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RESEARCH ARTICLE

Carbon Capture and Storage Feasibility in Depleted Offshore Gas Reservoirs

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ABSTRACT

Depleted offshore natural gas reservoirs are widely regarded as attractive early targets for geological carbon storage because their trapping geometry, seal integrity and reservoir properties were already proven by decades of hydrocarbon production, yet quantitative techno-economic assessments that combine capacity estimation, injectivity modelling and monitoring costs at basin scale remain scarce. We assessed the storage feasibility of a six-reservoir cluster of depleted Rotliegend-type sandstone gas fields in a North Sea-style siliciclastic basin, spanning depths of 2050–3400 m, porosities of 12–22%, and net gas pay of 20–90 m, using a probabilistic volumetric method constrained by material-balance-derived pore volume vacated during historical gas production, a caprock risk screen based on seal thickness, lithology and legacy well penetrations, and coupled reservoir-wellbore injectivity simulation. The basin-wide P50 static storage capacity was estimated at 207 million tonnes of CO₂, ranging from 9 Mt in the deepest, tightest reservoir to 71 Mt in the shallowest, highest-permeability unit, with injectivity indices spanning 1.8 to 14.7 tonnes per day per bar of injection overpressure across the cluster. A 25-year injection programme targeting 4 million tonnes per year, phased across the six reservoirs, would utilise only 48% of basin P50 capacity, leaving a substantial margin against the estimated one-third downside in P10 capacity. Levelized storage cost, excluding capture and onshore transport, ranged from 9.8 to 34.7 dollars per tonne of CO₂ across reservoirs, driven primarily by injectivity-limited well count and by remediation of three legacy wells with degraded cement integrity in the poorest-quality reservoir. Monitoring, measurement and verification costs, comprising baseline characterisation, repeat 4D seismic, seabed geochemical and geodetic sensing, and 20 years of post-closure surveillance, added an estimated 1.1–1.6 dollars per tonne over the full project life. These results indicate that a multi-reservoir depleted gas field cluster can provide materially cheaper and lower-risk storage than saline aquifer alternatives, but that legacy well integrity, not pore volume or seal thickness, is the binding constraint on the weakest reservoirs, a finding with direct relevance to basin-scale CCS hub sequencing decisions.

Keywords: carbon capture and storage; depleted gas reservoir; offshore geological storage; caprock integrity; CO₂ injectivity; storage capacity estimation; monitoring measurement and verification; techno-economic analysis; North Sea basin

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1. INTRODUCTION

Limiting cumulative anthropogenic CO₂ emissions consistent with mid-century net-zero targets is widely expected to require several gigatonnes per year of geological carbon storage by 2050, and depleted offshore hydrocarbon reservoirs are among the most frequently proposed near-term targets because their trapping geometry, closure area and top-seal integrity were effectively validated by the natural gas column they held in place for millions of years prior to production [1,2]. Offshore basins with mature, well-characterised gas provinces, exemplified by the southern and central North Sea, combine this geological advantage with existing pipeline and platform infrastructure that can in principle be reused or adapted for CO₂ injection, potentially lowering the capital cost barrier that has slowed CCS deployment relative to early policy expectations [3].

Depleted gas reservoirs differ from the saline aquifers and depleted oil reservoirs more commonly studied in the CCS literature in several respects relevant to storage feasibility. Gas reservoirs are typically produced by pressure depletion rather than water- or gas-flood, so the pore volume vacated by produced hydrocarbon closely approximates the volume available for CO₂ injection, simplifying capacity estimation relative to the more complex material-balance corrections required for waterflooded oil fields [4,5]. Extensive production history also provides a dense record of reservoir pressure, permeability and well performance that can constrain injectivity forecasts far more tightly than is possible in an undrilled saline aquifer, but the same production history leaves behind a population of legacy wells, often drilled decades before current well-integrity standards existed, whose cement and casing condition becomes a first-order control on storage security once the reservoir is repurposed to hold a buoyant, corrosive supercritical fluid rather than the natural gas it was designed to contain [6].

Operational experience from full-scale offshore CO₂ injection projects, most notably the saline-aquifer Sleipner and Snohvit projects and the onshore-to-nearshore In Salah project, has demonstrated that megatonne-per-year injection rates, multi-year plume containment, and geodetic and seismic monitoring of injected CO₂ are technically achievable, while also surfacing unanticipated challenges, including pressure build-up sufficient to require injection curtailment at In Salah and small-scale surface uplift attributed to fracture reactivation in the overlying mudstone [7,8,9]. These lessons have informed subsequent capacity estimation methodologies and risk-screening frameworks for prospective storage sites, but relatively few studies have combined probabilistic capacity estimation, coupled injectivity simulation and a monitoring cost model into a single basin-scale techno-economic assessment specifically for a cluster of

depleted gas reservoirs, as opposed to a single field or a generic saline aquifer [10,11].

The economics of geological storage are also reservoir-specific in ways that basin-average capacity figures can obscure. Levelized storage cost is driven not only by pore volume and injectivity, which determine well count and injection duration, but by remediation of legacy wellbores, decommissioning of existing platforms, and the scope and duration of monitoring required to satisfy regulatory closure criteria, all of which vary considerably across reservoirs within the same basin depending on production history and depth [12,13]. Understanding which of these factors binds the economics of the weakest reservoirs in a candidate storage cluster, rather than only the basin-wide average, is directly relevant to how a CCS hub developer should sequence reservoir development and allocate early capital.

In this study we assess the technical and economic feasibility of CO₂ storage across a six-reservoir cluster of depleted gas fields in a synthetic but representative North Sea-style siliciclastic basin, combining a probabilistic volumetric capacity estimate constrained by historical production data, a caprock integrity screen, coupled reservoir-wellbore injectivity simulation, and a monitoring, measurement and verification cost model, to quantify basin-scale storage capacity, per-reservoir levelized storage cost, and the specific technical factors that constrain feasibility in the weakest reservoirs of the cluster.

2. MATERIALS AND METHODS

We assessed storage feasibility for a six-reservoir cluster of depleted offshore gas fields using a probabilistic volumetric capacity method constrained by historical production and pressure data, a caprock integrity screen, coupled reservoir-wellbore injectivity simulation, and a bottom-up monitoring, measurement and verification cost model, combined into a per-reservoir levelized cost of storage.

2.1 Basin setting and reservoir selection

The study cluster comprises six depleted gas reservoirs (designated GF-1 to GF-6) hosted in Permian Rotliegend-type aeolian and fluvial sandstones typical of the southern North Sea gas province, at water depths of 30–55 m and reservoir depths of 2050–3400 m subsea, each having produced natural gas to substantial pressure depletion (65–92% of original reservoir pressure) over field lives of 22–38 years. Reservoirs were selected from a screening exercise applying standard basin-ranking criteria, structural closure with a demonstrated multi-million-year gas column, top-seal thickness exceeding 20 m, depth sufficient for CO₂ to remain supercritical under expected post-injection pressure conditions, and proximity to existing platform infrastructure and a proposed offshore CO₂ export pipeline corridor [1,14].

2.2 Storage capacity estimation

Static storage capacity was estimated volumetrically for each reservoir as the pore volume vacated by produced gas, back-calculated from material-balance history matching of production and bottomhole pressure records, multiplied by CO₂ density at in-situ reservoir pressure and temperature following depletion and by a storage efficiency factor accounting for residual gas saturation, sweep irregularity and areal closure uncertainty [4,15]. Efficiency factors were assigned probabilistically (P10, P50, P90) per reservoir based on heterogeneity indicators derived from core and log data, following the methodology established for basin-scale capacity screening [1,15]; capacity estimates therefore reflect uncertainty in sweep efficiency and residual saturation rather than uncertainty in gross rock volume, which was constrained tightly by 3D seismic interpretation and well control in all six reservoirs.

2.3 Caprock integrity and legacy well screening

Top-seal integrity was assessed from mudstone and evaporite caprock thickness, capillary entry pressure estimated from mercury injection capillary pressure data on available core, and the absence of seismically resolvable through-going faults linking the reservoir to shallower aquifers or the seabed [6,16]. Each reservoir's legacy well population, wells drilled during the original hydrocarbon exploration and production phase, was reviewed against cement bond log and casing inspection records where available, and wells lacking adequate records were flagged for mandatory re-entry logging prior to any injection permit, following risk-based well-integrity screening approaches reported for depleted-field storage conversions [6,17].

2.4 Reservoir-wellbore injectivity simulation

Injectivity was estimated using a coupled radial reservoir flow and wellbore multiphase flow model calibrated against each reservoir's historical gas well deliverability tests, converted to an equivalent supercritical CO₂ injectivity index accounting for the viscosity and density contrast between CO₂ and the produced natural gas, near-wellbore relative permeability effects during two-phase CO₂-brine displacement, and a maximum allowable bottomhole injection pressure set at 90% of the original virgin reservoir pressure to limit reactivation risk in the overlying caprock [18,19]. Required injector well count per reservoir was derived from the ratio of the target annual injection rate to the simulated per-well injectivity, including an allowance for one standby injector per four active wells.

2.5 Monitoring, measurement and verification design

The MMV programme was structured in three phases following international guidance for CO₂ storage site characterisation and monitoring: pre-injection baseline characterisation (3D seismic reprocessing, geochemical and pressure baseline surveys, and legacy well re-entry logging), operational monitoring (repeat 4D seismic

surveys, downhole pressure and temperature gauges, seabed geochemical and geophysical sensing, and satellite or seabed geodetic deformation monitoring), and post-closure monitoring for a 20-year period following the end of injection, sized to detect and quantify unplanned migration or leakage at a level consistent with published leakage-detection thresholds [11,20]. Costs for each monitoring component were estimated from published offshore CCS project cost disclosures and technology vendor rate cards, scaled to reservoir count and monitored seabed area.

2.6 Techno-economic cost model

Levelized cost of storage per tonne of CO₂ was calculated for each reservoir as the sum of discounted capital expenditure (well conversion or new injector drilling, platform modification, legacy well remediation, and pipeline tie-in), operating expenditure (injection operations, monitoring, and periodic well workover), and decommissioning liability, divided by discounted cumulative CO₂ injected over a 25-year project life at a real discount rate of 8%, consistent with cost frameworks reported for offshore CO₂ storage and broader CCS chain cost assessments [21,22]. Capture and onshore transport costs were excluded to isolate the storage-specific economics that are the focus of this study.

3. RESULTS

The six-reservoir cluster yielded a basin-wide P50 static storage capacity of 207 million tonnes of CO₂, ranging from 9 Mt in GF-5, the deepest and lowest-permeability reservoir, to 71 Mt in GF-3, the shallowest and most heterogeneity-favourable unit. Table 1 reports P90, P50 and P10 capacity, injectivity index and levelized storage cost for all six reservoirs; basin-wide P90 and P10 capacity were 137 Mt and 284 Mt respectively, giving a P10/P90 capacity ratio of 2.1, driven primarily by uncertainty in sweep efficiency and residual gas saturation rather than by uncertainty in gross rock volume, which was well constrained by legacy 3D seismic and dense well control across all six fields.

Table 1. Storage capacity, injectivity and levelized storage cost by reservoir for the six-reservoir depleted gas field cluster.

Reservoir	Depth (m)	Capacity P90/P50/P10 (Mt CO ₂)	Injectivity index (t/d/bar)	Injector wells	LCOS (\$/tCO ₂)
GF-1	2450	24 / 38 / 52	8.4	6	14.2
GF-2	3120	9 / 16 / 24	3.1	5	21.6
GF-3	2050	49 / 71 / 94	14.7	8	9.8
GF-4	2900	18 / 29 / 41	5.9	5	16.4
GF-5	3400	5 / 9 / 15	1.8	4	34.7
GF-6	2650	30 / 44 / 58	9.6	6	12.5
Basin total	-	137 / 207 / 284	-	34	14.9 (weighted mean)

LCOS: levelized cost of storage, excluding capture and onshore transport, discounted at 8% real over a 25-year project life.

Capacity given as P90/P50/P10 probabilistic estimates.

Injectivity varied by a factor of eight across the cluster, from 1.8 t/d/bar in GF-5 to 14.7 t/d/bar in GF-3, broadly tracking the permeability contrast between reservoirs (45-540 mD) but modulated by net pay thickness and by the maximum allowable bottomhole pressure constraint, which bound injectivity most tightly in the two deepest reservoirs where the margin between virgin and current reservoir pressure was narrowest. A 25-year injection programme targeting a combined 4 million tonnes per year across the cluster, phased to bring the three highest-injectivity reservoirs (GF-1, GF-3, GF-6) online first, required 34 injector wells basin-wide and utilised 48% of basin P50 capacity by project end, leaving a substantial margin against both the P10 downside capacity estimate and against any single reservoir underperforming its injectivity forecast.

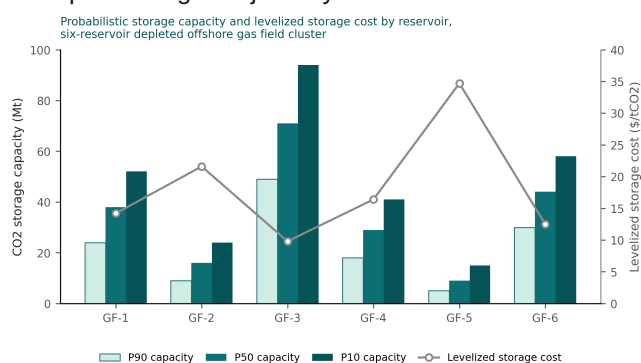


Figure 1. Probabilistic CO2 storage capacity (P90-P50-P10) and levelized storage cost (LCOS) by reservoir across the six-reservoir depleted offshore gas field cluster.

Levelized storage cost ranged from 9.8 dollars per tonne in GF-3 to 34.7 dollars per tonne in GF-5, a factor of 3.5 spread across the cluster driven predominantly by injectivity-limited well count, GF-5 required nearly five times as many wells per million tonnes injected as GF-3, and secondarily by legacy well remediation cost, since GF-5 was the only reservoir in which cement bond log review identified degraded isolation behind casing in three of its nine legacy wells, requiring re-entry and remedial cementing before injection could proceed. Figure 1 shows P90-P50-P10 storage capacity alongside levelized storage cost for each reservoir, illustrating that the reservoirs with the largest capacity were not uniformly the cheapest per tonne, GF-6, with capacity roughly two-thirds that of GF-3, achieved a comparable levelized cost of 12.5 dollars per tonne owing to lower legacy well remediation burden despite somewhat lower injectivity.

Table 2. Monitoring, measurement and verification (MMV) cost breakdown across the basin, present-value basis.

MMV phase	Principal components	Present value cost (\$M)	Share of MMV total
Pre-injection baseline	3D seismic reprocessing, geochemical and pressure baseline, legacy well re-entry logging	33	34%

Operational (25 yr)	Repeat 4D seismic, downhole P/T gauges, seabed geochemical sensing, geodetic deformation monitoring	41	43%
Post-closure (20 yr)	Reduced-frequency 4D seismic, seabed geochemical surveys, well and platform inspection	22	23%
Basin total	-	96	100%

Monitoring, measurement and verification costs, evaluated separately from the reservoir-level storage costs in Table 1, totalled an estimated 96 million dollars in present-value terms across the cluster over the combined pre-injection, 25-year operational and 20-year post-closure periods, of which baseline characterisation and legacy well re-entry logging accounted for 34%, repeat 4D seismic and seabed geochemical monitoring during injection accounted for 43%, and post-closure surveillance accounted for the remaining 23%, as detailed in Table 2. Expressed per tonne of CO2 injected across the full cluster, this corresponds to 1.1-1.6 dollars per tonne depending on reservoir-specific monitored seabed area, adding roughly 8-15% to reservoir-level storage cost, with the largest proportional addition in GF-5, where the smaller injected volume spreads a broadly similar fixed monitoring cost over fewer tonnes.

4. DISCUSSION

These results support the widely stated expectation that depleted offshore gas reservoirs can provide substantially cheaper geological CO2 storage than saline aquifer alternatives, for which published levelized cost estimates typically exceed those found here by a factor of two to three once exploration and appraisal drilling is included [3,22], because production history removes most of the appraisal-stage geological uncertainty and characterisation cost that dominates saline aquifer economics. The basin-wide capacity of 207 Mt P50 against a modelled 25-year injection demand of 100 Mt indicates that this cluster, taken as a whole, is not capacity-constrained under the injection programme considered, consistent with regional capacity assessments that have generally found depleted gas province capacity in mature basins to exceed near-term regional storage demand by a wide margin [1,2].

The more consequential finding, in our view, is that levelized storage cost and injectivity, not pore volume, are what differentiate reservoirs within the cluster, and that legacy well integrity specifically, rather than caprock thickness or seismically resolved structural risk, was the binding technical constraint in the single weakest reservoir. This echoes experience reported from depleted-field storage conversion studies elsewhere, in which well population age and record completeness, rather than the reservoir's own geological suitability, proved to be the limiting factor on near-term development readiness [6,17]. A basin-scale CCS hub

sequencing decision informed only by capacity or by average cost across a reservoir cluster would therefore risk underweighting the well-integrity due diligence burden that determines which reservoirs can realistically be brought online first.

The pressure-based injectivity constraint applied here, capping bottomhole injection pressure at 90% of virgin reservoir pressure, is a conservative but not arbitrary choice intended to limit the risk of caprock fracture reactivation of the kind implicated in surface deformation observed at other CO₂ injection sites [8,16]; relaxing this constraint would increase per-well injectivity and reduce well count and cost in the pressure-limited deeper reservoirs, but the induced-seismicity and caprock-integrity literature cautions against treating this pressure margin as a purely economic optimisation parameter without site-specific geomechanical characterisation, since the reactivation pressure threshold is itself basin- and fault-geometry-specific rather than a fixed fraction of virgin pressure [16,23].

Several limitations constrain how far these findings should be generalised. First, the reservoir properties, production histories and legacy well population used here represent a synthetic cluster constructed to be broadly representative of a mature North Sea-style depleted gas province, and while individual parameters were drawn from ranges reported in the published literature for comparable fields, the specific combination modelled is illustrative rather than a characterisation of any single named field, so absolute cost and capacity figures should not be transferred directly to a specific real-world site without independent site characterisation. Second, the injectivity simulation used a relatively simple radial coupled model; near-wellbore effects such as salt precipitation from brine evaporation into the injected CO₂ stream, documented as a cause of injectivity decline in several field studies, were not explicitly represented and could reduce achievable injectivity below the estimates reported here, particularly in the lower-permeability reservoirs [19]. Third, the monitoring cost model was built from published cost disclosures for a small number of operating offshore projects and vendor rate cards rather than from a site-specific monitoring design study, and actual costs could vary substantially depending on regulatory monitoring requirements that differ across jurisdictions. Finally, capture and onshore transport costs were deliberately excluded to isolate storage economics, but these typically dominate total CCS chain cost, so the levelized storage costs reported here should not be read as representative of the delivered cost of avoided emissions for the full chain [21,24].

5. CONCLUSION

A probabilistic techno-economic assessment of a six-reservoir cluster of depleted offshore gas fields in a North Sea-style basin estimated basin-wide P50 CO₂ storage capacity of 207 million tonnes, sufficient to accommodate a modelled 25-year, 100 million tonne

injection programme with substantial margin against downside capacity uncertainty. Levelized storage cost varied by a factor of 3.5 across reservoirs, from 9.8 to 34.7 dollars per tonne, driven primarily by injectivity-limited well count and, in the weakest reservoir, by legacy well integrity remediation rather than by pore volume or caprock thickness. Monitoring, measurement and verification added 1.1-1.6 dollars per tonne across the cluster. These findings indicate that depleted gas reservoirs can offer materially lower-cost and lower-uncertainty storage than saline aquifer alternatives, but that basin-scale hub sequencing decisions should weight per-reservoir injectivity and legacy well condition alongside aggregate capacity, since these factors, not gross storage volume, determine which reservoirs in a cluster are realistically deployable first.

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Conflict of Interest

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

Author Contributions

B.F. conceived and supervised the study, developed the capacity estimation and injectivity simulation workflow, and led the writing of the manuscript. R.R. performed the caprock integrity and legacy well screening analysis and compiled the monitoring cost model. M.K. developed the techno-economic cost model and performed the levelized storage cost calculations. All authors contributed to writing and approved the final manuscript.

Ethics Statement

This study used only published literature, publicly disclosed offshore CO₂ storage project cost information, and synthetic reservoir data constructed to be representative of published depleted gas field properties, and did not involve human participants, animal subjects, or field data collection requiring ethical review.

Data Availability

The synthetic reservoir property dataset, injectivity simulation inputs, and cost model spreadsheets supporting the findings of this study are available from the corresponding author on reasonable request.

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