An Evaluation of the Long-Term CO_2 Storage Potential in the Priirtysh Sedimentary Basin Using Hydrodynamic Simulation

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ABSTRACT

This study follows the preliminary geological screening and construction of a 3D static model (Phase I), which identified promising deep saline aquifers (Upper Jurassic–Cenozoic) in the Priyrtyush Sedimentary Basin for Carbon Capture and Storage (CCS). This paper's primary objective is to transition from a static volumetric assessment to a dynamic hydrodynamic simulation in order to evaluate the technical feasibility and operational constraints of large-scale CO_2 injection. A high-resolution geological model derived from integrated seismic and log data was imported into a commercial reservoir simulator to establish the dynamic framework. The methodology involves simulating a 100-year period of continuous CO_2 injection. A high-resolution hydrodynamic model was developed to assess plume migration and pressure dynamics under a sustained injection rate of 300,000 m^3/day, which was identified as a safe operational threshold. The findings quantify a dynamic storage capacity of 13 million tons of CO_2 over the 100-year period and project a maximum average reservoir pressure rise of 340.2 bar. This comprehensive hydrodynamic assessment provides the operational data necessary to progress from resource appraisal to field

development planning, offering a robust, data-driven foundation for realizing Kazakhstan's strategic goal of achieving carbon neutrality by 2060.

Keywords-hydrodynamic modeling; CO_2 storage; reservoir

I. INTRODUCTION

In accordance with the global transition toward carbon neutrality, developing Carbon Capture and Storage (CCS) infrastructure has become a strategic priority for large industrial regions. CCS in deep saline aquifers is governed by a complex interplay of four primary trapping mechanisms: structural, residual, solubility, and mineral. In the context of large-scale industrial injection, the most crucial factor for ensuring geomechanical safety and storage efficiency is the hydrodynamic response of the reservoir, specifically the evolution of the pressure field and the displacement of formation brine. International experience from pioneering projects, such as Sleipner in Norway and Quest in Canada, has demonstrated the feasibility of injecting millions of tons of CO_2 into deep saline formations, revealing that aquifer transmissivity and caprock integrity are decisive factors in storage success. Authors in [1-3] explored these dynamics in various geological settings, including the Ordos Basin in China, providing a framework for evaluating similar sedimentary complexes. Global climate change necessitates urgent, large-scale decarbonization [4], a particularly relevant challenge for Kazakhstan given its fossil fuel-dependent economy and CO_2 emissions of 255.16 million tons in 2023 [5]. To achieve the national strategic goal of carbon neutrality by 2060 [6], CCS has become a significant solution for reducing emissions from large, stationary sources [7]. Since coal combustion at thermal power plants accounts for about 146.57 million tons of the national total [5, 8], identifying regional storage assets is a priority. The Pavlodar region, a primary emission hub that records over 5 million tons of CO_2 annually, requires immediate attention [9]. The current study addresses this need by assessing the permanent geological storage potential of the nearby Priirtysh Sedimentary Basin. Authors in [10, 11] identified only six potential basins, excluding the Priirtysh basin despite its proximity to major emitters. This study transitions from static resource assessments to dynamic reservoir modeling. Advancements in carbon sequestration modeling have led to the development of new strategies, such as the few-shot learning Recurrent Neural Network (RNN) approach [12]. While these emerging techniques aim to reduce the computational burden of large-scale simulations, direct numerical simulations are still needed to capture complex fluid-rock interactions in specific regional settings, such as the Priirtysh basin. Following geological characterization, hydrodynamic modeling is essential to forecasting supercritical CO_2 plume behavior and pressure buildup [13, 14]. These models integrate parameters such as porosity, permeability, and structural geometry to provide the quantitative basis necessary for assessing geomechanical risks and containment feasibility. The main objective of this paper is the transition from a static volumetric assessment to a dynamic hydrodynamic simulation, in order to quantify dynamic storage capacity and evaluate operational safety margins by monitoring pressure evolution over a 100-year period. This serves as a necessary foundation for future coupled geomechanical studies, as there is a significant knowledge gap in the scientific community regarding long-term pressure stabilization trends in high-transmissivity frontier basins lacking prior geomechanical and dynamic calibration. While static capacity can be estimated, the unresolved scientific question is how the pressure field achieves hydrodynamic equilibrium in aquifers with infinite permeability without extracting formation fluids. This study aims to:

- Quantify the dynamic storage capacity and pressure response of the Priirtysh Basin under industrial injection rates.
- Identify the timeframe for hydrodynamic stabilization (reaching a quasi-steady state) over 100- and 176-year horizons.
- Validate the geomechanical safety margin by comparing peak simulated pressures against estimated regional fracture thresholds.

II. METHODOLOGY

A model was developed to simulate the injection of carbon dioxide (CO_2) into an aquifer in the Priyrtyush Sedimentary Basin. This was achieved through comprehensive reservoir simulation, or advanced hydrodynamic modeling, using the tNavigator software. The selected CO_2 storage site is located at a depth of 1,550 m. The combination of high reservoir pressure (200 bar) and a stable temperature (60°C) create favorable conditions for long-term carbon sequestration, ensuring that the CO_2 remains in a supercritical state. Figure 1 presents a flowchart that visually summarizes the integrated research workflow, which includes data acquisition, static modeling, and hydrodynamic simulation. The formation consists of high-porosity sandstone (22%) combined with low permeability (0.5 mD horizontally). This low permeability is critical because it minimizes the risk of CO_2 leakage and ensures the integrity of the geological seal.

A. Model Setup and Input Parameters

A three-dimensional, three-phase compositional model was used to perform the dynamic assessment. To ensure the reliability of the results, the numerical grid and physical properties were configured as:

- Spatial Discretization: The model uses a structured corner-point grid with approximately 1,770,000 active cells to maintain stratigraphic integrity.
- Thermal Regime: The simulation assumes an isothermal condition of 60°C.
- Initial and Boundary Conditions: An initial hydrostatic pressure of 200 bar was established at the reference depth. To simulate the regional pressure dissipation of the Priirtysh Basin, open boundary conditions (infinite-acting aquifer) were applied to the model's edges.

- Numerical Scheme: A Fully Implicit Method (FIM) was used to ensure mass conservation and numerical stability throughout the 100-year forecasting period.
- Caprock Integrity: It was assumed to be impermeable and geomechanically stable within the simulated pressure range.

The key input parameters used for the base case simulation are summarized in Table I.

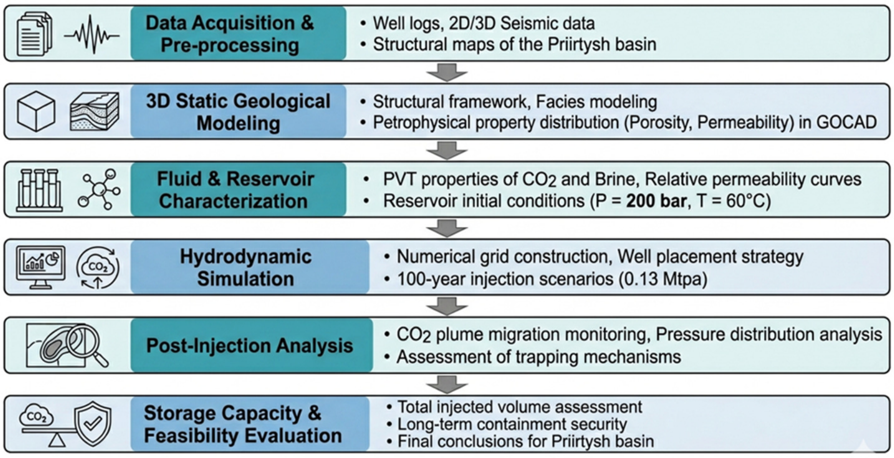


Fig. 1. Integrated research workflow for evaluating CO2 storage potential in the Priirtysh basin.

TABLE I. FLUID PROPERTIES OF THE RESERVOIR

Name of parameter	Value
Reservoir depth (m)	1550
Thickness (m)	20
Horizontal permeability (mD)	0.5
Porosity (%)	22
Water density (g/cm^3)	26.22
Rock composition (lithology)	sandstone
Grid elements (cell count)	1770000
Reservoir pressure (bar)	200
Reservoir temperature (°C)	60
Rock compressibility (bar)	$4.5{\times}10^{-5}$

The results presented in Table II reflect the simulation of the long-term performance of the CO_2 storage system in a deep saline aquifer. The modeling was conducted over a 100-year period. The hydrodynamic simulation used the tNavigator reservoir simulator (Rock Flow Dynamics).

TABLE II. SIMULATION RESULTS

Name of parameter	Value
Simulation duration (year)	100
CO_2 storage volume (Mt)	13.3682
CO_2 injection rate (m^3/day)	300000
Reservoir pressure (bar)	340.2

The model is based on a high-resolution, structured, corner-point grid comprising approximately 1,770,000 active cells. To accurately represent the CO_2-brine interaction, a compositional approach was employed, and CO_2 solubility in the aqueous phase was calculated using the Spycher-Pruess equation of state. The displacement processes are governed by the Brooks-Corey relative permeability model. Numerical integration was performed using a fully implicit solver to ensure mass conservation and stability over the 100-year forecast period.

Open boundary conditions were implemented at the model's periphery to simulate the infinite nature of the Priyrtyush sedimentary basin and allow for realistic pressure dissipation.

1) Storage Volume and Injection Regime

Specifying a net CO_2 flow rate of 300,000 m^3/day over the 100-year operation period enabled achieving a total sequestration volume of 13.3682 million tons. This metric serves as a quantitative estimate of the effective storage capacity of the reservoir under the given operating parameters.

2) Hydrodynamic Response and Stability

The dynamic simulation shows controlled pressure changes during the injection period. At the 100-year mark, the average reservoir pressure is 340.2 bar, which confirms that the system can accommodate the injected CO_2 volumes while maintaining a significant safety margin. To evaluate long-term stability further, the model was extended to a 176-year period. During this time, the pressure reached 404.18 bar. This stabilized pressure, recorded at the end of the extended modeled period, indicates sufficient reservoir permeability and the reservoir's ability to dissipate excess pressure via the regional open boundaries. The system's capacity to sustain a stable injection regime without surpassing the critical caprock fracture pressure affirms the mechanical stability of the reservoir system under both primary and extended operational conditions. Due to the absence of deep boreholes in the explored part of the Priyrtyush basin, this research is a theoretical hydrodynamic evaluation. Significant geomechanical parameters, such as Young's modulus and Poisson's ratio, were adopted from regional analogues and literature on similar sandstone-shale sequences. While the current model focuses on estimating CO_2 storage capacity and plume stabilization, a comprehensive geomechanical assessment of caprock integrity must be studied further.

III. RESULTS AND DISCUSSION

Figure 2 shows the results of the hydrodynamic simulation and demonstrates the key mechanisms that control the retention and migration of CO_2 within the deep saline aquifer.

A. Stabilization and Formation of the CO_2 Plume

By the end of the one-hundred-year period following the initiation of injection, gas saturation in the reservoir reaches a relatively stable stage. A persistent CO_2 plume (or plume front) is formed, characterized by a sharp contrast in gas concentrations between the central storage zone and the formation's periphery. Areas with maximum gas saturation ($Sg > 0.69$) are located directly next to the injection points, a direct result of continuous or cyclical injection practices.

B. Evidence of Caprock Integrity and Long-Term Containment

The saturation distribution shows the fluid's lateral spread. The absence of vertical CO_2 migration into the overlying horizons confirms the integrity of the regional caprock, validating the effectiveness of the hydrodynamic containment mechanism due to density and viscosity differences and the capillary trapping mechanism due to the high capillary entry pressure of the seal.

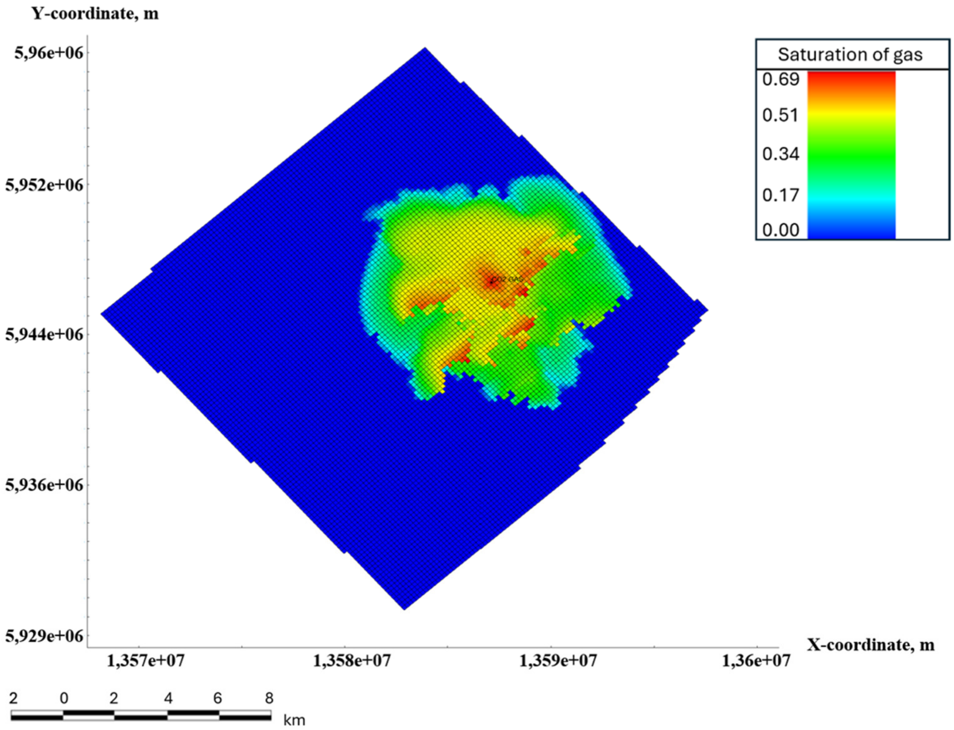


Fig. 2. Gas saturation at 100 years.

C. Conditions for Long-Term Sequestration

In conclusion, the observed gas saturation distribution, characterized by the localization of the CO_2 "bubble" within the target reservoir's boundaries under a reliable confining layer, confirms the formation's high storage capacity and isolation ability. The results indicate that the basin's geological structure and the reservoir's petrophysical properties ensure the reliable, long-term containment of CO2 throughout the one-hundred-year simulation period. These results provide a strong basis for evaluating the strategic potential of this aquifer for a large-scale geological CO2 storage project. The analysis of the spatial distribution of dissolved CO2, as depicted in Figure 3, is substantial to assessing the long-term reliability of geological sequestration. The solubility trapping mechanism is a key secondary retention process. Intensive dissolution of CO2 into formation water has two beneficial effects:

- Reduction of leakage potential: dissolution reduces the volume of CO_2 present in the free phase (the gaseous plume), thus minimizing its buoyancy and eliminating the driving gradient that could promote vertical migration.
- Enhancement of gravitational containment: CO2 dissolution increases the density of the formation water. This denser, "heavy" water sinks under the influence of gravity, promoting stable hydrodynamic containment of the gas in the deeper sections of the reservoir.

A high level of dissolved CO_2 indicates a transition to long-term chemical sequestration because the dissolved gas reacts with reservoir minerals to form stable carbon compounds (mineralization). Therefore, the high degree of CO2 integration into the pore water demonstrates the reliability and safety of long-term geological storage. Figure 4 illustrates the cumulative CO2 mass over time, reflecting the total mass of carbon dioxide injected into the reservoir throughout the active operational period. The gradual, monotonic growth of the accumulated mass, which is nearly linear, indicates high injection efficiency and the absence of significant geological constraints. Achieving the target storage volume of 13.3682 million tons confirms the reservoir's sufficient capacity and hydraulic permeability. While the graph confirms the project's operational success, it also underscores the need for continuous monitoring to verify the system's safety. To evaluate the temporal evolution and stabilization of the CO_2 storage process, the simulation period was extended to 176 years, ending in 2200. Figure 5 exhibits the reservoir's dynamic response and reveals distinct growth phases. At the 10-year mark (2034), the average reservoir pressure rises to 233.45 bar, reflecting the injection-driven displacement phase. By years 50 (2074) and 100 (2124), the pressure increases to 286.99 and 340.20 bar, respectively.

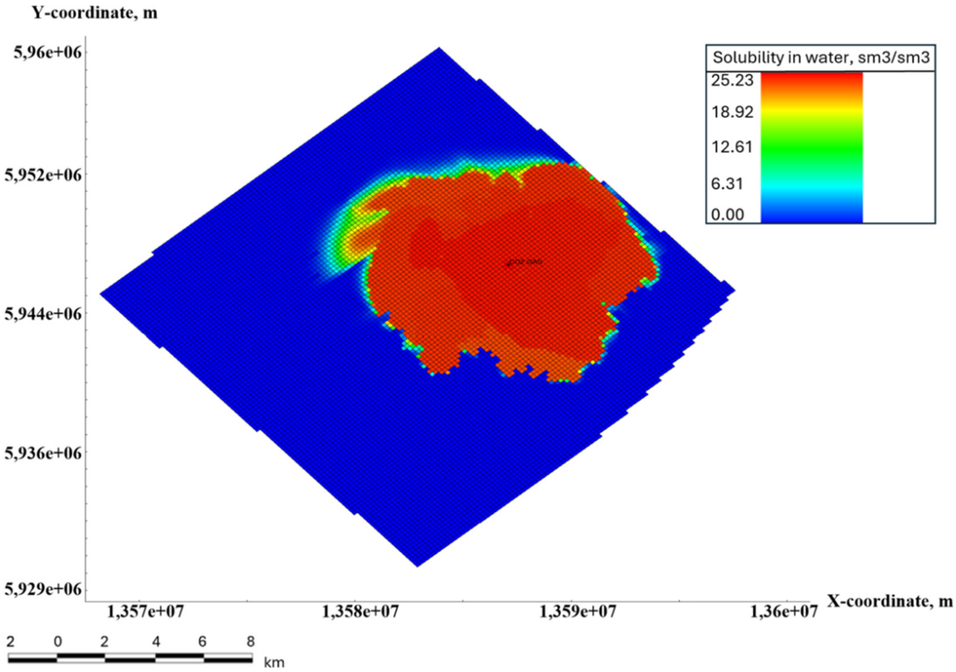
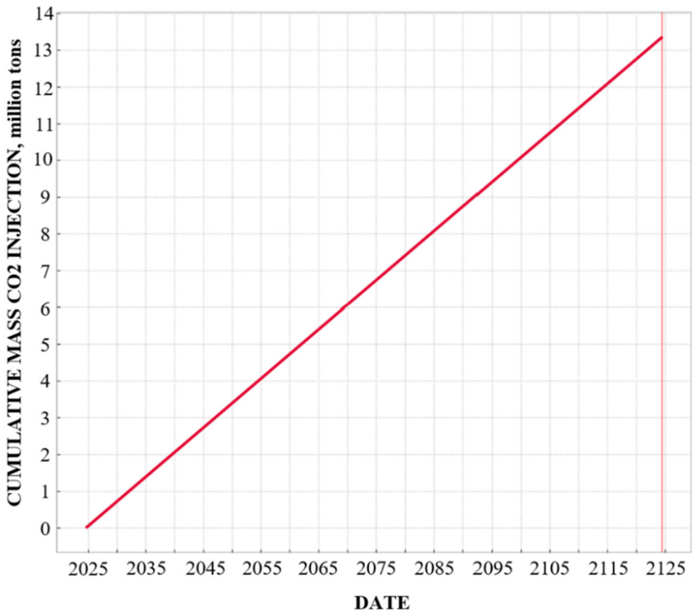


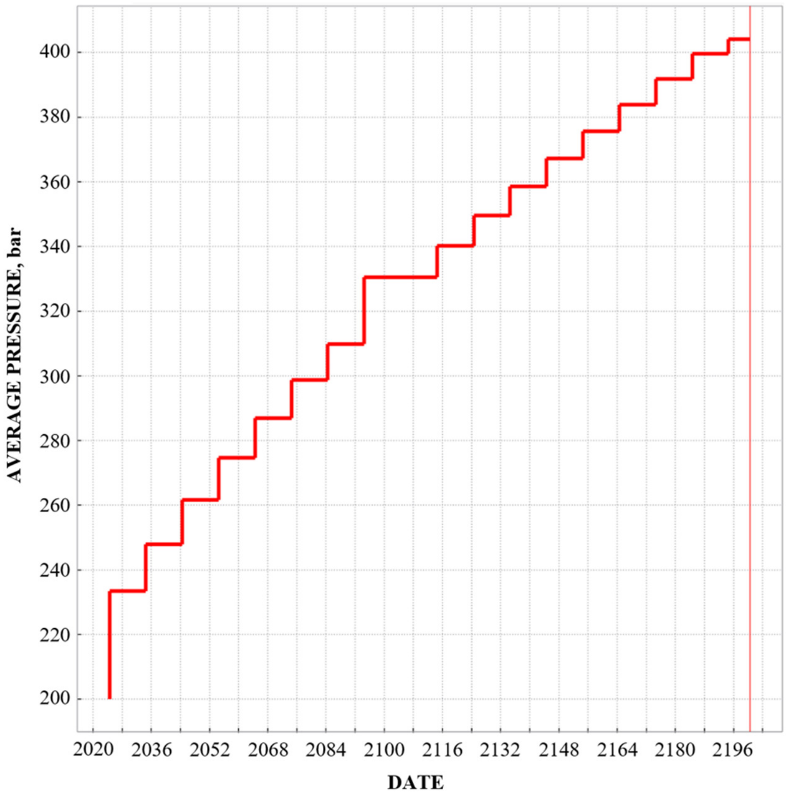
Fig. 3. Dissolved CO_2.



CUMULATIVE MASS CO2 INJECTION, million tons	
12.07.2024	0
12.07.2034	1.33663
12.07.2044	2.67363
12.07.2054	4.01026
12.07.2064	5.34726
12.07.2074	6.68389
12.07.2084	8.02089
12.07.2094	9.35752
12.07.2114	12.0312
12.07.2124	13.3682

Fig. 4. Cumulative mass CO_2 injection.

The analysis of pressure evolution shows a stepwise increase over the 176-year period. The critical caprock fracture pressure (P_{frac}) was calculated using the regional lithostatic gradient. For a reservoir at a depth of 1,550 m, the P_{frac} is estimated at 480 bar. This estimate assumes an average overburden bulk density of 2.75 gr/m^3 and a conservative fracture gradient of 0.31 bar/m. This gradient is typical of the dense shale and claystone intervals of the Priirtysh basin. The simulation results show that the average reservoir pressure will reach 340.2 bar after 100 years and will stabilize at 404.18 bar by the year 2200. Consequently, the pressure consistently remains below the fracture threshold, maintaining a safety margin of at least 15.8% (75.82 bar) by the end of the 176-year period. This confirms the geomechanical safety of the injection scenario. The stepwise progression of the curve demonstrates a significant decrease in the pressure buildup rate over time. This stabilization trend is a direct result of the open boundary conditions implemented, which allow for effective regional pressure dissipation within the Priirtysh Basin. Even after 176 years, the final pressure of 404.18 bar remains well below the estimated caprock fracture threshold, confirming the long-term hydrodynamic stability and safety of the storage scenario.



	average pressure, bar
12.07.2024	200
12.07.2034	233.453
12.07.2044	247.962
12.07.2054	261.605
12.07.2064	274.649
12.07.2074	286.987
12.07.2084	298.666
12.07.2094	309.751
12.07.2104	330.421
12.07.2114	340.122
12.07.2124	340.203
12.07.2134	349.534
12.07.2144	358.541
12.07.2154	367.249
12.07.2164	375.692
12.07.2174	383.886
12.07.2184	391.857
12.07.2194	399.616
12.07.2200	404.18

Fig. 5. Reservoir average pressure.

The simulation results for the Priirtysh Basin were compared with global CCS benchmarks. The total volume of 13.36 million tons of CO_2 injected over 100 years through a single injection well (averaging 0.13 Mt per year) aligns with the operational parameters of leading international projects. Authors in [1, 2] showed that the Sleipner project in Norway and the Quest CCS project in Canada exhibited similar injection rates and long-term plume stabilization trends in deep saline aquifers. The results of the 100-year injection scenario provide a high-fidelity physical representation of CO_2 plume migration. Compared with recent surrogate modeling trends, such as the RNN-based strategy [13], this study's traditional hydrodynamic approach ensures that site-specific geological heterogeneities and Pressure-Volume-Temperature (PVT) behaviors are fully accounted for. These detailed numerical datasets are crucial for training the next generation of machine learning models for CO_2 storage in deep saline aquifers. The observed storage efficiency and pressure buildup align with the hydrodynamic behavior reported for the Ordos Basin (China) [3]. Storage efficiency reaches 340.2 bar at the 100-year mark and stabilizes at 404.18 bar by the year 2200, confirming that the Priirtysh sedimentary complex has sufficient transmissivity and capacity to manage industrial-scale CO_2 volumes. Furthermore, the stabilization trends observed in the proposed model demonstrate that the injection process can be managed sustainably without compromising the geomechanical integrity of the caprock.

IV. CONCLUSIONS

This study is a comprehensive hydrodynamic assessment of the Priirtysh Sedimentary Basin, which is strategically important for Kazakhstan to achieve its national goal of carbon neutrality by 2060, and a dynamic simulation of long-term

(100-year) CO_2 sequestration in the region with the largest concentration of emitters. This project confirmed the following:

- High capacity and efficiency: the simulation confirmed the effective injection of a cumulative 13.3682 million tons of CO2 over 100 years.
- The pressure dynamics inevitably rise due to injection into a deep saline aquifer with no formation fluid extraction. However, the simulation showed P_{avg} stabilization at the safe level of 340.2 bar at the 100-year mark and 404.18 bar by the end of the extended 176-year period. This stabilization, achieved through regional pressure dissipation, guarantees the mechanical stability of the caprock and prevents leakage risks. The peak pressure remains well below the estimated fracture gradient, ensuring the long-term integrity of the CO2 storage site in the Priyrtysh Basin.
- Irreversibility of containment: sequential activation of all trapping mechanisms, including mineralization (chemical sequestration), was confirmed. This ensures the irreversible immobilization of CO2 over a geological timescale.

In conclusion, the obtained data provide a basis for progressing with field development planning. To verify the system's long-term stability, continuous monitoring of pressure and saturation is required.

DECLARATION OF COMPETING INTERESTS

Not applicable to this work.

ACKNOWLEDGMENT

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DATA AVAILABILITY

The datasets (seismic data, well logs, and regional geological reports) analyzed during the current study are proprietary and confidential. These data were utilized under the licensing and research regulations of the Ministry of Science and Higher Education of the Republic of Kazakhstan (Project No. AP14869955). Consequently, the raw data are not publicly available. Requests to access the processed simulation results may be directed to the corresponding author, subject to approval from the relevant data owners.

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