TESTING CENTER FOR OIL AND GAS LEMIGAS

SCIENTIFIC CONTRIBUTIONS OIL AND GAS (SCOG)

Vol. 49. No. 3, September: 53 – 66 - http://journal.lemigas.esdm.go.id

ISSN: 2089-3361, e-ISSN: 2541-0520

Published by:

LEMIGAS

Optimizing CO_2 Storage In Saline Aquifers Through Pressure Redistribution in Natuna D-Alpha Field, Indonesia

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Received: 13 May 2026; Revised in revised form 05 June 2026; Accepted 09 June 2026
Available online 30 September 2026.

ABSTRACT - The increasing concentration of carbon dioxide (CO_2) in the atmosphere is significantly contributing to the critical exploration of Carbon Capture and Storage (CCS) technology. Although deep saline aquifers offer substantial storage potential for CO_2, their effective capacity is often constrained by rapid formation pressure buildup near injector wells and poses safety risks. Therefore, this study aims to propose an integrated strategy to optimize CO_2 storage capacity using pressure redistribution method in a thick carbonate saline aquifer located in Natuna D-Alpha Field, Indonesia. A dynamic numerical simulation is developed by integrating 2D seismic, well logs, core analysis (RCAL/SCAL), and geomechanical parameters derived from log data. The effectiveness of lateral and vertical pressure redistribution is evaluated through brine production wells (PWs) and multi-depth injection, respectively, followed by perforation configuration optimization. Various scenarios are simulated to compare total gas injected and reservoir pressure response against rock fracture limits. The results showed that storage capacity is limited due to the absence of pressure management (Base Case). The implementation of lateral pressure redistribution through brine production proves to be the most significant strategy, capable of increasing storage capacity by approximately 64% of the Base Case in high-rate production scenarios. Furthermore, vertical redistribution strategy using multi-depth injection obtains a 13% capacity increase and improves vertical pressure distribution. A combination of multi-depth injection and brine production shows positive synergy, generating a 44% capacity increase with a storage efficiency of 0.58%. The results also indicate that variations in well perforation geometric patterns (line vs. cross) have minimal impact compared to global pressure management strategies. In line with the analysis, this study finds that brine extraction and vertical injection management are essential to maximizing safe CO_2 storage in thick aquifers.

Keywords: Carbon Capture and Storage (CCS), saline aquifer, pressure redistribution, brine production, numerical simulation, Natuna D-Alpha field

How to cite this article:

Roihan Arie Nirwana, Dedy Irawan, Amega Yasutra, Syarif Kamal, and Welly Ahmad Ramadan, 2026, Optimizing Co₂ Storage In Saline Aquifers Through Pressure Redistribution in Natuna D-Alpha Field, Indonesia, Scientific Contributions Oil and Gas, 49 (3) pp. 53-66.

1. Introduction

The increasing concentration of greenhouse gases, particularly carbon dioxide (CO_2), in the atmosphere is an urgent global issue due to its profound impact on climate change. This global challenge drives the critical exploration of Carbon Capture and Storage (CCS) technology, a transformative method designed to capture CO_2 emissions from industrial processes and ensure safe underground geological containment. In Indonesia, national efforts to advance CCS are being intensified through foundational studies evaluating country-specific CO_2 emission factors based on gas fuels (Herlina et al., 2025). These efforts are further supported by regional assessments that have successfully used geographic information system-based methods for evaluating CO_2 storage potential in Kalimantan basins (Susantoro et al., 2025). However, conceptual studies have shown the reduction of carbon emissions in the East Java power generation sector using saline aquifers as reliable CO_2 sinks (Widarsono et al., 2025).

Among various geological storage options, saline aquifers offer significant potential for long-term CO_2 sequestration due to their widespread availability and significant volumetric capacity. In this geological medium, CO_2 experiences complex physical and chemical transformations governed by interacting trapping mechanisms, such as buoyancy processes, residual trapping, and dissolution (Bachu 2008; Benson 2005; Izadpanahi et al., 2025).

Despite the advantages, the practical implementation of continuous CO_2 injection is significantly constrained by rapid formation pressure buildup near injection wells, creating a major gap between the theoretical storage expectations and the reality of injection operations (Zhou et al., 2008 and Jahediesfanjani et al., 2019). Saline aquifer pressures are often close to virgin pressure because of the absence of hydrocarbon accumulation. Consequently, continuous CO_2 injection rapidly raises formation pressure above initial conditions. This phenomenon imposes severe geomechanical limitations and increases the risks of caprock fracturing, fault reactivation, and subsequent CO_2 leakage (Gonzales et al., 2019). Therefore, managing formation pressure is an important aspect of storage operations. To address the operational considerations in a realistic and high-impact setting, Natuna D-Alpha Field in East Natuna Sea, Indonesia, is selected as the specific study location (Figure 1). This field is strategically significant because adjacent giant gas reservoirs (220 Tcf) contain exceptionally high native CO_2 concentrations (approximately 71%), which require massive, reliable, and localized CCS solutions to enable commercial development. Although the thick carbonate reef aquifer provides an unparalleled capacity for this reinjection, active pressure management remains essential to optimize overall storage capacity.

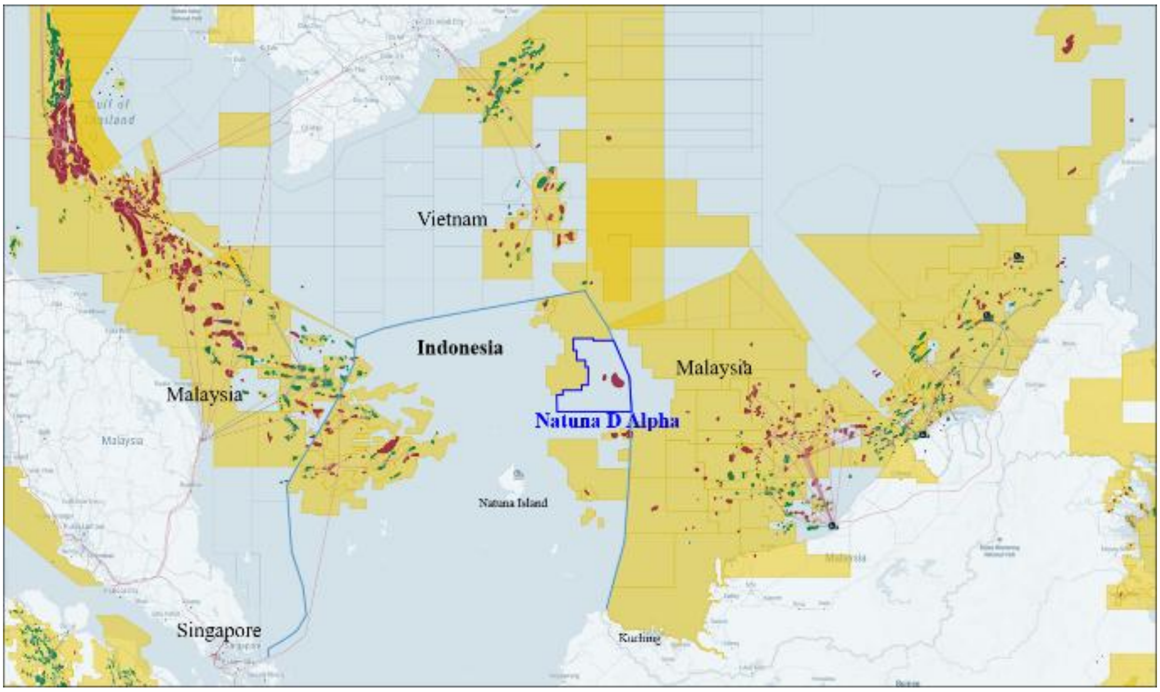

Figure 1.
Natuna D-Alpha Field location

Although various methods have been extensively explored to manage pressure buildup (Hamed & Shirif 2025 and Tao & Bryant 2014), most previous studies have often evaluated these strategies through lateral or vertical pressure management individually. For instance, the use of lateral pressure redistribution through brine extraction has been proven to effectively manage formation pressure and enhance storage capacity (Birkholzer et al., 2012; Buscheck et al., 2012; Cihan et al. 2015; Wang et al., 2023; Jung 2023; Yang & Okwen 2024; Eyitayo et al., 2024). Vertical pressure dissipation through multi-zone injection has also been explored for dispersing pressure in layered formations (Birkholzer et al., 2008; Doster et al., 2013; Zhang & Agarwal 2012).

An integrated evaluation of both pressure management strategies is particularly important in thick carbonate aquifers, where lateral and vertical heterogeneity can strongly influence pressure propagation and CO_2 storage efficiency. Therefore, this study applies an integrated numerical simulation method using advanced lateral and vertical pressure redistribution strategies. The method integrates lateral pressure management, achieved by injecting CO_2 alongside targeted formation water (brine) production, with vertical pressure management using multi-depth injection well configurations. A fully implicit integrated modeling method is considered appropriate by effectively capturing the dynamic physical interactions between the reservoir rock, fluid properties, and complex well configurations. By modelling these interactions against rock fracture limits, this study aims to provide insight into synergistic strategies to safely improve CO_2 storage capacity in the heterogeneous thick saline aquifer of Natuna D-Alpha Field located in East Natuna Sea, Indonesia.

2. Methodology

This study used a quantitative method through numerical simulation to investigate CO_2 storage optimization. The dynamic simulation model integrated geological, rock property, and geomechanical data to evaluate storage capacity and rock integrity realistically. The experiment was conducted in a thick saline Aquifer-1 in Natuna D-Alpha Field (Offshore East Natuna), representing a substantial Carbonate Reef Formation (Figure 2).

East Natuna Basin is geologically characterized by extensive Middle to Late Miocene carbonate buildups, commonly associated with Terumbu Formation. These reefal carbonates show substantial thickness and lateral continuity, with highly variable secondary porosity networks that are favorable for large-scale fluid injection. The target storage area is structurally overlain by thick, impermeable marine shales of Muda Formation, which act as a robust regional seal to ensure long-term containment (Figure 3).

2.1 Data availability and geological model

The dynamic model used in this study is designed from a static model using 2D seismic interpretation and exploration wells. Specifically, the target storage area is located at depths ranging between 5,000 ft and 10,000 ft. Meanwhile, the full-field Aquifer-1 spans an expansive area of approximately 2,000 km² with a massive thickness of roughly 5,000 ft, obtaining a total pore volume of 3,320 billion reservoir barrels. This pore volume is approximately 10 times larger than the adjacent gas field (220 Tcf), providing substantial capacity for long-term CO_2 injection. The target saline formation occurs at depths between 5,000 and 10,000 ft. Despite exceeding the commonly recommended 800–2,500 m (2,600–8,200 ft) range for cost-effective CO_2 storage, several geological and operational factors support its suitability. The elevated pressure and temperature regimes at these depths ensure that CO_2 remains in a dense, supercritical state to promote volumetric storage efficiency and minimize buoyancy-driven leakage risks beneath the regional shale caprock. Operationally, the excellent native permeability of the carbonate reef facilitates the sustenance of favorable injectivity, mitigating the challenges of deep hydrostatic pressure. Injection operations are further optimized by placing 1,000 ft perforation intervals within the upper part of the storage formation rather than extending wells to the deepest interval. This causes significant improvement in injectivity and reduces drilling costs. Economically, any increased capital expenditure for deeper drilling is effectively offset by the aquifer's direct adjacency to Natuna D-Alpha gas field. This colocation allows for immediate, localized disposal of the field's 71% native CO_2, thereby eliminating the need for extensive and costly subsea transportation pipelines.

In this study, rock permeability ranged from 1 mD to 1,000 mD, and permeability was distributed in the model using the correlation $k = 1992\phi^{3.26}$ derived from RCAL data. Storage security was maintained by an overlying

https://doi.org/10.29017/scog.v49i3.2119

shale caprock. Although well log data (AP-1X) showed a thickness exceeding 3,000 ft, the numerical model simplified this to an average of 1,000 ft to improve computational efficiency without sacrificing the accuracy of rock integrity evaluations, as shown in Table 1.

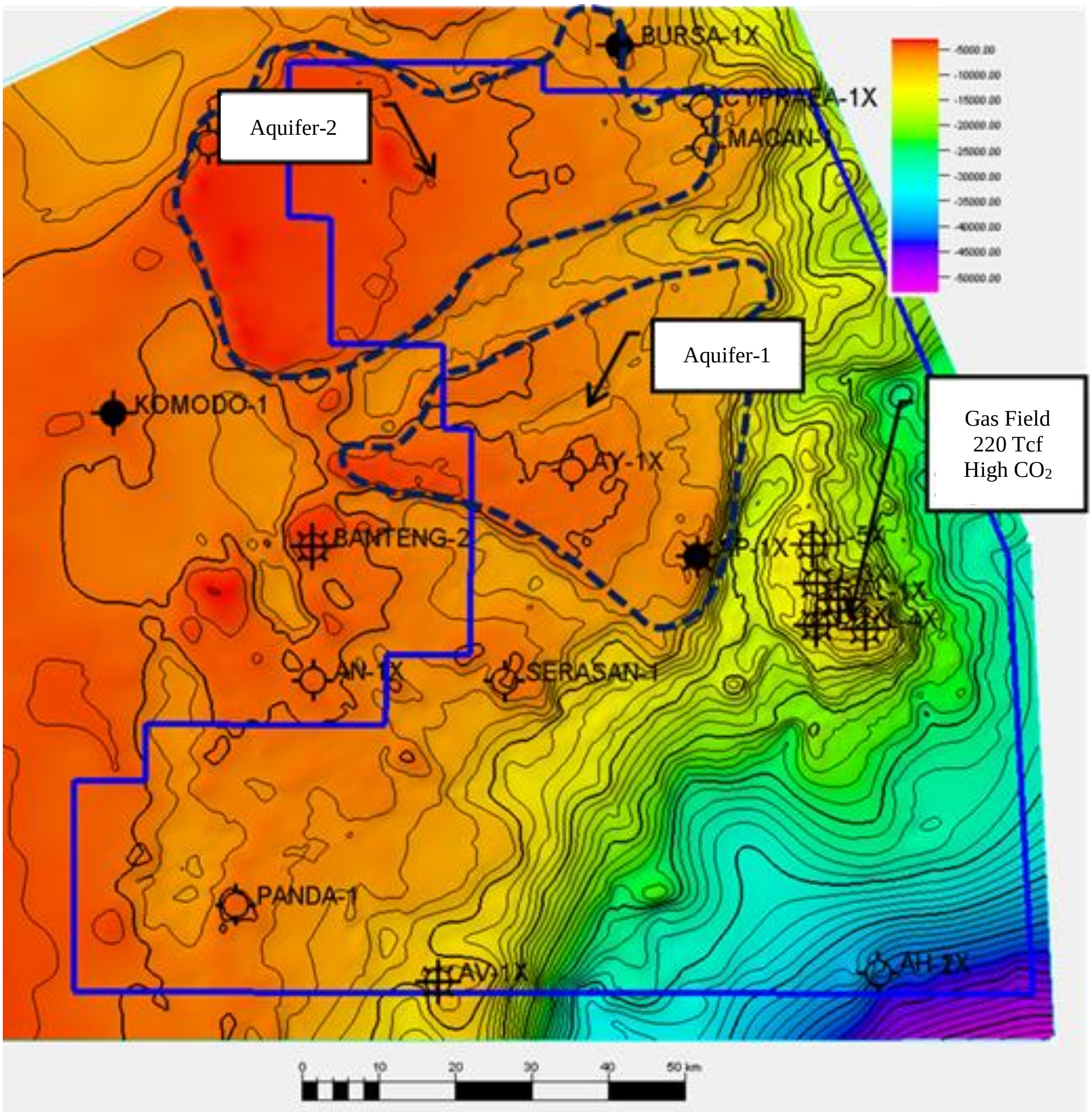

Figure 2.
Deep saline aquifer location for CO_2 sequestration

A dynamic sector model was developed to optimize computational efficiency while preserving critical near-wellbore grid resolution (Figure 4):

- The sector model consisted of a pore volume of 155,730 million Reservoir Barrels (MMRB).
- This massive volume ensured that boundary effects did not prematurely influence the pressure buildup analysis and CO_2 plume distribution, thereby maintaining simulated behavior representative of actual field conditions.

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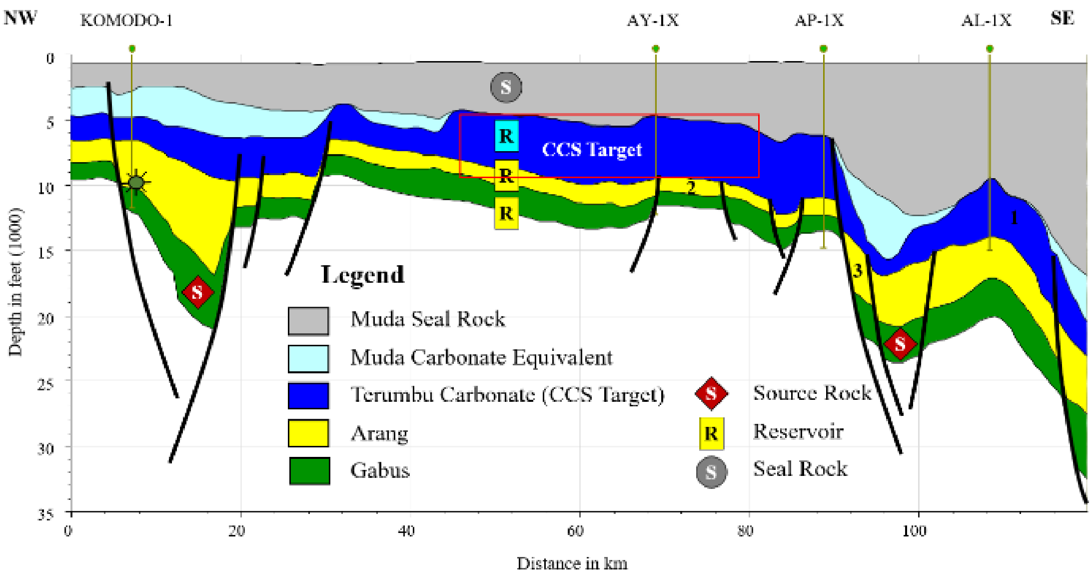

Figure 3.
Terumbu carbonate CCS target

Table 1.
Summary of data availability

Data parameter	Data source
Static Model Structural Geometry	2D Seismic, Wells AY-1, AP-1X
Petrophysical Parameters	Logs from Wells AY-1, AP-1X
Routine Core Analysis (RCAL)	Cores from Wells AY-1, AP-1X
Special Core Analysis (SCAL)	Cores from Wells SERASAN-1, CYPRAEA-1X
Cap Rock/Shale Layer	Logs from Wells AY-1, AP-1X
Geomechanical Properties	Logs from Wells AY-1, AP-1X
Fluid Properties (PVT)	Wells AL and L

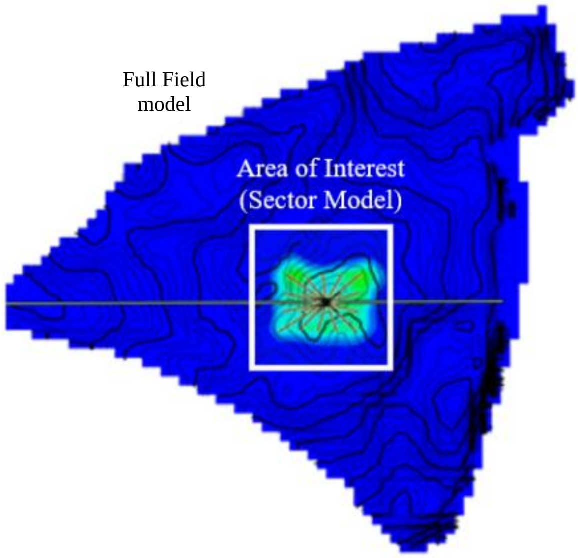

Figure 4.
Dynamic full field and sector model

2.2 Physics and fluid modeling

The simulator activated multiple features to represent true physical mechanisms:

- CO_2 STORE modeled the characteristics of CO_2, including solubility trapping within the formation brine.
- Relative Permeability Hysteresis: represented the residual trapping mechanisms where CO_2 was permanently locked in pore spaces.
- Geomechanics (GEOMECH) monitored reservoir integrity using Mohr-Coulomb failure criteria, analyzing parameters such as Young's Modulus (E), Poisson's ratio (ν), and friction angle against a fracture gradient of 0.78 psi/ft and an initial reservoir gradient of 0.45 psi/ft.

2.3 Well Configuration and Injection Strategy

Injection wells were strategically positioned at the crest of the structural dome close to AY-1X to overcome the operational challenges posed by the extreme depth and immense thickness of the target reservoir. This configuration ensured that the injected CO_2 plume naturally migrated upward, remaining securely contained through structural trapping beneath the primary caprock. Each well was completed with 7-inch tubing to maximize the flow area and minimize frictional losses, operating under a surface manifold injection pressure of 3,500 psi. This robust surface compression was critical to overcoming the high initial hydrostatic pressure of the deep formation, enabling the system to achieve and sustain massive injection rates.

2.4 Simulation scenarios

Numerical simulation evaluated individual and synergistic impacts of pressure management strategies. Base Case (BC-1) simulated injection without pressure management, while lateral pressure redistribution scenarios (L-1, L-2, L-3) introduced brine production wells (PWs) at varying rates, locations, and numbers. Vertical redistribution scenarios (V-1, V-2) altered injection depths (top vs. deep vs. multi-depth). Combination strategies (K-1) merged multi-depth injection with brine production, while perforation pattern optimizations (P-1, P-2) assessed parallel (line) versus intersecting (cross) perforation configurations between injection and PWs. The simulations evaluated individual and synergistic impacts across various pressure management scenarios, as shown in Table 2.

Table 2.
Matrix of simulation scenario design

Code	Scenario description	Objective
BC-1	Base Case: 3 Injectors, No Pressure Management	Baseline capacity without intervention
L-1	Lateral: Variation in Number of PWs (1 to 3 wells at 30 kbd)	Evaluate the impact of extraction volume
L-2	Lateral: Variation in PW Location (Far vs. Near)	Evaluate the impact of spatial proximity
L-3	Lateral: Variation in Brine Production Rate (20% vs. 60% of injection rate)	Maximize capacity through aggressive voidage replacement
V-1	Vertical: Perforation Depth Variation (Top vs. Deep)	Assess impact of rock quality and initial hydrostatic pressure
V-2	Vertical: Multi-depth Injection (3 depths simultaneously)	Distribute pressure vertically across layers
K-1	Combination: Multi-depth Injection + 3 Brine PWs	Leverage synergistic effects of lateral and vertical relief
P-1	Perforation Pattern: Parallel (Line)	Optimize geometric wellbore configurations
P-2	Perforation Pattern: Intersecting (Cross)	Optimize geometric wellbore configurations

3. Result and discussion

Simulations were executed according to the scenario matrix until the formation pressure reached the rock fracture limits. The primary success indicators analyzed were Total Gas Injected (FGIT), Storage Efficiency, and Field Pressure (FPR). The recapitulation of cumulative injection data is summarized in Table 3, while the perforation schematic of injection and PWs is shown in Figure 5.

3.1 Base case analysis (Scenario BC-1)

In the Base Case using three injection wells without brine production, the system reached a total CO_2 injection of 1,238 Bcf with a storage efficiency of 0.40%. Rapid pressure buildup restricted the injection rate, hitting the fracture limit after 16 years, thereby terminating the injection prematurely.

Table 3.
Summary of CO_2 storage optimization simulation results

No	Code	Scenario	FGIT (Bcf)	Increment (%)	Injection duration (Years)	Storage Eff. (%)
1	BC-1	Base Case (BC) - 3 injectors, (No Pressure Management)	1,238	0%	16	0.40%
2	L-1	Variation in PW Quantity (1 Well, 30 kbd)	1,395	13%	18	0.46%
3	L-1	Variation in PW Quantity (2 Wells, 30 kbd)	1,474	19%	19	0.48%
4	L-1	Variation in PW Quantity (3 Wells, 30 kbd)	1,553	25%	20	0.51%
5	L-2	Variation in PW Location (3 Wells Far Distance)	1,428	15%	19	0.47%
6	L-2	Variation in PW Location (3 Wells Close Distance)	1,641	33%	21	0.54%
7	L-3	Variation in Brine Prod. Rate (20% of Injection Rate)	1,553	25%	20	0.51%
8	L-3	Variation in Brine Prod. Rate (60% of Injection Rate)	2,030	64%	28	0.66%
9	V-1	Deep Perforation	244	-80%	14	0.08%
10	V-1	Top Perforation	1,501	21%	16	0.49%
11	V-2	Multi-depth Injection (3 depths)	1,396	13%	19	0.46%
12	K-1	Combination (V-2 + 3 PWs)	1,788	44%	25	0.58%
13	P-1	Perforation Optimization (Parallel/Line)	1,771	43%	24	0.58%
14	P-2	Perforation Optimization (Intersecting/Cross)	1,770	43%	24	0.58%

3.2 Lateral pressure redistribution (Scenario L)

The strategy was allowed to reduce formation pressure through brine extraction. Brine extraction significantly enhanced storage capacity by alleviating pressure buildup.

- Influence of Production Well (PW) Quantity (Scenario L-1): Scenarios were simulated with a total brine production of 30 kbd. Based on observation, increasing the number of PWs directly correlated with high storage capacity. The use of one PW increased capacity by 13% (1,395 Bcf), while three PWs obtained 25% (1,553 Bcf). A larger number of extraction points created a broader pressure sink, allowing injectors to operate longer before reaching fracture limits.
- Influence of PW Proximity (Scenario L-2): A total of three PWs were placed with an extraction rate of 10 kbd each. The result showed that placing wells at a close distance obtained a highly significant capacity increase of 33% (1,641 Bcf). This occurred because pressure communication was faster, allowing relief process to immediately affect the injection area. However, a far placement only yielded a 15% increase (1,428 Bcf) due to the lag time required for pressure reduction to reach the injectors.

- Influence of Brine Production Rate (Scenario L-3): Brine production rate proved to be the most sensitive variable. Simulating three PW with an aggressive rate of 20 kbd per well, totaling approximately 63% voidage replacement, achieved the highest results across all scenarios, with a 64% increase (2,030 Bcf). This scenario also extended the injection duration to 28 years. Extracting massive volumes of brine significantly increased available pore space for CO_2 and kept reservoir pressure low. However, this trade-off requires substantial surface water handling facilities, impacting capital and operational expenditure.

3.3 Vertical pressure redistribution (Scenario V)

The strategy evaluated the impact of injection depth and multi-depth methods using three wells without brine production. Each scenario used a perforation length of ~1,000 ft. The results showed that the depth of injection profoundly influenced injectivity due to vertical variations in rock quality and initial hydrostatic pressure.

- Perforation Depth Variations (Scenario V-1): Significant differences were observed between deep and top areas. Deep perforations showed the worst performance, injecting only 244 Bcf, an 80% decrease from Base Case. This is attributed to poorer rock properties at greater depths and a high initial hydrostatic pressure, causing a lower delta pressure for injection and severely reduced injectivity. However, top perforations obtained positive results (a 21% increase, 1,501 Bcf) by leveraging better rock quality and a higher delta pressure.
- Multi-depth Injection (Scenario V-2): Simultaneously injecting across three depth areas achieved a 13% increase. Although slightly lower in absolute volume than the top perforation, it successfully dissipated pressure vertically, mitigating localized pressure buildup and protecting caprock integrity.

3.4 Combination strategy and perforation optimization (Scenarios K & P)

- Lateral and Vertical Synergy (Scenario K-1): Combining multi-depth injection (V-2) with three brine PWs produced a substantial 44% capacity surge (1,788 Bcf). Multi-depth injection dispersed CO_2 vertically, minimizing single-point pressure accumulation, while PWs globally maintained low reservoir pressure.
- Perforation Configuration Optimization (Scenarios P-1 & P-2): The comparison of parallel (line) versus intersecting (cross) perforation patterns between injection and PW of approximately 1,000 ft perforations showed a very marginal difference of less than 1 Bcf. Both achieved an approximate 43% increase (1,771 Bcf and 1,770 Bcf, respectively). In highly permeable thick aquifers, geometric orientation impacts capacity minimally compared to macro-level global pressure management and vertical zone selection.

3.5 Discussion

The results obtained from the numerical simulations confirm that rapid formation buildup is the primary factor limiting CO_2 injection in closed or semi-closed thick aquifers when active pressure management is absent. All pressure management strategies implemented in this study, except deep-zone (Scenario V-1 Deep), successfully mitigated pressure buildup and enhanced storage capacity compared to Base Case.

The lateral redistribution of pressure through brine extraction proved to be highly effective. This method showed correlation with the principle that creating a pressure sink allowed injectors to operate longer before fracturing thresholds are breached. However, simulation results showed that pressure relief depended strongly on the spatial relationship between production and injection wells. Brine PW, located close to the injection-induced pressure plume, achieved a 33% increase in storage capacity. Meanwhile, PW positioned farther away increased capacity by only 15% because pressure communication required more time to develop.

Despite the clear advantages of pressure reduction, there is a significant difference between maximizing the injected volume and managing operational complexities. Although highly aggressive brine extraction (Scenario L-3) achieved the largest capacity increase (64%), it required massive surface water handling facilities, significantly impacting capital, operational expenditures, and environmental management. Consequently, the combination strategy (Scenario K-1) serves as the optimal operational middle ground. By using moderate brine production alongside multi-depth injection, it successfully dissipates pressure vertically and laterally, avoiding extreme water handling requirements while achieving a substantial 44% increase in capacity.

These results indicated that for massive, thick carbonate aquifers like Natuna D-Alpha Field, global pressure management influences overall capacity far more than micro-level wellbore configurations. The geometric orientation of perforations (line vs. cross) showed negligible differences (<1 Bcf). This indicates that azimuthal orientation is secondary to vertical zone selection and lateral extraction rates.

Technical, Operational, and Economic Challenges of Deep Storage: The target saline formation in Natuna D-Alpha Field extends to depths between 5,000 and 10,000 ft, significantly exceeding the commonly recommended 800–2,500 m (2,600–8,200 ft) threshold for conventional CO_2 storage. This extension introduces technical, operational, and economic challenges that require a balanced assessment of the associated challenges when evaluating practical feasibility. Technically, overcoming the high initial hydrostatic pressure of the deep formation requires massive surface compression power to force CO_2 into the rock matrix without exceeding the geomechanical fracture gradient of 0.78 psi/ft. Operational challenges are also considerable because deep formation brines, elevated temperatures, and supercritical CO_2 create a highly corrosive carbonic acid environment, requiring corrosion-resistant alloys (CRAs) for well completion. Furthermore, the proposed lateral pressure redistribution strategy requires lifting massive volumes of brine from extreme depths, showing the need for high-capacity artificial lift systems. These technical and operational challenges indicate higher capital expenditures (CAPEX) and operational expenditures (OPEX) for drilling, compression, and water handling. However, the deep aquifer remains a practically and economically viable option due to the unique colocation with Natuna D-Alpha gas reservoir, avoiding the multi-billion-dollar construction of subsea CO_2 transportation pipelines.

Challenges and Limitations: Despite the technical successes observed, the simulation has several methodological limitations. This study depended exclusively on numerical simulation without including direct field or laboratory experiments. The numerical model primarily focused on macroscopic fluid flow and dynamic pressure behavior under isothermal conditions. Consequently, thermodynamic changes such as the Joule-Thomson cooling effect during CO_2 expansion and the associated risks of near-wellbore freezing were not evaluated. Complex microscopic phenomena, including water vaporization into CO_2 stream, salt precipitation, and long-term geochemical or microbiological interactions, were simplified to prioritize regional pressure responses. This study also assumed adequate wellbore integrity throughout the injection period and did not deeply analyze the broader socio-environmental impacts or detailed economic variables. From a macro-operational perspective, the need to handle substantial brine production volumes for effective pressure relief (Scenario L-3) showed that surface water treatment infrastructure would remain a major project consideration. Therefore, future investigations should incorporate fully coupled thermo-hydro-mechanical-chemical (THMC) compositional modeling to evaluate these localized microscopic effects and temperature variations over extended time horizons.

Comparison with Previous Studies: To contextualize the results within the broader literature, the simulation data were compared with recent studies on CO_2 storage in saline aquifers. In line with existing reports, active reservoir management appeared to significantly expand storage capacity. For instance, Firoozmand & Leonenko (2024) reported approximately a 162% capacity increase using simultaneous extraction in a simplified model, while Razali et al. (2024) observed a 61% effective volume use in restricted aquifers. Consistent with the increasing trend, the high-rate lateral brine extraction modeled in this study (Scenario L-3) obtained a 64% capacity increment over the base case. Although previous reports have extensively focused on idealized domains or relatively thin clastic formations, this study addresses the specific complexities of Natuna D-Alpha Field. As an exceptionally thick (5,000-ft) carbonate reef with heterogeneity and low-permeability baffles, the proposed system presents unique pressure-trapping challenges that cannot be fully resolved by conventional methods. In line with previous evaluations of isolated pressure management (e.g., Zhang & Agarwal 2012), this study introduces a synergistic 3D framework designed for complex environments. By coupling lateral brine extraction with multi-depth vertical injection, the proposed combined method (Scenario K-1) helps bypass intra-formational barriers more effectively. This integrated strategy achieves a balanced 44% capacity increase and an overall storage efficiency of 0.58%, while maintaining reservoir pressures safely below the 0.78 psi/ft fracture gradient. The results provide valuable insights as a practical reference for safely managing large-scale CCS operations in similarly complex, high-CO_2 carbonate fields.

Economic and Commercial Implications: The development of high-CO_2 gas fields like Natuna D-Alpha presents a feasible commercial pathway. Although massive CO_2 handling and deep injection require significant CAPEX, recent assessments indicate that economic viability is attainable (Farhan et al., 2026). The pressure redistribution strategy proposed in this study provides a reliable technical foundation for the operations. By integrating optimized CCS with methane monetization and supportive government fiscal frameworks, such as enhanced contractor splits and tax incentives, investment risks can be effectively managed. This integrated techno-economic method facilitates the safe development of stranded gas resources, thereby contributing to regional energy security and national Net Zero Emission (NZE) targets (Farhan et al., 2026).

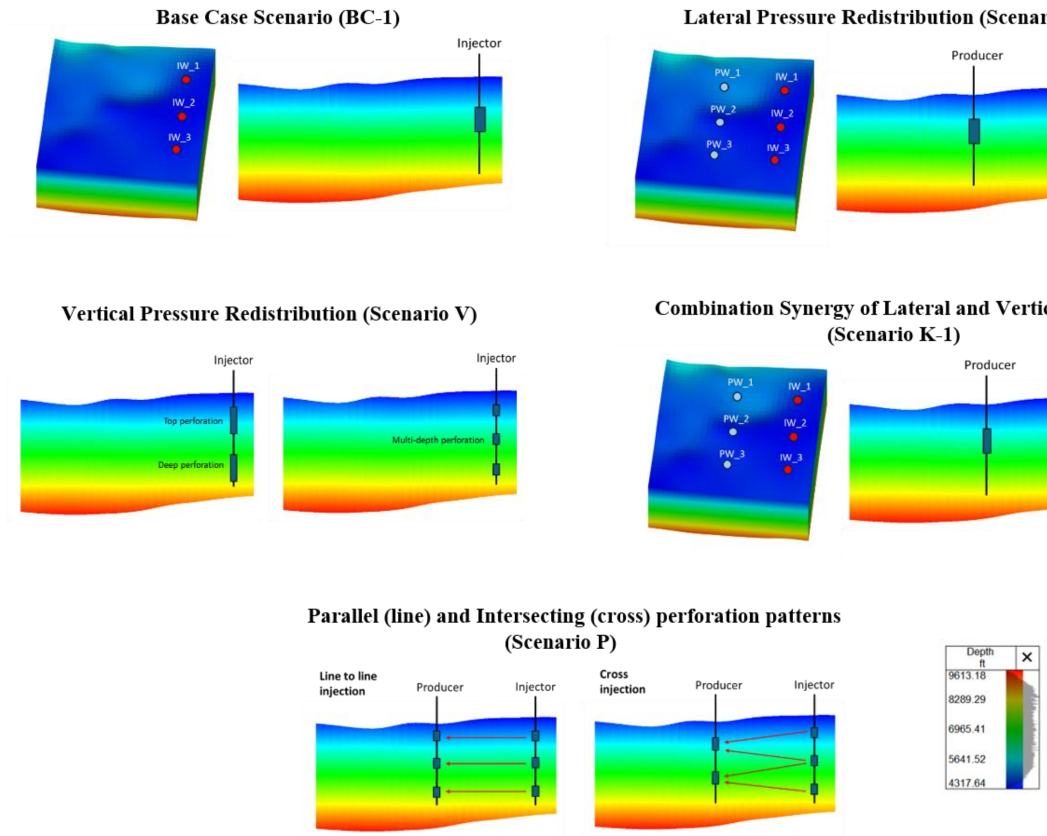

Figure 5.
Schematic representation of the simulated well and perforation configurations for all investigated pressure management strategies. The scenarios include Base Case (no active pressure management), lateral redistribution via brine extraction, vertical redistribution assessing top, bottom, and multi-depth injection, combined lateral-vertical multi-depth strategies, and varying geometric perforation patterns.

4. Conclusion

In conclusion, this study shows that the implementation of lateral pressure redistribution through brine production serves as the most significant individual strategy for optimizing CO_2 storage capacity. The addition of brine producers effectively mitigates reservoir pressure buildup, allowing for significantly larger volumes of injected gas before rock fracture limits are reached. Scenarios using high-rate brine extraction show a peak capacity increase of 64%, with spatial proximity playing a crucial role. Specifically, PW placed closer to the injector provides faster pressure relief than those at a larger distance. The results show that vertical pressure redistribution through multi-depth injection successfully mitigates localized pressure accumulation by distributing the pressure more evenly across vertical layers. Although multi-depth injection obtains a 13% capacity increase, the selection of the perforation depth is proven to be highly critical. Injecting strictly into deeper areas severely reduced injectivity due to degraded rock properties and lower available delta pressure, while top-area perforations capitalized on superior rock quality to yield highly positive results.

A synergistic combination of lateral and vertical strategies provides the most balanced method for field development. Integrating multi-depth injection with brine PW produces a substantial 44% increase in storage capacity and a storage efficiency of 0.58%. This combined strategy optimizes spatial CO_2 distribution while maintaining global reservoir pressures. The method also prevents the extreme surface water handling demands associated with aggressive brine-only extraction scenarios.

In thick, highly permeable aquifers such as the Carbonate Reef in Natuna D-Alpha Field, variations in the geometric patterns of well perforations, specifically parallel versus intersecting configurations, exert a negligible impact on overall storage capacity. The dominant factors governing safe and efficient CO_2 storage are macro-level global pressure management through brine extraction and the strategic selection of vertical injection areas, rather than the azimuthal orientation of the wellbores.

5. Acknowledgement

The authors are grateful for the support received from the Petroleum Engineering Department at Institut Teknologi Bandung in facilitating this study. Furthermore, the authors are grateful to KUFPEC Indonesia for providing the field data and operational insights from Natuna D-Alpha joint study, which fundamentally assisted in the preparation of this study.

6. Declarations

6.1 Author contribution

The authors declare that this study is original, has not been published previously, and is not currently under consideration for publication elsewhere.

R.A. Nirwana: Writing - Original Draft, Conceptualization, Formal Analysis, Investigation. D. Irawan: Writing - Review & Editing, Supervision, Validation. A. Yasutra: Writing - Review & Editing, Formal Analysis, Visualization, Supervision. S. Kamal: Resources, Data Curation, Validation. W.A. Ramadhan: Methodology (Static Modeling), Data Curation (G&G). All authors read and approved the final paper.

6.2 Funding statement

None.

6.3 Competing interest

None.

6.4 The use of AI or AI-assisted technologies

During the preparation of this manuscript, the authors used AI-assisted technologies only for language editing, grammar checking, and formatting purposes to improve clarity and ensure compliance with journal guidelines. The authors carefully reviewed and revised all AI-assisted outputs as necessary and take full responsibility for the accuracy, integrity, and final content of this publication.

7. Glossary of terms and symbols

Terms & Symbols	Definition	Unit
BC	Base Case	-
CAPEX	Capital Expenditure	-
CCS	Carbon Capture and Storage	-
CO_2	Carbon Dioxide	-

IW	Injection Well	-
NZE	Net Zero Emission	
OPEX	Operational Expenditure	-
PW	Production Well	-
RCAL	Routine Core Analysis	-
SCAL	Special Core Analysis	-
THMC	Thermo-Hydro-Mechanical-Chemical	
FPR	Field Pressure	psi
FGIT	Field Gas Injection Total	Bcf
ϕ	Porosity	fraction / %
k	Permeability	mD
E	Young's Modulus	psi/GPa
ν	Poisson's Ratio	-

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66

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