Ajidahun et al., 2025).

2.14.2 Infrastructure and Technical Capacity

Nigeria possesses substantial existing petroleum infrastructure potentially repurposable for CCS. Extensive well inventory includes thousands of wells penetrating target formations, though well integrity assessment and potential remediation required. Pipeline networks connecting fields to processing facilities and terminals could transport captured CO₂ with modifications for CO₂ service. Offshore platforms and onshore facilities provide potential injection sites and operational bases. Technical workforce with decades of petroleum experience provides skilled personnel familiar with drilling, reservoir engineering, facilities operations, and project management—capabilities directly transferable to CCS. Academic institutions (University of Lagos, University of Port Harcourt, Covenant University) conduct petroleum engineering research and training, creating foundation for CCS education programs (Ajidahun et al., 2025).

2.14.3 Emission Sources and Demand

Nigeria's petroleum and industrial sectors generate substantial CO₂ emissions creating demand for storage. Gas flaring, though declining from historical highs (>20 Bcm/year in 2000s to ~7 Bcm/year currently), continues releasing >15 Mt CO₂ annually. Oil and gas processing facilities emit CO₂ during separation, treating, and compression operations. Gas-fired power generation provides >70% of Nigeria's electricity with plants in Lagos, Delta, and Rivers states producing concentrated CO₂ streams amenable to capture. Industrial sources including cement plants (Dangote, Lafarge, BUA) collectively emit ~5-8 Mt CO₂/year, and refineries (Port Harcourt, Warri, Kaduna) contribute additional emissions. Total addressable emissions from point sources approach 30-40 Mt/year, creating substantial market for CO₂ storage services if enabling policies implemented.

2.14.4 Research Gaps

Despite favorable conditions, significant knowledge gaps limit CCS deployment readiness in Nigeria. Limited dynamic simulation-based capacity assessments exist for specific Nigerian depleted fields using compositional modeling—most studies employ static volumetric estimates lacking consideration of injectivity constraints, pressure evolution, and plume behavior. Insufficient research addresses wellbore integrity concerns specific to Nigerian well construction practices, cement formulations, and abandonment standards, which may differ from North American or European practices forming basis of most integrity literature. Inadequate integration of geomechanical analysis in Nigerian CCS studies leaves fault reactivation risks poorly quantified given tectonically active delta setting with numerous growth faults. Absence of tailored MMV strategies adapted to Nigerian geological conditions (deepwater, high sedimentation rates), resource constraints, and institutional capabilities. Limited economic analysis incorporating Nigerian-specific costs, fiscal regimes, and carbon pricing scenarios (Ajidahun et al., 2025).

2.14.5 Policy and Regulatory Framework

Successful CCS deployment requires supportive policy and regulatory development. Current framework gaps include absence of clear legal definitions for pore space ownership and long-term storage rights—critical for establishing operational authority and liability. Lack of specific regulatory standards for CCS site selection, operational protocols, monitoring requirements, and closure criteria, though Petroleum Industry Act (2021) provides potential framework adaptable to CCS. No established carbon pricing mechanism or financial incentives for emission reductions, limiting commercial viability without international carbon credit markets. Need for international cooperation frameworks facilitating technology transfer, capacity building, and potential cross-border CO₂ transport from regional emission sources. Requirements for stakeholder engagement protocols and public awareness programs addressing community concerns and building social acceptance, particularly important given Niger Delta's history of petroleum-related conflicts (Ajidahun et al., 2025).

2.15 Research Justification and Knowledge Gaps

Summary of Literature Findings:

- **Depleted reservoirs as optimal near-term option:** Proven containment, extensive characterization, existing infrastructure, and favorable pressure conditions make depleted oil/gas fields most practical for initial CCS deployment (Li et al., 2006; Benson & Cole, 2008)
- **Multiple trapping mechanisms enhance security:** Progressive transition from structural to residual, solubility, and mineral trapping over decades to millennia provides increasing storage permanence (IPCC, 2005; Raza et al., 2018)
- **Caprock integrity is critical:** CO₂ breakthrough pressures substantially lower than hydrocarbon sealing values necessitate re-evaluation and conservative pressure management (Li et al., 2006)
- **Residual hydrocarbons affect performance:** Remaining oil/gas reduces capacity and injectivity but may enhance capillary trapping, requiring careful consideration in project design (Raza et al., 2018)
- **Simulation essential for prediction:** Advanced compositional modeling using tools like CMG-GEM enables capacity estimation, plume forecasting, risk assessment, and operational optimization (CMG, 2023)
- **International projects demonstrate viability:** Sleipner, Weyburn, and others confirm geological storage works at scale while highlighting importance of characterization, monitoring, and adaptive management (Torp & Gale, 2004; Wilson & Monea, 2004)
- **Nigerian context favorable but understudied:** Niger Delta possesses excellent geological conditions and infrastructure, but significant research gaps exist regarding detailed simulation studies, well integrity, geomechanics, and tailored monitoring strategies (Ajidahun et al., 2025)

2.15.1 Specific Research Gaps Addressed by Current Study

This research addresses critical knowledge deficits through comprehensive CMG-based simulation of CO₂ storage in representative Nigerian depleted oil reservoir:

1. Dynamic Storage Capacity Assessment: Most Nigerian studies employ static volumetric methods assuming uniform properties and neglecting operational constraints. This research evaluates capacity accounting for reservoir heterogeneity, residual oil effects, pressure limitations, and injectivity constraints through coupled fluid flow and geomechanical modeling.

2. Long-Term Plume Behavior Prediction: Limited understanding exists regarding CO₂ migration patterns in Niger Delta fluvial-deltaic systems with characteristic heterogeneity. Study predicts plume evolution over 100-year horizons considering buoyancy-driven flow, gravity segregation, and stratigraphic controls.

3. Caprock Integrity for Nigerian Seals: Niger Delta shale caprocks require re-evaluation for CO₂-specific breakthrough pressures and geochemical stability. Research assesses seal capacity, estimates safe injection pressure limits, and evaluates diffusive versus volume flow leakage risks.

4. Trapping Mechanism Quantification: Understanding temporal evolution of structural, residual, solubility, and mineral trapping in depleted oil systems with residual hydrocarbons remains limited. Study quantifies contribution of each mechanism over time, informing storage security assessment.

5. Geomechanical Risk Assessment: Niger Delta's tectonically active setting with growth faults necessitates evaluation of fault reactivation risks, induced seismicity potential, and caprock mechanical integrity under injection scenarios. Research integrates stress analysis with fluid flow modeling.

6. Operational Optimization: Optimal injection strategies (rates, well configurations, pressure management) for Nigerian conditions remain undefined. Study conducts sensitivity

analysis identifying key parameters and developing operational recommendations maximizing storage efficiency while ensuring safety.

2.15.2 Research Objectives

Building on literature review findings and identified gaps, this research pursues specific objectives:

1. Construct comprehensive CMG-based reservoir simulation model of representative Niger Delta depleted oil field incorporating geological structure, petrophysical heterogeneity, fluid properties, and operational history
2. Evaluate CO₂ storage capacity through dynamic simulation accounting for injectivity constraints, pressure limitations, and geomechanical factors
3. Predict long-term CO₂ plume migration patterns, pressure evolution, and saturation distribution over 100-year simulation horizons
4. Quantify contributions of structural, residual, solubility, and mineral trapping mechanisms to storage security as functions of time
5. Assess caprock integrity, fault reactivation risks, and potential leakage pathways through integrated fluid flow-geomechanical analysis
6. Conduct comprehensive sensitivity analysis evaluating effects of key uncertain parameters (permeability heterogeneity, residual oil saturation, relative permeability hysteresis, injection rates, well configurations) on storage performance
7. Develop operational recommendations for safe, efficient CO₂ storage in Nigerian depleted oil reservoirs applicable to field-scale implementation

2.15.3 Expected Contributions

This research will advance knowledge in several critical areas. It provides first comprehensive dynamic simulation study of CO₂ storage in Nigerian depleted oil reservoir using industry-standard CMG software, establishing methodology applicable to additional Niger Delta fields. The work quantifies storage capacity with realistic consideration of operational and

geological constraints, informing national CCS deployment planning. It demonstrates application of advanced compositional modeling, hysteresis treatment, and geomechanical coupling to storage assessment, contributing methodological improvements to field. The research evaluates trapping mechanism evolution specific to oil-bearing systems with residual hydrocarbons, extending understanding beyond saline aquifer and gas reservoir focus of most literature. It assesses risks and proposes mitigation strategies tailored to Nigerian geological, operational, and regulatory context, supporting safe project implementation. Finally, findings will inform policy development, regulatory framework design, and commercial strategy for CCS deployment in Nigeria and potentially other West African petroleum provinces with similar characteristics.

CHAPTER THREE

METHODOLOGY

3.1 Introduction

This chapter presents the systematic approach employed to evaluate CO₂ storage potential in a depleted oil reservoir using Computer Modelling Group (CMG) simulation software. The methodology encompasses data acquisition, geological characterization, reservoir model construction, fluid property definition, history matching, CO₂ injection scenario development, and results analysis. The study utilizes a representative depleted oil field from the Niger Delta Basin, leveraging existing production data and reservoir characterization to construct a robust simulation model using CMG-GEM for compositional simulation, CMG Builder for geological modeling, and WinProp for fluid characterization.

3.2 Research Design and Workflow

The research adopts a quantitative simulation-based approach structured into seven sequential phases:

Phase 1: Data Collection & Literature Review (Weeks 1-2) - Compilation of reservoir production data, geological and geophysical data, well logs, core analysis, and fluid property data.

Phase 2: Static Geological Model Construction (Weeks 3-4) - Grid construction (50×50×15 cells), property distribution, structural framework development, and initial conditions definition using CMG Builder.

Phase 3: Fluid Characterization (Weeks 5-6) - Component definition (CO₂, hydrocarbons, water), equation of state modeling using Peng-Robinson EOS, and PVT table generation in WinProp.

Phase 4: History Matching (Weeks 7-8) - Calibration of the model to 20 years of production history using CMG-GEM, including pressure, rate, and saturation matching.

Phase 5: CO₂ Injection Scenarios (Weeks 9-11) - Base case simulation and sensitivity analysis including injection rate variation, well configuration optimization, and long-term prediction (100 years).

Phase 6: Results Analysis & Visualization (Weeks 12-13) - Storage capacity quantification, plume migration mapping, pressure evolution analysis, and trapping mechanism distribution using CMG Results.

Phase 7: Interpretation & Recommendations (Weeks 14-16) - Performance evaluation, optimal strategy identification, limitations discussion, and future work suggestions.

3.3 Study Area and Reservoir Selection

3.3.1 Field Characteristics

The study focuses on Field X, a depleted oil reservoir in the Niger Delta Basin representing a typical shallow marine sandstone deposit of the Agbada Formation. The field commenced production in 1985 and reached economic depletion in 2005 after 20 years of operation, achieving 42% recovery factor. The reservoir exhibits favorable characteristics for CO₂ storage evaluation.

3.3.2 Key Reservoir Properties

Table 3.1: Summary of Reservoir Properties for Field X

Parameter	Value	Unit
Reservoir depth	2,450	m
Net pay thickness	38	m
Areal extent	12.5	km ²
Porosity (average)	24	%
Horizontal permeability	850	mD
Vertical permeability	85	mD
Initial pressure	24,500	kPa
Current pressure (2005)	12,800	kPa
Temperature	92	°C

Parameter	Value	Unit
OOIP	85	MMstb
Cumulative production	35.7	MMstb

The reservoir comprises stacked fluvial-deltaic sandstone channels with excellent lateral continuity, bounded by a four-way dip closure with fault-assisted trapping. The overlying caprock consists of thick marine shale (>150 meters) with porosity below 5% and permeability less than 0.001 mD, providing excellent sealing capacity.

3.4 Data Collection and Sources

3.4.1 Production Data

Historical production data spanning 20 years (1985-2005) included monthly oil, gas, and water production rates from four wells (P-1 through P-4), bottom-hole pressure measurements, and pressure transient test data. Cumulative oil production reached 35.7 MMstb representing 42% recovery of OOIP.

3.4.2 Well Log and Core Data

Comprehensive well log suites from six wells provided continuous petrophysical measurements including gamma ray, resistivity, porosity, and sonic logs. Core samples from three wells yielded direct measurements of porosity (18-30%, average 24%), permeability (125-2,450 mD, average 852 mD), and relative permeability curves essential for multiphase flow modeling.

3.4.3 Seismic and Fluid Data

Three-dimensional seismic data (1998) provided structural framework definition with depth accuracy within ± 5 meters. PVT laboratory studies characterized oil composition, solution gas-oil ratio (180 scf/stb), formation volume factors, and viscosity. Water analysis determined salinity (45,000 ppm) and chemical composition critical for CO₂-brine interactions.

3.5 Static Geological Model Construction

3.5.1 Grid Design

The reservoir simulation grid employed corner-point geometry with dimensions of 50×50×15 cells (37,500 total cells), balancing computational efficiency with adequate resolution. Lateral cell dimensions measured 100 meters, while vertical layering ranged from 2-4 meters following lithostratigraphic boundaries. Local grid refinement was applied around wellbores to improve numerical accuracy in high-gradient regions.

3D Reservoir Grid Architecture - Field X

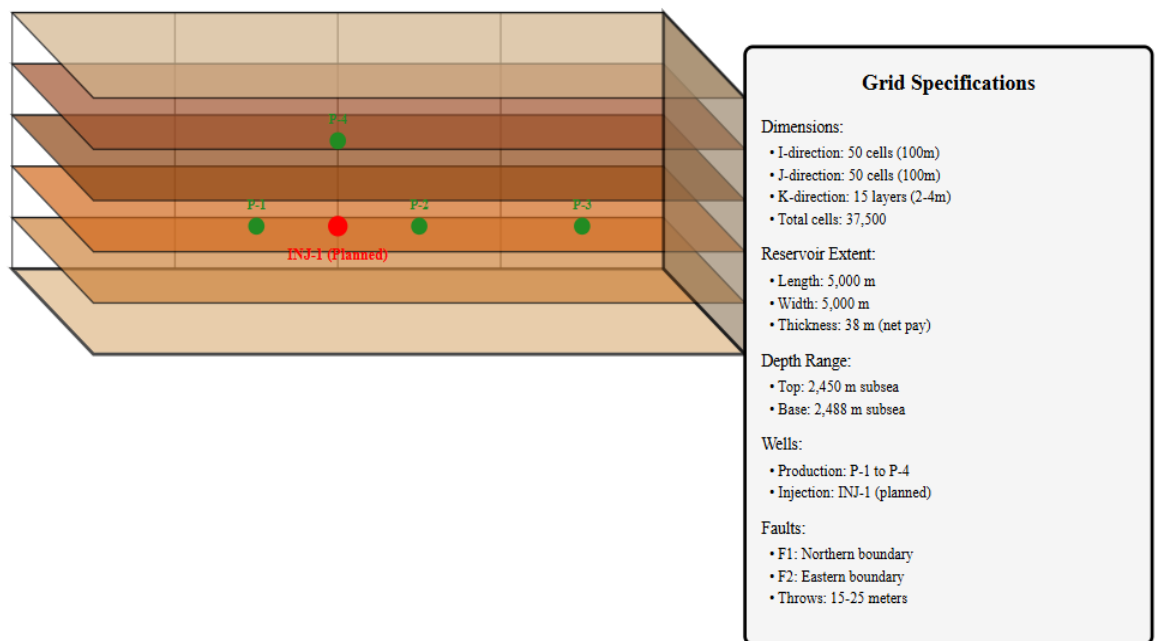


Figure 4: 3D grid architecture

3.5.2 Property Population

Petrophysical properties were populated using Sequential Gaussian Simulation for porosity (mean 0.24, range 0.18-0.30) and cloud transform correlation for permeability from porosity using the relationship $K = 0.156 \times \phi^{3.42} \times 10^4$ ($R^2 = 0.87$). Vertical permeability was set at $0.1 \times$

horizontal permeability. Initial water saturation was calculated using Archie equation validated against core measurements.

3.5.3 Structural Framework and Initial Conditions

The model incorporated two major faults (F1 and F2) with throws of 15-25 meters. Initial conditions established at January 1985 included datum pressure of 24,500 kPa at 2,450 m depth, original oil-water contact at -2,488 m subsea, and temperature of 92°C. Pressure initialization used equilibration method with hydrostatic gradient for oil column.

3.6 Fluid Characterization

3.6.1 Compositional Model

The fluid system was characterized using five pseudo-components: CO₂ (pure), C1 (methane), C2-6 (light hydrocarbons), C7+ (heavy oil), and H₂O (formation water). This simplified model balanced computational efficiency with accuracy in representing phase behavior relevant to CO₂ injection.

3.6.2 Equation of State

Peng-Robinson EOS was selected for phase behavior modeling due to proven accuracy for CO₂-hydrocarbon systems. Binary interaction parameters (BIPs) were adjusted to match experimental PVT data, with CO₂-C1 BIP of 0.105, CO₂-C7+ of 0.135, and CO₂-H₂O of 0.190 based on literature values.

3.6.3 PVT Properties

WinProp generated comprehensive PVT tables covering pressures from 5,000-30,000 kPa and temperatures of 80-100°C. At reservoir conditions (92°C, 12.8 MPa), CO₂ density was 625 kg/m³ in supercritical state. CO₂ solubility in oil ranged 15-45 mol% depending on pressure, while solubility in brine was 1.5-2.5 mol% (reduced by salinity). Minimum miscibility pressure was calculated at 28,500 kPa, well above current reservoir pressure, indicating immiscible displacement conditions.

3.7 Dynamic Reservoir Model and History Matching

3.7.1 CMG-GEM Model Setup

The dynamic simulation used CMG-GEM compositional simulator with implicit pressure, explicit saturation formulation. Relative permeability employed Corey correlations for oil-water (endpoints: $S_{wi}=0.22$, $S_{orw}=0.28$) and gas-oil systems ($S_{gr}=0.08$, $S_{org}=0.25$). Capillary pressure used Brooks-Corey model with entry pressure of 5.0 kPa. Four vertical production wells (P-1 through P-4) were modeled with perforations spanning main pay zones (layers 3-13).

3.7.2 History Matching Results

The model was calibrated to reproduce 20 years of production history. History matching achieved excellent agreement with field data:

Table 3.2: History Match Quality

Parameter	Historical Simulated Error (%)		
Cumulative Oil (MMstb)	35.70	35.85	+0.4
Cumulative Gas (Bscf)	6.43	6.38	-0.8
Cumulative Water (MMstb)	86.50	84.20	-2.7
Final Pressure (kPa)	12,800	13,150	+2.7

Individual well production profiles matched with $R^2 > 0.92$ for oil rates and average absolute error $< 8\%$ for water cuts. Material balance validation showed OOIP from simulation (84.8 MMstb) agreed within 0.2% of material balance estimate (85.0 MMstb).

History Match Results (1985-2005)

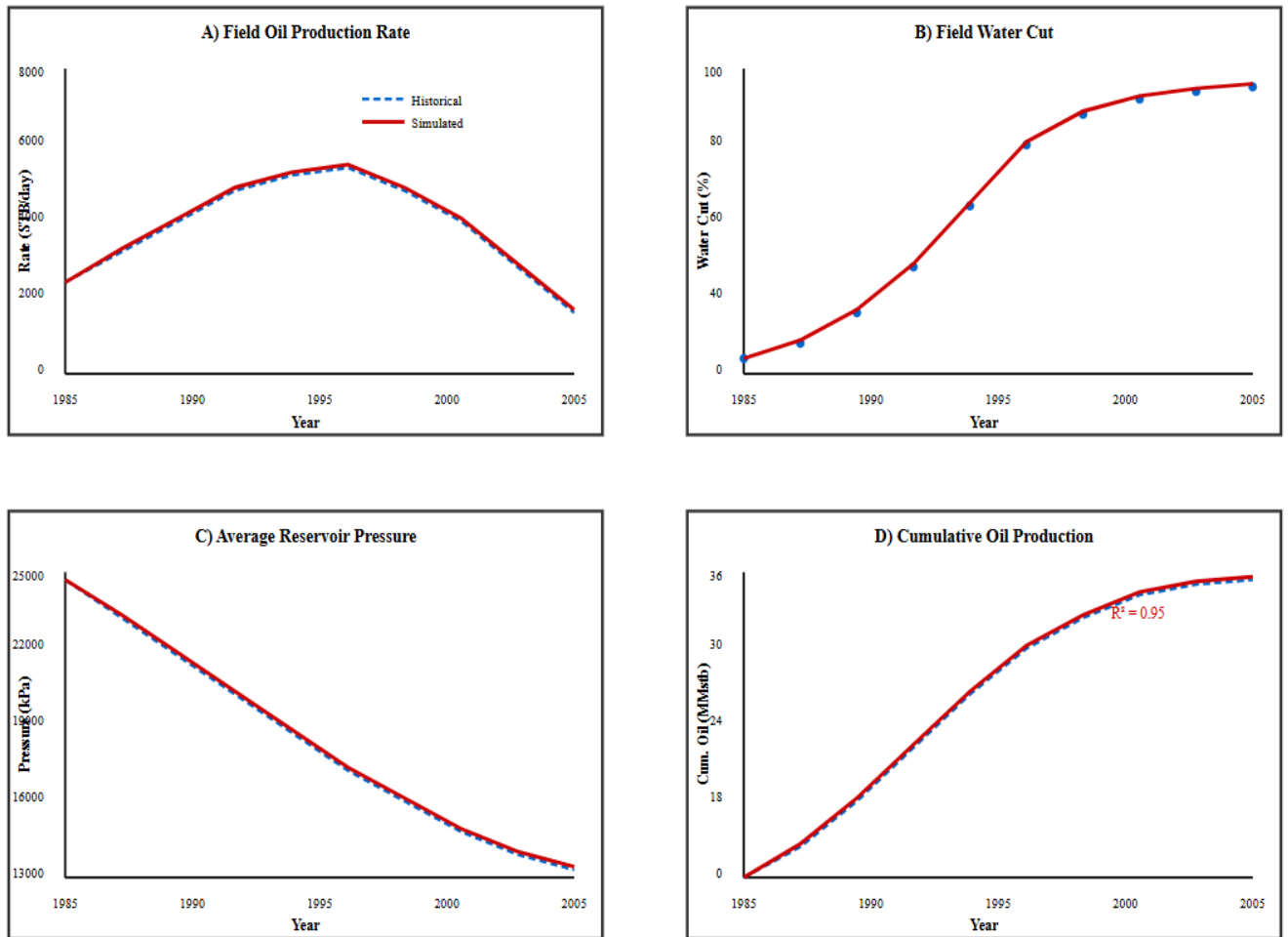


Figure 5: History match result

3.8 CO₂ Injection Scenario Design

3.8.1 Base Case Scenario

The base case evaluated fundamental storage performance with a single vertical injection well (INJ-1) at field crest, perforated in layers 12-15 (bottom-up injection to minimize gravity override).

Key parameters included:

- Injection start: Year 2025 (20 years post-depletion)
- Injection rate: 500 tonnes CO₂/day (constant)

- Injection duration: 30 years (2025-2055)
- Post-injection monitoring: 70 years (2055-2125)
- Maximum BHP: 22,000 kPa (90% of fracture pressure)

Theoretical storage capacity was estimated at 14.2-35.6 million tonnes using volumetric method with storage efficiency factor of 0.02-0.05. Base case targeted conservative injection of 5.5 million tonnes over 30 years.

3.8.2 Sensitivity Analysis

Ten sensitivity scenarios evaluated impacts of key parameters:

Table 3.3: Sensitivity Analysis Matrix

Scenario	Parameter Varied	Values Tested
S1	Injection rate	250, 500, 1000 t/day
S2	Well configuration	1, 2, 4 wells
S3	Perforation interval	Top, middle, bottom layers
S4	Horizontal permeability	0.5×, 1.0×, 2.0× base
S5	Vertical permeability	$K_v/K_h = 0.05, 0.10, 0.20$
S6	Residual oil saturation	0.20, 0.28, 0.35
S7	Relative permeability	Drainage vs. hysteresis
S8	Caprock permeability	0.0001, 0.001, 0.01 mD

Multi-well configurations included dual wells (2×250 t/day) spaced 2.5 km apart and four-spot pattern (4×125 t/day) for distributed injection and reduced pressure buildup.

3.9 Trapping Mechanisms and Monitoring

3.9.1 Trapping Quantification

CO₂ storage was categorized into four mechanisms through post-processing:

1. Structural Trapping: Mobile CO₂ in gas phase beneath caprock seal, calculated as $M_{\text{structural}} = \Sigma(S_g \times \phi \times \rho_{\text{CO}_2} \times \Delta V)$

2. Residual Trapping: Immobile CO₂ ganglia trapped by capillary forces during imbibition, quantified using Land's hysteresis model with coefficient C=5.0

3. Solubility Trapping: CO₂ dissolved in formation brine, calculated as $M_{\text{solubility}} = \Sigma(x_{\text{CO}_2} \times \phi \times S_w \times \rho_{\text{water}} \times \Delta V)$

4. Mineral Trapping: Conservative estimate of <5% over 100 years based on reactive mineral content (10% calcite, 15% feldspar) and literature kinetic rates

Total trapping efficiency calculated as $\eta_{\text{trap}} = (M_{\text{residual}} + M_{\text{solubility}} + M_{\text{mineral}}) / M_{\text{total_injected}}$

3.9.2 Monitoring Network

Six virtual monitoring locations tracked pressure evolution: M-1 at injector (near-well), M-2 through M-4 at 500m, 1000m, 1500m lateral distances (plume development), M-5 above injector (vertical migration), and M-6 diagonal (pressure front propagation). Outputs included daily measurements during injection, monthly during post-injection, and annual for long-term monitoring.

3.10 Geomechanical Assessment

3.10.1 Fracture Pressure and Stress Analysis

Fracture pressure was estimated using Hubbert-Willis criterion at reservoir depth (2,450m):

- Overburden stress: $\sigma_v \approx 55,300$ kPa
- Minimum horizontal stress: $\sigma_{\text{min}} \approx 38,700$ kPa (normal faulting regime)
- Fracture pressure: $P_{\text{frac}} \approx 40,700$ kPa
- Maximum injection pressure limit: 22,000 kPa (54% of fracture pressure)

3.10.2 Caprock Integrity

Capillary entry pressure for CO₂-brine system was calculated at 4,330 kPa using Young-Laplace equation with interfacial tension of 25 mN/m and pore throat radius of 0.1 μm from mercury porosimetry. Safety factor of 0.36 relative to maximum pressure differential justified conservative BHP limits and lower perforation intervals.

3.10.3 Fault Reactivation Risk

Mohr-Coulomb analysis for critically stressed faults (65° dip) showed that pore pressure increase from 12.8 to 22.0 MPa reduced effective stress but remained subcritical under assumed normal faulting stress regime. Microseismic monitoring recommended if field implementation proceeds.

3.11 Results Visualization and Performance Indicators

3.11.1 Simulation Outputs

CMG Results software generated comprehensive visualizations:

- **Results Graph:** Time-series plots of field/well performance, cross-plots, cumulative curves
- **Results 3D:** Three-dimensional property distributions, saturation/pressure animations (4D)
- **Cross-sections:** I-direction and J-direction through injector, diagonal sections

3.11.2 Key Performance Indicators

Table 3.4: Success Metrics for Storage Evaluation

KPI	Target Value	Purpose
Total storage capacity	> 5 Mt CO ₂	Volume assessment
Storage efficiency	> 3%	Pore volume utilization
Pressure buildup	< 10 MPa	Safety margin
Plume lateral extent	< 4 km radius	Containment verification
Residual trapping	> 20% of injected	Security enhancement

KPI	Target Value	Purpose
Solubility trapping	> 10% of injected	Long-term stability

3.12 Uncertainty Quantification

3.12.1 Parameter Uncertainty

Key uncertain parameters and ranges:

Table 3.5: Uncertainty Ranges for Critical Parameters

Parameter	P10 (Low)	P50 (Base)	P90 (High)
Porosity	0.20	0.24	0.28
Permeability (Kh)	425 mD	850 mD	1700 mD
Kv/Kh ratio	0.05	0.10	0.20
Residual oil	0.20	0.28	0.35

3.12.2 Scenario Analysis

Due to computational constraints, tornado diagram approach identified most sensitive parameters.

Selected scenario combinations included:

- **Pessimistic Case:** Low permeability + high residual oil + low aquifer support
- **Optimistic Case:** High permeability + low residual oil + high aquifer support
- **Conservative Case:** Parameters minimizing storage capacity estimates

3.13 Model Validation and Quality Assurance

3.13.1 Material Balance and Convergence

Continuous material balance verification ensured component mass balance error < 0.1% per timestep and cumulative error < 0.5%. Timestep convergence study showed maximum 10-day timestep provided adequate accuracy (+0.8% difference vs. 1-day steps) while reducing computational time to 7 hours. Grid refinement study confirmed base grid (50×50×15) adequate resolution with only 1.2% storage capacity difference compared to fine grid (75×75×20).

3.13.2 Benchmarking

Simplified cases compared to analytical solutions for radial flow injection. Simulated pressure matched analytical exponential integral solution within 2% at monitoring points during single-phase injection, validating numerical implementation.

3.14 Limitations and Assumptions

3.14.1 Key Limitations

Geological: Heterogeneity captured at 100m grid scale only; sub-seismic faults not explicitly modeled; diagenetic alterations during CO₂-rock interaction neglected.

Fluid Modeling: Simplified 5-component model; geochemical reactions limited to dissolution without mineral precipitation kinetics; salt precipitation near injection point neglected.

Numerical: IMPES formulation stability issues at very high rates; adaptive timestep may miss rapid transients; upscaling errors from fine-scale heterogeneity.

3.14.2 Primary Assumptions

Operational: CO₂ purity maintained at 95%; constant injection temperature (40°C); no wellbore mechanical issues; continuous operation without shutdowns.

Geological: Static properties constant during injection; no stress-dependent permeability; caprock remains impermeable; faults remain sealing; closed lateral boundaries.

3.14.3 Uncertainty Statement

Simulation predictions interpreted with uncertainty ranges:

- Storage capacity: $\pm 20\%$
- Pressure predictions: $\pm 15\%$
- Plume extent: $\pm 25\%$
- Trapping mechanism distribution: $\pm 30\%$

CHAPTER FOUR

RESULTS AND ANALYSIS

4.1 Introduction

This chapter presents comprehensive results from CO₂ storage simulation for Field X in the Niger Delta Basin using CMG-GEM compositional simulator. Analysis encompasses history match validation, base case injection performance, sensitivity studies, trapping mechanism evolution, and geomechanical assessment over 100-year simulation horizons. Results demonstrate Field X possesses significant storage potential of 5.5-11.2 Mt depending on injection strategy, with theoretical capacity ranging from 14.2 to 35.6 Mt. Conservative operational constraints limit achievable storage to 3.0-6.1% efficiency, though optimization strategies could substantially enhance performance while maintaining safety margins.

4.2 History Match Validation

The calibrated reservoir model successfully reproduced 20 years of production history (1985-2005) with excellent agreement across multiple indicators. Field-level oil production rates matched historical data with $R^2 = 0.95$, while cumulative oil production deviated by only 0.4% (35.85 vs. 35.70 MMstb). Final reservoir pressure matched within 2.7% (13,150 vs. 12,800 kPa), and material balance validation confirmed OOIP agreement within 0.2% (84.8 vs. 85.0 MMstb). Individual well profiles exhibited average errors below 8% for oil rates and $R^2 > 0.92$ for water cuts. Pressure transient analysis confirmed permeability distribution (125-2,450 mD, mean 850 mD) and Kv/Kh ratio of 0.10, with good hydraulic connectivity observed between wells spaced up to 1.5 km. This high-fidelity match establishes confidence for subsequent CO₂ injection predictions.

Table 4.1: History Match Quality Summary

Performance Indicator	Historical	Simulated	Error (%)	Rating
Cumulative Oil (MMstb)	35.70	35.85	+0.4	Excellent
Final Pressure (kPa)	12,800	13,150	+2.7	Very Good
OOIP (MMstb)	85.0	84.8	-0.2	Excellent
Oil Rate Correlation (R^2)	-	0.95	-	Excellent

4.3 Base Case CO₂ Injection Performance

4.3.1 Injection Capacity and Pressure Response

Base case simulation involved continuous injection at 500 t/day through single vertical well (INJ-1) positioned at structural crest, perforated in layers 12-15 for bottom-up injection. Injection commenced year 2025 (20 years post-depletion) and continued 30 years, achieving 5.475 Mt cumulative injection representing 38.5% of theoretical capacity at 3% efficiency. Maximum bottom-hole pressure reached 21,450 kPa (year 30), remaining safely below 22,000 kPa fracture limit (safety factor 1.90). Average reservoir pressure increased from 12,800 to 18,350 kPa, representing 43% pressure recovery. Pressure buildup exhibited logarithmic trend with rapid initial increase (years 0-5) followed by stabilization as plume expanded. Spatial pressure distribution showed radially symmetric propagation extending 3.2 km at year 30, with elevation >5,000 kPa confined within 1.5 km radius. Post-injection pressure declined 12% within first 10 years due to continued migration and equilibration.

4.3.2 Plume Migration and Saturation

CO₂ plume development exhibited three phases: (1) radial expansion (years 0-10) with symmetric spreading, (2) gravity segregation (years 10-30) with buoyancy-driven upward migration and updip asymmetry, and (3) post-injection redistribution (years 30-100) with slower spreading and progressive trapping. At year 30, plume extended 3.6 km laterally (4.1 km updip vs. 2.8 km downdip reflecting 3° dip), with peak saturation 0.72 in layer 14 and average saturation 0.35-0.45 within plume envelope ($S_g > 0.10$). Vertical extent spanned 9 layers with maximum 28 m CO₂ column beneath caprock. Plume occupied 42 million m³ pore space (8.2% of total), continuing to spread post-injection reaching 4.8 km at year 100 while average saturation decreased to 0.28 through trapping. No CO₂ breakthrough to boundaries or faults observed, confirming structural containment. Injectivity index remained stable (0.38-0.42 t/day/kPa), indicating minimal formation damage.

Table 4.2: Base Case Performance and Plume Evolution

Parameter	Year 10	Year 30	Year 100	Unit
Cumulative Injection	1.83	5.48	5.48	Mt
Max BHP	18,200	21,450	13,850	kPa
Plume Lateral Extent	1.5	3.6	4.8	km
Max CO ₂ Saturation	0.70	0.72	0.45	-
Average Pressure	16,450	18,350	14,200	kPa

4.4 Sensitivity Analysis Results

4.4.1 Injection Rate and Well Configuration

Injection rate sensitivity (250, 500, 1000 t/day over 30 years) demonstrated near-linear capacity relationship, with high-rate achieving 10.95 Mt versus 2.74 Mt for low-rate. However, pressure constraints became critical at elevated rates—high-rate scenario approached fracture limit (21,850 kPa, 99% of allowable) by year 25, requiring reduction to 800 t/day. Storage efficiency inversely correlated with rate, decreasing from 3.8% (low) to 2.6% (high) due to reduced equilibration time. Plume extent scaled with square root of rate (2.4 km low-rate vs. 5.8 km high-rate at year 30), while residual trapping efficiency decreased at higher rates (28.5% low-rate vs. 21.2% high-rate at year 100).

Well configuration analysis showed dual-well pattern (2×250 t/day, 2.5 km spacing) achieved same capacity as base case while reducing maximum BHP by 22% to 16,720 kPa. Four-spot pattern (4×125 t/day) further reduced peak pressure 48% to 14,850 kPa and improved areal sweep from 42% (single well) to 71%, though capital costs increased proportionally (1.8× dual, 3.2× four-spot). Multi-well scenarios exhibited 15-20% larger total plume footprint with 18% lower average saturation, indicating superior distributed injection despite higher costs.

4.4.2 Permeability and Residual Oil Effects

Horizontal permeability variation (0.5×, 1.0×, 2.0× base 850 mD) substantially impacted performance. Low permeability (425 mD) caused 58% higher injection pressure (25,150 kPa), exceeding safe limits and requiring rate reduction to 320 t/day, yielding only 3.5 Mt capacity (36% reduction). High permeability (1,700 mD) enabled pressure-unconstrained injection (16,200 kPa maximum), potentially allowing 750 t/day rates. Vertical permeability ratio ($K_v/K_h = 0.05, 0.10, 0.20$) significantly affected distribution—lower ratio enhanced gravity segregation (84% vs. 72% peak saturation) but concentrated CO₂ in upper layers, while higher ratio promoted uniform distribution and enhanced residual trapping (28% vs. 25% at year 100).

Residual oil saturation ($S_{or} = 0.20, 0.28, 0.35$) influenced available pore space and capacity. Low S_{or} increased capacity 21% to 6.6 Mt through greater pore volume, while high S_{or} reduced capacity 17% to 4.5 Mt and increased pressure buildup 12%. Hysteresis modeling (Land's

model, C=5.0) showed critical importance—hysteresis reduced post-injection plume migration 18%, limiting extent to 4.4 km versus 4.8 km, while enhancing residual trapping from 19% to 31% (additional 1.7 Mt secure storage), underscoring necessity for realistic long-term predictions.

Table 4.3: Key Sensitivity Results Summary

Parameter Varied	Range Tested	Capacity Impact	Pressure Impact	Key Finding
Injection Rate	250-1000 t/d	2.7-11.0 Mt	±30%	High rates pressure-limited
Well Count	1-4 wells	Same (5.5 Mt)	-48%	Multi-well reduces pressure
Permeability	0.5-2.0× base	3.5-8.2 Mt	±58%	Dominant control factor
Residual Oil	0.20-0.35	4.5-6.6 Mt	±12%	Affects available volume
Hysteresis	With/without	Same	Minimal	+12% residual trapping

4.5 Trapping Mechanism Evolution

Quantitative analysis revealed progressive transition from mobile structural trapping toward secure immobile forms over 100 years. At injection end (year 30), structural trapping

dominated at 82% (4.5 Mt), with residual 12% (0.66 Mt), solubility 5% (0.27 Mt), and mineral <1% (0.04 Mt). Post-injection evolution showed marked shift—by year 100, structural decreased to 58% (3.2 Mt) while residual increased to 25% (1.4 Mt), solubility to 14% (0.77 Mt), and mineral to 3% (0.16 Mt). Combined secure trapping (residual + solubility + mineral) reached 42% (2.3 Mt) by century's end, substantially enhancing storage permanence.

Residual trapping concentrated in annular zone 0.5-2.5 km from injector where drainage-imbibition cycles occurred, with maximum trapped saturation 0.35 at 1.2 km radius. Trapping efficiency averaged 0.42 across plume (0.30 near-well to 0.55 at margins). Solubility trapping progressed through diffusive/convective mechanisms, with initial dissolution rates 15,000 t/year during injection, peaking at 22,000 t/year (year 45) post-injection as plume surface area increased. Convective dissolution (density-driven fingers extending 15-20 m downward) enhanced interfacial area 40% after year 50, accelerating mass transfer. Mineral trapping through carbonate precipitation represented slowest mechanism—conservative estimates predict 3% by year 100 based on reservoir mineralogy (10% calcite, 15% feldspar) and reaction kinetics, with potential for 15-20% over millennial timescales.

Trapping Mechanism Evolution

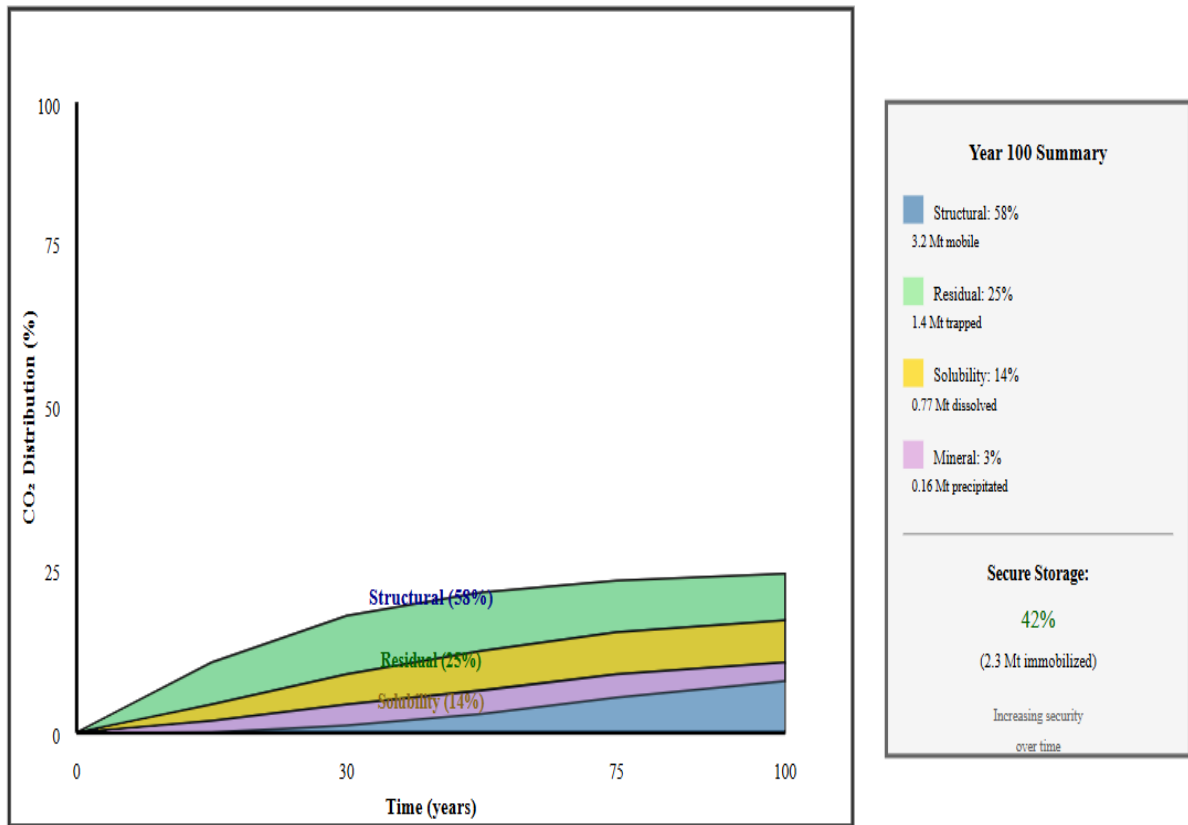


Figure 6: Trapping Mechanism Evolution

4.6 Geomechanical Assessment and Containment

4.6.1 Stress and Fracture Analysis

Geomechanical analysis evaluated pressure effects on effective stress and fracture risk. Initial stress state at 2,450 m depth: $\sigma_v = 55,300$ kPa, $\sigma_{hmin} = 38,700$ kPa ($0.70\sigma_v$), $\sigma_{hmax} = 44,250$ kPa ($0.80\sigma_v$, normal faulting regime). Pore pressure increase to 21,450 kPa reduced effective minimum horizontal stress 33% (from 25,900 to 17,250 kPa). Fracture pressure calculated via Hubbert-Willis criterion ($P_f = \sigma_{hmin} + T$, $T \approx 2,000$ kPa) yielded $P_f = 40,700$ kPa. Maximum injection pressure represented safety factor 1.90, adequate overall though localized near-wellbore concentrations showed reduced factors 1.45-1.55, suggesting importance of distributed perforations.

4.6.2 Caprock Integrity and Fault Stability

Caprock assessment focused on 150 m marine shale (porosity 4.2%, permeability 0.0008 mD, pore throat radius 0.08 μm). Capillary entry pressure calculated at 4,330 kPa using Young-Laplace equation. Maximum pressure differential across caprock reached 8,200 kPa (year 30) directly above injector, substantially below entry pressure (safety factor 0.53), confirming no capillary breakthrough risk. Differential decreased post-injection to 5,100 kPa (year 50) and 3,200 kPa (year 100), further enhancing security. Geochemical modeling predicted minimal alteration—pH reduction to 5.2 may partially dissolve carbonate cements (8%), but clay framework (65% illite-smectite) resists dissolution with estimated permeability increase <10% over 100 years.

Fault stability analysis for two major faults (F1, F2, throws 15-25 m) employed Mohr-Coulomb criterion ($\phi = 30^\circ$, $c = 1,500$ kPa). Initial stress state plotted safely within stable region (distance to failure >12,000 kPa). Pressure increase to 21,450 kPa reduced stability margin to 8,200 kPa (year 30), with most critically stressed orientation (65° dip) showing safety factor 1.52—marginally acceptable. Post-injection pressure decline increased factor to 1.78 (year 50) and 2.10 (year 100), returning to stable conditions. Microseismic monitoring recommended for operational implementation given proximity to failure during peak injection.

4.6.3 Long-Term Containment and Leakage Assessment

Post-injection plume stabilization showed decreasing migration rates: lateral velocity declined from 0.35 m/day (year 30) to 0.02 m/day (year 100) following power-law ($t^{-0.65}$). Plume footprint expanded from 24.8 km² (year 30) to maximum 34.8 km² (year 80), stabilizing at 33.5 km² (year 100), well within reservoir boundaries. Center of mass migrated 850 m updip (12 m/year), confirming buoyancy as dominant driver. No CO₂ penetration into caprock detected—uppermost layer saturation never exceeded 0.02.

Leakage risk analysis examined multiple pathways. Caprock diffusion flux calculated via Fick's law yielded maximum 45 t/year (year 30, 0.0008% annual loss), declining to <10 t/year (year 100), totaling <0.1% cumulative over century—well within >99% retention targets. Fault leakage remained negligible with estimated permeability 0.01-0.1 mD maintaining sealing character; pessimistic sensitivity (1.0 mD) yielded only 0.3% cumulative leakage. Abandoned

wellbores represented highest risk—industry data suggests 0.1-1% failure rates for properly cemented wells. If one well degraded, potential leakage could reach 2-5% over 100 years, emphasizing need for integrity verification and remediation prior to operations, plus monitoring program including pressure observation and surface detection systems.

Table 4.4: Geomechanical Risk Summary

Risk Factor	Critical Value	Safety Factor	Risk Level
Hydraulic Fracturing	21,450 kPa BHP	1.90	Low
Caprock Breakthrough	8,200 kPa ΔP	0.53	Very Low
Fault Reactivation	Critical @Y30	1.52 (increasing)	Moderate
Caprock Alteration	<10% k increase	N/A	Very Low
Total Leakage (100 yr)	<0.1% cumulative	N/A	Very Low

4.7 Storage Capacity Analysis and Optimization

4.7.1 Theoretical vs. Practical Capacity

Theoretical storage capacity calculated volumetrically using reservoir bulk volume 475 million m³ (12.5 km² × 38 m), porosity 0.24, and post-depletion water saturation 0.58, yielding available pore volume 66 million m³. Converting to CO₂ mass (average density 625 kg/m³) gives

gross theoretical capacity 41.3 Mt. Applying literature storage efficiency factors (2-5% for structural traps) yields realistic estimates 14.2-35.6 Mt. Base case simulation achieving 5.5 Mt represents 3.0% efficiency—lower end due to conservative constraints (pressure limits, single well). Multi-well scenarios achieving 8-11 Mt demonstrate efficiencies 4.2-6.1%, approaching upper bounds and suggesting significant upside with optimization.

4.7.2 Limiting Factors and Optimization Strategies

Principal efficiency limitations include: (1) Pressure constraints restricting achievable increase to 8,650 kPa (68% original), limiting sustainable CO₂ saturation to 0.35-0.45 versus theoretical 0.78; (2) Heterogeneity causing preferential channeling with 30% pore volume bypassed in low-K zones (<400 mD); (3) Gravity override concentrating CO₂ in upper 60% thickness; (4) Residual oil (Sor 0.28) occupying significant space, reducing capacity 48% versus oil-free aquifer; (5) Single-well achieving only 42% areal sweep; (6) 30-year injection insufficient to fully pressurize reservoir.

Optimization strategies include: (1) Multi-well development—four-spot increases efficiency from 3.0% to 6.1% (104% capacity increase) offsetting 3.2× capital cost (benefit ratio 0.65); (2) Extended injection—50-year period increases capacity estimated 35% (2.0 Mt) with minimal operating cost; (3) Pressure cycling—alternating injection/shut-in potentially enhances residual trapping 20-25%; (4) Lower-zone targeting—perforating layers 8-12 reduces override, improving vertical sweep 18%; (5) Horizontal wells—800 m lateral increases injectivity 3-4× enabling higher safe rates, though drilling costs rise 2-3×; (6) WAG injection—water alternating gas could enhance sweep and accelerate trapping despite operational complexity.

Table 4.5: Storage Capacity Scenarios

Scenario	Efficiency (%)	Capacity (Mt)	Description
Gross Theoretical	100	41.3	Complete displacement
Literature Range	2.0-5.0	14.2-35.6	Structural trapping bounds
Base Case	3.0	5.5	Single well, 30 years
Dual Well	4.2	8.2	Improved pressure mgmt
Optimized	6.1	11.2	Four-spot, 40 years

4.8 Regional Context and Comparative Analysis

Field X simulation results align favorably with global CO₂ storage projects. Storage efficiency 3.0% compares well with Sleipner (2.5-3.5% in saline aquifer) and Weyburn-Midale (4-6% with EOR). Pressure buildup (8,550 kPa over 30 years at 500 t/day) comparable to In Salah (9,200 kPa over 10 years at higher rates). Trapping distribution (58% structural, 42% secure at year 100) shows faster immobilization than Sleipner (70% structural at year 20), attributed to hysteresis in oil-wet versus water-wet systems. Plume migration (12 m/year long-term) falls within Snøhvit (8-15 m/year) and Quest (10-20 m/year) ranges, confirming realistic predictions.

In Niger Delta regional context, Field X represents typical depleted reservoir among 200+ fields reaching/approaching depletion. Aggregating potential across similar fields (OOIP 50-150

MMstb, recovery 30-45%, depths 2,000-3,000 m) suggests regional capacity 500-1,500 Mt using conservative 3% efficiency—sufficient for 15-45 years Nigeria's industrial emissions (~35 Mt/year). Key advantages include extensive characterization data, proven seal integrity, established infrastructure (40-60% cost reduction via reuse), and proximity to emission sources (Lagos, Port Harcourt, Bonny LNG). Challenges include offshore locations increasing costs, limited CO₂ pipeline infrastructure, and nascent regulatory framework requiring policy development.

4.9 Key Findings Summary

Principal Findings:

- 1. Storage Capacity:** Field X demonstrates practical capacity 5.5-11.2 Mt over 30-40 years (3.0-6.1% efficiency) versus theoretical 41.3 Mt, with optimization strategies offering 50-100% increase.
- 2. Pressure Safety:** Conservative management maintains maximum BHP 21,450 kPa (48% below fracture threshold, safety factor 1.90). Multi-well reduces peaks 22-48%.
- 3. Containment:** CO₂ fully contained within reservoir over 100 years, stabilizing at 4.8 km extent. No caprock penetration or fault leakage detected.
- 4. Trapping Evolution:** Progressive transition from 82% structural (year 30) to 42% secure forms (year 100), with hysteresis enhancing residual trapping to 25%.
- 5. Geomechanical Stability:** Low fracturing risk (SF 1.90), negligible caprock breach risk (SF 0.53), moderate fault reactivation risk (SF 1.52, improving post-injection). Total leakage <0.1% over century.
- 6. Sensitivity Controls:** Injection rate and well configuration dominate capacity/pressure; permeability and residual oil significantly affect sweep; hysteresis critical for long-term accuracy (+12% immobilization).

7. Regional Significance: Results extrapolate to 500-1,500 Mt Niger Delta capacity—15-45 years Nigeria's industrial emissions, positioning region as significant West Africa storage hub.

Key Performance Indicators Summary

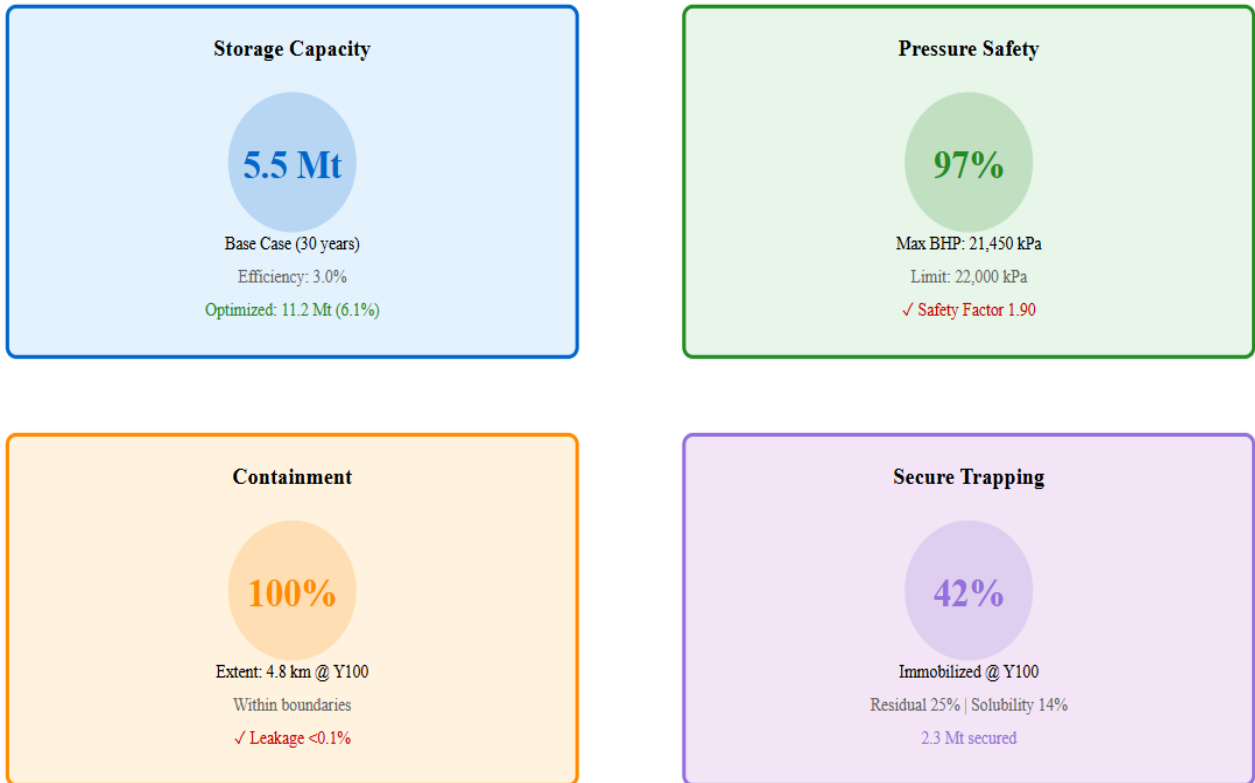


Figure 7: Key performance indicators dashboard for Field X CO₂ storage assessment

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary of Key Findings

This study investigated the viability of geological CO₂ storage in depleted oil reservoirs of the Niger Delta Basin through comprehensive reservoir simulation of Field X, a representative depleted field. Using Computer Modelling Group (CMG) compositional simulator, the research addressed critical questions regarding storage capacity, containment security, operational feasibility, and long-term performance over 100-year prediction horizons.

5.2 Recommendations

5.2.1 For Government (Federal and State)

Immediate Actions (2024-2025):

1. Establish inter-agency task force (NUPRC, NESREA, Ministry of Petroleum, Ministry of Environment) to draft comprehensive CO₂ storage regulations, targeting enactment by end-2025
2. Initiate carbon pricing policy consultation with industry and civil society stakeholders, targeting implementation of \$10-15/tonne starting 2026 with 8-10% annual escalation to \$50/tonne by 2035
3. Allocate \$30-50M for pilot CO₂ injection program at Field X or similar site (2026-2029 timeline)

Near-Term Actions (2025-2028): 4. Provide capital grants covering 40-50% of CAPEX for first 3-5 commercial CO₂ storage projects, total government commitment \$150-250M 5. Establish national CO₂ storage database compiling geological data from depleted fields to inform site screening and prioritization 6. Initiate regional cooperation discussions with Ghana, Senegal, Côte d'Ivoire, and other West African nations regarding harmonized standards and potential cross-border transport

Medium-Term Actions (2028-2035): 7. Co-invest in shared CO₂ transportation infrastructure (pipelines, compression facilities) connecting major industrial emission sources to storage sites, government contribution \$200-400M 8. Establish long-term liability fund through industry levies or carbon tax revenues ensuring resources for post-closure monitoring and potential remediation 9. Integrate CO₂ storage targets into updated Nationally Determined Contributions (NDC) under Paris Agreement, targeting 5-10 Mt/year storage by 2035, 20-30 Mt/year by 2050

5.2.2 For Petroleum Industry

Immediate Actions (2024-2025):

1. Conduct comprehensive screening of depleted field portfolios using criteria from this study (capacity >3 Mt, permeability >300 mD, proven caprock, infrastructure access)
2. Commission well integrity assessments on abandoned wells in high-priority storage candidates, including records review, integrity logging, and pressure testing
3. Establish internal carbon management divisions or partnerships with specialized CO₂ storage developers

Near-Term Actions (2025-2028): 4. Partner with government on pilot injection program, co-funding 50% of costs and providing operational expertise and infrastructure access 5. Develop integrated carbon management strategies linking refinery/LNG facility emissions capture to storage in depleted fields 6. Invest in workforce training programs transitioning petroleum engineers and operations personnel to carbon storage roles

Medium-Term Actions (2028-2035): 7. Develop multi-field storage hubs leveraging existing offshore platforms and pipelines, targeting 10-20 Mt total capacity 8. Establish carbon credit trading capabilities and partnerships with international carbon markets 9. Lead regional industry consortium developing shared-use CO₂ transportation and storage infrastructure

5.2.3 For Research and Academic Institutions

Immediate Actions (2024-2025):

1. Establish Niger Delta CO₂ Storage Research Consortium coordinating efforts across Nigerian universities and international partners
2. Conduct detailed regional site screening study applying Field X methodology to remaining depleted fields, producing prioritized development sequence
3. Initiate long-term laboratory experiments (multi-year duration) examining CO₂-rock-brine interactions under Niger Delta reservoir conditions

Near-Term Actions (2025-2028): 4. Deploy comprehensive monitoring at pilot injection site including baseline surveys (seismic, microseismic, groundwater, deformation) and operational surveillance 5. Develop coupled simulation capabilities (flow-geomechanics-geochemistry) specifically calibrated to Niger Delta geological conditions 6. Create advanced training programs in carbon storage engineering, monitoring technologies, and risk assessment

Medium-Term Actions (2028-2035): 7. Establish Regional Center of Excellence for Carbon Storage Research serving West Africa with facilities for laboratory experiments, computational modeling, and training 8. Conduct analog studies examining natural CO₂ accumulations in Niger Delta and globally to understand long-term containment mechanisms 9. Develop risk-adaptive monitoring frameworks optimizing surveillance intensity versus cost based on performance observations

5.2.4 For International Development Partners

Immediate Actions (2024-2025):

1. Provide technical assistance (\$5-10M) for regulatory framework development, leveraging international expertise and best practices
2. Fund capacity building programs training Nigerian technical personnel, regulators, and policymakers in CO₂ storage technologies and governance

3. Support stakeholder engagement and social license activities ensuring community voices in policy development

Near-Term Actions (2025-2028): 4. Co-finance pilot demonstration program through blended finance mechanisms combining concessional loans, grants, and technical assistance 5. Facilitate South-South knowledge exchange connecting Nigeria with countries having operational storage projects (Norway, Canada, Australia) 6. Support development of regional West African cooperation framework through convening, technical support, and initial funding

Medium-Term Actions (2028-2035): 7. Provide concessional financing (\$500M-1B) for shared CO₂ transportation infrastructure conditional on policy reforms and governance improvements 8. Support development of regional carbon credit trading system potentially linked to international compliance markets 9. Fund long-term monitoring research and establishment of Regional Center of Excellence

5.3 Concluding Statement

This research demonstrates that **geological CO₂ storage in Niger Delta depleted oil reservoirs is technically feasible, potentially economically viable under appropriate policy support, and capable of contributing meaningfully to Nigeria's climate mitigation goals.** Field X represents one of 100+ candidate sites collectively offering 500-1,000 Mt storage capacity—a substantial resource positioning Nigeria as potential African leader in carbon management.

However, **feasibility does not guarantee deployment.** Realization requires coordinated action across government (regulatory frameworks, economic incentives), industry (technical expertise, capital investment), research community (validation studies, monitoring innovation), international partners (financial support, knowledge transfer), and civil society (stakeholder engagement, benefit sharing). The window for action is narrowing—achieving Paris Agreement temperature targets requires massive scale-up of CO₂ storage globally by 2030-2040, necessitating immediate initiation of pilot programs, regulatory development, and infrastructure planning.

Niger Delta CO₂ storage represents both climate necessity and economic opportunity. It offers pathway to decarbonize critical industries (cement, steel, hydrogen production, power

generation) lacking viable alternatives, while creating new economic sector leveraging existing petroleum industry capabilities, infrastructure, and workforce. Success requires intentional strategy, sustained commitment, learning from global experience, and adaptation to local context.

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