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**Geological CO₂ Storage at the Regional Scale:
A Comprehensive Study through Geological Modelling,
Numerical Flow Simulation, and Well-Integrity
in the North Sea**

AUTHOR
Mattia De Luca

SUPERVISORS
Prof. Vittorio Scisciani
Prof. Eric J. Mackay

DOCTORAL COORDINATOR
Prof. Luigi Berardi

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“The secret to change is to focus all of your energy, not on fighting the old, but on building the new.”

— Dan Millman, “Way of the Peaceful Warrior”

“Essentially, all models are wrong, but some are useful.”

— George E.P. Box, “Science and Statistics”

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Prof. Luigi Berardi (President),

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Politecnico di Bari, Italy

Thesis Reviewers

Dr. Luca Mattioni,

IFP Energies Nouvelles, France

Dr. Stefano Patruno,

University of Nicosia, Cyprus

Declaration of Originality

I declare that this thesis titled “Geological CO₂ Storage at the Regional Scale: A Comprehensive Study through Geological Modelling, Numerical Flow Simulation, and Well-Integrity in the North Sea”, and the work presented in it are my own, performed under the supervision of Prof. Vittorio Scisciani and Prof. Erick J. Mackay, at the Department of Engineering and Geology, Università degli Studi G. d’Annunzio di Chieti-Pescara, at the Institute of GeoEnergy Engineering at the Heriot-Watt University, and at Wellynx S.r.l. Company. All published and unpublished material used in the thesis has been given full acknowledgement. This thesis has not been previously submitted in whole or in part for a degree or any other qualification at this University or any other institution.

Mattia De Luca

July 22nd, 2025

Data Availability Statement

WesternGeco/SLB provided the 3D Cavendish surveys used in this study through a partnership established with the author and their supervisors via Università degli Studi G. d'Annunzio and Heriot-Watt University.

In addition to these proprietary datasets, publicly available data were also analysed.

All geological, geophysical, and GIS data utilised in this research are accessible through the UK North Sea Transition Authority's (NSTA) National Data Repository (NDR) and Open Data platform, and through the British Geological Survey (BGS) website. Requests for data access should be directed to <https://ndr.nstauthority.co.uk/>, <https://www.nstauthority.co.uk/data-centre/nsta-open-data/> and <https://www.bgs.ac.uk/>.

Bathymetry data were retrieved from the European Marine Observation and Data Network (EMODnet) and can be accessed at: <https://emodnet.ec.europa.eu/en/bathymetry>.

For further inquiries regarding dataset access, please refer to the respective repositories or contact the data providers directly.

Abstract

Rapid systemic transformations are essential to tackle climate change, particularly in energy and industry. Carbon Capture and Storage (CCS) is a proven technology for reducing carbon emissions in these hard-to-abate sectors. In recent years, studies on CCS have increased significantly; however, they mainly focused on the field scale. As the demand for larger CCS deployment grows, regions with optimal geological conditions will witness multiple concurrent operations. Reconstructing an accurate geological framework and understanding interactions within regionally interconnected storage sites is crucial for evaluating the deployment of multiple injections.

This study assesses the feasibility and implications of geological CO₂ storage in two UK North Sea regions: the Greater East Shetland Platform and the Silverpit Basin. To investigate these uncertainties, the work was subdivided into three phases: (i) site identification and geological reconstruction of the storage complex, (ii) static modelling and dynamic simulation sensitivities of CO₂ injection, and (iii) evaluation of potential risk related to abandoned wells within the storage complex.

Integration of available wellbore and seismic data with gravity and magnetic forward modelling revealed promising intra-platform basins within the underexplored Greater East Shetland Platform, with potential CO₂ storage capacities of 170 to 640 Mt. This approach demonstrated the effectiveness of these exploration methods as screening tools for areas with limited data availability. However, further investigation and additional data are required to advance modelling before developing numerical simulations, thereby redirecting the study toward the Silverpit Basin.

In the Silverpit Basin, geological reconstruction validated the Triassic Bunter Sandstone Formation (BSF) as a prime CCS candidate. Reconstruction of a 9000 km² regional model facilitated dynamic simulations to evaluate plume migration, pressure responses, and storage heterogeneities. Six static models were created to simulate fifteen scenarios aimed at investigating their behaviour. Results indicate that the BSF could safely store over 700 Mt of CO₂ with the proposed development strategy. Findings also highlight the importance of understanding the regional behaviour of pressure diffusion and brine displacement, which generate interference within the storage complex.

The extensive history of hydrocarbon production in the Silverpit Basin poses challenges to CCS due to hundreds of abandoned wells. Many lack specific integrity measures, acting as leakage pathways for CO₂ and formation brine, posing potential risks for containment efficiency. The assessment of seventeen wells revealed risks of casing collapse due to increasing lateral pressure induced by nearby injection. Additionally, many wells lack the capacity to retain CO₂ due to inadequate placement of abandonment plugs, potentially compromising containment integrity.

In conclusion, this research underscores the need for comprehensive regional-scale and long-term analyses to account for regional interferences affecting CCS operations before field-scale refinement. It highlights the value of regional models in identifying key uncertainties and guiding risk mitigation for large-scale CCS. Understanding geological heterogeneities, pressure dynamics, hydrogeological flows, and well integrity is essential to mitigating local risks and ensuring safe, efficient CCS deployment in other complex settings similar to the North Sea.

Preface

This thesis comprises five chapters, with Chapters 2 through 4 presented in a paper format. Each chapter reflects a critical stage in addressing the overarching research objectives, advancing techniques to explore new regions for geological CO₂ storage, and evaluating regional features that influence the large-scale deployment of CO₂ storage through numerical flow simulation. Additionally, the research highlights potential risks associated with existing legacy infrastructures.

Chapter 2 has been published in *Tectonophysics*. To align with the scope of the journal, the description of CO₂ storage potential was omitted from the publication. However, it has been included and discussed in this thesis to provide a more comprehensive perspective on the research and its broader implications. This chapter was developed at the Università degli Studi G. d'Annunzio di Chieti-Pescara.

Chapter 3 originated at the home university and was further developed in collaboration with the research team at Heriot-Watt University of Edinburgh during a six-month international research exchange and further collaboration, a required component of the PhD programme. Under the guidance of Professor Mackay, this collaboration provided specialised training in numerical flow simulation, access to cutting-edge simulation tools, and opportunities to refine technical skills. Additionally, the collaboration facilitated the establishment of an academic agreement for access to commercial seismic data, significantly improving the resolution and accuracy of the models. Part of the study presented in Chapter 3 was shared at international conferences attended during the PhD programme. This chapter also includes unpublished material prepared for submission to a peer-reviewed journal, with co-authors acknowledged in the “List of Publications and Conference Proceedings” section.

Chapter 4 presents the outcomes of a six-month collaboration with Wellynx S.r.l., the industrial partner supporting this research. This collaboration enabled the evaluation of plug-and-abandonment (P&A) conditions and the well-integrity analysis of selected wells for the study. The chapter demonstrates the adaptation of findings to address real-world challenges and highlights the potential for academic research to drive practical innovations in well engineering. It has been prepared for submission to a peer-reviewed

journal, with contributions from the Wellynx team and Matteo Loizzo, a well-engineering consultant who contributed to the refinement of the code needed for the calculation of the minimum safe abandonment depth.

The candidate served as the primary author for all these manuscripts, taking full responsibility for conceptualising the studies, conducting data collection, interpretation and analysis, preparing figures, drafting the initial versions of the papers, and incorporating edits in response to peer-review comments.

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List of Publications and Conference Proceedings

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CONFERENCES

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Chapter 1

Introduction and Motivations

1.1 The 21st Century Climate Challenge

Climate change stands as one of the most critical global challenges of the 21st century, primarily caused by the increasing concentration of anthropogenic greenhouse gases (GHGs) in the atmosphere (Fig. 1.1) (e.g. IEA, 2021; IPCC, 2021; and references therein). GHGs trap heat within the Earth's atmosphere, intensifying the greenhouse effect and exacerbating global warming. The principal GHGs include carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O), which are predominantly emitted through fossil fuel combustion, deforestation, and agriculture, leading to climate change and environmental disruptions. Among these, CO₂ is recognised as the primary contributor to global warming due to its direct correlation with global temperature anomalies perfectly fitting with the industrial development over the last two centuries (Fig. 1.2)(e.g. IPCC, 2021 and references therein). The increasing levels of CO₂ in the atmosphere (Fig. 1.1) emphasise the urgent need for effective mitigation strategies, necessitating immediate action to curtail emissions across various polluting sectors.

Recent estimates indicate that over 50 gigatons (Gt; billions of tons) of GHGs are released into the atmosphere annually, primarily from anthropogenic sources of energy such as fossil fuel combustion (Fig. 1.3). Within this context, CO₂ accounts for the largest share with approximately 37 Gt released in 2019 (e.g. Olivier and Peters, 2020; Fig. 1.3).

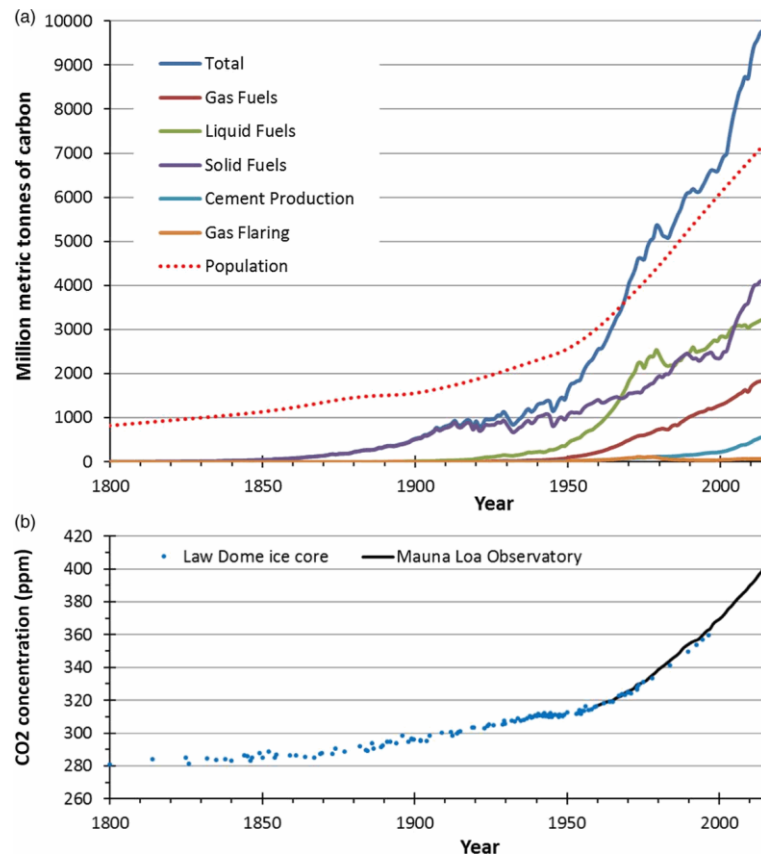


Fig. 1.1 Correlation of CO₂ emissions and anthropic activity from (Ringrose, 2017). (a) Global CO₂ emissions. CO₂ emissions are expressed in millions of metric tonnes of carbon; to convert to the mass of CO₂ multiply by the molecular ratio 3.667. (b) Mean annual CO₂ concentration in the atmosphere.

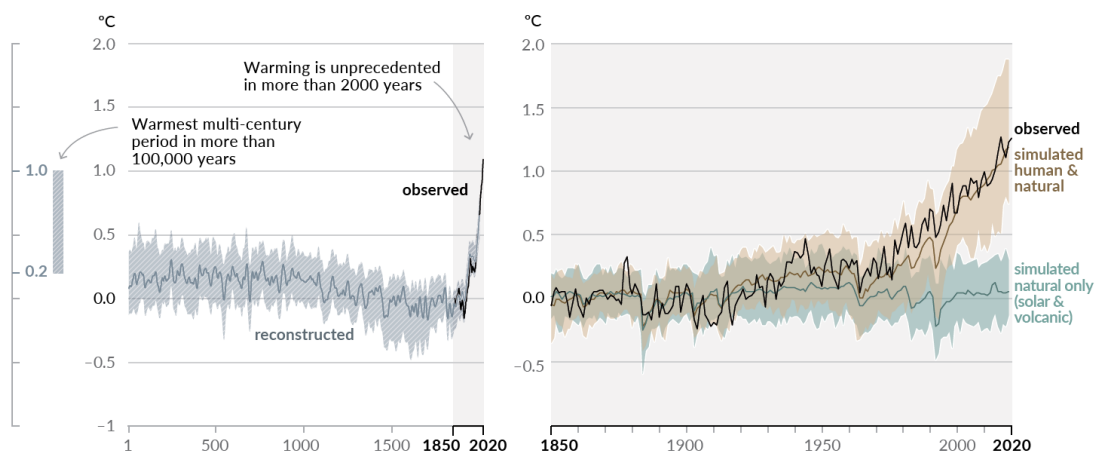


Fig. 1.2 Changes in global surface temperature (left) reconstructed and observed, and (right) correlated to anthropic activities over time (from IPCC, 2021).

In 2015, the Conference of the Parties (COP21) under the Paris Agreement committed to limiting global temperature rise to below 2°C, aiming for 1.5°C above pre-industrial levels if feasible. Despite this effort, recent data reported in the Climate Bulletins of the Copernicus Climate Change service (C3S, 2025), indicate that January 2025 recorded a temperature 1.75°C above the pre-industrial level. Notably, this marked the 18th month in the past nineteen where the global average surface air temperature exceeded 1.5°C, highlighting the urgency of accelerating mitigation efforts. Therefore, current emission reduction measures remain insufficient, as many countries continue to rely on fossil fuels, and existing policies lack the necessary enforcement and financial support for large-scale low-carbon energy adoption and carbon sequestration initiatives. Achieving net-zero emissions by mid-century will thereby necessitate the deployment of negative-emission technologies, which need to extensively contribute to this global challenge.

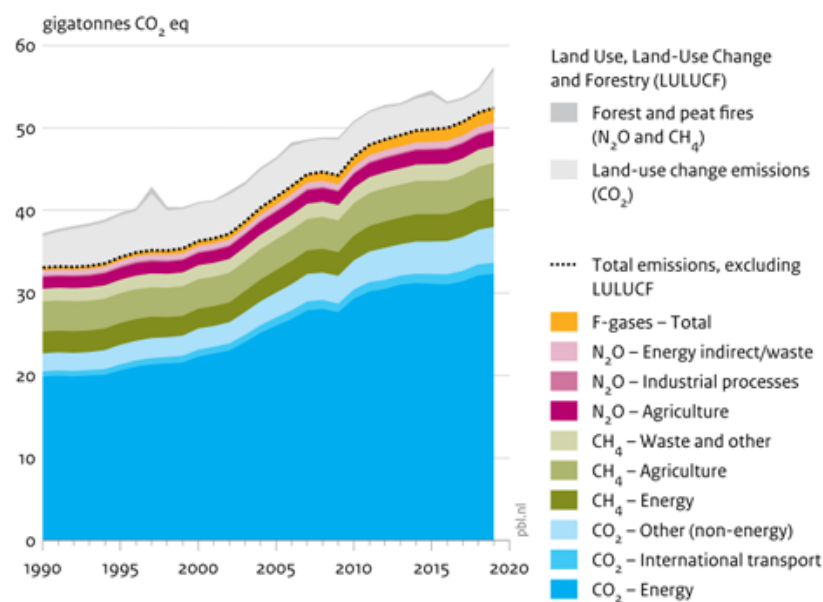


Fig. 1.3 Global greenhouse gas emissions, per type of gas and source, including LULUCF from (Olivier and Peters, 2020).

Carbon Capture and Storage (CCS) has emerged as a key technology in transitioning towards a low-carbon future, particularly for hard-to-abate industries where direct decarbonisation is challenging (e.g. IEA, 2021; IPCC, 2021; and references therein). CCS is particularly important for sectors such as cement and steel production, power

generation, and petrochemical industries (IEA, 2021a). In this regard, CCS offers a crucial pathway for achieving this goal by capturing CO₂ emissions from industrial sources, and transporting them to a geological storage site to be permanently and safely stored in the subsurface.

1.2 Carbon Capture and Storage Technologies

Carbon Capture and Storage (CCS) is a multi-stage process designed to mitigate CO₂ emissions by capturing, transporting, and securely storing carbon dioxide (Fig. 1.4). Each stage requires advanced engineering solutions and robust regulatory frameworks to ensure effectiveness and safety and are briefly described as follows (GCCSI, 2023; Merz et al., 2005).

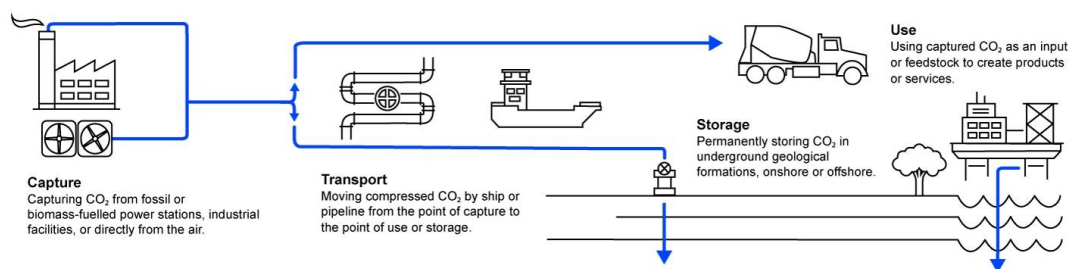


Fig. 1.4 Schematic representation of the carbon capture and storage (CCS) chain from IEA (2024).

The process begins with CO₂ capture from industrial sources or directly from the atmosphere through chemical and physical methods. The main capture technologies are: pre-combustion capture, where fuel is converted into hydrogen and CO₂, with the latter subsequently separated; post-combustion capture, which isolates CO₂ from flue gases using chemical solvents; oxy-fuel combustion, where fuel burns in pure oxygen, producing a flue gas composed primarily of CO₂ and water vapour, simplifying separation; and inherent capture, where CO₂ is integrated into the process design,

maintaining high purity by preventing contamination with other gases. Beyond point-source emissions, CCS also enables carbon removal through methods such as Bioenergy with Carbon Capture and Storage (BECCS), where CO₂ absorbed by biomass during growth is captured upon combustion, and Direct Air Capture (DAC) with CCS, which extracts CO₂ directly from the atmosphere. However, the latter is still in its early stages, capturing only 0.01 Mt/yr (IEA, 2024b, 2021).

Once processed, CO₂ is transported to storage sites via high-pressure pipelines, similar to those in the natural gas industry or within tanks transported by ship, rail, or truck. Efficient CO₂ transport requires careful handling, as wet CO₂ has high corrosion potential due to carbonic acid formation; thus, it is typically dried before transport.

Finally, the captured CO₂ is injected into deep geological formations such as depleted hydrocarbon reservoirs, saline aquifers, or unmineable coal seams for permanent sequestration. Alternative storage methods include mineral carbonation, where CO₂ reacts with minerals to form stable carbonates, and ocean storage; however, the latter remains controversial due to environmental concerns.

As of 2024, the Global CCS Institute (2024) reports 50 commercial CCS projects operating worldwide, collectively capturing approximately 50 Mt/yr, with an additional 44 projects under construction, and over 500 more in the development phase, which have the potential to capture over 400 Mt/yr of CO₂ (Fig. 1.5). Nevertheless, to achieve mitigation of climate change, CCS need to be scaled up at to balance CO₂ emissions and further deployed.

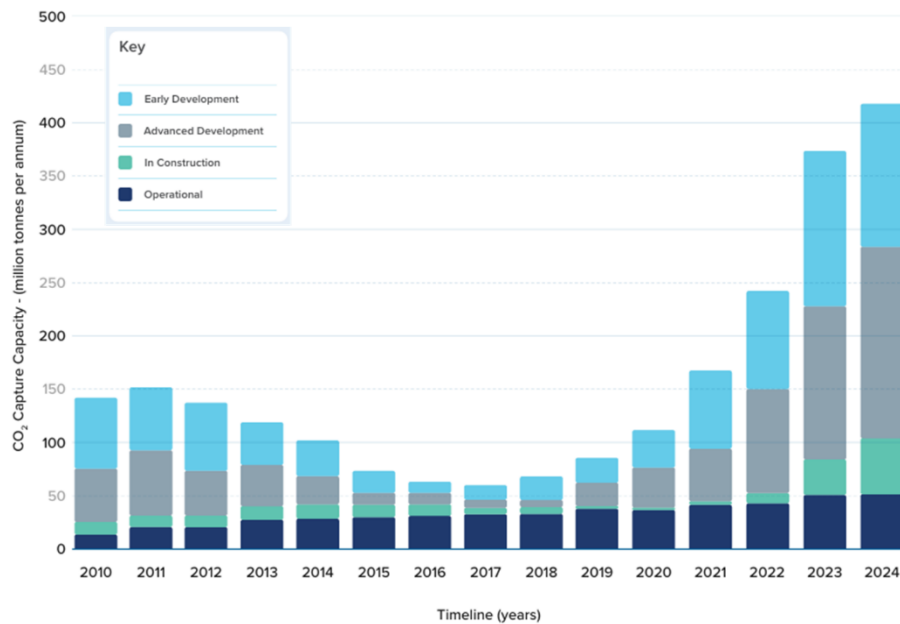


Fig. 1.5 CO₂ capture capacity of commercial CCS facility pipeline development since 2010 (GCCSI, 2024).

1.3 Geological CO₂ Storage

Geological carbon storage involves the injection of CO₂ into deep subsurface formations, which consist of permeable porous rocks capped by an impermeable sealing layer, known as a caprock, that prevents upward migration and potential leakage (Gluyas and Mathias, 2014; Merz et al., 2005; Ringrose, 2020). Among the various geological storage options, saline aquifers offer the most suitable and largest potential storage capacity, making them of primary interest for CO₂ storage deployment. However, due to the limited exploration for hydrocarbon production, data availability for saline aquifers remains scarce, posing challenges for detailed site assessment and characterisation.

At depths greater than 800 m, the CO₂ exists in a dense supercritical phase, significantly reducing its volume and buoyancy effect. This enhances containment by limiting mobility and increasing the efficiency of storage mechanisms (Gluyas and Mathias, 2014; Merz et al., 2005; Ringrose, 2020).

Once injected in the subsurface, the CO₂ is securely trapped through structural, residual, solubility, and mineral trapping mechanisms (Fig. 1.6)(Benson and Cook, 2005).

Structural and stratigraphic trapping occurs where geological formations allow the confinement of the CO₂ plume within a structural or stratigraphic configuration restricting its lateral and vertical migration. Residual trapping, also known as capillary trapping, immobilises CO₂ within the pore spaces due to capillary forces. Solubility trapping occurs as CO₂ dissolves into the formation brine, gradually integrating into the subsurface fluid system. Over extended timescales, mineral trapping takes place when CO₂ reacts with the host rock to form stable carbonate minerals due to carbonate precipitation, ensuring its permanent sequestration.

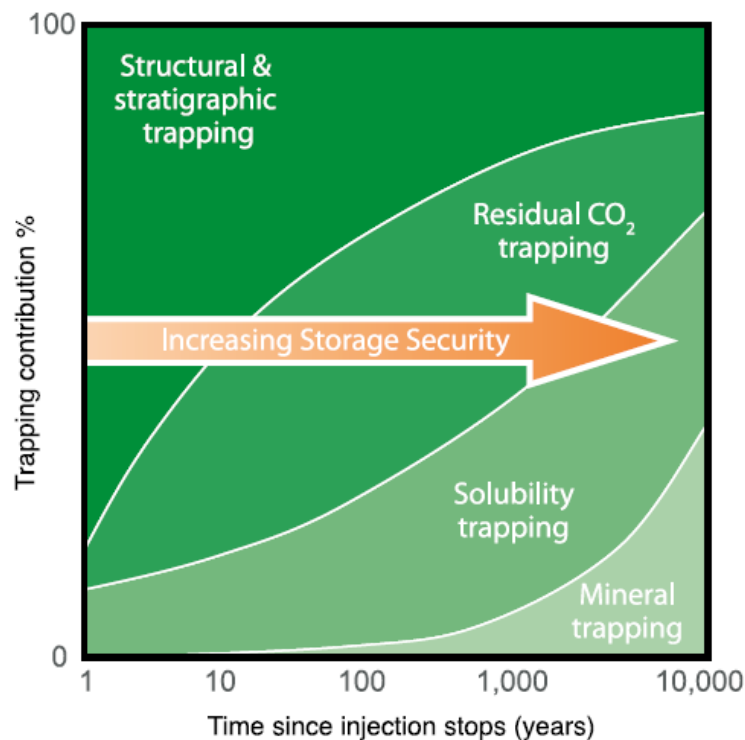


Fig. 1.6 Storage trapping mechanisms from (Benson and Cook, 2005).

Geological storage represents the most extensive and durable approach for long-term CO₂ sequestration, with saline aquifers and depleted hydrocarbon reservoirs serving as the primary target formations (Gluyas and Mathias, 2014; Merz et al., 2005; Ringrose, 2020). The global capacity for geological CO₂ storage is estimated to be on the order of 1000 Gt, exceeding the CO₂ storage requirements needed to limit global warming to 1.5°C by 2100 (Benson and Cook, 2005; IPCC, 2023).

However, large-scale deployment of CO₂ storage faces significant challenges that require further investigation, including the identification and characterisation of suitable storage sites; geological uncertainties related to long-term storage integrity and site behaviour; complex heterogeneities influencing CO₂ flow behaviour; potential risks associated with existing infrastructure, which could compromise containment; and regulatory and policy constraints to permit large-scale deployment.

1.4 Study Objectives

Ensuring the long-term stability of stored CO₂ requires comprehensive geological characterisation and a detailed understanding of multi-scale processes, from pore-scale interactions to basin-wide dynamics. This study focuses on investigating regional-scale aspects of CO₂ storage by integrating geological and geophysical methods, developing regional geological models, conducting numerical flow simulations, and assessing the impact of large-scale storage on nearby abandoned wells. These approaches aim to analyse subsurface heterogeneities, evaluate uncertainties in site evolution, and assess potential risks associated with pre-existing infrastructure. The ultimate goal is to refine site selection strategies and identify key challenges that must be addressed to facilitate large-scale CCS deployment.

1.4.1 Screening of Underexplored Geological Basins

Expanding the search for viable CO₂ storage sites is crucial for enhancing storage capacity, supporting climate change mitigation, and meeting international commitments. Large-scale CCS deployment necessitates the exploration of expansive, underexplored regions such as deep saline aquifers. However, data limitations in these areas present significant challenges for site characterisation (Chadwick et al., 2008 and references therein). Integrating geological and geophysical methods, including seismic imaging, well log interpretation, and gravity and magnetic data analysis, facilitates the identification and reconstruction of suitable storage sites.

Chapter 2 explores the application of these methodologies in characterising potential CO₂ storage sites within the Greater East Shetland Platform in the UK Continental Shelf of the Northern North Sea. By integrating well data, seismic interpretation, and forward modelling of gravity and magnetic anomalies, this study reconstructs the geological framework and assesses storage potential in regions where geological data are sparse, ensuring preliminary site characterisation for further evaluation.

1.4.2 Site Modelling and CO₂ Flow Simulation

Simulation studies highlight the critical influence of reservoir heterogeneity on CO₂ plume migration, necessitating high-resolution models that accurately represent geological complexities (Benson and Cook, 2005; Chadwick et al., 2008; Gluyas and Mathias, 2014; Ringrose, 2020). A key aspect of CCS deployment is regional site modelling and the simulation of multiple CO₂ injections to assess potential interferences and the impact of concurrent storage activities in interconnected systems. Regional model development is constrained by uncertainties due to data resolution limitations. Inaccuracies in velocity models can lead to depth model errors, affecting well placement, plume migration predictions, and overall storage capacity assessments. Additionally, CO₂ saturation is strongly influenced by geological heterogeneities. High-permeability zones enhance CO₂ saturation, while low-permeability barriers, such as halite-cemented layers, create anomalies (Benson and Cook, 2005; Bergmo et al., 2011; Birkholzer et al., 2009; Birkholzer and Zhou, 2009; Chadwick et al., 2008; Gluyas and Mathias, 2014; Krevor et al., 2023; Nicot, 2008; Noy et al., 2012; Ringrose, 2020; Smith et al., 2011; Thibeau et al., 2014; Zhou et al., 2010, 2008).

The presence of multiple injection sites requires comprehensive basin-wide pressure management strategies to prevent excessive pressure buildup, reducing the risk of structural failures or unintended fluid displacement (Benson and Cook, 2005; Bergmo et al., 2011; Birkholzer et al., 2009; Birkholzer and Zhou, 2009; Chadwick et al., 2008; Gluyas and Mathias, 2014; Krevor et al., 2023; Nicot, 2008; Noy et al., 2012; Ringrose, 2020; Smith et al., 2011; Thibeau et al., 2014; Zhou et al., 2010, 2008). Without such strategies, pressure accumulation could induce structural weaknesses, such as fracturing,

and lead to unexpected fluid displacement. Advanced geological and reservoir modelling techniques are applied to simulate CO₂ injection and migration, aiding in predicting pressure variations, plume behaviour, and potential leakage risks.

Chapter 3 details the development of geological models and numerical simulations designed to assess storage site behaviour through sensitivity studies addressing key challenges. The research employs regional-scale modelling to examine pressure evolution, plume migration, and the effects of geological heterogeneities. The findings enhance understanding of regional gradients and contribute to mitigating risks associated with CO₂ injection.

1.4.3 Investigation of Abandoned Wells

A significant challenge in geological storage is the presence of abandoned and legacy wells from past hydrocarbon exploration and production, which may become leakage pathways if not properly sealed. While cement plugs and steel casings are designed for long-term isolation, factors such as corrosion, mechanical failure, and inadequate abandonment practices can increase leakage risks (Bachu and Watson, 2009; Bai et al., 2016; Benson and Cook, 2005; Carroll et al., 2016; Das et al., 2024; Duguid et al., 2017; Gasda et al., 2004; Gluyas and Mathias, 2014; Khalifeh and Saasen, 2020; Loizzo et al., 2024; Moghadam et al., 2023; Ringrose, 2020; Romdhane et al., 2022; Scherer et al., 2005; Tiong et al., 2019; Vrålstad et al., 2019; Watson and Bachu, 2009, 2008). Comprehensive well integrity assessments, including casing collapse analysis and plug efficiency evaluations, are essential to mitigate these risks.

Chapter 4 examines the potential risks posed by abandoned wells in CCS projects. The study evaluates wellbore integrity through casing collapse calculations and plug efficiency assessments. Identifying these risks is crucial for ensuring the containment of CO₂ and preventing leakage pathways that could compromise storage security.

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Chapter 2

Iapetus Ocean Serpentinites and Mesozoic Intra-platform Basins Revealed by Gravity and Magnetic Modelling Across the Greater East Shetland Platform (Northern North Sea, UK)

Abstract

The Greater East Shetland Platform and its intra-platform basins (i.e. the Dutch Bank Basin and East Orkney Basin) are examples of poorly explored areas in the UK Continental Shelf (Northern North Sea), hosting a locally thick (1-8 km) Devonian-to-Tertiary sedimentary succession that unconformably overlies the Caledonian crystalline basement.

Starting from a grid of seismic reflection lines, six recently acquired profiles were selected, interpreted and depth-converted. The resulting geological cross sections were integrated with forward modelling of the observed Bouguer gravity and magnetic anomalies, and constrained by the available wellbore-derived petrophysical parameters.

Our seismic interpretation and modelling suggest that the first-order contributors to the observed Bouguer gravity anomalies are related to the scattered distribution of the Mesozoic sedimentary sequences in the intra-platform basins. Furthermore, the main sources of the modelled magnetic anomalies are related to high-susceptibility (≤ 0.05 SI units) bodies in the crustal basement that locally correspond to zones of high reflectivity imaged in the seismic profiles. Such deep sources are interpreted as paleo-domains

inherited from the pre-Devonian tectonic evolution of the study area and assembled during the Caledonian Orogeny. This may be relatable to the offshore extension of first-order pre-Devonian tectonic lineaments exposed in the Scottish Highlands and Orkney-Shetland islands.

2.1 Introduction

The combined modelling of gravity and magnetic anomalies can significantly contribute to the understanding of subsurface geology, particularly if constrained by the field geology and/or by well-data and seismic profiling (e.g., Garland, 1951; Telford et al., 1990; Düzgüt et al., 2006; Rybakov et al., 2011; Mancinelli et al., 2020; Mancinelli et al., 2022). Moreover, this method of study becomes crucial to define the subsurface framework when some of such external constraints are lacking or sparse as in the Greater East Shetland Platform (GESP – *sensu* Patruno and Reid, 2016) in the Northern North Sea (NNS), which is the focus area of this work (Fig. 2.1).

Hydrocarbon-oriented exploration of this area has been historically less developed than in other surrounding basins (e.g., the Viking Graben) due to the early interpretations of this continental platform as a tectonic high with shallow acoustic basement and rare mature source rocks (Platt, 1995; Platt and Cartwright, 1998; Zanella and Coward, 2003). As a consequence, the GESF area was investigated by only few regional studies. These were based on deep seismic profiles (White, 1989; McBride and England, 1999), sometimes combined with gravity and magnetic modelling (Holliger and Klemperer, 1989; Holliger and Klemperer, 1990; Fichler and Hospers, 1990; Fichler et al., 2011; Arsenikos et al., 2016; Kimbell and Williamson, 2016; Frogtech Geoscience, 2017; Patruno et al., 2017; Karstens et al., 2022).

The study area is approximately $33 \times 10^3 \text{ km}^2$ and includes the UK quadrants 1-2, 5-9, 12-15 (Fig. 2.1). It is located in the UK NNS and corresponds to a large-scale Mesozoic platform to the east of the alignment of the Caithness headland – Orkney Island – Fair Isle – Shetland Island – Unst Basin, to the west of the Viking Graben and East Shetland Basin, and to the north of the Moray Firth Basin and Witch Ground Graben (Fig. 2.1b).

This area is interposed between the outcropping British and Scandinavian Caledonian orogen and is thought to include the north-eastward continuation of the Highland terranes and intervening boundary faults closely exposed in Scottish mainland (Strachan and Woodcock, 2021). Due to the overprint of the Mesozoic rifting onto the pre-existing Caledonian sutures, the limits between Laurentia, Baltica and Avalonia plates involved in the Caledonian collision are poorly constrained and they remain masked underneath a thick pile of the North Sea rift and post-rift sediments (Soper et al., 1992; Turner et al., 2018; Patruno et al., 2022). Despite the relevant reconstructions close to land exposures by deep seismic-reflection profiles around the UK, Ireland, and eastern North Sea (NW of Denmark – Beamish and Smythe, 1986; Soper et al., 1992; Abramovitz and Thybo, 2000), the prolongation of the British-Irish Caledonian Terranes and the intervening main faults (e.g., the Great Glen Fault, Highland Boundary Fault and Southern Upland Fault – Fig. 2.2a – Flinn, 1961; Flinn, 1992; Strachan and Woodcock, 2021) in the GESP and their relationship with the Scandinavian Caledonides remains unclear and it is still matter of debate (Coward et al., 2003).

In this work, we provide a first-order geological and geophysical investigation of the main sedimentary basins in the GESP and the interpretation of nature and geometries of deeper bodies within the crust. In particular for the shallower basins, we focus on the still under-explored Dutch Bank Basin, the East Orkney Basin and East Fair Isle Basin (Fig. 2.1b), together with their related fault-bounded structural highs – i.e. the Caithness Ridge, Fair Isle Platform and the West Fladen High (Fig. 2.1b – Johnson et al., 2005; Richardson et al., 2005; Patruno and Reid, 2016; Patruno and Reid, 2017; Arsenikos et al., 2016; Arsenikos et al., 2018; Kimbell and Williamson, 2016; Patruno et al., 2019; Scisciani et al., 2021).

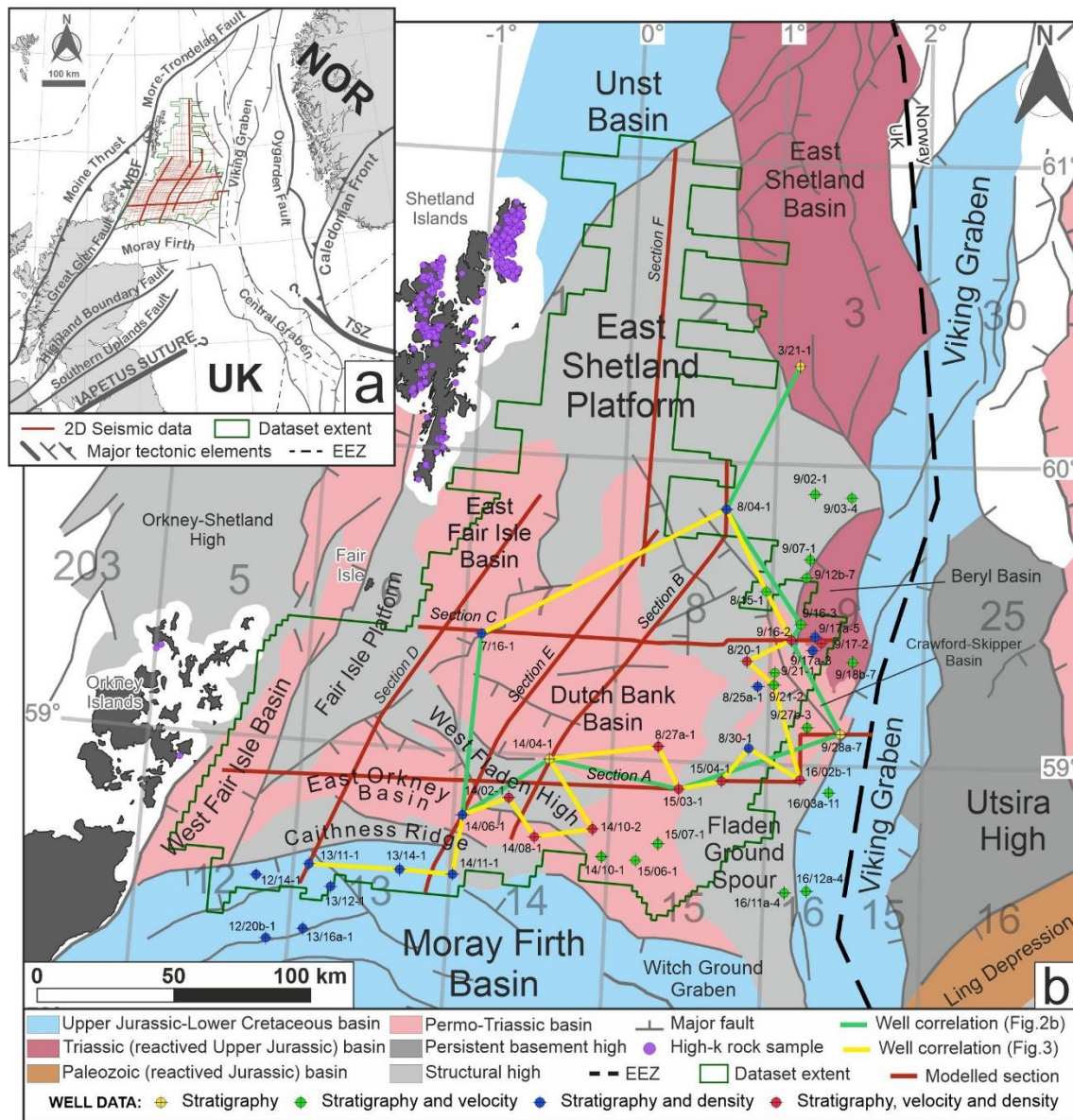


Fig. 2.1 (a) Location of the grid of 2D seismic profiles (thin red lines) from the PP162DGOGA survey (NSTA, 2022) and *high-resolution* gravity-magnetic dataset (delimited by green line) in the UK sector of the NNS. Simplified tectonic lineaments modified from Zanella and Coward (2003) and Strachan and Woodcock (2021). WBF, Walls Boundary Fault; TSZ, Tornquist Fault Zone. (b) Regional structural scheme showing the main Palaeozoic-Mesozoic basins and structural highs in the NNS modified from Scisciani et al. (2021). Dataset extent indicates the extension of the Bouguer gravity and magnetic anomaly data from Bliss et al. (2016). Traces of seismic lines and geological cross-sections modelled in this work are in red; seismic profiles were retrieved from the National Data Repository (NDR) of NSTA (2022). Violet dots show the distribution of onshore gabbroic, serpentinite and serpentinized rock samples (BGS, 2022) that can be related to high magnetic susceptibility (high-k rock samples). EEZ, exclusive economic zone; UK, United Kingdom; NOR, Norway. Original name of the sections: Section A – 228A045_EXTRA_C, Section B – 045B028 EXTRA-A, Section C – 024A024 EXTRA-B,

Section D – OA16ESP00039A032, Section E – OA16ESP00109A011, Section F – OA16ESP00091A093.

2.2 Tectonic and Geological Setting

2.2.1 Tectonic Setting

Starting from Cambrian times, the study region experienced alternating phases of compressional and extensional tectonics, separated by periods of relative tectonic quiescence (e.g., Patruno and Scisciani, 2021). The main compressional phase occurred during the Caledonian Orogeny (Silurian-Early Devonian) which was preceded by the closure of the previously rifted apart margins of the East Iapetus Ocean (Robert et al., 2021) and the collision of Laurentia with Avalonia and Baltica plates (Soper et al., 1992; Turner et al., 2018; Patruno et al., 2022). The assemblage and exhumation of the Caledonian orogen was accompanied by multiple plutonic intrusions (Atherton and Ghani, 2002, and references therein) and by later Devonian extensional collapse or strike-slip reworking (McClay et al., 1986; Coward et al., 1989; Seranne et al., 1989). The Devonian tectonics led to the development of widespread and deep basins infilled by thick wedges of “Old Red Sandstone” (Steel et al., 1985) in western Scandinavia, Northern Scotland and neighbouring offshore areas (e.g., East Shetland Platform and West Shetland Basin; Norton, 1987; Osmundsen et al., 1998; Seranne and Seguret, 1987; Fossen, 1992; Platt and Cartwright, 1998; Marshall and Hewett, 2003; Fossen and Hurich, 2005; Fossen, 2010; Wilson et al., 2010; Vetti and Fossen, 2012; Bird et al., 2015; Fossen et al., 2016; Phillips et al., 2016; Patruno et al., 2019; Scisciani et al., 2019; Scisciani et al., 2021; Patruno et al., 2022). The Devonian basins were later affected by a regional inversion tectonic phase in the Upper Carboniferous (Platt, 1995; Platt and Cartwright, 1998; Patruno et al., 2019), concurrently with the Variscan Orogeny (Ziegler, 1975).

Since early Permian times, the area underwent multiple extensional events which culminated in the Late Jurassic-Cretaceous North Sea rifting (Zanella and Coward, 2003; Johnson et al., 2005). During the Middle Jurassic, a further magmatic and erosional event (Aalenian Mid North Sea doming – Underhill and Partington, 1993) affected the Caledonian terranes and preceded the subsequent rift development (Ziegler, 1992; Fraser et al., 2003; Patruno et al., 2022).

During Tertiary, the post Mesozoic-rifting subsidence was interrupted by localised Alpine-age compressional events and contemporaneously large-scale epeirogenic uplift affected the rift margins with erosion of vast area in the UK (White, 1989; Glennie & Underhill, 1998; Smallwood et al., 1999; Smallwood & White 2002).

2.2.2 Geological and Structural Setting of the GESP and adjacent onshore areas

NW and SW of the GESP, there are outcropping metamorphic and plutonic rocks which form the ground of the mainland Scottish Caledonides (Lambert and McKerrow, 1976; Dewey and Shackleton, 1984; Strachan et al., 2002). In particular, the study area extends east of the Walls Boundary Fault (Fig. 2.1a), a main lineament trending approximately NNE-SSW from the west Orkney Islands through the Shetland Islands (Seranne, 1992; Flinn, 1992). This fault was previously thought to have accommodated significant left-lateral movement and it is interpreted as the north-eastern extension of the Great Glen Fault (Fig. 2.1a), along which an analogous horizontal movement has been documented (Andrews et al., 1990; Underhill and Brodie, 1993; Stewart et al., 1999; Roberts and Holdsworth, 1999; Dewey and Strachan, 2003; Mendum and Noble, 2010). The Great Glen Fault separates the Moine from the Dalradian terranes and it accommodated horizontal deformation during the Caledonian orogeny before being reactivated in more recent times (Hutton and McErlean, 1991; Stewart et al., 1997; Le Breton et al., 2013; Armitage et al. 2021). The Dalradian Group was deposited on the south-eastern margin of Laurentia and was affected by at least two rifting episodes that culminated with the opening of the Iapetus Ocean ca. 600 Ma (Soper and England, 1995; Dewey et al., 2015). Similar syn-rift successions, referred to the Dalradian block, are also exposed in the north-eastern Shetland Islands, where they are tectonically overlaid along a Caledonian thrust fault to the Shetland Ophiolite Complex (e.g., Prichard and Lord, 1993; Flinn, 2001). This complex consists of two thrust-bounded nappes composed of mafic and ultramafic igneous rocks, with associated low-grade metasedimentary rocks and mélanges that include both basic and metavolcanic rocks (Flinn, 1999; Flinn et al., 2013 and references therein). The Shetland ophiolites are thought to be obducted onto the Laurentian

continental margin during Ordovician times (Grampian Orogeny – Crowley and Strachan, 2015) and then telescoped onto the Dalradian terrane during the Silurian-age Scandian orogenic event following the westward movement and collision of Baltica (Flinn and Oglethorpe, 2005). The Shetland Ophiolite Complex is now recognised as a fragment of the Iapetus Ocean or most likely a related marginal basin and it shows several analogies in composition, structural setting and age with a chain of ophiolite fragments found throughout the Laurentian Caledonides of the British Isles and occurring along the Highland Border in Scotland and on the west coast of Ireland (Williams and Smyth, 1973; Flinn, 1999, and references therein). Several lines of evidence suggest that ophiolites were formed in supra-subduction zone arc–forearc settings shortly prior to orogenesis and then thrust (obducted) onto a colliding passive margin. These ophiolites were emplaced during the early to mid-Ordovician Grampian orogenic event, which records the initial stages in closure of the Iapetus Ocean (Chew et al., 2010). The collision of a juvenile oceanic arc with the Laurentian passive margin resulted in NW-directed ophiolite obduction (present reference frame) with regional deformation and metamorphism of footwall metasedimentary successions (e.g., Dewey and Shackleton, 1984; Chew et al., 2010).

In the GESP, the basement was rarely penetrated by exploration wells and the few available logs report high grade metamorphic rocks and numerous intrusive bodies, including Devonian granites penetrated at the eastern edge of the GESP (e.g., Well 3/21-1 on Fig. 2.1 – Donato and Tully, 1982; Holloway et al., 1991; Bassett, 2003; Patruno and Reid, 2016; Whitbread and Kearsley, 2016; Patruno and Reid, 2017; Arsenikos et al., 2018; Patruno et al., 2019; Kombrink and Patruno, 2020). South-east of the GESP, Middle Jurassic mafic effusive and volcanoclastic sequences were encountered by wells and imaged by seismic reflection in the Rattray Volcanic Province at the triple junction of the Mesozoic North Sea rift system (e.g., Quirie et al., 2018). High-susceptibilities rocks were reported in the ophiolites of the Shetland islands (e.g., gabbroid and serpentized rocks – Flinn, 1996 and references therein). These mafic rocks are interpreted, with intermediate intrusives, in the lower crust north-east of the British Isles, where they are presumably related to an island-arc system pertaining to the Iapetus Ocean (Fichler et al.; 2011). Similar mafic rocks, seemingly buried under granitoid rocks, were reported at the bottom of a few hydrocarbon wells in the offshore East Shetland Platform (e.g., hornblend-biotite

schists with metamorphic cooling age of 393 Ma described in Well 9/04a-1 by Bassett, 2003; Patruno et al., 2017; Scisciani et al., 2019).

Recent revision of the available well-log and interpretation of seismic reflection data in the GESP (Patruno and Reid, 2016; Patruno and Reid, 2017; PGS, 2017; Patruno et al., 2019; Scisciani et al., 2019; Scisciani et al., 2021) revealed a laterally discontinuous but locally thick (up to 7-8 km) sedimentary cover, unconformably overlaying the Caledonian igneous and metamorphic basement (Fig. 2.2). This sedimentary sequence mainly consists of easterly tilted Devonian-to-Cretaceous deposits overlain by a wedge-shaped and west-north-westerly thinning Cenozoic units (Fig. 2.2a).

Underneath the Tertiary unit, the GESP is arranged in several structural highs (Fig. 2.1b) with different attitudes (including the E-W trending Caithness Ridge, the SSW-NNE trending Fair Isle Platform, the NW-SE trending West Fladen High, NW-SE trending East Shetland Platform and the N-S trending Fladen Ground Spur) separated by intervening late Palaeozoic and Mesozoic basins (Fig. 2.2a – East Orkney Basin, Dutch Bank Basin, West Fair Isle Basin, East Fair Isle Basin, Crawford-Skipper Basin – Andrews et al., 1990; Platt, 1995; Platt and Cartwright, 1998; Richardson et al., 2005; Patruno and Reid, 2016; Patruno and Reid, 2017; Scisciani et al., 2021).

Field exposures in north-western Britain (e.g., Orcadian Basin) and wells penetration in the GESP or in the Moray Firth Basin indicate Devonian sediments of the Old Red Sandstone Group at the base of the sedimentary cover unconformably overlaying the Caledonian basement (Marshall and Hewett, 2003; Kendall, 2017; Whitbread and Kearsy, 2016; Marshall et al., 2019).

This interval consists of Devonian sediments (Fig. 2.2) with sandstone-rich continental deposits (e.g., upper Devonian Buchan Formation – Fm.), marls, lacustrine mudstones, marine anhydrite-dolomite markers (e.g., middle Devonian Eday Group – Gp., Strath Rory Fm. and Orcadia Fm.), and Lower Devonian fluvial sandstones with thick conglomerates (Marshall and Hewett, 2003; Patruno et al., 2019).

In the GESP, Carboniferous units have only been preserved in the Dutch Bank Basin and Piper Shelf depocenters (e.g., wells 14/08-1, 8/27a-1), a fact which suggest uplift and erosion of large sector of the platform during this time (Patruno and Reid, 2016; Patruno

and Reid, 2017). In fact, the succession composed of lower-upper Permian Rotliegend Group and a thin uppermost Permian Zechstein is directly underlain by the Base Permian Unconformity, which reflects the Upper Carboniferous Variscan uplift and inversion tectonics (Fig. 2.2b – Patruno et al., 2019; Scisciani et al., 2021). These units are respectively represented by the sandstones of the Auk Fm. at the base (e.g., well 9/28a-7 in the Crawford-skipper Basin) and the carbonate-evaporite cyclothems of the Zechstein Group at the top (well 9/28a-7 – Glennie et al., 2003; Patruno and Reid, 2017; Patruno et al., 2019).

Throughout the GESP, Triassic deposits are confined into syn-tectonic intra-platform extensional fault-related basins (Fig. 2.1 and Fig. 2.2 – Johnson, 2005; Patruno and Reid 2017; Scisciani et al., 2021) and tend to conformably overlie the Zechstein Gp. (e.g., Patruno et al., 2019). The lower facies comprise lacustrine and alluvial claystone of the Smith Bank Fm., overlain by the fluvial sandstones of the Skagerrak Fm. (Fig. 2.2b – Goldsmith et al., 2003). The complex tectonic of the Upper Triassic–Jurassic North Sea trilete rift system that led to the development of the border faults of the Viking Graben and Moray Firth half-grabens and grabens (Roberts et al., 1990; Ziegler, 1992), started with the post-rifting thermal subsidence of Upper Triassic–Lower Jurassic period (Zigler, 1992; Steel, 1993) that was followed by a non-deposition or erosion of the lower-middle Jurassic deposits in the NNS during the Mid-Cimmerian Unconformity (Steel, 1993; Underhill and Partington, 1993; Coward et al., 2003; Johnson et al., 2005). Conversely, these deposits are better preserved further south (e.g., Inner Moray Firth – Patruno et al., 2019) and are locally overlaid by thin veneer of upper Jurassic mudstones and sandstones layers (Patruno et al., 2019; Scisciani et al. 2021).

The inherited Jurassic paleo-reliefs were passively infilled by Cretaceous sediments (Fig. 2.2) mostly covering the older sequences with very thin Lower Cretaceous claystones and marlstones (Cromer Knoll Group – Davies et al., 1999), and the more widespread Upper Cretaceous limestone and marls (Chalk/Shetland Groups – Patruno and Reid, 2016; Patruno and Reid, 2017; Patruno et al., 2019). These deposits are confined mostly in the southern basin, where they form thick syn-rift wedges in the hangingwall block of Cretaceous normal faults (e.g., Witch Ground Graben, Moray Firth Basin). As a contrast,

in the northern area (e.g., Dutch Bank Basin, East Shetland Platform) the Cretaceous succession is typically much thinner (Patrino et al., 2019).

The Cenozoic non-marine, deltaic and shallow-marine mudstone-sandstone cycles (Fig. 2.2b) onlap the underlying Mesozoic deposits and progressively thins towards the west, with Tertiary deltaic progradational clinoforms expanding their thickness eastwards due to a regional tilting phase (Fig. 2.2a). In the western sector, close to the Shetland and Orkney islands, these deposits are often erosively truncated at the seabed. These sequences are generally only weakly deformed and affected by gentle folds and inversion structures related to the Alpine deformation phase (Pegrum and Spencer, 1990; Glennie and Underhill, 1998).

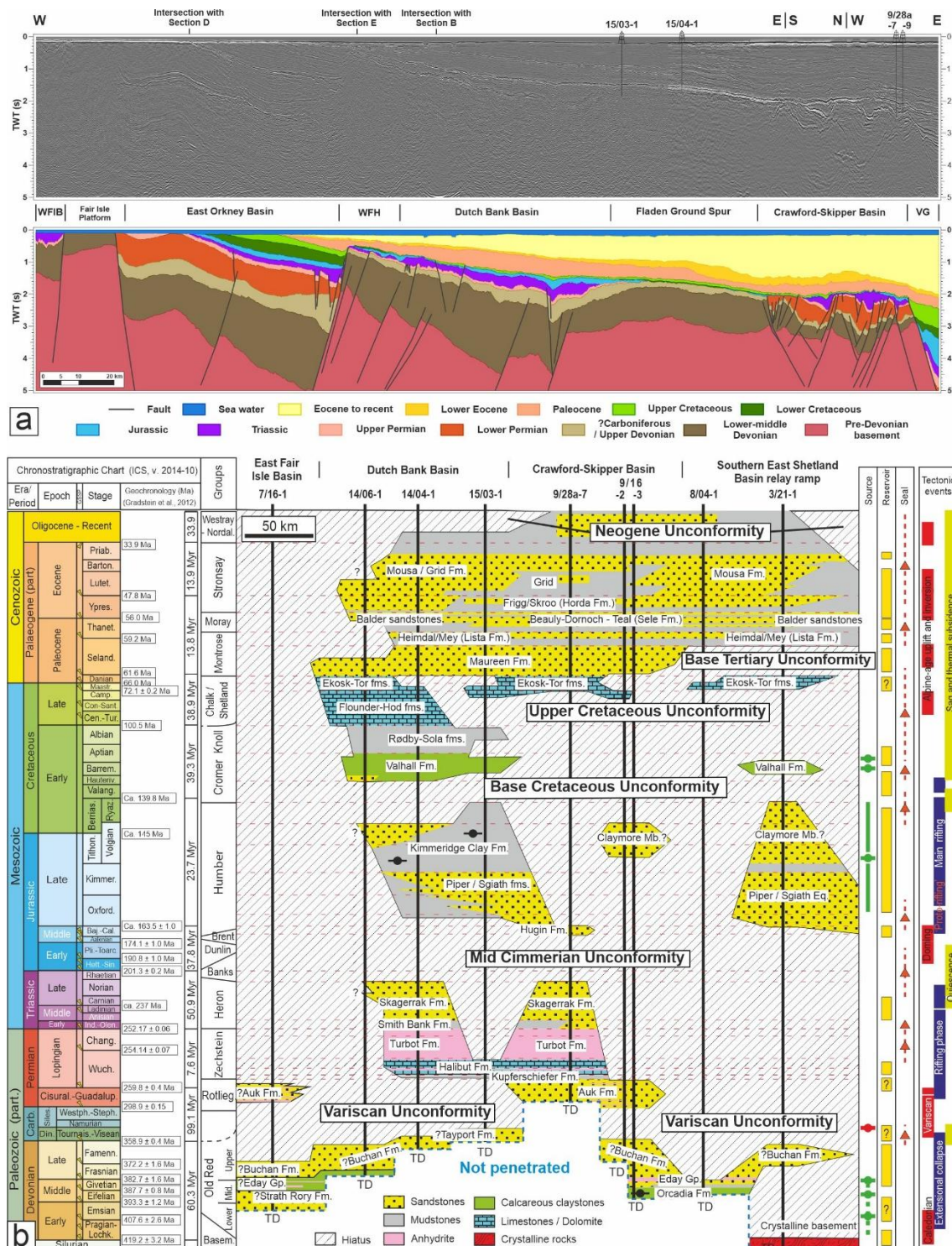


Fig. 2.2 (a) Uninterpreted and interpreted version of the regional seismic reflection profile (Section A in Fig. 2.1b for location) showing the different ages and thickness distribution of sedimentary basins overlaying the metamorphic basement. (b) Regional chronostratigraphic and lithostratigraphic correlation panel of wells (green line in Fig. 2.1b) showing the inhomogeneous lateral and vertical distribution of the sedimentary cover and unconformities related to the main tectono-magmatic events (modified from Scisciani et al., 2021). WFIB, West Fair Isle Basin; WFH, West Fladen High; VG, Viking Graben.

2.3 Data and Methods

2.3.1 Well Data

Stratigraphic, lithological, compressional seismic velocity (V_p) and bulk density (ρ) data of the sedimentary units (Devonian to Quaternary in age) were inferred from well data analysis of joined wireline and composite logs. The information from the 43 wells used in this study (Fig. 2.1) were retrieved from the UK National Data Repository (NDR – NSTA, 2022). The well-correlation showed in Fig. 2.3 briefly highlights the stratigraphic setting, showing also how poorly the basement was investigated at the centre of the GESP area. Only one well (7/16-1) was drilled in the inner part of the East Shetland Platform, at the junction between the Dutch Bank Basin and East Fair Isle Basin. It penetrated a presumed Permian-Devonian red to red/brown sandstone succession. A thick (600-2200 m) Cenozoic succession at the GESP margin is overlaying thin older sediments (e.g., Wells 16/02b-1, 9/16-2). Moving to the southernmost Moray Firth Basin (e.g., Wells 13/11-1, 13/14-1) the thickness of the Cenozoic sediments reduces, while a thick Cretaceous (mostly Lower Cretaceous) sequence stands out reaching thicknesses >2000 m (Fig. 2.3). Conversely, the Dutch Bank intra-basin wells (e.g., Wells 14/04-1, 8/27a-1) reveal a Jurassic-Triassic sediments thickening (100-700 m). Palaeocene-to-Recent deposits show an eastward-thickening trend, reaching maximum thicknesses in the easternmost part of the study area (Well 16/02b-1), while the thickness of the Lower Eocene deposits shows significant lateral variations across the study area (Fig. 2.3).

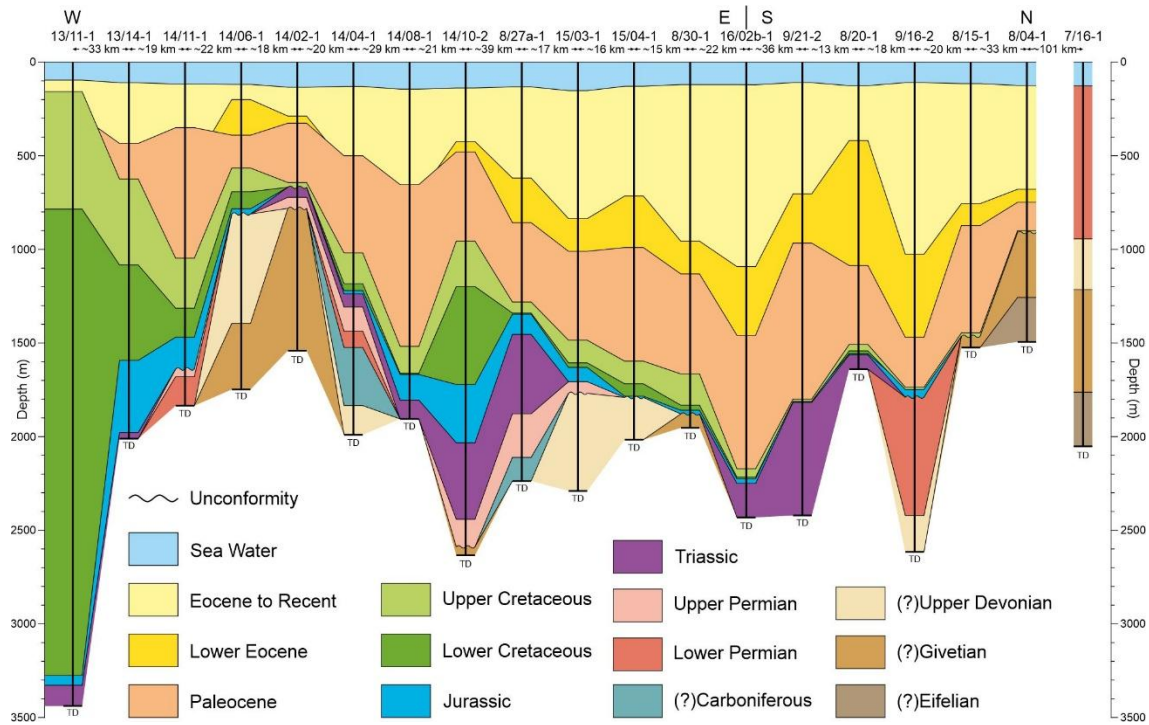


Fig. 2.3 Regional well-correlation panel (yellow line in Fig. 2.1). Well 7/16-1 was not correlated due to its distance (>100 km) from all the other wells. The lateral distance between the wells shown here is not to scale.

CHRONOSTRATIGRAPHY	SEISMIC VELOCITY (m s^{-1})	DENSITY (ρ , kg m^{-3})	SUSCEPTIBILITY (k , SI)
Sea Water	1500 ¹	1030 ²	—
Eocene to Recent (EtR)		1997 - 2011 (1610 - 2156)	—
Lower Eocene (LE)	1907 (1461 - 2253)	2021 - 2070 (1963 - 2129)	—
Paleocene (P)		2094 (1969 - 2240)	—
Upper Cretaceous (UK)	3725 (2399 - 5177)	2239 - 2550 (2239 - 2647)	—
Lower Cretaceous (LK)	3436 (2931 - 4397)	2232 - 2479 (1626 - 2571)	—
Jurassic (J)	2675 (1458 - 4705)	2072 - 2393 (2072 - 2451)	—
Triassic (T)	3515 (2813 - 4518)	2070 - 2385 (2070 - 2470)	—
Upper Permian (UP)	4526 (3192 - 5357)	2442 - 2587 (2428 - 2832)	—
Lower Permian (LP)	4558 (3859 - 5765)	2428 - 2558 (2292 - 2521)	—
Carboniferous? - Upper Devonian? (CuD)			—
Lower-middle Devonian (emD)	4067 (3360 - 5460)	2335 - 2670 (2335 - 2670)	—
Basement (B)	6000 ¹	2700-2750 ²	0.001 - 0.05 ³
Lower Crust (LC)	—	2900 ²	0.05 ³
Mantle (M)	—	3300 ²	0 ⁴

Tab. 2.1 Simplified stratigraphic column showing the layers and the relative values of seismic velocity, density and magnetic susceptibility adopted for time-to-depth conversion of seismic profiles and gravity and magnetic modelling. The values within brackets indicate minimum and maximum values retrieved from the available borehole data. Bold values were used for the depth-

conversion and modelling. Reference values from: ⁽¹⁾ Kearey et al. (2002), Reynolds (2011); ⁽²⁾ Lyngsie and Thybo (2007), Gradmann et al. (2013), Baykiev et al. (2018), Fichler and Pastore (2022); ⁽³⁾ Fichler et al. (2011), Beamish et al. (2016); and ⁽⁴⁾ Wasilewski et al. (1979), Wasilewski and Mayhew (1992).

The seismic velocity data (Tab. 2.1) were retrieved from 26 wells (Fig. 2.1b) among the total selected wells. These data were used to tie the seismic time-to-depth conversion. Despite the boreholes carrying wide ranges of velocities pertaining to each unit (Tab. 2.1), to simplify the time-to-depth conversion procedure we chose to set one seismic velocity value for each unit. The chosen values represent the weighted average of the seismic velocities from check-shot measured in wells (Tab. 2.1). Considering the lithological similarities between the units, and bearing in mind the stratigraphical uncertainties as reported in the logs, we grouped the Palaeocene, Lower Eocene and Eocene-to-Recent deposits in one single seismic unit by attributing the interval velocity of 1907 m s^{-1} . The same approach was used for the Carboniferous?-Upper Devonian? and Lower-middle Devonian units that were grouped in one seismic unit and depth-converted with the interval velocity of 4067 m s^{-1} (Tab. 2.1). The Mesozoic and Palaeozoic layers were depth-converted using velocities in the $2675\text{--}4558 \text{ m s}^{-1}$ range (Tab. 2.1). Due to paucity of direct data, we assumed a seismic velocity of 6000 m s^{-1} for the basement, whilst the sea-water layer was depth-converted with a seismic velocity of 1500 m s^{-1} (Kearey et al., 2002; Reynolds, 2011).

The modelling of the observed gravity anomalies was derived from the mean density (ρ) of each chronostratigraphic layer calculated from wireline bulk density logs (Tab. 2.1) available from 25 wells within and around the study area (Fig. 2.1b).

Relatively lower density values have been found in the Tertiary units ($1997\text{--}2094 \text{ kg m}^{-3}$), while higher densities have been observed in the Upper Cretaceous ($2239\text{--}2550 \text{ kg m}^{-3}$), followed downwards by lower densities in the Lower Cretaceous ($2232\text{--}2479 \text{ kg m}^{-3}$), Jurassic ($2072\text{--}2393 \text{ kg m}^{-3}$) and Triassic units ($2070\text{--}2385 \text{ kg m}^{-3}$). The deeper intervals (Permian to Lower Devonian) show the highest densities ($2335\text{--}2670 \text{ kg m}^{-3}$) within the sedimentary cover. In some cases, the synthetic blocks representing the same sedimentary unit were modelled with slightly different density values. These values always fall within the ranges provided by all well data (Tab. 2.1) but were constrained to the nearby well

when available, hence the slight misfit. Reference density values were assigned to the sea water (1030 kg m^{-3}), basement ($2700\text{-}2750 \text{ kg m}^{-3}$), lower crust (2900 kg m^{-3}) and mantle (3300 kg m^{-3}); these values are similar to those adopted in the surrounding areas (e.g., Lyngsie and Thybo, 2007; Gradmann et al., 2013; Baykiev et al., 2018; Fichler and Pastore, 2022).

2.3.2 Seismic Data

The six lines investigated in this work (total line-length of about 1046 km), shown in Fig. 2.1b and described by PGS (2017) and Scisciani et al. (2021), have been selected from a 2D regional broadband seismic dataset covering the GESP (total line-length of about 15,000 km). This 2D survey was acquired and processed by PGS in 2016-2017 for the UK Oil & Gas Authority (OGA) (NSTA, 2017) and subsequently freely distributed to industry and academia via the NDR online platform (NSTA, 2022). In this work, we follow the Devonian-to-Recent GESP seismic-stratigraphic units grouping proposed in Scisciani et al. (2021).

These lines extend until 5 sec two-way-time (TWT) depth highlighting a clear discrepancy between the shallow and deep reflectors. The Base Triassic-Top Upper Permian (Top Zechstein) reflector marks a distinctive change in the seismic facies with a high amplitude, laterally continuous bright trough. Above this, medium to high-amplitude laterally continuous reflectors can be observed. Directly beneath the Top Zechstein reflector, there are opaque low amplitude seismic facies until low-frequency high-amplitude zones are reached at depth.

The tectono-stratigraphic framework was defined by the interpretation of key horizons from the Sea Bottom to the Top Basement as reported in Tab. 2.1.

Starting from the seismic velocity values in Tab. 2.1, we depth-convert the six seismic lines using a simplified velocity model that provides an average value for each chronostratigraphic interval (Glover, 2000). The conversion function was guided by the following relationship (Etris et al., 2002):

$$Z = V_0 \frac{e^{\kappa t} - 1}{\kappa} \quad (1)$$

where Z is the thickness of the layers in meters, V_0 is the velocity at the top of the layer in m s^{-1} , κ corresponds to the variation frequency of the velocity with the increase in depth and t indicates the one-way time ($t = \text{TWT}/2$) for the layer thickness in seconds. Due to the extreme lateral variation of the seismic units and the resulting horizontal changes in seismic velocity with depth, a constant interval velocity model has been adopted to simplify the time-to-depth conversion. In this case, the κ parameter equals to zero and the previous relationship is simplified as follow:

$$Z = V_0 t \quad (2)$$

2.3.3 Gravity and Magnetic Anomaly Data

The gravity and magnetic anomaly data (Fig. 2.4) were acquired by Austin Exploration Inc. and were processed by Bridgeport Company (Bliss et al., 2016) that applied the following standard corrections to the original data (Bliss et al., 2016). The Bouguer gravity anomaly dataset was filtered with a 6 km cut-off Gaussian filter, interpolated on a regular 2x2 km grid and calculated with a reduction density of 1800 Kg m^{-3} (Fig. 2.4a). The magnetic anomaly data were interpolated on a 2x2 km grid, reduced to the pole (RTP) and filtered using a Gaussian filtering with an 8 km cut-off (Fig. 2.4b). The magnetic modelling was carried out using field data referred to the magnetic epoch of data acquisition (July-September 2016). In particular, the magnetic field intensity (H), inclination (FI) and declination (FD) were set to 40.475218 A/m , 72.121° and -1.907° , respectively (Bliss et al., 2016).

Given the lack of borehole data concerning the magnetic susceptibility (k) of the modelled units, we modelled the magnetic anomaly data using k values within the range $0 - 0.05$ SI units which is representative of the possible magnetic sources in the area (Telford et al., 1990; Lyngsie and Thybo, 2007; Fichler et al., 2011; Beamish et al., 2016). Within this range, lowest or null k values were attributed to the sedimentary units while higher values were used to model the basement and lower crust sources.

The modelling was constrained by the available literature also concerning the thermal gradients of the sedimentary and continental crust, and the depth of the Moho discontinuity. In particular, we model a thermal gradient of $30\text{ }^{\circ}\text{C km}^{-1}$ for the sedimentary layers (Harper, 1971), and of $12\text{ }^{\circ}\text{C km}^{-1}$ for the continental crust (Fichler et al., 2011; Gradmann et al., 2013; Baykiev et al., 2018; Fichler and Pastore, 2022). Finally, we model the Moho discontinuity ranging between 28 and 35 km depth (Fichler and Hospers, 1990; Fichler et al., 2011; Frogtech Geoscience, 2017 and references therein; Baykiev et al., 2018). Considering all the above, and assuming a Curie temperature of $600\text{ }^{\circ}\text{C}$, the Curie depth would fall below the Moho discontinuity. Since the mantle is not contributing to the observed magnetic anomaly (e.g. Wasilewski, et al., 1979; Wasilewski and Mayhew, 1992), we can expect magnetic contributions from the entire crust.

In the study area, the Moho discontinuity shows a general westward-deepening trend since it ranges between 28 km depth in the area close to the Viking Graben, to about 35 km beneath the Shetland Islands and the Moray Firth Basin, while in the central part it is estimated to range between 32 and 34 km (Fichler and Hospers, 1990; Fichler et al., 2011; Frogtech Geoscience, 2017; Baykiev et al., 2018).

All the data described above were integrated in the following 2D combined forward modelling of gravity and magnetic anomalies (e.g., Garland, 1951; Telford et al., 1990; Düzgüt et al., 2006; Rybakov et al., 2011; Mancinelli et al., 2020; Mancinelli et al., 2022).

2.4 Results

2.4.1 Bouguer Gravity and Magnetic Grid observations

A pronounced gravity minimum of -30 mGal is observed at the centre of the Bouguer gravity anomaly grid (Fig. 2.4a). This minimum is grossly E-W elongated, with a NW-SE turn at its westernmost termination, roughly approximating the shape of the Dutch Bank Basin. Furthermore, two less pronounced gravity minima, both considering their amplitude and extension, are found in the East Orkney Basin (still with an approximate E-W trend) and in the East Shetland Platform (roughly N-S trend). In the southwestern portion (quadrants 6, 12 and 13), there is an area of high gravity anomaly with values $>+30\text{ mGal}$. This V-shaped positive anomaly locates along the Caithness Ridge and the

Fair Isle Platform, with E-W and NE-SW elongations, respectively. In the other parts of the study area (quadrants 7, 8), the gravity anomaly shows values ranging between +10 and -10 mGal with the only exceptions found in the northernmost area, where two circular positive gravity anomalies are partially covered by the dataset. Comparing the Bouguer gravity map and the interpreted seismic profiles, the anomaly highs generally match the areas of basement at shallow depth, while the lows are located over intra-platform Permo-Triassic basins (*sensu* Scisciani et al., 2021).

The magnetic anomaly map (Fig. 2.4b) shows two notable peaks, a positive and a negative one. The $\sim +400$ nT, 20 km-diameter positive peak is centred in quadrant 13, north of Wells 13/11-1 and 13/12-1 and east of the Section D. The magnetic anomaly minimum of ~ -200 nT spatially relates with the East Fair Isle Basin. This minimum intercept the northern portion of the Section D and part of the Section C (supplementary Fig. S2.1, Fig. S2.2) where the basement is shallow underneath a thin cover of Lower Permian to Lower Devonian sediments in the East Shetland Platform. In the south-eastern half of the study area, the magnetic anomaly shows wide undulations with anomaly values in the range $+30/-70$ nT. In this area, a thick sedimentary cover is highlighted from the seismic profiles (supplementary Fig. S2.5). In the northern sector of the study area, a positive-negative couplet is partially covered by the dataset.

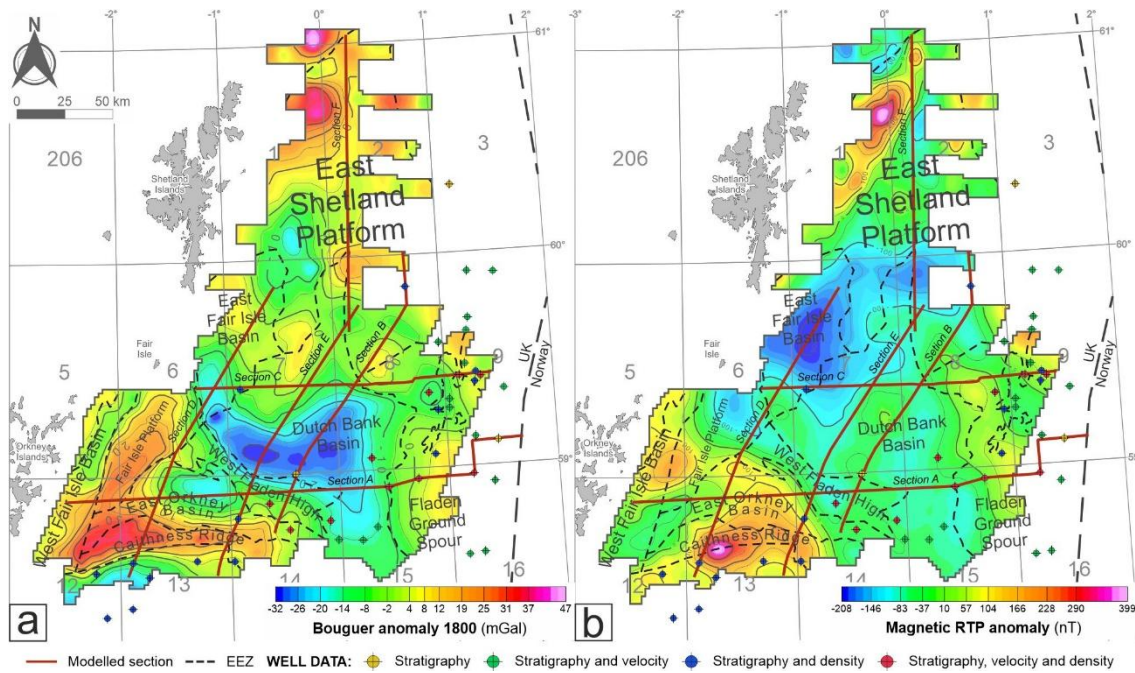


Fig. 2.4 Full anomaly grids (Bliss et al., 2016). (a) Bouguer gravity anomaly grid with a reduction density of 1800 kg m⁻³ and (b) reduced to the pole (RTP) magnetic anomaly grid. Both grids are 2x2 km spaced. Contour spacing is 5 mGal (1 mGal = 1x10⁻⁵ m s⁻²) for (a) and it is 50 nT for (b). Black dashed lines indicate structural boundaries from Fig. 2.1. For any details about the standard corrections applied to these data, the reader may refer to Bliss et al. (2016). Wells labels are indicated in Fig. 2.1b. EEZ, exclusive economic zone; UK, United Kingdom.

As an additional constraint to the forward modelling, we calculated the time thickness map of the Mesozoic interval across the study area (Fig. 2.5). The overall distribution of this interval throughout the survey was derived from Sea Bottom, Base Tertiary (Top Chalk) and Base Triassic (Top Zechstein) reflectors. When compared with the contours of the Bouguer anomaly map in Fig. 2.4a, the resulting map shows how the spatial distribution of the maximum thicknesses of the Mesozoic succession closely correlates with the Bouguer gravity minima (Fig. 2.5).

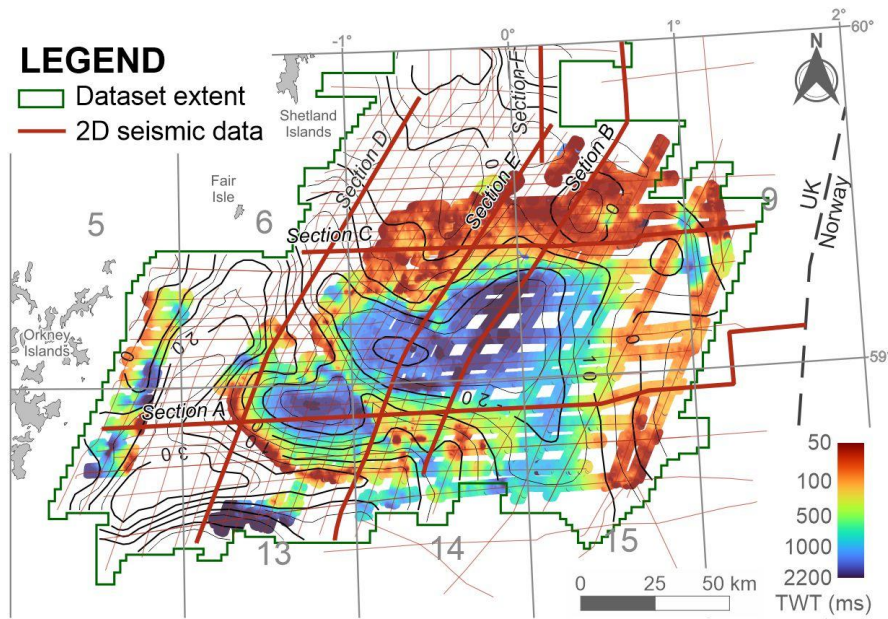


Fig. 2.5 Time thickness grid of the Mesozoic sequence. Black lines represent the contour of Bouguer gravity anomaly (contour interval 5 mGal) from Fig. 2.4a. Thin red lines are traces of the interpreted 2D seismic lines (NSTA, 2022) used to calculate the time thickness maps; thick red lines show the sections modelled in this work. Green line shows the extension of the Bouguer gravity and magnetic anomaly data from Bliss et al. (2016).

Furthermore, to better understand the Bouguer gravity and magnetic anomalies correlations with structural features in the study area, we performed a simple filtering of the original datasets. In particular, using a 50 km wavelength threshold, we calculated high-pass (HP) and low-pass (LP) anomalies of both the gravity and the magnetic datasets (Fig. 2.6).

While the gravity signature of the Dutch Bank Basin is removed by the HP filter (Fig. 2.6a), in the southwestern area, the HP gravity anomaly highlights further features with a more limited extension (small <50 km), clearly matching with local basement highs and basins delimited by major faults (e.g., Scisciani et al. 2021). The sedimentary basins (e.g., East Orkney Basin, West Fair Isle Basin) almost retrace the gravity lows, as well as the basement highs (e.g., Caithness Ridge, West Fladen High, Fair Isle Platform) are matched by gravity highs. On the contrary, the LP Bouguer anomaly (Fig. 2.6b) enhances the E-W gravity minimum found in the Dutch Bank Basin and the positive signature in the western sector of the Caithness Ridge. These two gravity signatures are clearly related to

wide and/or deep sources carrying strong negative and positive density contrasts, respectively.

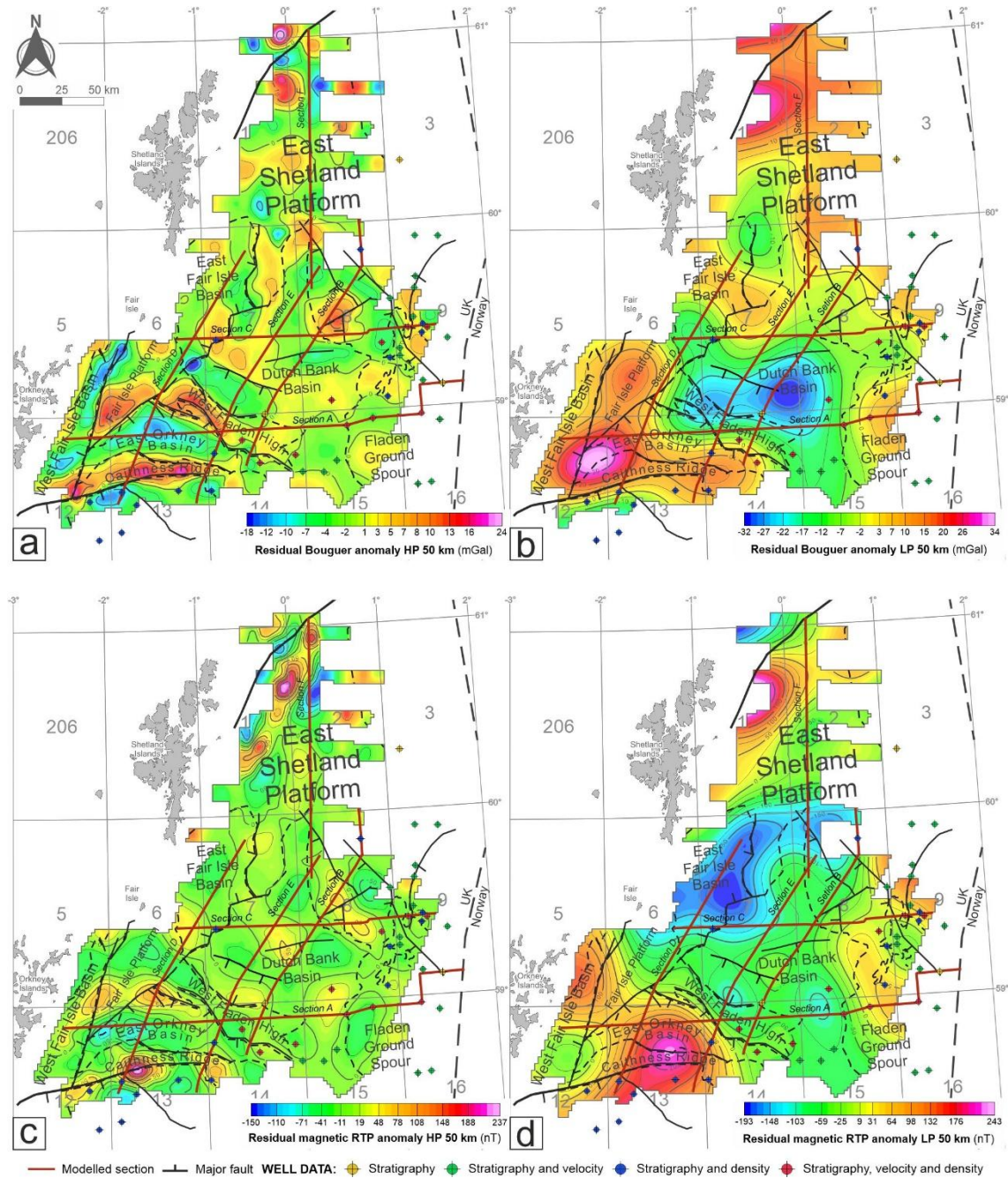


Fig. 2.6 Filtered gravity and magnetic datasets. (a) 50 km high-pass (HP) Bouguer gravity. (b) 50 km low-pass (LP) Bouguer gravity. (c) 50 km HP magnetic anomaly. (d) 50 km LP magnetic anomaly. Contour spacing is 5 mGal for (a) and (b) and it is 25 nT for (c) and (d). Structural elements modified from Scisciani et al. (2021). Black dashed lines indicate structural boundaries from Fig. 2.1. See Fig. 2.1b for well and seismic lines labels.

The same filtering process was applied to the RTP magnetic anomaly grid. In comparison with the full anomaly map in Fig. 2.4b, the HP magnetic anomaly (Fig. 2.6c) shows a general ± 50 nT trend throughout the study area with local exceptions found on the Caithness Ridge and in the northernmost part of the dataset, where the E-W negative-positive-negative trend persists, suggesting low-wavelength sources. A local ~ -100 nT minimum is observed in the westernmost part of the East Orkney Basin, surrounded by local maxima southwards (Caithness Ridge), to the northeast and to the northwest (towards the West Fair Isle Basin). The LP magnetic anomaly shown in Fig. 2.5d, depicts a wide minimum (~ -200 nT) in the East Fair Isle Basin and a near-circular maximum ($\sim +250$ nT) on the Caithness Ridge.

The full anomaly maps and the low- and high-wavelength components of the gravity and magnetic anomalies show significant spatial correlations with the main tectonic features throughout the study area (Fig. 2.4, Fig. 2.5 and Fig. 2.6). This is sufficient motivation to further investigate the observed anomalies and address their sources by forward modelling the geometries retrieved after the time-to-depth conversion of the seismic data against the observed full Bouguer gravity and magnetic anomalies. For the sake of brevity, in the following chapter we discuss only two of the six modelled sections. These two sections, namely Section A and Section B, carry results that are representative also for the other four sections that are showed in the supplementary material (supplementary Fig. S2.1-Fig. S2.4).

Density and magnetic susceptibility values used in the modelling procedure have been kept in the ranges reported in Tab. 2.1 (bold values) across all the modelled sections. It should be noted that all the values used for the modelling fall within values retrieved from the available wellbores (bold and within-brackets values in Tab. 2.1). The modelling was constrained by cross tie between the sections; in particular, each modelling step was performed by minimizing the misfit between crossing sections both considering the depth of the modelled horizons and the densities and magnetic susceptibilities of the modelled blocks. The following chapter illustrates the resulting best-fit models.

Below the depth-converted seismic data, the geometries of the synthetic blocks proposed in the resulting models (Fig. 2.7, Fig. 2.8 and S1-S4), are constrained only to the

coinciding Curie and Moho depths and to the observed gravity and magnetic anomalies, no other interpretative constraint is included.

2.4.2 Modelling results

Fig. 2.7 shows the depth-converted (Fig. 2.7a) and the modelled (Fig. 2.7c) Section A. In the eastern sector of the East Orkney Basin, in the hanging-wall of the main boundary normal fault, the depth-conversion results in ~9000 m of sedimentary sequence with significant contributions from the Carboniferous?-to-Lower Devonian (4000-6000 m in thickness), Lower Permian (1000-2000 m in thickness) and Cretaceous (1000-1500 m in thickness) deposits, respectively. Another main sedimentary depocenter is located in the Dutch Bank Basin where, conversely to what found in the East Orkney Basin, the Cretaceous and Permian sequences are extremely thin or completely missing. Along the section, Palaeocene-to-recent deposits are absent in the western sector, and they increase in thickness east of the East Orkney Basin towards the maximum thickness of ~2000 m. The modelled depth of the basement along section A is ~1500 m shallower in the western side of the East Orkney Basin (hangingwall block to the east of the Fair Isle Platform).

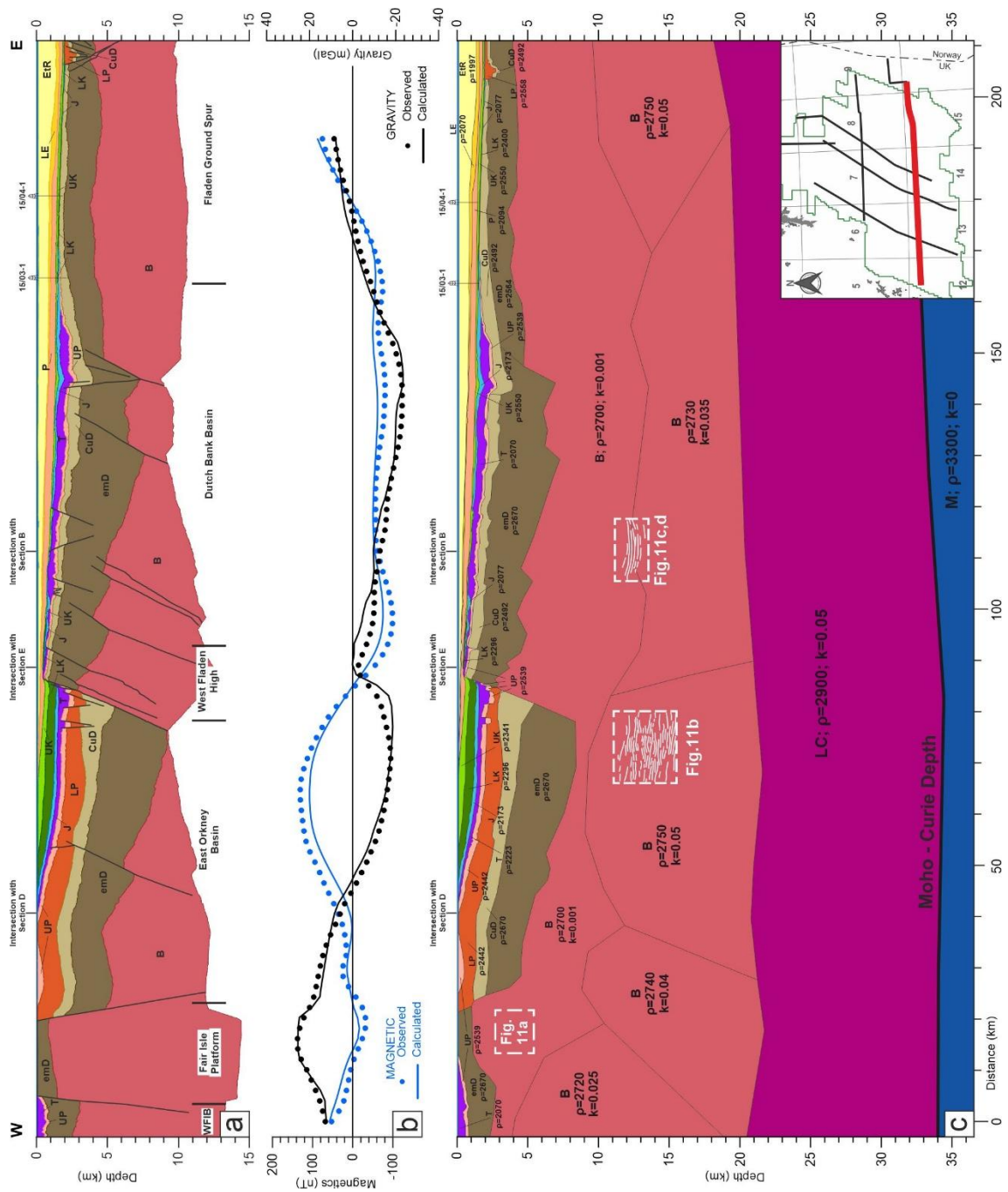


Fig. 2.7 Gravity and magnetic anomalies model across the Section A. (a) Depth-converted section. (b) Anomaly curves best fitting. (c) 2D integrated forward model. Modelled density (ρ) and magnetic susceptibility (k) values are given for each block in the lower panel. Bathymetry across the modelled profile ranges between 50 and 150 m. Colours and label abbreviations are the same of those shown in Tab. 2.1. In the inset, the thick red line shows the extent of the modelled section while the green line represents the extent of the modelled gravity and magnetic anomaly grids. White dashed boxes locate seismic reflections (white thin continuous lines) shown in Fig. 2.11. WFIB, West Fair Isle Basin.

The modelling results of the observed Bouguer gravity and magnetic anomalies, being constrained by well and literature data, are consistent with the geometries of main crustal blocks retrieved after the depth conversion. This is demonstrated by the good fit obtained both in the Bouguer gravity and magnetic anomaly profiles (Fig. 2.7b) with maximum mismatches of ± 5 mGal and ± 15 nT, respectively. Interestingly, the gravity and magnetic anomalies show divergent trends from the West Fair Isle Basin to the westernmost end of the Dutch Bank Basin. In the East Orkney Basin, the gravity reaches its minimum due to the thick sedimentary cover infill, and the magnetic reaches its maximum in the central part of the basin (Fig. 2.7b). Considering the null magnetic contribution carried by the sedimentary cover, we model the lower crust and the basement with high magnetic susceptibilities (0.05 and 0.025-0.05 SI units, respectively) suggesting strong magnetic composition of the basement both beneath the East Orkney Basin and the Dutch Bank Basin.

Across this section, the top of the lower crust ranges between 18 and 22 km with a gentle westward-deepening trend, while the Curie depth, coinciding with the Moho discontinuity, ranges between 32 and 35 km.

Fig. 2.8 shows the depth-converted (Fig. 2.8a) and the modelled (Fig. 2.8c) Section B. In the Dutch Bank Basin, the depth-conversion results in ~ 7000 m of sedimentary sequence still with the significant contribution from the Carboniferous-to-Lower Devonian deposits (4000-5000 m thickness). Furthermore, the thickness of the Triassic sediments increases from the West Fladen High (500 m) to the Dutch Bank Basin (1500-2000 m) while in the East Shetland Platform these intervals are lacking. On the contrary, the sedimentary cover tends to thin in the northern half of this section where the basement reaches its shallowest depth (2000-2200 m).

A good fit was obtained both in the gravity (± 6 mGal) and magnetic (± 16 nT) profiles (Fig. 2.8b). Compared to the Section A, the gravity and magnetic anomalies along the Section B shows divergent trends from the Dutch Bank Basin to the westernmost end of the GESP. In fact, in this section the gravity anomaly reaches its minimum where the maximum thickness of the Triassic sediments is found in the Dutch Bank Basin. On the contrary, the magnetic anomaly shows wide fluctuations reaching local maxima both in

the Dutch Bank Basin and in the East Shetland Platform (Fig. 2.8b). As in the previous section, also in this case we model both the basement and the lower crust with high magnetic susceptibilities (≥ 0.03 SI units) suggesting strong magnetic contributions of the basement beneath the Dutch Bank Basin.

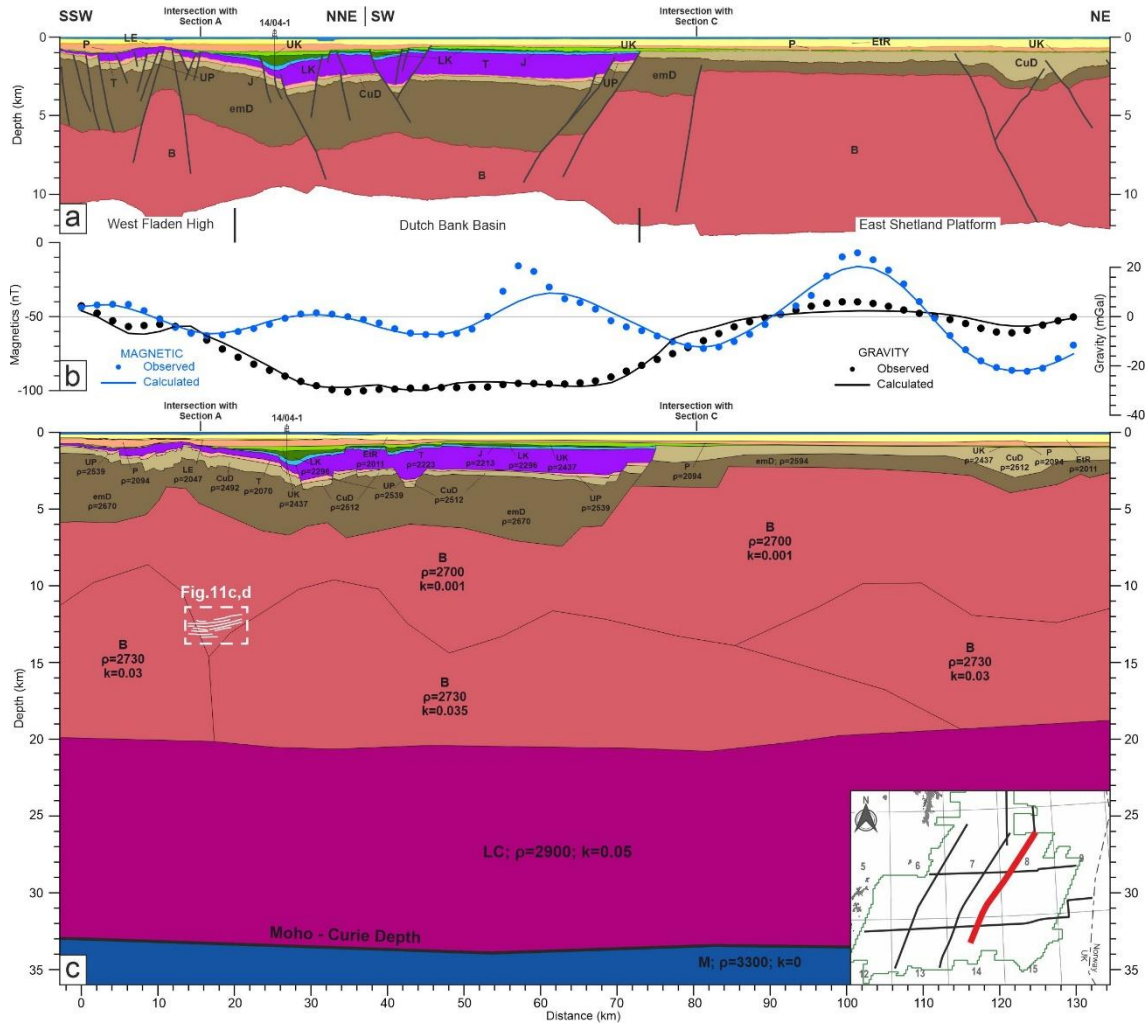


Fig. 2.8 Gravity and magnetic anomalies model across the Section B. (a) Depth-converted section. (b) Anomaly curve best fitting. (c) 2D integrated forward model. Modelled density (ρ) and magnetic susceptibility (k) values are given for each block in the lower panel. Bathymetry across the modelled profile ranges between 50 and 150 m. White dashed boxes locate seismic reflections (white thin continuous lines) shown in Fig. 2.11. Colours and label abbreviations are the same of those shown in Tab. 2.1. In the inset, the thick red line shows the extent of the modelled section while the green line represents the extent of the modelled gravity and magnetic anomaly grids.

Across this section, the top of the lower crust is found at ~ 19 -20 km, while the Moho-Curie depth ranges between 32.5 km depth at the southernmost and northernmost ends of

the section, and 34 km depth in the central part of the section, beneath the Dutch Bank Basin.

Comparing the best-fitting geometries across the modelled sections with the depth-converted interpretations of the seismic lines we find a general good match of such interpretations with the modelled synthetic blocks.

Considering that the results presented above are representative for all the modelled sections we can draw some general considerations about the spatial relations between the modelled Bouguer gravity and magnetic anomalies and their main sources.

Lower-Devonian to Carboniferous sequences show significant thickness (1000-5000 m) throughout the study area with four main depocenters striking W-E to NW-SE, two located in the southern part (i.e. East Orkney Basin and Dutch Bank Basin) and two in the northern part (i.e. East Fair Isle Basin, East Shetland Platform) of the study area. In the southern basins we find the higher thicknesses (>3000 m), while in the northern basin we find the thinnest Devonian-Carboniferous sequences (<3000 m). Despite their lateral variations of thickness, these unit do not spatially relate to the observed Bouguer gravity anomaly. In fact, in the modelled sections, the thickening of these sequences is not ubiquitously matched by a local minimum of the Bouguer anomaly (e.g. the southernmost end of section B in Fig. 2.8), while the thinning of these deposits does not always corresponds to local Bouguer anomaly maximum (e.g. between km 90 and 140 of section C in Fig. S1). Furthermore, local Bouguer anomaly undulations are not matched by significant thickness changes of the Devonian-Carboniferous sequences (e.g. between km 30 and 100 of section E in Fig. S3).

The Lower Permian units are found only in the western part of the study area (i.e. East Orkney Basin and East Fair Isle Basin) with maximum thickness of ~1500 m (Fig. 2.7, supplementary Fig. S2.1, Fig. S2.2) while they are lacking in the northern part of the study area (i.e. Dutch Bank Basin, East Shetland Platform, West Fladen High; Fig. 2.8, supplementary Fig. S2.1, Fig. S2.3). This asymmetrical distribution reflects the non-deposition or erosion of this interval in the Dutch Bank Basin, West Fladen High and East Shetland Platform due to the Lower Permian uplift affecting these areas (Patruno et al., 2019, Scisciani et al., 2019). Furthermore, this uplifting resulted in the deposition of less

than 200 m thickness of Upper Permian sequence that extends mostly from the easternmost Dutch Bank Basin to the westernmost East Orkney Basin, and in the West Fair Isle Basin (Fig. 2.7). In fact, in this area the Upper Permian deposits are present only in the Crawford-skipper Basin (Fig. S1) where the complex structural framework allowed also Lower Permian deposition. Across this sedimentary basin, the geometries resulting from the seismic interpretation of Scisciani et al. (2021) properly fit the modelled gravity anomaly (Fig. S1).

The development of syn-tectonic intra-platform extensional basins and the later rifting tectonic phase (Roberts et al., 1990; Ziegler, 1992; Steel, 1993; Underhill and Partington, 1993; Coward et al., 2003; Johnson et al., 2005; Phillips et al., 2019), has driven the distribution of Triassic deposits (Patruno et al., 2019; Scisciani et al., 2021). Section A (Fig. 2.7) shows quite constant E-W thickness of this unit. Instead, the N-S spatial distribution of this interval is better highlighted in Section B (Fig. 2.8) where a north-eastward thickening, from 700 to 2000 m is observable. Triassic unit are thinner southwards moving from the basins (e.g., Dutch Bank Basin) to the nearest structural highs (e.g., West Fladen High) while these deposits are completely lacking in the northern area (e.g., East Shetland Platform).

The thickness of the Jurassic deposits is moderate (200-300 m) throughout the study area. In Fig. 2.7, a thin Jurassic layer is visible. It extends from the westernmost East Orkney Basin to the easternmost Dutch Bank Basin, conformably overlying the Triassic sequence. On the contrary, looking at the N-S profiles (Fig. 2.7, S3) its thickness (200-300 m) tends to decrease eastward whilst in the N-S direction it maintains a constant thickness. The modelling of the Bouguer gravity anomaly highlights how the distribution of the Triassic-Jurassic deposits matches with the main gravity low in the Dutch Bank Basin (Fig. 2.9c). This is observed throughout all the sections crossing the latter (Fig. 2.7, Fig. 2.8, supplementary Fig. S2.3) where a drop of the gravity anomaly appears over the maximum Triassic thickness.

The Lower Cretaceous E-W trend shows a constant thickness (<250 m) enclosed in the East Orkney Basin, where the deposits infilled the tilted paleo-reliefs. Where present, in the remaining of the southern area (e.g., Dutch Bank Basin), it allocates a thin layer (<100

m thickness), while in the north (e.g., East Shetland Platform, East Fair Isle Basin) it is completely missing. N-S trend of Lower Cretaceous unit highlights that this deposit is limited to the principal basins (e.g., East Orkney Basin, Dutch Bank Basin) with maximum thicknesses found at their centres. Similarly, Upper Cretaceous deposits are found as really thin (<200 m) layers, but they are spatially widespread (Fig. 2.7, Fig. 2.8, Fig. 2.9a, supplementary Fig. S2.1, Fig. S2.3).

The thickness of the Palaeocene-to-Recent units presents a constant N-S trend but it tends to increase eastwards, towards the Viking Graben (up to 2000-2500 m; Fig. 2.7, supplementary Fig. S2.1). On the contrary, this unit is completely missing in the western sector of the study area (quadrants 5, 6, 12 and 13) and its spatial distribution does not match the trends of the Bouguer gravity anomaly across the modelled sections (e.g., Fig. 2.7, Fig. 2.8).

Across the entire study area, we found a close spatial relationship between the distribution of Bouguer anomaly lows and the depocenters of sedimentary basins. This can be clearly seen in the East Orkney Basin and in the Dutch Bank Basin – i.e. the two main depocenters of the study area (Fig. 2.7, Fig. 2.8). Conversely, the gravity anomaly tends to reach high values where the thickness of the sedimentary deposits is reduced. The main gravity minimum (Fig. 2.4a) is located above the Triassic depocenter in the Dutch Bank Basin (Fig. 2.7b, Fig. 2.8b, supplementary Fig. S2.3), whilst the extent of the East Orkney Basin gravity minimum matches the Lower Cretaceous deposits extension (e.g., Fig. 2.7). This evidence is further clarified in figure 5 where the correspondence between the maximum thickness in time and the contour of the gravity anomaly is observable. Long-wavelength undulations (≥ 100 km) of the Bouguer gravity anomaly are mostly controlled by the depth to the top-basement. However, low-density contributions from sedimentary basins are always required in order to fit the observed long-wavelength gravity anomalies (Fig. 2.7, Fig. 2.8, supplementary Fig. S2.1-Fig. S2.4).

Concerning the sources for the modelled magnetic anomaly, we locate three distinct sets, each contributing depending on their thickness, depth and lateral extent. The shallow sources, roughly corresponding with the upper portion of the basement were modelled with an average susceptibility value of 0.001 SI units, the deepest sources are found in

the lower crust, and they are modelled with magnetic susceptibility of 0.05 SI units. Finally, the central sources are found at intermediate depths (i.e. in the middle crust, beneath the upper basement and the lower crust) and they were modelled with lateral variations of magnetic susceptibilities ranging between 0.02 and 0.05 SI units, corresponding to density values ranging between 2720 and 2750 Kg m^{-3} , respectively. As expected, the magnetic contribution of the Devonian-to-Tertiary sedimentary sequences is null (i.e. magnetic susceptibility is zero) due to their sedimentary nature.

2.5 Discussion

Historical uncertainties about the under-explored GESP led us to investigate the structural framework of this area by a detailed and multidisciplinary approach supported by recent high-quality data. Bearing in mind the non-uniqueness of the potential field modelling, all the available constraints were included to evaluate the gravity and magnetic contributions against the observed anomalies. Such approach was further encouraged by the spatial correlation we found between the high- and low-wavelengths components of the modelled anomalies and well-known tectonic features across the study area (Fig. 2.6).

Geometrical models retrieved after the time-to-depth conversion of the seismic interpretations required little adjustments once their gravity and magnetic signature were modelled. Maximum vertical shifts ≈ 500 m was required for the geometry of the Lower-middle Devonian and top of the Caledonian basement in section B (e.g., in the Fair Isle Platform – Fig. 2.7) in order to fit the observed gravity and magnetic anomalies. For all the other sections the vertical shift was < 300 m. Considering the uncertainties derived from the seismic data interpretation and time-to-depth conversion, this is not surprising. Other minor adjustments were required, in order to fit the observed gravity and magnetic anomalies, concerning the shape and dip of major faults affecting the basement. Similarly, the intersections between crossing modelled sections were used as control-points for the correctness and coherency of the models both for geometries and properties of the modelled blocks. The models shown in Fig. 2.7, Fig. 2.8 and supplementary Fig. S2.1-Fig. S2.4 were achieved with maximum misfit at intersections of 100 kg m^{-3} and 0 (SI units) concerning the density and the magnetic susceptibility of the Devonian-to-recent

sedimentary units, respectively. The misfit concerning the density values is always bounded to the ranges provided in Tab. 2.1, with local well data driving local variations of densities. In other words, the density values that were used to model a section derive from the closest well, resulting in a maximum 100 kg m^{-3} misfit at intersections. Concerning the basement, lower crust and mantle blocks the models were achieved with zero misfit both concerning the density and magnetic susceptibility of the synthetic blocks and with maximum misfit of tens of meters concerning the depth of the modelled horizons (i.e. block boundaries).

Considering that the modelling has benefited from all the geological and geophysical constraints available in public data repositories or in the published literature, we provide a detailed and geologically-consistent reconstruction of the crustal geometries in the GESP that expands the discussion already proposed by previous authors (e.g., Fichler and Hospers, 1990; Hollinger and Klemperert, 1989; Hollinger and Klemperert, 1990; Fichler et al., 2011; Kimbell and Williamson, 2016; Frogtech Geoscience, 2017).

Interestingly, the gravity and magnetic anomalies, both considering their full (Fig. 2.4) or filtered (Fig. 2.5) signatures, do not relate to each-other and often show opposite trends (Fig. 2.7, Fig. 2.8, supplementary Fig. S2.1-Fig. S2.4). We interpret this evidence as a differentiation of sources for the two modelled fields. In fact, commonly the trend of the top of basement governs both the magnetic (being the first contributor with depth) and the gravity anomaly (being the first ubiquitous density contrast), but this is not the case in the GESP. On one side we found high-susceptibility bodies (up to 0.05 SI units) throughout the modelled sections, these sources control the magnetic signature. While on the other side, we report strong contributions due to Mesozoic sedimentary sequences in the main basins especially Triassic and Cretaceous intervals (i.e. Dutch Bank Basin, East Orkney Basin) that alter the gravity signature at different wavelengths, corresponding to the size of the source basin. Following previous authors, we do not consider remanent magnetization but limit the modelling to induced contributions (e.g., Fichler et al., 2011).

We split the following discussion in two main parts, one concerning the outcomes of the gravity modelling and one concerning those related to the magnetic modelling.

2.5.1 Gravity modelling outcomes

Three main intervals were distinguished by the interpretation of seismic profiles and their thicknesses were reconstructed (Fig. 2.9). Based on well-to-seismic ties, they correspond to the Upper Cretaceous (Fig. 9a), Lower Cretaceous (Fig. 2.9b) and Triassic-Jurassic (Fig. 2.9c), and they are indicative of three different tectono-sedimentary phases in the evolution of the GESP (Fig. 2.2b).

It is evident that the Triassic and Jurassic deposits mainly contributed to the Dutch Bank Basin infill, while the Cretaceous deposits mostly contributed to the East Orkney Basin and Moray Firth Basin, south of the Caithness Ridge. The thickness trend of the Triassic deposits in the Dutch Bank Basin (e.g., Fig. 2.8, Fig. 2.9) exhibits evident decrease both southwards and eastwards with values <800 m. Instead, thicknesses of 1500-2000 m (Fig. 2.8, Fig. 2.9) are mainly found in the depocenter where the minimum in low-pass filtered anomaly is found (Fig. 2.6b).

The East Orkney Basin is surrounded by gravity highs (Fig. 2.5, Fig. 2.6, Fig. 2.9). The Lower Cretaceous deposits in this basin are clearly affected by major faults (Fig. 2.5, Fig. 2.6, Fig. 2.9b) contributing, with the Jurassic and Triassic layers (Fig. 2.9c), to the observed Bouguer anomaly low.

Such observations suggest a differential tectonic control through the GESP during the Triassic-to-Cretaceous times. The Dutch Bank Basin was the main depocenter during the Triassic-Jurassic times, with a reduced sedimentary input in Cretaceous times. On the contrary, the East Orkney Basin showed a reduced sedimentation rate in the Triassic-Jurassic times and relatively high subsidence during the subsequent Cretaceous phase. The full (Fig. 2.4a) and filtered (Fig. 2.5a and b) gravity maps support a dimensional relationship between the basins and the gravity anomaly.

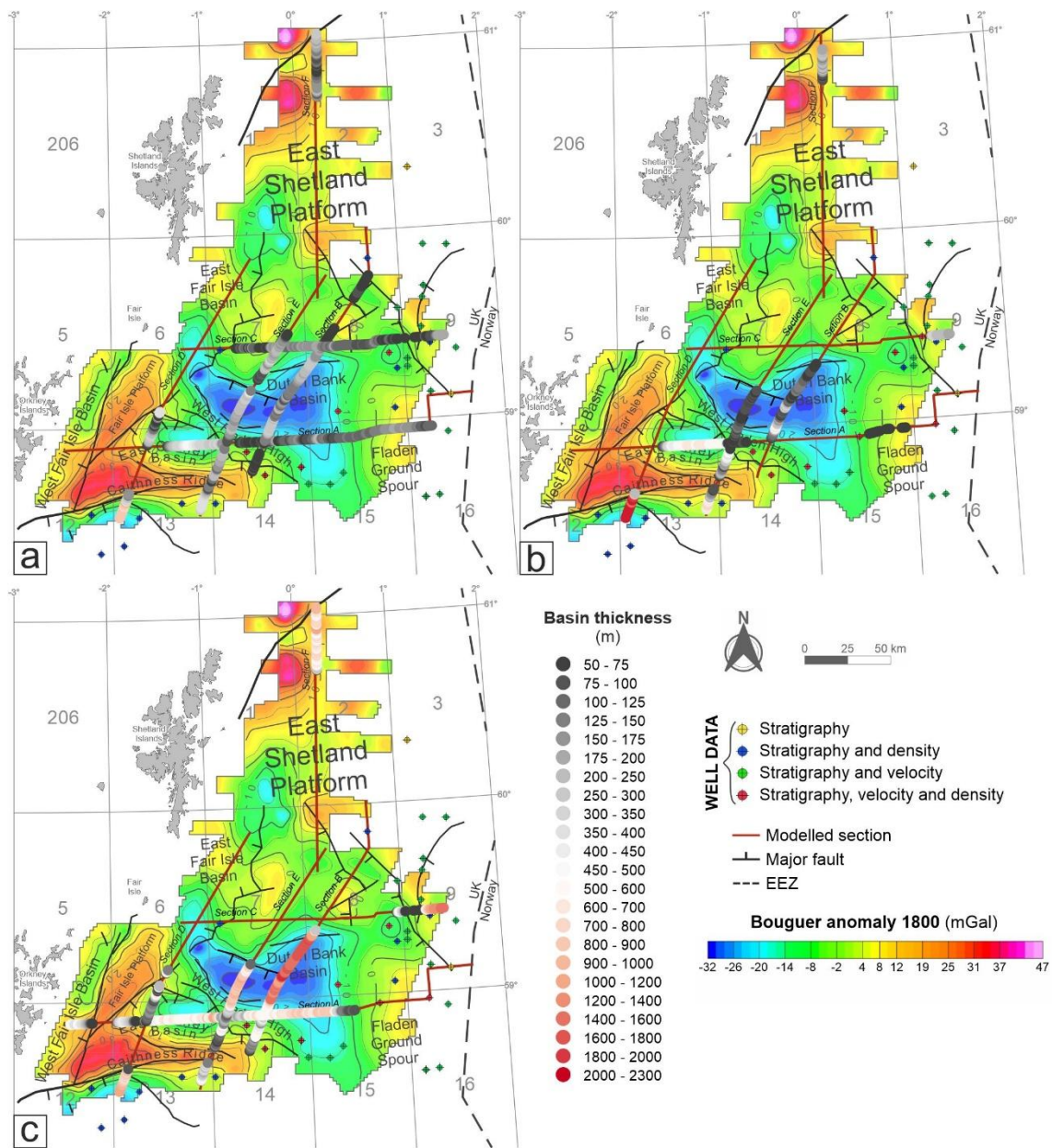


Fig. 2.9 Thickness values of (a) Upper Cretaceous, (b) Lower Cretaceous and (c) Triassic-Jurassic deposits overlying the Bouguer gravity anomaly map. Parts of the profile where dots are missing represent deposits with thickness <50 m, representing erosion or non-deposition. Thickness of the mapped deposits are all shown with the same black-red colour scale. Structural elements modified from Scisciani et al. (2021). Labels of the main structural features correspond to those in Fig. 2.1, Fig. 2.4 and Fig. 2.6. See Fig. 2.1b for well labels. EEZ, exclusive economic zone; UK, United Kingdom.

The thickness of the Triassic and subordinately of Jurassic mudstones/sandstones deposits in the Dutch Bank Basin show evident lateral variations, with maximum values of ~2000 m (Fig. 2.7, Fig. 2.9a) found in the central and northern part of the basin in the

hangingwall block of a set of SSE-dipping normal faults, and decreasing both westwards and southwards within the basin. The density used to model this unit ($2070 - 2393 \text{ kg m}^{-3}$) is compatible with mudstones/sandstones and valid across the entire basin. The north-eastward thickening across the latter (Fig. 2.8, supplementary Fig. S2.3) and the abrupt northern termination against the WSW-ENE to WNW-ESE trending normal faults, in addition to the spatial distribution of the gravity depocenter, suggests a faulting mechanism related to grossly N-S to NW-SE oriented extensional axis. Faults with similar attitude and with Triassic and probably pre-Triassic syn-tectonic growth wedges have been also described in the East Shetland Basin and Unst Basin (Claringbould et al., 2017). This suggests that the overall GESP probably suffered an early N-S trending extension culminated in Triassic times and subsequently, during late Jurassic and Cretaceous, underwent near E-W to NE-SW trending extension. This second phase was preceded by a regional uplift (Late Cimmerian inversion in Patruno et al., 2019) and subsequently produced a marked footwall uplift along the main faults bounding the major basins (e.g., the Fladen Ground Spur along the western margin of the Viking Graben and the West Fladen High along the eastern margin of the East Orkney Basin). The concomitant uplift occurred along the eastern and south-western part of the Dutch Bank Basin prevented the erosion of the pre-Jurassic succession, only at the central part of the basin where the Triassic depocenter has been preserved. This two-stage evolution promoted the development of an approximately E-W trending Mesozoic basin with a distinctive shape and dissimilar from trends of other basins across the GESP area. At regional scale, the Dutch Bank Basin represents the lowest gravity anomaly within the entire GESP area with a clear E-W elongation, in contrast with the N-S trend of previously reconstructed Triassic basins especially along the Norwegian continental platform located to the east of the Viking Graben (e.g., Steel and Ryseth, 1990; Nøttvedt et al., 1995; Færseth, 1996; Richardson et al., 2005; Bell et al., 2014; Phillips et al., 2019). Once the gravity grid is filtered with 50 km high-pass and low-pass cut-off (Fig. 2.6a, b), it preserves its E-W shape only on the low-pass output (Fig. 2.6b), still locating the lowest observed gravity anomaly within the study area.

An impressive correlation between tectonic elements and gravity anomalies is found in the south-western area on the high-pass filtering (Fig. 2.6a). The match between the structural

framework and the gravity anomaly is enhanced by this filtered grid, allowing to infer the gross extent of these tectonic structures at different scales of view. Additionally, small depocenters (supplementary Fig. S2.6) (i.e. north of West Fladen High, northeast of East Fair Isle Basin, southern part of West Fair Isle Basin), that were not directly crossed by the modelling but are visible in the seismic sections, stand out in the filtered grid. Considering the gravity footprints of the latter and supported by the outcropping Cretaceous deposits reported by the offshore bedrock map (BGS, 2022), we suggest that these were filled by Mesozoic (i.e. Lower Cretaceous, Jurassic, Triassic) sediments as well. This interpretation is supported by the comparison with the gravity signatures generated by the aforementioned Triassic and Cretaceous units (Fig. 2.4a, Fig. 2.6a) and observed in the modelling of section A (Fig. 2.7).

The main contributions to gravity lows are provided by the Cretaceous, Jurassic and Triassic deposits. The underlying Permian and Devonian successions, due to their relative basement-like high-density, have a minor influence on gravity anomaly distribution with respect to the younger sediments. Consequently, the gravimetric modelling results particularly useful to distinguish between Mesozoic and Palaeozoic basins. This is very significant for the study of basins occurring at shallow depths close to the Shetland and Orkney Islands, where seismic show reflective intervals overlaying the basement but the absence of well control prevents to define the age of these basins.

2.5.2 Magnetic modelling outcomes

The comparison between the main structural elements (Fig. 2.1b) and the full (Fig. 2.4b) or filtered (Fig. 2.6c, d) magnetic anomaly maps does not highlight any evident correlations between the fault-controlled basins and mapped anomalies. Considering the sedimentary nature of the post-Caledonian units (Fig. 2.2), possible magnetic sources are located within the basement and lower-crust (e.g., Donato and Tully, 1982; Holloway et al., 1991; Bassett, 2003; Fichler et al., 2011; Patruno et al., 2017; Scisciani et al., 2019; Kombrink and Patruno, 2020).

In our interpretation, the shallower portion of the basement, mainly composed of metamorphosed sediments (Bassett, 2003; Patruno et al., 2017; Scisciani et al., 2019; Kombrink and Patruno, 2020), contributes with low-susceptibility values (0.001 SI units) while deeper contributions are related to high-susceptibility bodies. This is also consistent with previous studies where high-susceptibility bodies were inferred within the crust (Donato and Tully, 1982; Fichler et al., 2011; Beamish et al., 2016; Arsenikos et al., 2018).

As stated before, the parametrization of the modelled blocks was carried out considering all the available geological constraints. Among these we include information of metamorphic and igneous facies from exposures and boreholes in and around the study area (Fig. 2.10; Bassett, 2003; Fichler et al., 2011; Patruno et al., 2017; Scisciani et al., 2019; Kombrink and Patruno, 2020; BGS, 2022).

Some high susceptibility body values (0.025 - 0.05 SI units) at 15 km depth were modelled throughout the study area (see area delimited by black dashed lines in Fig. 2.10). It should be noted that the highest-susceptibility areas are not isolated but rather these are always flanked by high-susceptibility (0.025-0.04 SI units) blocks (Fig. 2.7, supplementary Fig. S2.1-Fig. S2.3). Within the basement, the increase of magnetic susceptibility is modelled also by including slight increases of the density of the modelled blocks. The density of the basement ranges between 2700 and 2750 kg m⁻³ corresponding to minimum (0.001 SI units in the upper basement) and maximum (0.05 SI units) magnetic susceptibilities respectively. Such a wide distribution of high-susceptibility volumes suggests a regional-scale phenomenon and excludes that high-magnetic anomalies are associated with scattered sources such, for example, as local intrusions within the crust. A similar configuration is also evident in the northern sector of NNS (East Shetland Basin area), located at ~60 km NNE of our study area. In this zone, Fichler et al. (2011) located high-susceptibility bodies within the crust (red dashed line in Fig. 2.10) by combining forward modelling of gravity and magnetic anomalies. These authors interpret such bodies as a combination of intermediate intrusives and mantle serpentinization in an island-arc system pertaining to the Iapetus Ocean whose offshore continuation is still debated. Such interpretation is also in agreement with previous studies investigating the Viking Graben and the NNS (Hollinger and Klemperert, 1989; Fichler

and Hospers, 1990) where magnitudes and wavelengths of the magnetic anomalies are very similar to those in our study area. Considering their densities and magnetic susceptibilities, the serpentinized blocks we model should range between 40% and 80% of serpentinized fraction (e.g. figure 8 in Fichler et al., 2011), similarly to what proposed for the East Shetland Basin area in the NNS (Fichler et al., 2011).

A similar interpretation for the GESP has been proposed by Patruno et al. (2017) and Scisciani et al. (2019). These authors note that the crystalline basement in the study area can be divided into a shallower, acoustically opaque part, largely composed by granitoid and alkaline rocks, as suggested by several partial well penetrations (Kombrink and Patruno, 2020), and by a deeper, reflective layer showing high amplitude and low frequency content. This intra-basement reflective layer (*‘high-reflective deep-seated package’* in Patruno et al., 2017) has been fortuitously penetrated by at least one well (9/04a-1 – Fig. 2.10), which reported ‘hornblend-biotite gneiss or shists’ with a metamorphic cooling age of 393 Ma (Early Devonian – Basset, 2003; Patruno et al., 2017; Scisciani et al., 2019). This deep reflector was therefore interpreted by Patruno et al. (2017) as a regional-wide transition between major crystalline units characterized by substantially different composition and acoustic impedance values (e.g., granites over gneiss, or acidic crystalline rocks over Iapetus-domain meta-basalts, as suggested by the hornblend-biotite mineralogy – Patruno et al., 2017).

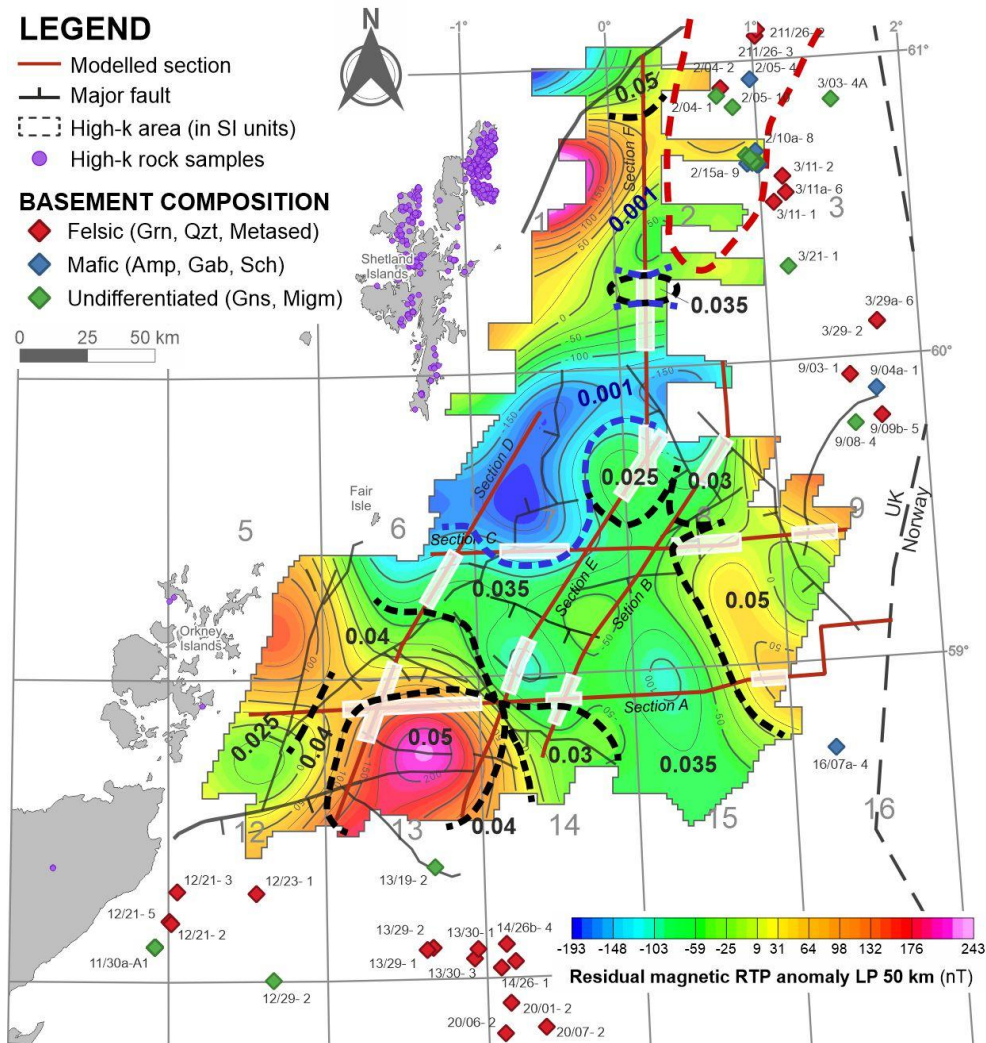


Fig. 2.10 Filtered magnetic dataset (50 km LP filtering of the RTP magnetic anomaly). The thick dashed lines provide a 15 km-depth slice of the distribution of the magnetic susceptibilities of the basement. Black dashed lines enclose volumes with high susceptibility basement (0.025-0.05 SI units), while the thick blue dashed line encloses the area with low-susceptibility basement (0.001 SI units). The thick dashed red line encompasses the area proposed as serpentinized crust by Fichler et al. (2011). White transparent polygons along the modelled profiles (red lines) enclose areas of high reflectivity matching with high-susceptibility volumes. High-k rock samples refer to onshore gabbroid or serpentinized rocks (BGS, 2022). Diamonds locate well cores that sampled the basement, classified according to Bassett (2003). Contour spacing of the basemap is 25 nT. Structural elements are modified from Scisciani et al. (2021). See Fig. 2.1b for seismic lines labels. Abbreviations: Grn, granite; Qtz, quartzite; Metased, meta sediment; Amp, amphibolite; Gab, gabbro; Sch, schist; Gns, gneiss; Migm, migmatite.

Interestingly, the blocks we modelled with the maximum magnetic susceptibility, often correspond to areas of anomalous crustal reflectivity in the analysed seismic profiles (examples are given in Fig. 2.11) at TWT depth ≥ 5 sec. Analogous, intra-basement areas

of anomalously-high crustal reflectivity were described by Patruno et al. (2017) and Scisciani et al. (2019) in a shallower sector beneath the Crawford-skipper Basin, Beryl Basin and Fladen Gound Spur, but it seems that similar basement seismic facies can be observed throughout the NNS (Fazlikhani et al., 2017). These strong reflections were variously interpreted by previous authors as: i) crustal blocks and terranes inherited from the Caledonian orogeny (Freeman et al., 1988); ii) crustal-scale fault zones developed during the Mesozoic rifting (e.g., Bell et al., 2014; Phillips et al., 2019); or iii) Mesozoic or Tertiary magmatic intrusions related to the North Sea rift and North-Atlantic opening (Tankard and Balkwill, 1989). Since there is no evidence throughout the GESP or the East Shetland Basin (Fichler et al., 2011) of recent volcanic activity and considering the significant distance of the GESP from the Jurassic-Lower Cretaceous rifting zones to the east, the latter hypothesis can be ruled out. The observed crustal reflectivity is not limited to few kilometres, as typically imaged in fault-related shear zones (Phillips et al., 2019), but it commonly forms huge crustal volumes adjacent to others with similar size and characterized by low-amplitude and discontinuous-to-reflection-free seismic facies (e.g., Fig. 2.11a). Given the lack of evidence supporting significant crustal-scale fault zones and the relatively low crustal stretching factors estimated in this area (e.g., Christiansson et al., 2000), also the second hypothesis can be ruled out.

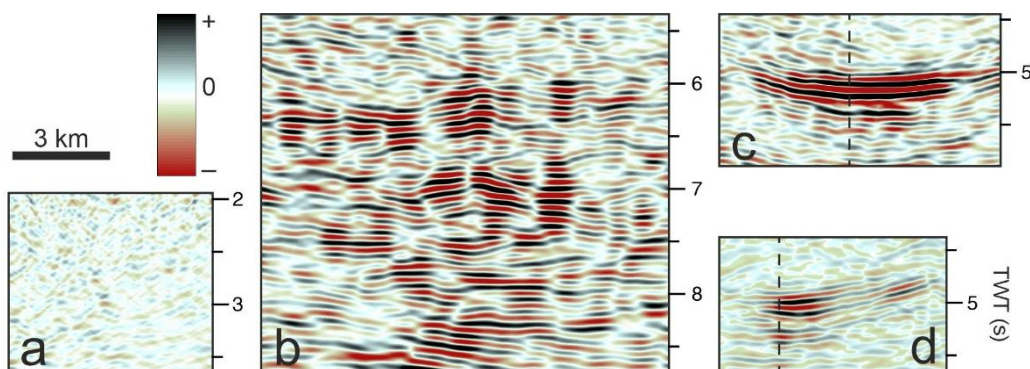


Fig. 2.11 Portions of seismic reflection profiles showing the different reflectivity of basement and crust in the study area. (a) Low-reflectivity zones (i.e. areas with low-amplitude and discontinuous reflections) match with zones of low magnetic anomaly. Conversely, low-frequency high-reflectivity intervals (b, c and d) generally correspond to high-susceptibility bodies modelled in this work. Dashed lines indicate profile intersection. See Fig. 2.7 and Fig. 2.8 for location in sections A and B.

Considering all the above, these strongly-reflective and high-susceptibility volumes ($k \geq 0.04$ SI units) are here interpreted as inherited serpentinized crustal domains that formed in island-arc systems of the Iapetus ocean and, following its closure, were stacked during the Caledonian orogeny. If this interpretation is correct, the areas depicted by magnetic susceptibility higher than 0.04 SI units, would represent the southwards continuation of the island-arc chain proposed for the East Shetland Basin by Fichler et al. (2011), while the surrounding volumes with magnetic susceptibility of 0.025 – 0.04 SI units may allocate intermediate intrusives whose emplacement was lateral to the island-arc system pertaining to the Iapetus Ocean (Fichler et al., 2011). Considering that the top of the high-susceptibility volumes within the middle crust ranges between 9 and 20 km depth across all the modelled profiles, a more detailed classification of these volumes in the GESP, perhaps attempting to pinpoint the buried part of the Iapetus ophiolitic suture, is challenging at the very least since it would require strong independent constraints currently not available. The interpretation we propose, relating high-susceptibility bodies with island-arc systems, would be similar to the one proposed for other crustal frameworks (Mancinelli et al., 2022, and references therein).

An alternative interpretation of such regional-scale high-susceptibility volumes would involve volcanic episodes affecting the entire southern East Shetland Platform between Permian and Cretaceous times. When compared with the model proposed in this work, such volcanic-source scenario would allocate shallower magnetic sources in an alternative but still plausible interpretation. Such wide event(s) would result in widespread and thick deposits leading to a crustal setup similar to the one proposed for the Rattray Volcanic Province (Quirie et al., 2018). However, all the available boreholes within and surrounding the study area never reported of volcanic deposits throughout the drilled Permian-Cretaceous sequences (Fig. 2.2, Fig. 2.3), an evidence that drove our modelling by avoiding the unsupported volcanic-source model setup.

2.5.3 CCS potential of the study area

Carbon capture and storage (CCS) has been proposed as one of the key promising technologies to mitigate climate changes (Gluyas and Mathias, 2013; Global CCS Institute, 2022). In particular, geological storage of CO₂ currently represents the most

efficient and likely the only short-to-medium term option for trapping large volumes of greenhouse gases, thus significantly reducing net CO₂ emissions into the atmosphere (IPCC, 2022; Global CCS Institute, 2022).

In this work we have highlighted significant thicknesses of potential late Palaeozoic and Mesozoic reservoirs in the GESP possibly top sealed by Late Jurassic, Early Cretaceous and Palaeocene mudstones and shales (Fig. 2.2).

In the analysed sections, the Devonian Old Red Sandstone Group is usually thicker than 1000 m (Fig. 2.4, Fig. 2.7, Fig. 2.8 and S3). This thick Devonian succession was not entirely penetrated but the top of Devonian reservoir was sampled in various wells drilled in the GESP. Fluvial and aeolian Devonian sandstones are reservoirs and working source rocks for several North Sea oil and gas fields (Marshall and Hewett, 2003; Patruno and Reid, 2016) some of which could host sizeable hydrocarbon accumulations, usually in large structural closures (e.g. the Clair and Buchan fields – Mark et al., 2008). Seep and fluid escape data suggest a working “deep” kitchen in the GESP and confirm the existence of Palaeozoic plays, including possible source rocks and reservoir intervals (Richardson et al., 2005; Patruno and Reid, 2016, Patruno and Reid, 2017). Moreover, in this setting due to the thermally immature Jurassic section found at shallow depth, the Palaeozoic remain the only promising source capable to charge Mesozoic reservoirs found in the GESP intraplateau basins (Monaghan et al., 2018; Patruno et al., 2019).

In the GESP, good quality Devonian reservoir are fractured sandstones encountered in wells, also with oil shows, along the western flank of the VG (e.g., the 8/04-1; 9/07-1; 9/16-2; 9/16-3) which are similar to reservoir rocks of the Stirling oilfield (16/21a-2; Gambaro and Currie, 2003) and in the MFB (Quad 13). In the GESP, these correspond to the Buchan Formation sandstones, with variable thickness and net-to-gross, sometimes with shale sections in between sandstone units. Better porosities are found where the Devonian is shallow (up to 22% at less than 1km) but still reasonable where deeper (up to 18% at close to 2km). Similar reservoir quality and petrophysical characteristics are reported from other wells drilled in the Moray Firth and Central Graben basins (Monaghan et al., 2018).

Carboniferous reservoirs are limited to the southern part of the GESP where thin (~10-20m) sandstones levels with limited porosity ($\phi \sim 8-10\%$) are intercalated within shales in the Tayport Formation (e.g., 15/3-1 and 15/07-1 wells). The poor reservoir potential of these sandstones and the paucity of well constraints to define the possible extension to the north and north-east of these levels make very difficult the exploitation of the Carboniferous interval for fluid storage.

The Lower Permian Rotliegend sandstones are locally very thick (about 600-1000m) especially within intraplateau basins (e.g., the CSB and EOB) and show a moderate porosity (up to $\phi=16-20\%$ in the 9/16-2 and 9/16-3), resulting in good potential targets for storage. Similarly, also the Triassic interval is widespread in the central and southern sector of the GESP and consists of very thick sections of sandstones (up to about 35 m) with fairly good porosity (up to $\phi=30\%$, 18-30% in average). The Triassic is a proven reservoir for several fields in the Crawford-Skipper. In this area several Mesozoic structural-stratigraphic closures were formed owing to inherited highs or to the Tertiary inversion tectonics affecting deep-seated faults (Scisciani et al., 2021). Additional high-resolution 3D-seismic data are necessary to delineate further traps in the wide DBB where the Triassic interval is more consistent both in continuity and thickness. Hence, a preliminary estimation has been undertaken based on the result of the modelling.

A Monte Carlo simulation was performed using a Python code to estimate the effective storage capacity based on the following equation (USDOE, 2010; Bachu et al., 2007)

$$M_{CO_2} = A \times h \times \phi \times \rho_{CO_2} \times E$$

where M_{CO_2} is the mass of CO_2 , A is the reservoir area, h is the average reservoir thickness, ϕ is the average reservoir porosity, ρ_{CO_2} is the density of CO_2 at the reservoir conditions in supercritical state based on the reservoir depth (CO2CRC, 2008), and E is the storage efficiency factor. Given the very limited availability of data, we adopted a probabilistic approach to assess uncertainties in the estimations. This method (Asante et al., 2021) involved generating 10,000 random values from a truncated normal distribution, using average, minimum, maximum, and standard deviation as input parameters. Only the two Mesozoic intra-platform basins were considered for the calculation.

According to our models, these basins have a gross extent of 2000 km² (Fig. 2.5 and Fig. 2.9), which has been considered as the maximum end member in the simulation. Instead, a value of 2 km² has been applied as the minimum end member. The latter is 0.001 of the gross extent and is tuned on the order of magnitude of the plume observed at the nearby site of Sleipner. Similarly, the applied minimum thickness of 200 m was derived. According to the resulting models (Fig. 2.9), the maximum thickness was set at 2000 m. The average values applied are as follows: 200 km² of area, 800 m of thickness, 700 kg/m³ of CO₂ density at reservoir conditions, and a conservative porosity value of 0.15. According to the measurements in the area surrounding the GESP, a maximum value of 0.3 and a conservative minimum porosity of 0.01 were applied. For open saline aquifers with vertical but no lateral confinement, efficiency factors between 1% and 4% have generally been proposed (Doughty et al., 2001; Bachu et al., 2007; Vangkilde-Pedersen et al., 2009; Goodman et al., 2011; Bachu et al., 2015). Given the ongoing debate around the E value and the need for further investigation into the lateral connectivity of the study area, a conservative efficiency factor of 1% was assumed, along with an average value of 2%.

The preliminary estimate resulting from the Monte Carlo simulation (Fig. 2.12) indicates a P10-P90 effective capacity of 170-640 Mt of CO₂ with a P1-P99 of 70-930 Mt of CO₂. While these estimates provide a promising indication of the CO₂ storage potential in this region, further refinements incorporating detailed 3D seismic interpretation, petrophysical calibration, and additional reservoir engineering assessments are necessary to reduce uncertainties. Such refinements would require a larger dataset with possible direct samples not currently available for the area, which is essential to define the extent of lateral transmissibility of injected CO₂ and induced pressure. Key factors influencing actual storage capacity include lateral reservoir connectivity, caprock integrity, and the dynamic response of the pressure of the reservoir. Future investigations should focus on addressing such uncertainties prior to defining the actual storage capacity.

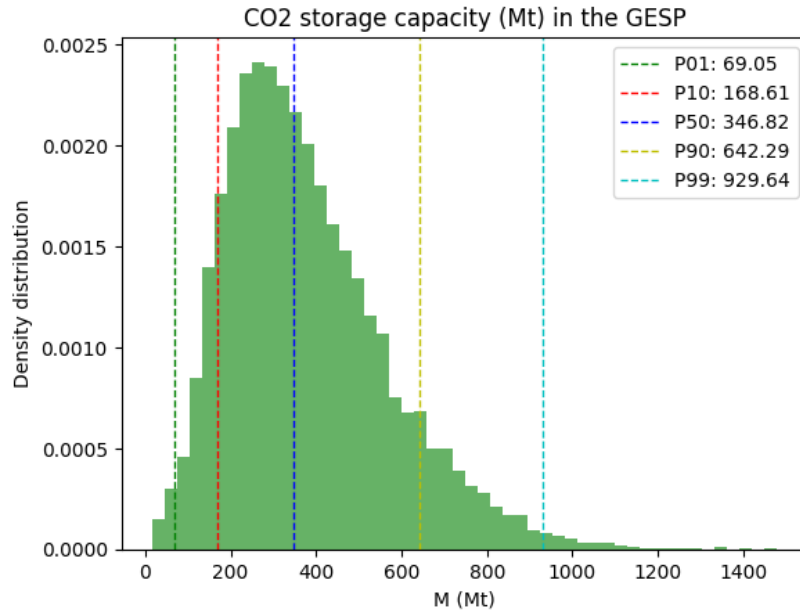


Fig. 2.12 CO₂ storage capacity estimated through the Monte Carlo simulation.

Finally, the analysis of the available data, even if scattered and inhomogeneous across the study area, through the Monte Carlo simulation indicates that the GESP is an area offering new targets for fluid storage in shallow waters, either below or close to producing fields. As far as CCS and CCU potential is concerned, industry and government co-funded projects to build or re-use existing pipelines to transport CO₂ in North Sea traps have been recently put forward by both the UK and Norway (e.g., Acorn, Sleipner and Northern Lights projects – Pale-Blue, 2021a, Pale-Blue, 2021b; DNV, 2021). The current storage targets are not distant from our UK study area (Fig. 2.1a) and in the next future the GESP could improve the storage capacity of nearby areas by the injection of greenhouse gases or other fluids in structural traps based on older reservoir intervals and located closer to the present-day coastlines. Most of these structures are currently dry but may be feasible targets for CCS and CCUS projects.

2.6 Conclusions

In this work, the first integrated forward modelling of gravity and magnetic anomalies across the Greater East Shetland Platform (GESP) was carried out. In order to investigate

this under-explored region of the Northern North Sea, six newly processed seismic reflection profiles were interpreted and depth-converted after well-to-seismic tie; the resulting geological cross sections were compared with the observed Bouguer gravity and magnetic anomalies. The time-to-depth conversion of these seismic profiles, combined with stratigraphy, seismic velocity and bulk density data retrieved from well log analysis, allowed to highlight the spatial and temporal evolution of the major basins (i.e. the East Orkney Basin and the Dutch Bank Basin) and the age/thickness of basin infill.

This first order characterisation revealed a spatial relationship between the observed gravity anomalies and the Mesozoic sedimentary sequences (Fig. 2.9). The two prominent gravity lows match with the depocenters of two main extensional intra-platform basins in the area (i.e. the Dutch Bank Basin and East Orkney Basin). In particular, the Dutch Bank Basin underwent significant Triassic infilling (Fig. 2.9c) that, in addition to thinner Jurassic units, contributed to the main gravity low observed on the GESP region. On the contrary, the smaller East Orkney Basin underwent a significant tectonic subsidence in the Lower Cretaceous (Fig. 2.9b). Similar sedimentary contributions can be envisaged for smaller basins close to the Shetland Islands (e.g., north-east of the East Fair Isle Basin). Bouguer gravity anomaly highs are mostly found in areas where the sedimentary cover is reduced in thickness and mainly consists of Devonian sediments in the south-western part of the study area (e.g., the Caithness Ridge and Fair Isle Platform).

The modelling of the magnetic anomaly revealed two main contributing sources. The upper basement is characterised by low-susceptibility values compatible with acoustically-opaque metamorphosed sediments and granitoid/alkaline igneous rocks. In contrast, high-susceptibility volumes within the basement and lower crust likely represent mafic bodies or serpentinized crust, visible in seismic profiles as a widespread high-amplitude and low-frequency layer. These high-susceptibility volumes are the main contributors to the observed magnetic anomaly (Fig. 2.7, Fig. 2.8, Fig. 2.10, supplementary Fig. S2.1-Fig. S2.4) and can be related to structural paleo-domains connected to the Caledonian orogeny and the pre-Caledonian Iapetus Ocean. If confirmed, this interpretation would provide new constraints to the understanding of the geodynamic evolution of the region by locating island-arc crustal remnants that pertained to the Iapetus Ocean.

From a carbon storage perspective, the GESP displays thick reservoir intervals within the Palaeozoic and Mesozoic successions and appears, at first glance, to offer considerable theoretical potential for CCS. Based on available data and standardised assumptions, a preliminary Monte Carlo simulation yielded a wide range of possible storage capacities, from 170 to 640 Mt of CO₂. This variability reflects significant uncertainties related to key parameters such as porosity, thickness, CO₂ density, and spatial continuity.

However, several critical geological risks undermine the reliability of this first-order estimate. Most notably, the presence of pervasive faulting, including structures that may extend from deep Palaeozoic intervals to the seabed, represents a potential leakage risk that should not be overlooked. In addition, the quality and thickness of regional sealing intervals appear variable and, in some locations, insufficient to guarantee effective long-term containment. These structural and stratigraphic challenges, combined with the limited availability of high-resolution seismic and petrophysical data, currently constrain the feasibility of developing a robust regional model and cast doubt on the suitability of the GESP for large-scale CCS deployment.

While the approach used here does not introduce fundamentally new methods, the integration of gravity and magnetic forward modelling with seismic interpretation across this under-explored platform represents a novel application in this context. The study offers a useful regional framework and highlights key uncertainties that must be addressed prior to more advanced assessments. Future investigations would benefit from improved seismic imaging and detailed fault and seal characterisation, particularly in light of the proximity of this area to ongoing CCS initiatives such as Acorn and Northern Lights.

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Chapter 3

Static Modelling and Numerical Simulation: an integrated regional scale approach of geological CO₂ storage: A case study from the Bunter Sandstone Formation (Southern North Sea, UK)

Abstract

Carbon Capture and Storage (CCS) technologies are crucial for reducing anthropogenic carbon emissions by enabling the subsurface storage of millions of tons of CO₂ annually. These activities are essential for achieving international climate agreements and contributing to short- and mid-term climate mitigation efforts. The extensive saline aquifer of the Bunter Sandstone Formation in the Silverpit Basin in the UK Continental Shelf of the Southern North Sea has been identified as a high storage capacity reservoir that can contribute to deploying CCS activities. This region will be the focus of multiple CO₂ injection projects. Therefore, understanding the regional sensitivity of the aquifer is of primary importance.

This study investigates the boundary conditions and reservoir structure to assess the regional behaviour of the aquifer. Simulations of 14 wells injecting 1 Mt/yr/well over 50 years have been developed. Subsequently, the reservoir has been observed for 5000 years to analyse the impact of the available pore volume affecting reservoir pressure build-up and plume migration. Results suggest that the reservoir can safely accommodate over 700 Mt of supercritical CO₂, although pressure front diffusion highlights the need for a

thorough understanding of the regional connectivity. The latter is crucial for evaluating the necessity of brine production for pressure management and addressing potential pressure interference between licenses.

3.1 Introduction

Carbon Capture and Storage (CCS) is a well-established technology (Eiken et al., 2011; Rock et al., 2017; Worth et al., 2017) that is expected to play a pivotal role in decarbonising energy generation and industrial processes, particularly in sectors where emissions are challenging to eliminate (IEA, 2021b; IPCC, 2021b). This approach is essential for mitigating anthropogenic CO₂ emissions, especially for hard-to-abate industries. Although interest in CCS has grown substantially in recent years, most studies have focused on field-scale operations (Eiken et al., 2011).

Since the beginning of the last century, the Southern North Sea (SNS) has garnered significant attention due to its abundant hydrocarbon fields, driving sustained investment in the exploration and exploitation of its resources. Some notable discoveries, including Forbes, Esmond, Gordon, Caister, and Hunter, are associated with the Early Triassic Bunter Sandstone Formation (BSF – Fig. 3.1). In contrast, the majority of hydrocarbon accumulations are found within the Early Permian Rotliegend Group (Gp) and Carboniferous clastic sediments (Fig. 3.1), located directly beneath the well-known Late Permian Zechstein Group. The salt interval of the Zechstein Group has played a dual role in this region: it acts as a sealing layer for deeper traps, such as those in the Early Permian and Carboniferous formations (fms), and contributes to the formation of salt-driven anticlines in the Triassic to Cretaceous sequences. Tectonic strain and overburden loading have facilitated the growth of predominantly northwest-striking diapirs, forming dome-like traps within the Triassic sediments. These salt anticlines, as classic hydrocarbon traps, are also highly suitable for the storage of anthropogenic emissions.

Recent studies have underscored the potential of the Silverpit Basin in the SNS for CO₂ storage (Bentham, 2006; Heinemann et al., 2012; Holloway et al., 2006; Noy et al., 2012). Geological assessments reveal that the basin hosts numerous well-defined closures within

the BSF, which are characterised by periclinal and domal structures (Hollinsworth et al., 2022). Detailed seismic analyses and volumetric calculations suggest that this region holds substantial capacity for CO₂ sequestration (Bentham, 2006; Heinemann et al., 2012; Hollinsworth et al., 2022; Holloway et al., 2006; Patruno et al., 2024). Individual closures within the basin have the potential to store hundreds of millions of tons of CO₂, making the region a prime candidate for CCS initiatives in the SNS.

In this regard, the UK government has issued licenses for CCS projects targeting the BSF aquifer within the UK Continental Shelf of the SNS (Fig. 3.1). The BSF has been recognised as a promising site for large-scale CCS activities (Agada et al., 2017; Heinemann et al., 2012; Kolster et al., 2018; Noy et al., 2012; Patruno et al., 2024), with initial injection operations planned for 2027 (BP, 2023). Six licenses (i.e. CS001, CS006, CS007, CS020, CS022, CS025) fall within the study area. The comprehensive knowledge and infrastructure developed during the long history of hydrocarbon exploration within the region significantly reduce the risks and costs associated with CCS investment. Additionally, the proximity of the BSF to significant onshore industrial CO₂ emitters enhances the effective implementation of CCS at a larger scale.

The geological framework of the SNS, along with its extensive history of exploration, increasing activities related to CCS licensing, existing infrastructure, and its proximity to industrial sources of CO₂, collectively establish the region as a pivotal hub for prospective CCS initiatives in Europe (BP, 2023). This study thoroughly analyses the key factors that influence large-scale CO₂ storage in the BSF. These include plume migration, regional pressure evolution, reservoir connectivity to the seabed, petrophysical heterogeneity, and development strategies. By examining the interplay of these variables in a large, interconnected subsurface system, this research aims to enhance understanding of CO₂ plume behaviour and regional pressure responses during and after injection. Such insights are critical for effective risk management and compliance with regulatory frameworks.

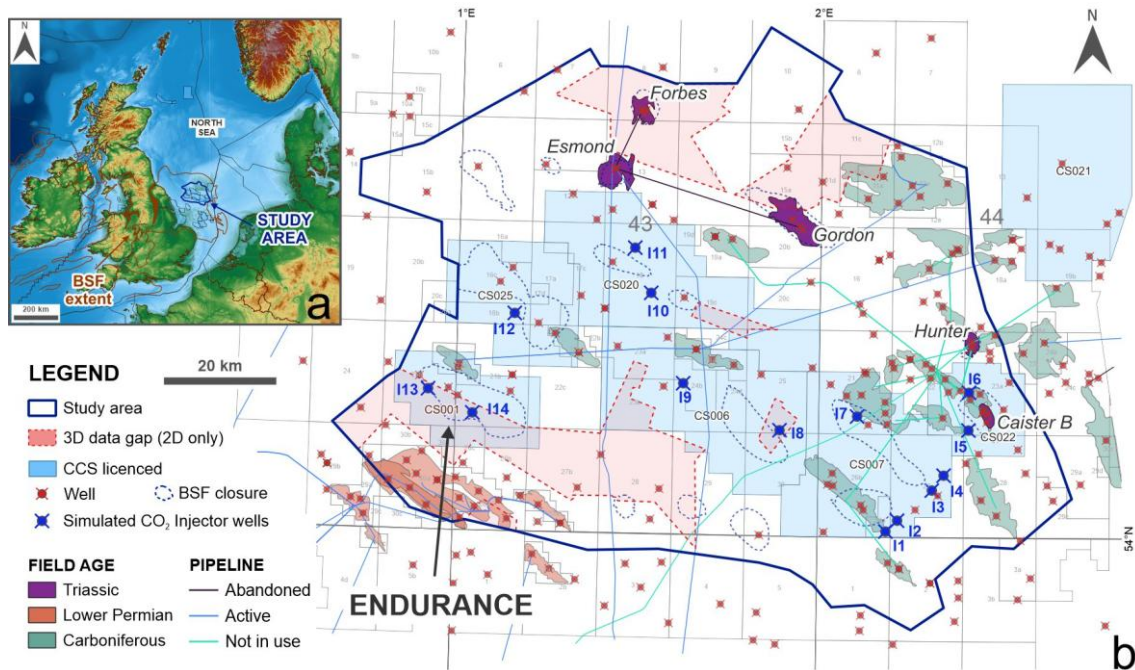


Fig. 3.1 (a) Location map of the study area, highlighting the Bunter Sandstone Formation extent and the onshore reservoir outcrop in orange (Gibson-Poole et al., 2024). (b) Key elements within the study area. Well indicates publicly available well data (NSTA, 2024a) within and surrounding the study area used in this work. Principals BSF domes are highlighted.

3.2 Geological Setting

3.2.1 Structural Evolution of The Southern North Sea

The Southern North Sea (SNS) Basin exhibits a complex tectonic history spanning from the Late Carboniferous to the Cenozoic (Cameron et al., 1992). The fundamental basin architecture emerged through the Caledonian and Variscan orogenies, establishing the crustal framework that influenced subsequent tectonic episodes (Doornenbal and Stevenson, 2010; Glennie, 1998; Patruno et al., 2022; Praeg, 2004; Underhill, 2003; van Hoorn, 1990; Van Wijhe, 1987; Woodcock and Strachan, 2012; Ziegler, 1990).

Late-Devonian to Early-Carboniferous rifting phases created accommodation space for sediments, transitioning from continental red beds to marine carbonates (Besly, 2018). As rifting ceased, the basin evolved into a sag basin during the mid-Carboniferous, accumulating thick sequences of deltaic and shallow marine sediments, including significant coal and sandstone deposits, which subsequently served as hydrocarbon

sources (Besly, 2018). In the late Carboniferous, the Variscan orogeny caused compression, leading to folding and faulting that formed structural traps (Besly, 2018).

During the Permian period, significant basin extension led to the development of major rift systems and extensive volcanic activity (Ziegler, 1992). This extensional phase facilitated the deposition of the Rotliegend Group (Bailey et al., 1993; George and Berry, 1997, 1993; Glennie and Provan, 1990; Howell and Mountney, 1997), followed by the emplacement of Zechstein Supergroup evaporite sequences (Duguid and Underhill, 2010; Fyfe and Underhill, 2023; Taylor, 1998; Underhill, 2003). The deposition of the Zechstein evaporites had a major influence on later structural development, as the salt layer acted as a detachment horizon, enabling halokinesis and significant subsidence during the Triassic and Jurassic (Allen et al., 1994; Barnett et al., 2023; Fyfe and Underhill, 2023; Grant et al., 2019a; Kley, 2018; Maystrenko et al., 2012; McKie, 2017; McKie and Williams, 2009; Stewart and Coward, 1995; Underhill, 2009). During the Mesozoic and Cenozoic, the Early-Permian Silverpit Fm and Zechstein salt layers served as effective seals for subsequent hydrocarbon accumulation originating from Carboniferous sources (Besly, 2018).

The following Triassic to Jurassic evolution was characterised by regional thermal subsidence and extension, forming the North Sea graben (Ziegler, 1992), and the development of diverse depositional environments, including fluvial, aeolian, and playa systems (Bachmann et al., 2010; Brook et al., 2003; McKie, 2017; McKie and Williams, 2009). During this period, the basin was influenced by the initiation of salt movement, which later created salt pillows and diapirs, thereby controlling accommodation space and sediment distribution (Allen et al., 1994; Bachmann et al., 2010; Brennan and Adam, 2022; McKie, 2017; McKie and Williams, 2009; Underhill, 2009). During the Jurassic, rifting led to the formation of several half-graben structures, and the interaction between salt mobilisation and tectonic extension generated complex subsurface geometries that have had a lasting impact on reservoir development (Glennie, 1998; Grant et al., 2019b; Hansen et al., 2021; van Hoorn, 1990).

The Late Cretaceous was marked by a major phase of basin inversion due to compressional forces linked to the Alpine orogeny (Patrino et al., 2022; Underhill, 2009).

This phase led to the reactivation of pre-existing extensional faults, resulting in uplift and the formation of inversion-related folds and anticlines (Patruno et al., 2022; Underhill, 2009; van Hoorn, 1990; Van Wijhe, 1987). The Alpine compressional forces were particularly influential in reshaping the pre-existing structural configuration, creating prominent inversion features such as anticlines that serve as hydrocarbon traps in the present-day subsurface (Hansen et al., 2021; Stewart et al., 1996). The inversion involved thick-skinned, where deep-seated basement faults were reactivated, and thin-skinned deformation involving decoupling along the Zechstein salt (Barnett et al., 2023).

The Cenozoic period witnessed additional phases of compression, driven by far-field stresses from the Alpine orogeny, which further modified the structural fabric of the SNS Basin (Patruno et al., 2022; Underhill, 2009; van Hoorn, 1990). During this period, subtle uplift and further inversion processes affected basin architecture and overburden deformation, leading to the creation of subtle but economically important structural traps (Brennan and Adam, 2022; Thomson, 2004).

3.2.2 The Silverpit Basin Framework

The Silverpit Basin (Fig. 3.2) represents a distinctive region within the SNS that underwent significant structural deformation. It is structurally bounded by regional fault systems such as the North Dogger fault zone to the north, the Dowsing fault zone to the west, and to the east and south by the complex Silverpit boundary zone of faults and salt walls. Towards the southeast, the region is affected by erosional truncation (Supplementary Fig. S3.7) from the Base Cretaceous Unconformity (BCU). Salt tectonics involving the Zechstein evaporites played a fundamental role in the evolution of this basin (Bailey et al., 1993; Duguid and Underhill, 2010; Fyfe and Underhill, 2023; George and Berry, 1993; Glennie and Provan, 1990; Hansen et al., 2021; Howell and Mountney, 1997; Taylor, 1998; Underhill, 2009, 2003; van Hoorn, 1990). In this context, the Carboniferous interval served as the source of hydrocarbon generation (Bailey et al., 1993; Besly, 2018). Initially formed during the Permian as a result of regional extension, the Silverpit Basin evolved during subsequent Mesozoic extensional phases, with rifting

leading to the creation of the stratigraphic and structural configuration of the region (Allen et al., 1994; Grant et al., 2019a, 2019b; Underhill, 2009; Van Wijhe, 1987).

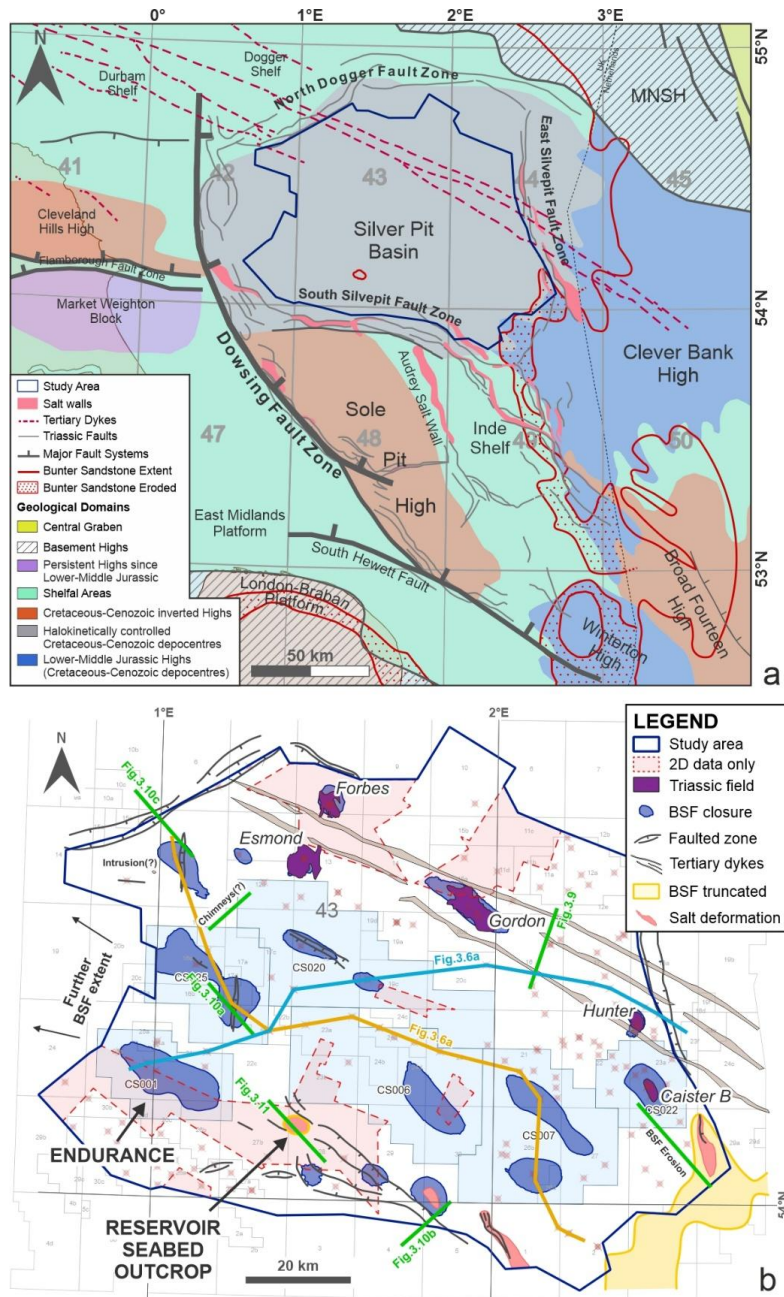


Fig. 3.2 (a) Regional geological map. Bunter Sandstone Fm extent (red line) from English et al. (2024) and references therein. Triassic faults and salt walls from Rushton et al. (2024). Tertiary dykes from Carver et al. (2023). Geological domains and major fault systems from Grant et al. (2019c) and Preiss and Adam (2021). (b) Interpreted key structural elements within the study area affecting the reservoir and/or sealing interval. BSF erosional truncation and inferred gas chimneys are shown in Fig. S3.7 and Fig. S3.8, respectively.

The interaction of halokinesis with regional tectonics has been particularly important in shaping the Silverpit Basin. Differential loading during the Triassic and Jurassic periods induced subsequent salt movement, forming domes and pillows that modified sedimentation patterns and created accommodation space for both siliciclastic and carbonate sequences (Allen et al., 1994; Brook et al., 2003; Grant et al., 2019b; Hansen et al., 2021; Stewart and Coward, 1995).

Subsequently, the area was intersected by the BCU, a key regional feature formed during Late Jurassic to Early Cretaceous tectonic uplift and erosion (Underhill, 2003; van Hoorn, 1990; Van Wijhe, 1987). It marks a significant stratigraphic boundary between Jurassic and Cretaceous sediments, often seen as a high-amplitude seismic reflector (Hollinsworth et al., 2022). The BCU reflects angular discordance and deep truncation of Jurassic and Triassic deposits (Allen et al., 1994; Brennan and Adam, 2022). In the Silverpit Basin, the BCU preserves unique features influenced by salt movement, which created variable erosion and sedimentary patterns (Stewart and Coward, 1995; Thomson, 2004). Above the BCU, shallow marine Cretaceous sediments onlap the surface (Hansen et al., 2021; McKie, 2017; McKie and Williams, 2009).

During the Late Cretaceous, the carbonate unit of the Chalk Group marks a significant deposition period. It is characterised by its broad distribution and considerable thickness variations due to underlying structural influences like salt tectonics and faulting. The Chalk primarily consists of fine-grained bioclastic carbonates deposited in a stable marine shelf environment. Its thickness and preservation in the Silverpit Basin are affected by local tectonics, which created structural traps and influenced sedimentation patterns (Hollinsworth et al., 2022).

The Silverpit Basin underwent significant inversion during the Late Cretaceous to Paleogene, driven by compressional forces related to the Alpine orogeny (Thomson, 2004; Underhill, 2009; van Hoorn, 1990).

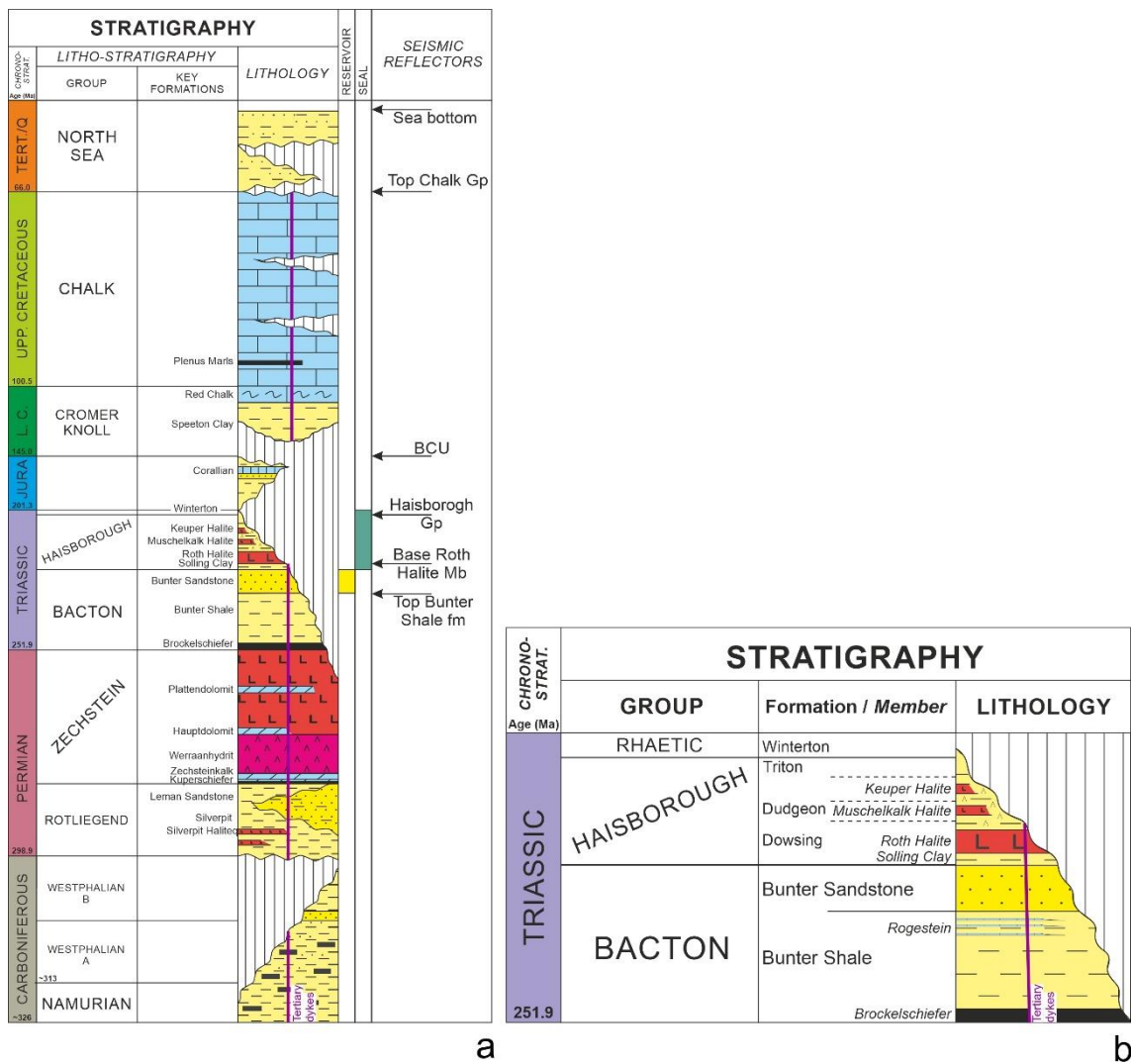


Fig. 3.3 (a) Silverpit Basin simplified stratigraphy, and (b) detail of the Triassic interval. Modified after Patruno et al. (2024).

3.2.3 The Storage Complex: Reservoir and Sealing Formations

3.2.3.1 The Bunter Sandstone Formation Reservoir

The Bunter Sandstone Formation (BSF, Fig. 3.3), part of the Early Triassic Bacton Group, represents a significant geological unit within the UK sector of the SNS. It is also referred to as part of the Sherwood Sandstone Group in the UK onshore areas (Brook et al., 2003; English et al., 2024; and references therein). The BSF comprises a continuous sequence of fluvial and aeolian sandstone facies and is bounded stratigraphically by the Middle

Triassic Haisborough Group above and the Bunter Shale Formation below (Bifani, 1986; Brook et al., 2003; Johnson et al., 1994; Ritchie and Pratsides, 1993).

The BSF is a prominent candidate for CO₂ storage due to its favourable porosity and permeability characteristics, well-defined structural traps, and the presence of salt-rich intervals that enhance sealing integrity. These geological features position the BSF as an integral component of the future geoenergy landscape in the SNS (Brook et al., 2003; English et al., 2024; Gibson-Poole et al., 2024; Hollinsworth et al., 2024).

This regional aquifer demonstrates considerable potential for CO₂ storage applications (BP, 2023; Gammer, 2016; Heinemann et al., 2012; Holloway et al., 2006; Noy et al., 2012; Patruno et al., 2024). It extends from the offshore area into eastern England, with onshore exposures from Nottingham to Teesside and further continuity into the Dutch, German, and Polish sectors (Fig. 3.1a and Fig. 3.2a – Bachmann et al., 2010; English et al., 2024; Geluk et al., 2018; McKie, 2017; McKie and Williams, 2009). Notable hydrocarbon accumulations in fields such as Esmond, Forbes, and Gordon underscore their reservoir capabilities, highlighting their potential to store large volumes of gaseous phases, including CO₂ (Bifani, 1986; Ketter, 1991; Ritchie and Pratsides, 1993).

The structural configuration of the BSF is shaped primarily by salt tectonics associated with the underlying Zechstein Salt. Salt mobilization has resulted in large-scale domes and pillows, forming structural traps (Bifani, 1986; Brook et al., 2003) that are ideal for CO₂ storage (Bentham, 2006; Heinemann et al., 2012; Hollinsworth et al., 2022; Holloway et al., 2006). Individual closures, such as the Endurance structure, are considered prime targets for CO₂ storage due to their capacity to contain substantial volumes of CO₂ (BP, 2023; Gibson-Poole et al., 2024; Gluyas and Bagudu, 2020). However, the variability in porosity and the presence of intraformational barriers, such as mudstones and halite-cemented layers (Brook et al., 2003; Williams et al., 2013), influence both injectivity and plume migration. These intraformational barriers can affect the distribution and containment of injected CO₂, underscoring the importance of site-specific analysis for effective CO₂ storage. Faults and fractures, commonly observed over the crests of salt domes, have implications for both reservoir integrity and containment security (Bentham et al., 2013; Hollinsworth et al., 2022).

The BSF displays significant lithological variability across the region, transitioning from well-sorted, medium- to coarse-grained sandstones near the basin margins to finer-grained deposits in the central SNS basin (Bachmann et al., 2010; Brook et al., 2003; English et al., 2024; McKie, 2017; McKie and Williams, 2009). These sandstones consist primarily of quartz, feldspar, and lithic fragments, with conglomeratic intercalations near proximal areas (Brook et al., 2003; English et al., 2024; Geluk et al., 2018; Johnson et al., 1994). The depositional environment of the BSF is predominantly non-marine, reflecting semi-arid to arid conditions with a variety of braided river channels and alluvial fans contributing to its sedimentary structure (Bifani, 1986; Brook et al., 2003; English et al., 2024; Geluk et al., 2018; Johnson et al., 1994). The mineralogy and grain size distribution reflect a change from proximal to distal conditions, indicating that sediment supply likely originated from the London-Brabant Massif, southwest of the study area (Fig. 3.2 – Bachmann et al., 2010; Cameron et al., 1992; English et al., 2024; Gluyas and Bagudu, 2020; McKie, 2017; McKie and Williams, 2009).

Despite these challenges, the overall geological properties of the BSF, including its significant storage capacity and the presence of structural and stratigraphic traps, make it one of the most promising candidates for large-scale CCS projects in the SNS.

3.2.3.2 *The Haisborough Group Seal*

The Middle Triassic Haisborough Group (Fig. 3.3) serves as a critical sealing interval for the Bunter Sandstone Formation in the Southern North Sea (SNS) Basin, particularly in the Silverpit Basin. Structurally, this group overlies the Bunter Sandstone Formation, forming an effective barrier to vertical fluid migration. Salt movement and halokinesis within the Zechstein Supergroup strongly influenced the deposition and distribution of the Haisborough Group, creating variable thicknesses and localised structural highs and lows that enhance its seal integrity (Allen et al., 1994; Brennan and Adam, 2022; Hollinsworth et al., 2022).

In the Middle Triassic, episodic marine incursions from the east resulted in the deposition of the Dowsing Formation, composed of marine and minor lacustrine evaporites, mudstones, and dolomitic limestones. This phase was succeeded by a return to non-

marine conditions, with ephemeral playa lake environments contributing to the deposition of mud-dominated and evaporitic sediments within the Dudgeon and Triton Formations (Geluk et al., 2018). By the end of the Triassic, the Winterton Formation marked a period of marine transgression from the southwest, transitioning depositional environments from non-marine to paralic systems and eventually to fully marine settings by the early Jurassic (Bachmann et al., 2010; Geluk et al., 2018).

The Haisborough Group is stratigraphically characterised by its three principal halite intervals: the Röt Halite, the Muschelkalk Halite, and the Keuper Halite. These evaporite sequences are interbedded with mudstones and minor anhydrite layers, providing excellent caprock properties. The halite intervals, particularly the Röt and Muschelkalk halites, exhibit significant lateral continuity and ductility, essential for maintaining seal integrity across tectonically active regions such as the Silverpit Basin (Brennan and Adam, 2022; Brook et al., 2003). The interbedded lithologies suggest periods of fluctuating depositional conditions, with mudstone layers representing episodes of reduced salinity (Geluk et al., 2018; Hollinsworth et al., 2022).

The depositional environment of the Haisborough Group reflects a dominantly arid to semi-arid climate during the Middle Triassic. The halite intervals formed in restricted basins under high evaporation conditions, while the interbedded mudstones and anhydrite reflect episodic shifts towards lacustrine and playa lake settings (Brook et al., 2003; McKie, 2017; McKie and Williams, 2009). These depositional dynamics were controlled by regional tectonics and climatic variations, with marine incursions influencing the stratigraphy in certain intervals (Gibson-Poole et al., 2024; McKie, 2017; McKie and Williams, 2009). Evidence from seismic surveys highlights the continuity of the halite seals even in structurally complex areas, underscoring their effectiveness as barriers to fluid flow (Brennan and Adam, 2022; Brook et al., 2003; Hollinsworth et al., 2022).

In the Silverpit Basin, the Haisborough Gp halite seals are particularly vital for trapping hydrocarbons and ensuring the containment of CO₂ in proposed storage sites. The high mechanical strength and impermeability of the halites, combined with their stratigraphic consistency, make the group a cornerstone in the geological framework of the SNS Basin (Hollinsworth et al., 2022; Ritchie and Pratsides, 1993). As CCS initiatives expand, the

Haisborough Group role as an effective seal will remain central to subsurface resource management in the region.

3.3 Geological Model

3.3.1 Structural Model

The geological reconstruction of the Silverpit Basin was carried out through the interpretation of both 2D and 3D seismic data. The majority of the study area is covered by the PGS 3D SNS MegaSurvey (NSTA, 2024a), a standardized and reprocessed seismic dataset with a bin spacing of 12.5 m and a vertical resolution of 20–30 m. To address a significant data gap at the centre of the study area, the 2019 reprocessing of the Greater Cavendish PreSDM survey (bin spacing of 12.5 m and vertical resolution of 18–20 m), along with the Cavendish Extension dataset, both provided by SLB, were integrated into the analysis.

Supplementary publicly available seismic volumes (i.e. BH963D0001 and SH883F0004 surveys), as well as legacy 2D surveys, were instrumental in refining interpretations in areas where the main datasets lacked coverage, such as the subcrop of the Bunter reservoir at the seabed (Fig. 3.2b).

Additionally, over 250 wells within and around the study area provided essential data (Fig. 3.1b – i.e. composite logs, checkshots, deviation surveys, joined wireline and well report; NSTA, 2024). These datasets were pivotal in integrating seismic and geological interpretations and enabled the identification of key seismic horizons (Fig. 3.3, Fig. 3.5) and faults (Fig. 3.2b) influencing the structural framework of the Silverpit Basin.

The BSF exhibits a median thickness of 167 meters, thinning progressively toward the northeast (Fig. 3.4a), likely as a result of erosion due to the Hardeggen Unconformity (Bachmann et al., 2010; Geluk and Röhling, 1997; Johnson et al., 1994). It is sealed regionally by the Middle Triassic Haisborough Group, a sequence of anhydritic shales exceeding 500 meters in thickness (Fig. 3.4b). This interval provides robust sealing capacity, while the basal Solling (Röt) Claystone Member forms the initial critical sealing

layer, with a thickness of 12–18 meters concentrated in the eastern depocenter (Fig. 3.4c). The overlying Röt Halite Member, averaging 100 meters in thickness (Fig. 3.4d), serves as the primary seal, supported by additional halite-rich intervals within the broader Haisborough Group (Brook et al., 2003). The broader Haisborough Group sealing interval incorporates two additional halite layers—the Muschelkalk and Keuper—predominantly present in the central study area (Brook et al., 2003). Diagenetic processes have significantly influenced the reservoir quality of the BSF. Early diagenesis, including grain dissolution and carbonate cementation, has affected primary porosity, while later mesodiagenetic processes have introduced secondary cements, impacting permeability (Brook et al., 2003; Gibson-Poole et al., 2024; Williams et al., 2013). Porosity in the BSF typically ranges between 0.1 and 0.25 (Brook et al., 2003; Heinemann et al., 2012; Hollinsworth et al., 2022; Patruno et al., 2024), although its distribution is highly variable. Permeability is similarly affected by the spatial occurrence of diagenetic cements, particularly halite-cemented layers that can impede flow.

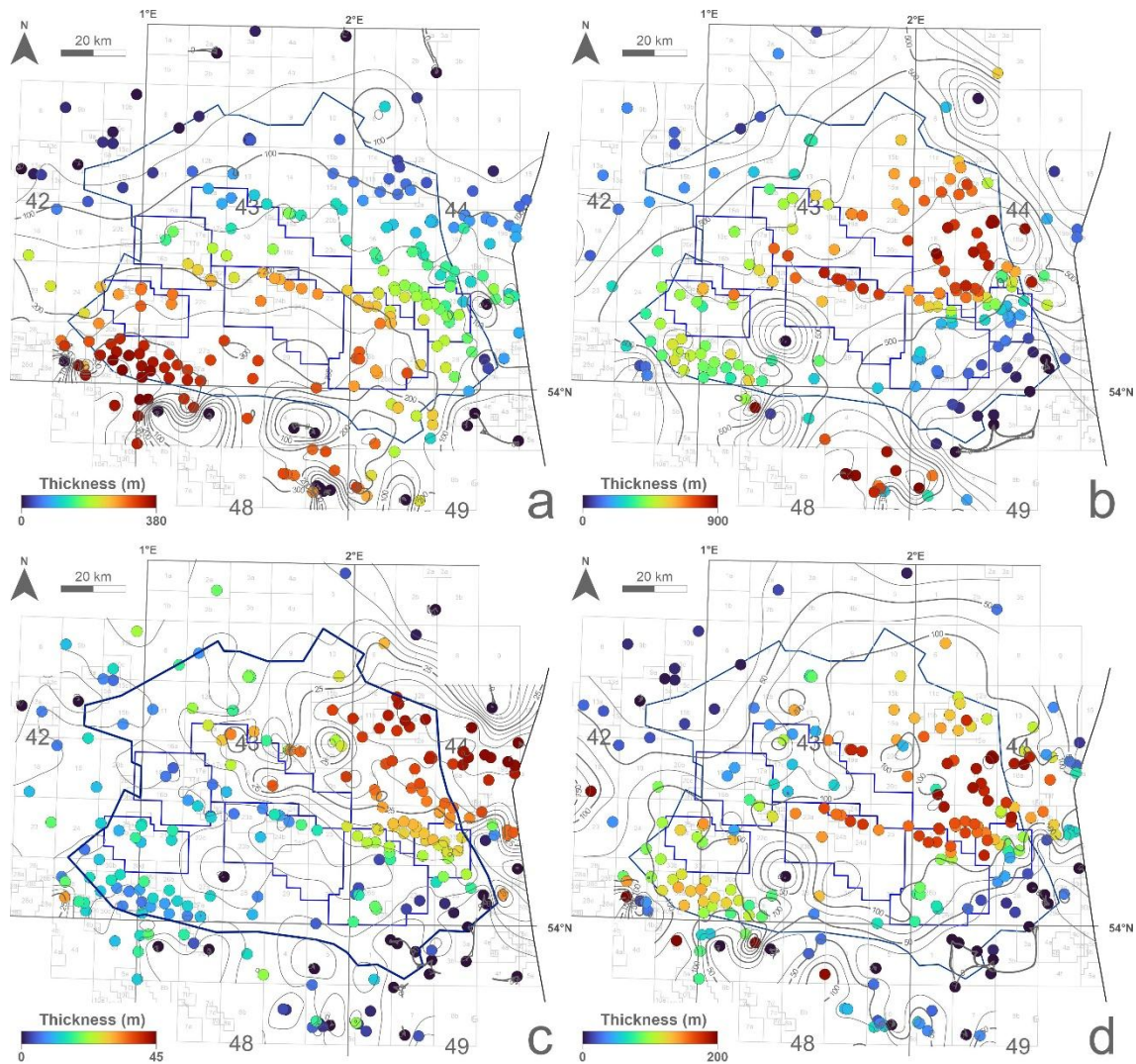


Fig. 3.4. Well-derived thickness of the (a) Bunter Sandstone Fm, (b) Haisborough Gp, (c) Solling Claystone Mb, and (d) Röt Halite Mb.

Fig. 3.5 illustrates five (i.e. Top Chalk Gp, BCU, Top Haisborough Gp, Base Röt Halite Mb, Base Bunter Sandstone) of the six (i.e. Top Zechstein Gp) key seismic reflectors interpreted. The Base Röt Halite reflector (Fig. 3.5e) has been used as a proxy to define the top reservoir structure, serving as a key near-reservoir seismic horizon across the study area. This reflector is characterised by a prominent, laterally continuous soft-kick in seismic data (Patrino et al., 2024) but is affected by phase reversals in the Endurance area and further south, as noted by previous studies (Gluyas and Bagudu, 2020;

Hollinsworth et al., 2022; Patruno et al., 2024). Beneath the Röt Halite Member lies the Solling Claystone (Fig. 3.3b), a 10 to 40 m thick layer (Fig. 3.4c), generally below the seismic resolution, that separates it from the BSF reservoir.

Above the Röt Halite Member, the sealing interval of the Haisborough Group contains additional evaporitic layers, including the Muschelkalk Halite and Keuper Halite. These layers exhibit distinctive gamma-ray drops and high-amplitude reflectors, which are laterally continuous across most of the study area (Fig. 3.6).

The bottom boundary of the reservoir is defined by the Top Bunter Shale reflector (Fig. 3.5f), which appears as a discontinuous, low-amplitude seismic feature, creating interpretational challenges in its precise delineation (Hollinsworth et al., 2022).

The BSF reservoir spans depths ranging from 800 ms to 2000 ms (milliseconds), dipping toward the east-southeast (Fig. 3.5). The Röt Halite depth ranges from 700 ms to 2170 ms, with a mean depth of 1360 ms, while the Bunter Shale depth spans 220 ms to 2270 ms, averaging 1460 ms (Fig. 3.5).

The interpretation of the remaining three seismic surfaces provided critical constraints for refining the model. Notable erosional truncations of the Top Chalk Gp (Fig. 3.5b) and BCU (Fig. 3.5c) surfaces were observed along the western margin. Moreover, the seismic interpretation allowed to identify the BSF reservoir subcrop (Fig. 3.5e).

To complete the reconstruction, the seabed horizon was derived through depth-to-time conversion of the EMODnet (2022) bathymetry, assuming a water velocity of 1500 m/s (Hollinsworth et al., 2022). These surfaces provided the foundation for subsequent time-to-depth conversion, enabling a detailed and accurate depiction of the structural and stratigraphic framework of the Silverpit Basin.

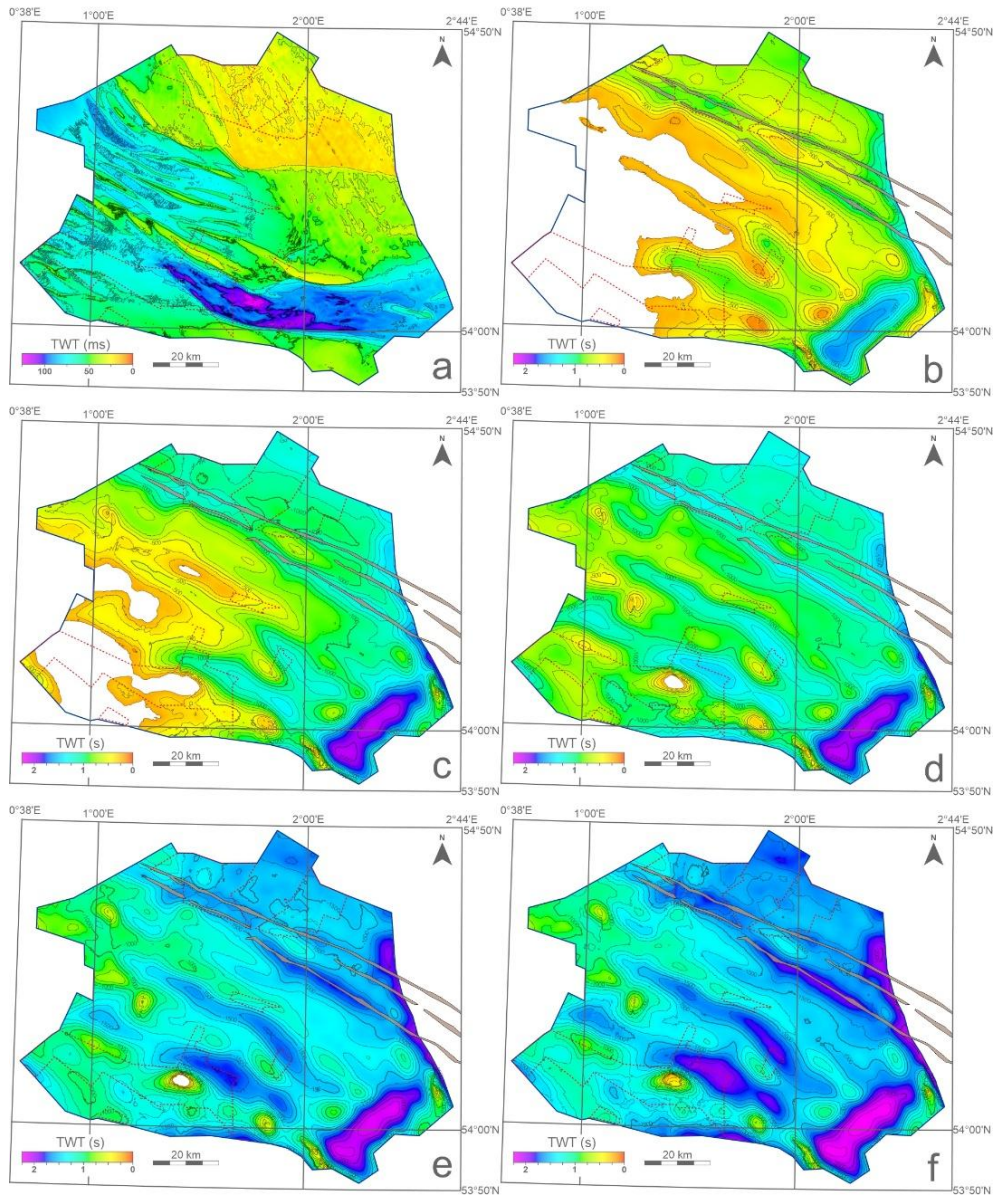


Fig. 3.5 Time surfaces of (a) sea bottom, (b) Top Chalk Gp, (c) BCU, (d) Top Haisborough Gp, (e) Base Röt Halite Mb, and (f) Base Bunter Sandstone Fm. Also highlighted Tertiary dikes (grey), and 3D seismic gap (dotted red polygon). Within the study area, Top Chalk and BCU surfaces are affected by erosion on the western margin. The BSF reservoir seabed subcrop is observable in (e).

The seismic interpretation revealed prominent NW-SE striking structural ridges (Fig. 3.5, Fig. 3.6), where BSF 4-way dip closures have developed as a result of salt tectonics associated with the Zechstein Gp. Additionally, the lateral continuity of the BSF reservoir across almost the entirety of the Silverpit Basin was emphasised (Fig. 3.6). Within this

region, the BSF reservoir appears to maintain lateral continuity, with only a limited number of faults displacing both the reservoir and the overlying Haisborough Gp seal. Notably, two closures in the northern part of the region exhibit significant fault throws, introducing uncertainty regarding the conductivity of these faults. One of these closures falls within the license area CS025 (Fig. 3.6a), necessitating further investigation to assess the potential impact on fluid flow and reservoir connectivity.

Conversely, defining the fault structures and their flow transmissibility at the edges (Fig. 3.6b) of the study area remains challenging. This uncertainty underscores the need for further investigation to evaluate their potential impact on reservoir connectivity and fluid dynamics.

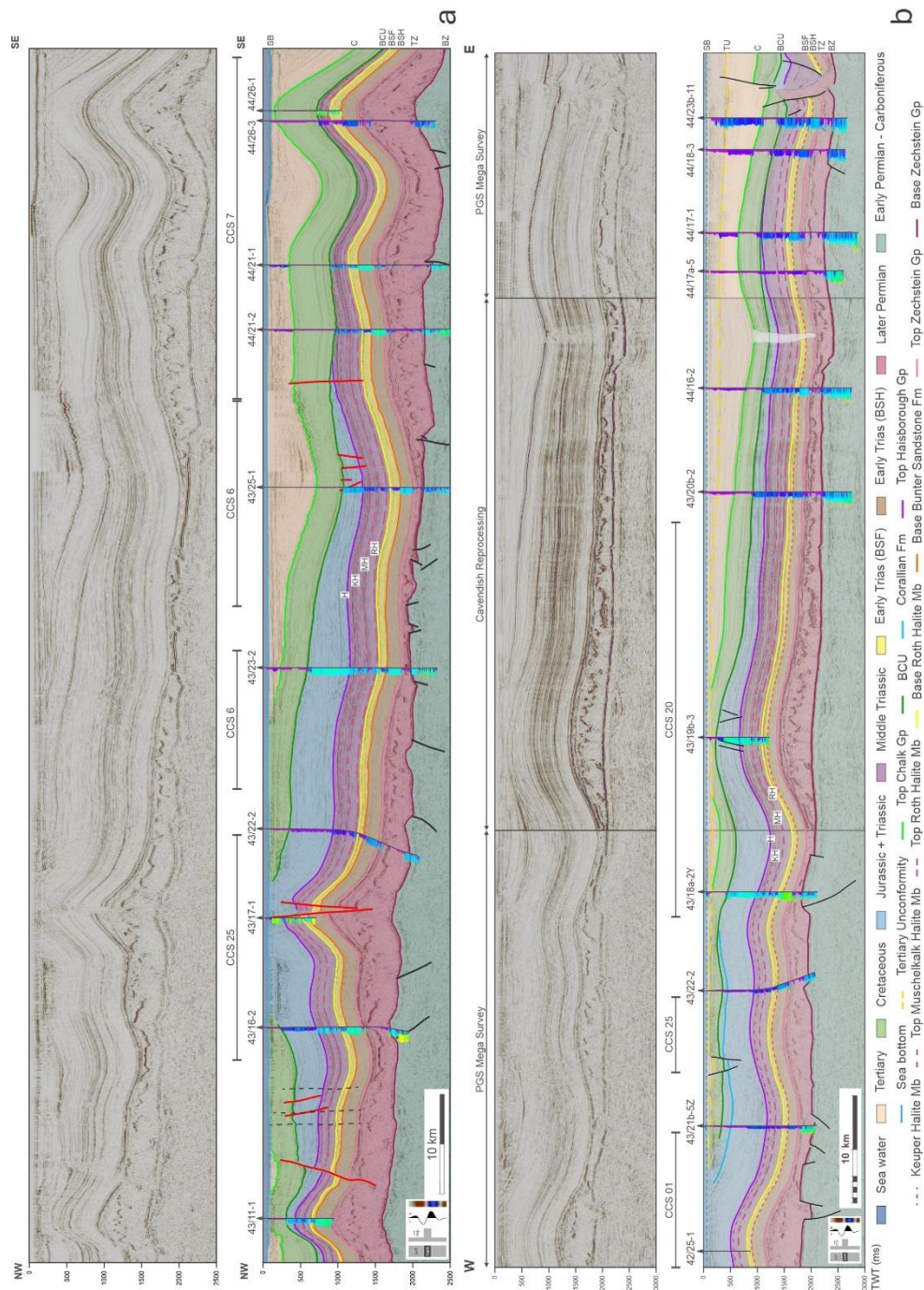


Fig. 3.6 Uninterpreted and interpreted (a) NW-SE and (b) W-E seismic cross-sections across showing the geological setting of the basin and CO₂ storage license location. Red lines indicate major faults affecting the reservoir and/or sealing interval, black lines indicate major pre-Zechstein faults, dashed black lines indicate possible chimneys, and white polygon indicates Tertiary dyke. Gamma-ray logs displayed along well tracks. See Fig. 3.2b for location. Nomenclature: SB, sea bottom; TU, Tertiary unconformity; C, Top Chalk Gp; BCU; Base Cretaceous Unconformity; H, Top Haisborough Gp; BSF, near Top Bunter Sandstone Fm; BSH, Top Bunter Shale/Base Bunter Sandstone Fm; TZ, Top Zechstein Gp; BZ, Base Zechstein Gp.

3.3.2 Storage Complex Uncertainties

The feasibility of geological CO₂ storage relies fundamentally on the ability of the storage complex to ensure containment integrity. This requires addressing the interplay of geological, hydrodynamic, and engineering factors to ensure the safe and effective retention of CO₂ within the storage system. Key considerations include the impermeability of caprock, the stability of faults and conduits, and the impact of geological heterogeneities. These factors must be thoroughly evaluated to anticipate potential risks and design mitigation strategies. A comprehensive assessment of these issues is essential before developing targeted simulations to optimise storage performance. This study focused on domain conversion, reservoir connectivity, heterogeneities and physical conditions.

3.3.2.1 Velocity Model and Depth Conversion

Constructing a regional velocity model presents significant challenges due to the spatial distances between data points and the pronounced lateral variability within the geological framework (Blackburn, 1986; Hillis et al., 1995; Japsen, 1993; Veeken et al., 2005). These complexities introduce inherent uncertainties into velocity models when applied across large regions (Hillis et al., 1995; Kulikowski et al., 2018; Veeken et al., 2005). To address this, a sensitivity analysis of the depth conversion process was performed to evaluate the potential influence of structural variations on CO₂ phase behaviour and plume migration, therefore affecting containment efficiency.

Depth conversion of geological interpretations in the time domain is a critical step that must be carefully evaluated before analysing the evolution of plume migration and its associated impacts, which can be significant even with dips of less than 1° (Zweigel and Hamborg, 2002). Dip angle of resulting structures after the depth-conversion also impact on the diffusivity of the CO₂-plume (Awag et al., 2024a, 2024b; Jing et al., 2023; Wang et al., 2016), and therefore require to be carefully defined. In this study, two linear velocity models were employed to derive depth-domain surfaces and assess their differences in flow simulations. Specifically, two top reservoir (e.g., Top BSF) maps were

generated by depth-converting the Base Röt Halite surface and adding the Solling Claystone thickness derived through well data interpolation (Fig. 3.4c). Subsequently, base reservoir maps were constructed. These were the top and bottom constraints for building the geocellular grids used to quantify the effects of structural model uncertainties derived from the top reservoir and spill-point depths.

The depth conversion utilized a linear velocity method (SLB, 2023) calibrated with data from 146 wells, resulting in an error margin of ± 100 m. These grids were constructed using depth surfaces derived from two different velocity models: (1) a basic linear velocity model and (2) an advanced linear velocity model. The results of these models are presented in Fig. 3.7a and Fig. 3.7b, respectively.

The basic linear velocity model follows the equation:

$$V = V_0 + KZ \quad (1)$$

where V is the calculated velocity for a given surface, V_0 is the velocity at the seismic reference datum (SRD – i.e. mean sea level), K is the velocity variation factor, and Z is the depth from the datum.

Conversely, the advanced linear velocity model refines the calculation using the equation:

$$V = V_0 + K(Z - Z_0) \quad (2)$$

Where V_0 represents the velocity at the top of the zone, and $Z - Z_0$ is the distance between the point and the top of the zone.

To optimize these models, data from all wells were analysed collectively. For each value of K , V_0 is calculated for all wells. This analysis was then fine-tuned by recalculating V_0 individually for each well using the optimized K . The final depth values for each model were subsequently derived using the following equation:

$$Z = Z_0 + \left(\frac{V_0}{K} + Z_0 \right) (e^{K(T-T_0)} - 1) \quad (3)$$

This approach facilitated a robust comparison between the two models, enabling the identification of structural and depth uncertainties and their implications for plume migration and reservoir behaviour.

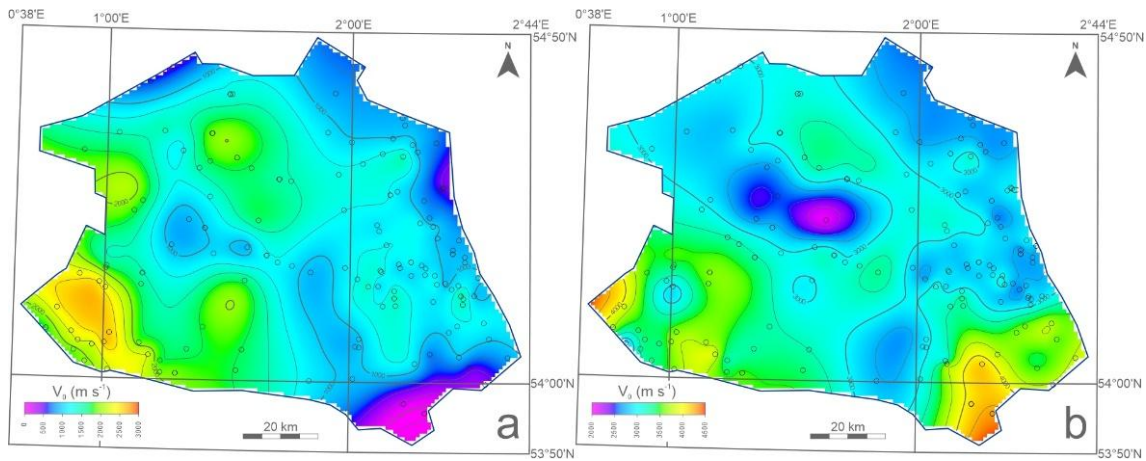


Fig. 3.7 Velocity (V_0) map at seismic reference datum of the Base Röt Halite Fm derived from (a) equation (1) (K value of 1.46) and (b) equation (2) (K value of 1.99).

In model (1)(Fig. 3.8a), anticlines appear shallower and synclines deeper than those modelled with velocity model (2)(Fig. 3.8b), highlighting variations in the structural representation of the reservoir. Notably, the top reservoir surface resulting from equation (2) is generally smoother compared to the surface derived from equation (1). Differences between the two calculations range from -400 to 350 m (Fig. 3.8c), yielding motivation to investigate any variability in the plume migration direction.

The most significant discrepancies are concentrated in the area surrounding the reservoir seabed subcrop (Fig. 3.8c), where well data are limited, and vertical rock variability is larger. This region is characterized by extensive salt tectonic activity and limited data availability, which reduces the reliability of calculations in this zone.

The top reservoir depth ranges between 65 m and 2955 m with a median of 1810 m, while the bottom reservoir ranges between 310 m and 3145 m with a median of 1980, as resulting from the equation (1). Results from equation (2) show the same median value but variation in the minimum and maximum, 70 and 2980 m for the top and 300 and 3210 m for the bottom, respectively.

The results of the time-to-depth conversion have also identified areas shallower than 800 m (Fig. 3.8a, b). Moreover, the approximate seabed outcrop area of the reservoir was determined to be about 13 km². This could probably be slightly bigger than the actual area (SLB, 2023) as a result of sparse legacy profiles. This area establishes a connection

between the reservoir and the seabed and was included as a focal point in the sensitivity simulations conducted in this study.

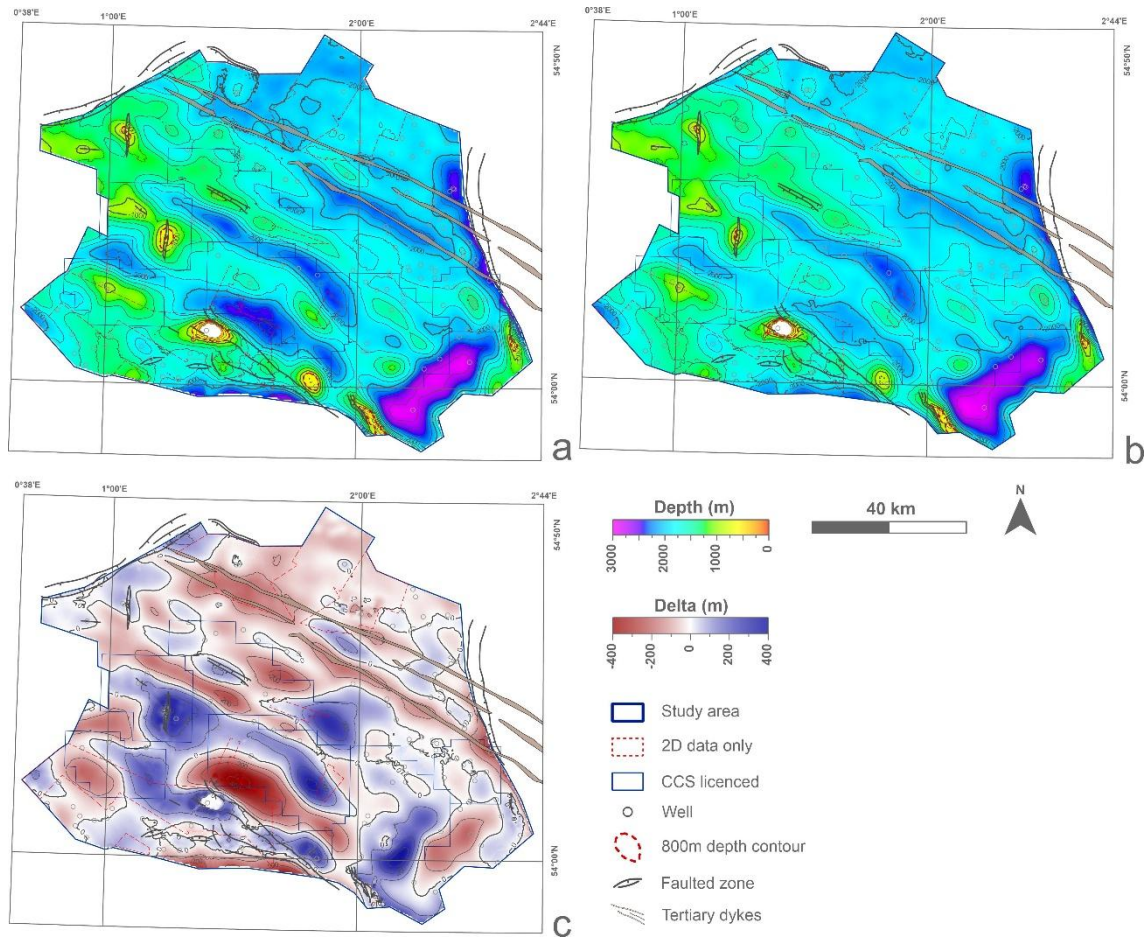


Fig. 3.8 Depth map. (a) Top reservoir map resulting from the depth conversion calculation by using the interval velocity model. (b) Top reservoir map obtained by the advanced interval velocity model. (c) Residual map of the difference between the two depth maps.

3.3.2.2 Faults and dykes

Caprock integrity is crucial for containing injected CO₂. In the BSF, the overlying Haisborough Group serves as the primary seal, effectively preventing the upward migration of CO₂. These geological features have demonstrated their ability to seal historical gas accumulations (Bifani, 1986; Ketter, 1991). However, structural complexities arise from crestal faults and dykes. Such weaknesses may compromise the

seal, potentially providing pathways for CO₂ to migrate to overlying strata or even reach the surface (Ambrose et al., 2014; Bentham et al., 2013; Phillips et al., 2020).

Elongated NW-SE-oriented Tertiary dikes (Fig. 3.2) extending into the Silverpit Basin represent significant magmatic activity during the Paleogene period (Carver et al., 2023; Thomson, 2004). These primarily basaltic dikes are associated with the North Atlantic Igneous Province and reflect regional extensional tectonics and crustal fracturing linked to the opening of the North Atlantic (Carver et al., 2023; Underhill, 2009). High-resolution seismic data reveal the offshore continuation of these dikes, cutting through the Triassic, Jurassic and Cretaceous strata (Brennan and Adam, 2022; Thomson, 2004). These intrusions exert localized structural effects, including fault reactivation and thermal alteration of surrounding rocks, which may significantly impact reservoir quality and seal integrity (Brennan and Adam, 2022; Carver et al., 2023; Patruno et al., 2024). Within the Silverpit Basin, hydrocarbon accumulations are observed along these dikes (Fig. 3.2 and Fig. 3.9), underlining their role as conduits for gas migration from the Carboniferous source interval (Brown et al., 1994; Kortekaas et al., 2018). The observed gas accumulations beneath the Haisborough Group, coupled with the absence of gas shows above the BSF, confirm the vertical sealing potential of this interval. By contrast, the discontinuous nature of the dikes (Hollinsworth et al., 2022; Patruno et al., 2024) and evidence of pressure communication between the Caister and Hunter fields (Patruno et al., 2024) suggest lateral connectivity through the dikes within the BSF aquifer.

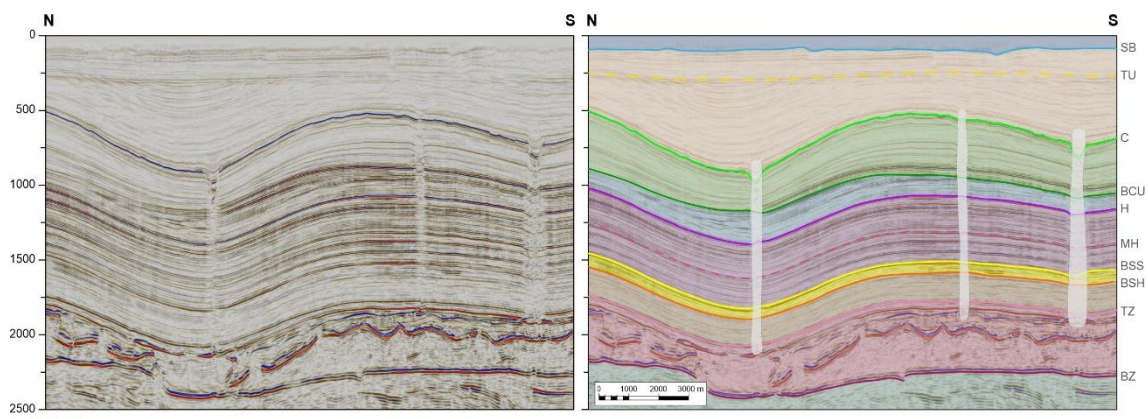


Fig. 3.9 (left) uninterpreted and (right) interpreted seismic section imaging of Tertiary dykes. See Fig. 3.2b for location, Fig. 3.6 for colour legend.

Faults and dykes intersecting the reservoir or seal pose potential risks to vertical containment (Espinoza and Santamarina, 2017; Phillips et al., 2020) and may impact fault transmissibility (Ballas et al., 2015; Farrell et al., 2014). Within the study area, major fault systems have been identified (Fig. 3.2b), although only a limited number of faults above the seismic resolution are observed to affect the reservoir and seal, primarily in the northern sector. Particularly, two closures within blocks 43/11 and 43/17-43/22 exhibit significant fault throws. One of these closures, located within license CS025 (Fig. 3.10b), is crosscut by a pair of antithetic N-S faults that extend from the Zechstein Group to the seabed. At this location, the BSF is displaced, forming a graben structure between the two faults (Fig. 3.10b). This structural complexity poses a risk due to stratigraphic offset, potentially juxtaposing the reservoir against non-sealing strata, thereby compromising containment (Bentham et al., 2013). Uncertainties also persist regarding possible minor faults affecting the "Bunter 36" closure (James et al., 2016). Similarly, the Endurance closure is characterized by faults within the Haisborough Gp, displaying throws of a few tens of meters. These faults originate at the top of the Haisborough Gp and sole out within the Röt Halite (Gibson-Poole et al., 2024), which acts as a detachment zone in this area (Fig. 3.10a; Stewart et al., 1996). While minor fault systems across the Silverpit Basin generally do not appear to disrupt the reservoir, the potential risk of undetected sub-seismic faults remains (Hollinsworth et al., 2022), necessitating further investigation to ensure structural integrity and containment.

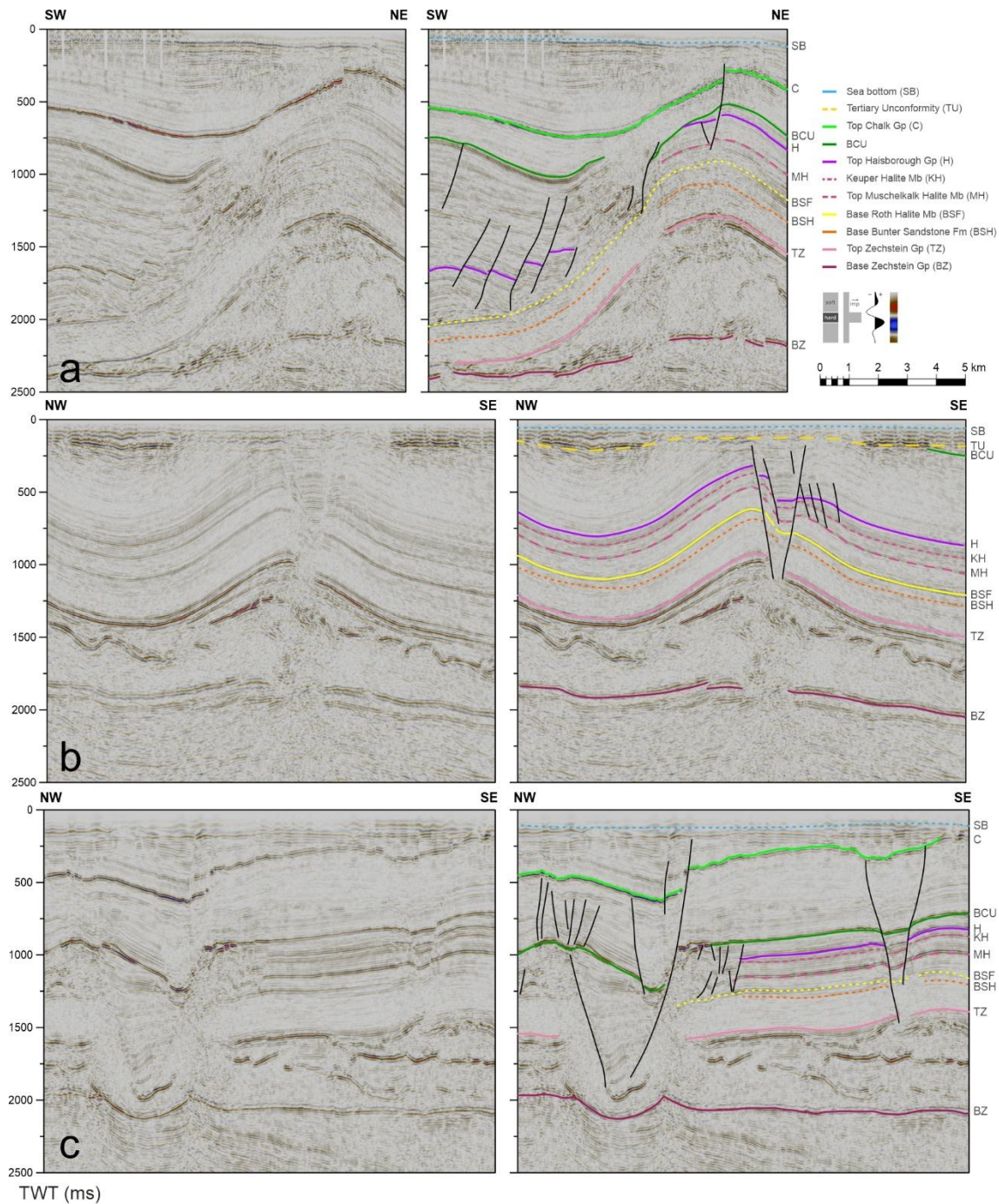


Fig. 3.10 Seismic section showing uninterpreted and interpreted faults. (a) Domino faults dislocating the sealing interval with detachment zone into the Röt Halite Mb, (b) extended fault throw cutting from the Zechstein Gp to the seabed, (c) North Dogger fault zone. See Fig. 3.2b for location.

The edges of the study area are marked by several major structural events, extending over tens of kilometres and significantly influencing the subsurface framework (Fig. 3.2b). In

the northern sector, the North Dogger Fault Zone (Fig. 3.10c; Griffiths et al., 1995) dominates. This fault zone, extending over 50 km in a WSW-ENE direction, exhibits a complex geometry that impacts the sedimentary sequence from the seabed to the Zechstein Group. Within this region, the fault zone entirely dissects the BSF reservoir, potentially acting as a sealing boundary that restricts flow and pressure communication (Bentham et al., 2017b).

Similarly, the eastern portion of the study area is characterized by extensive structural complexities with a NNW strike (Fig. 3.2b). This region is shaped by the interplay of compressional tectonics, salt intrusion, and local fault inversion (Fig. 3.6b). These processes collectively dissect the reservoir, forming an extended barrier along the reservoir boundary and further complicating fluid dynamics.

In the southern sector, the transitional area between the Silverpit Basin and the Sole Pit High is dominated by significant salt tectonics. This activity has led to the formation of extensive salt domes, causing intense segmentation of the supra-salt sequences (Fig. 3.10a). The extensional setting has also produced a prominent fault zone trending NNW-SSE, which affects the Haisborough Group and generally detaches into the Röt Halite Member.

This structural framework underscores the necessity of thoroughly investigating reservoir connectivity. Such studies are essential for understanding the potential effects of structural barriers on reservoir pressure dynamics and containment efficiency (Noy et al., 2012; Williams et al., 2014). However, in order to maintain a more straightforward model and reduce computational time, these structural complexities have been deliberately excluded from this study, thus creating a basis for future research.

3.3.2.3 Seabed subcrop

Evidence from well data (i.e. 43/28a-3) and interpretation of legacy seismic profiles (Fig. 3.11) highlight uncertainties associated with the interaction between the BSF and the seabed in areas where the reservoir subcrops. In this region, the underlying salt dome has uplifted the BSF, resulting in approximately 13 km² of the reservoir interval either directly

exposed at the seabed or covered by a thin layer of recent sediments. This geological configuration introduces a potential vulnerability to the storage complex.

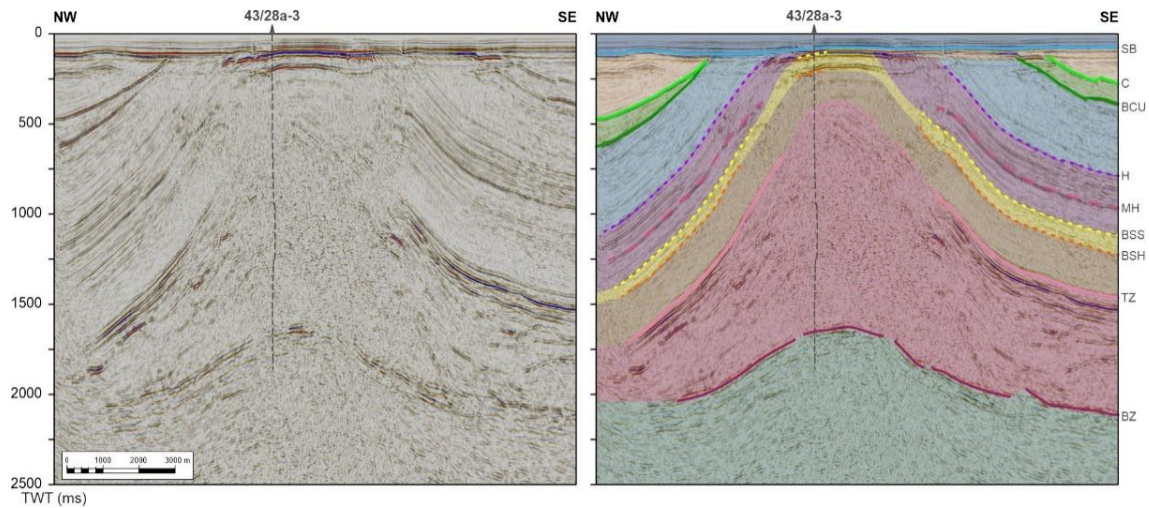


Fig. 3.11 Seismic section illustrating the approximate extent of the BSF subcrop at the seabed. See Fig. 3.2b for location. Nomenclature: SB, sea bottom; TU, Tertiary unconformity; C, Top Chalk Gp; BCU, Base Cretaceous Unconformity; H, Top Haisborough Gp; BSF, near Top Bunter Sandstone Fm; BSH, Top Bunter Shale/Base Bunter Sandstone Fm; TZ, Top Zechstein Gp; BZ, Base Zechstein Gp.

Injecting CO₂ in the subsurface alters the reservoir pressure equilibrium with subsequent mobilization of formation water (i.e. saline brine). The subcrop exposure of the reservoirs turns into a weak point within the system, which could act as a conduit for brine displacement to the seabed. The absence of overlying sealing intervals exacerbates this risk by reducing the natural containment capacity of the reservoir in the exposed areas.

Furthermore, this exposure creates a potential pathway for CO₂ migration from the reservoir to the seabed due to the absence of overlying sealing intervals if CO₂ is displaced beyond the nearby trap boundary. Dynamic modelling studies (Noy et al., 2012) have shown that while seabed outcrops can dissipate the reservoir pressure by acting as natural pressure relief points, they also pose significant environmental risks due to brine displacement. This emphasizes the need for robust monitoring and management strategies to address these geological uncertainties and ensure the integrity of the storage system.

3.3.2.4 Reservoir Heterogeneities

The phase of active basin extension in the Southern North Sea region diminished during the late Permian, giving way to a period of thermal subsidence and tectonic stability that persisted from the Triassic through to the Early Jurassic (Grant et al., 2019b; Underhill, 2003). During this period, such relaxation led to semi-arid continental conditions, characterized by ephemeral fluvial systems draining from the London-Brabant Massif and Pennine High to the southwest (Fig. 3.2a – Bachmann et al., 2010; Cameron et al., 1992; Geluk et al., 2018; McKie, 2017; McKie and Williams, 2009). Sedimentation within the Triassic Bacton Group occurred in fluvial, lacustrine, and playa lake environments, often modified by aeolian processes (Bachmann et al., 2010; Bifani, 1986; Geluk et al., 2018; Ketter, 1991; McKie, 2017; McKie and Williams, 2009; Ritchie and Pratsides, 1993).

The heterogeneous nature of the Triassic depositional systems, characterized by the intercalation of fluvial, lacustrine, aeolian, and episodic marine deposits, has resulted in significant lateral and vertical heterogeneities within the BSF reservoir. Vertical heterogeneity is particularly pronounced due to the presence of cemented sandstone layers and halite-cemented horizons, which vary in porosity and permeability across the reservoir (Ketter, 1991; Ritchie and Pratsides, 1993; Williams et al., 2013). These features, shaped by diagenetic processes, act as barriers to flow and pressure migration. For example, a prominent cemented layer has been identified in the “Bunter 36” (well 44/26-1) and in the Caister B gas field (well 44/23-1; Williams et al., 2013). This layer, along with other intraformational baffles such as clay-rich intervals, contributes to the compartmentalization of the reservoir, which poses challenges for achieving an even distribution of injected CO₂ and managing pressure effectively (Noy et al., 2012; Williams et al., 2013).

These heterogeneities, influenced by both depositional and diagenetic processes, play a critical role in shaping reservoir behaviour. High-permeability zones may facilitate CO₂ dispersal, while intraformational barriers hinder migration, impacting storage efficiency and plume dynamics. This complex interplay underscores the importance of characterizing these features for effective CO₂ storage and management within the BSF reservoir.

3.3.3 Geocellular model

The modelled area extends approximately 140 km NE-SW and 100 km NW-SE. To achieve a balance between basin-scale detail with computational efficiency, the static model was developed with a horizontal cell resolution of 200 m. The grid was subdivided into 20 vertical layers using the proportional layering method (SLB, 2023), with thicknesses ranging from 0.1 m to 42 m and an average thickness of 8 m (st. dev.: 3 m). Moreover, the grid was rotated 55 degrees to align with the NW-striking ridges characteristic of the BSF. This configuration, based on surfaces generated by equation (1), results in a discretization of $539 \times 693 \times 20$ ($i \times j \times k$), yielding approximately 4.5 million active cells, which served as the reference model. For comparative purposes, an alternative grid derived from equation (2), incorporating two additional cells in the i and j directions and a maximum layer thickness of 25 m, was employed to assess uncertainties in spill-point depth.

This modelling approach supports the analysis of the structural framework, including spill-point depths, and facilitates investigations into petrophysical heterogeneities and reservoir connectivity.

3.3.4 Petrophysical Model

Despite the presence of numerous wells throughout the study area, there is a significant lack of information regarding the petrophysical characterization of the BSF reservoir interval. This limitation arises primarily from the fact that much of the aquifer is dry and water-bearing (e.g. 43/16-1, 43/18-1, 44/26-1), which hinders further investment in exploring this interval. As a result, the petrophysical model was developed using parameters derived from core measurements, describing primarily the upper portion of the BSF reservoir, gathered from the 24 wells available within the Silverpit region (Fig. 3.12).

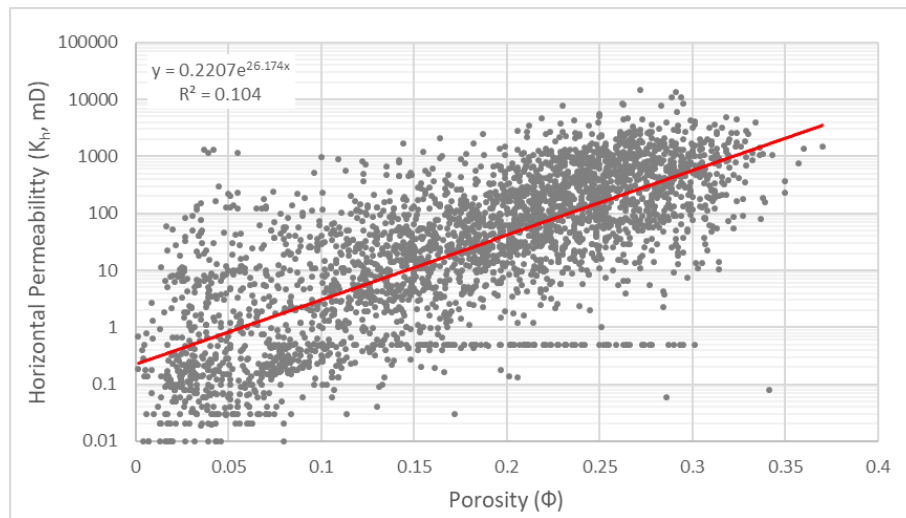


Fig. 3.12 Correlation plot of porosity and horizontal air permeability data obtained from 24 wells within the Silverpit region.

Comprehensive technical reports (e.g. 43/18 wells), wireline log analysis (Patrino et al., 2024; Williams et al., 2013) and description of Triassic BSF discoveries (Bifani, 1986; Ketter, 1991; Ritchie and Pratsides, 1993; Williams et al., 2013) highlight substantial vertical variability in reservoir properties. This variability reflects depositional environments dominated by fluvial and aeolian sandstones, characterized by braided channel systems, alluvial plains, and fans with subsequent aeolian reworking. Additional complexities include cemented layers resulting from compaction diagenesis or elevated shale content and halite precipitation directly beneath the Solling Claystone. Capturing these local heterogeneities at the basin scale is inherently challenging also because of the uncertainties in the depositional setting characterization. Such heterogeneities can act as low-permeable layers representing potential baffles impacting fluid flow and containment.

Consequently, porosity and permeability values were assigned using a normal distribution to establish a reference scenario, reflecting the limited information on depositional environments and lateral facies changes within the BSF. This approach provides a foundation for further refinement at the field-scale as additional data become available.

Core measurements (Tab. 3.1, Fig. 3.12) indicate a porosity (Φ) range of 0.01 to 0.37, with a median value of 0.19 and a standard deviation of 0.08. Horizontal permeability (k_h)

varies from 0.01 to 15,000 mD, with a median of 35 mD and an arithmetic mean of around 290 mD. Due to the limited availability of direct sampling, particularly across the extensive study area, permeability values were assigned as a function of porosity to provide a consistent model (Fig. 3.12).

Vertical permeability (k_v), constrained by sparse data, is generally observed to be an order of magnitude lower than horizontal permeability. To account for this, a vertical-to-horizontal permeability ratio (k_v/k_h) of 0.1 was applied to 18 of the 20 layers in the model. To simulate the influence of potential flow barriers, this ratio was further reduced to 0.01 in the seventh and fourteenth layers.

Net-to-gross value in the BSF is generally 0.8-1.0 (Brook et al., 2003; Gibson-Poole et al., 2024; Hollinsworth et al., 2022; Noy et al., 2012; Patruno et al., 2024). For simplicity, in this study it is assumed to be 100%.

Value	Min	Max	Mean	Median	St. Dev.
Φ	0.01	0.37	0.18	0.19	0.08
k_h	0.01	15000	289	35	577
k_v	0.0001	4580	83	3	270

Tab. 3.1 Petrophysical analysis of BSF core measurements for porosity (Φ), horizontal (K_h) and vertical (K_v) air permeability.

This approach integrates available data with simplifying assumptions to capture the influence of vertical heterogeneity and potential barriers on fluid flow within the reservoir. To address the inherent uncertainties, five petrophysical models were developed:

- A homogeneous model based on the median value of porosity and permeability (Tab. 3.1);
- A base case reference model (De Luca et al., 2025) uses the median and standard deviation values to spatially distribute porosity via the SGS algorithm, k_h is modelled as a function of porosity, while k_v is assigned using the k_v/k_h ratio, as described above;

- Three heterogeneous models (Fig. 3.13) designed to assess the impact of petrophysical anisotropy by varying correlation lengths in porosity distribution and assigning the permeability as in the reference model.

Given the limited understanding of depositional environments and lateral facies variations within the BSF reservoir, a sensitivity study was conducted to assess the impact of varying petrophysical assumptions and lateral heterogeneities on subsurface integrity. The study explored scenarios ranging from short lateral variations, resembling fluvial channels, to extended permeable pathways. To achieve this, three stochastic realizations were generated using the SGS algorithm, calibrated to honour available core data. Correlation lengths were varied to capture spatial variability along the principal direction with anisotropy ranges of 1 km, 2.5 km, and 5 km. The principal direction was oriented toward NE to reflect sediment influx from the southwestern margin, consistent with previous geological interpretations (Bachmann et al., 2010; Cameron et al., 1992; English et al., 2024; Gluyas and Bagudu, 2020; McKie, 2017; McKie and Williams, 2009). Similarly to the methodology applied in the Endurance project evaluation (BP, 2021), the variogram in the orthogonal direction was set at two-thirds of the principal range.

These heterogeneous stochastic models aim to provide a more accurate representation of the influence of 3D permeability distribution on fault reactivation and potential leakage. By contrast, simplified homogeneous and base case models serve as reference scenarios for comparative analysis, offering insights into the dynamic behaviour of the reservoir under varying geological assumptions.

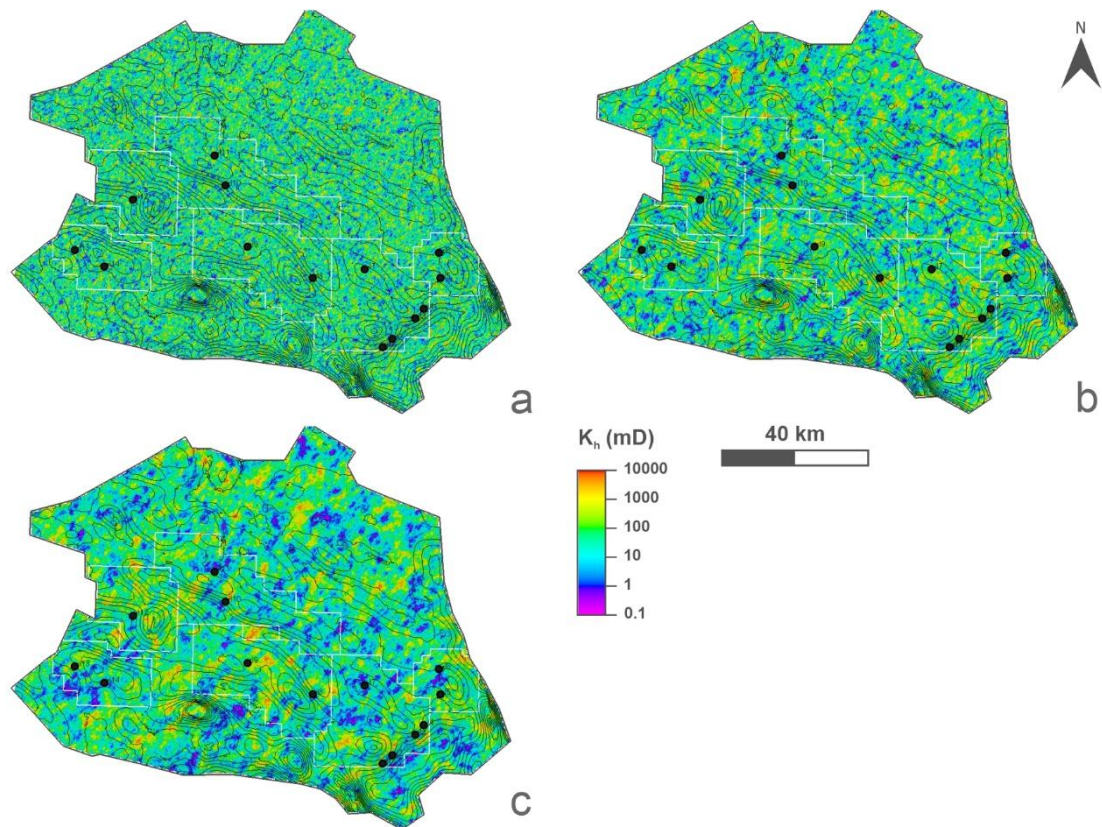


Fig. 3.13 Horizontal permeability map illustrating the anisotropy sensitivity across the petrophysical heterogeneous models. The anisotropy is characterised by variogram correlation lengths in the X and Y directions, defined as follows: (a) short-range with lengths of 1 km and 0.7 km, (b) medium-range with lengths of 2.5 km and 1.7 km, and (c) long-range with lengths of 5 km and 3.4 km. NE orientation has been applied to reflect sediment influx from the southwestern massif (Bachmann et al., 2010).

3.3.5 Reservoir volume and connectivity

Understanding reservoir volume (i.e. pore volume available for injection) is critical for managing CO₂ storage in geological formations. The pore volume dictates the storage capacity and directly influences pressure dynamics within the reservoir, which are critical for maintaining caprock integrity (Buscheck et al., 2012; Court et al., 2011). As highlighted by Bachu et al. (2007), effective CO₂ storage requires a precise assessment of pore volume to prevent over-pressurization, which can lead to caprock fracturing and potential leakage. Additionally, the pressure front extends tens of kilometres beyond the CO₂ plume (Birkholzer et al., 2009; Birkholzer and Zhou, 2009; Person et al., 2010), necessitating careful pressure management that accounts for geological heterogeneities,

boundary conditions, and the compressibility of reservoir fluids and rock. Static and dynamic pressure assessments (Agada et al., 2017; Kolster et al., 2018; Noy et al., 2012; Williams et al., 2013) are crucial for understanding fluid displacement and pressure dissipation, enabling safe injection rates without exceeding the fracture pressure of the caprock. In this regard, estimating the aquifer pore volume and its connectivity across the extensive region is critical.

The limited availability of seismic data northwest of the Endurance anticline (Fig. 3.2 and Fig. 3.14) has impeded a detailed geological reconstruction, restricting the ability to precisely assess the pore space required for accurate pressure distribution simulations. This connected region extends approximately $1.2 \times 10^9 \text{ m}^2$ with an average thickness of 180-200 m (Fig. 3.4a). Assuming the median porosity value (Tab. 3.1), the reservoir volume is estimated to be on the order of $4 \times 10^{10} \text{ m}^3$ for this region. This limitation underscores the urgent need for further investigation into reservoir connectivity in this area to improve pressure modelling and predict plume migration more effectively.

Furthermore, to address uncertainties associated with fluid transmissibility and boundary connectivity, a sensitivity study was conducted. The reservoir was divided into nine regions (Fig. 3.14) to monitor fluid properties (i.e. density and viscosity), inter-region flows, in-place volumes, and other critical parameters. Region 1 (R.1) represents part of the external reservoir. Region 2 (R.2) outlines the BSF reservoir seabed subcrop, Region 9 (R.9) encompasses the connection with available pore space toward NW, and has been the object of sensitivity studies. Regions 3 to 8 correspond to the CO₂ storage licences awarded by the UK Government. The modelled BSF reservoir is defined by the combined volumes of Regions 1, and 3 to 8, while Regions 2 and 9 were assigned pore volume multiplier to simulate a large, connected volume capable of dissipating pressure and facilitating water displacement.

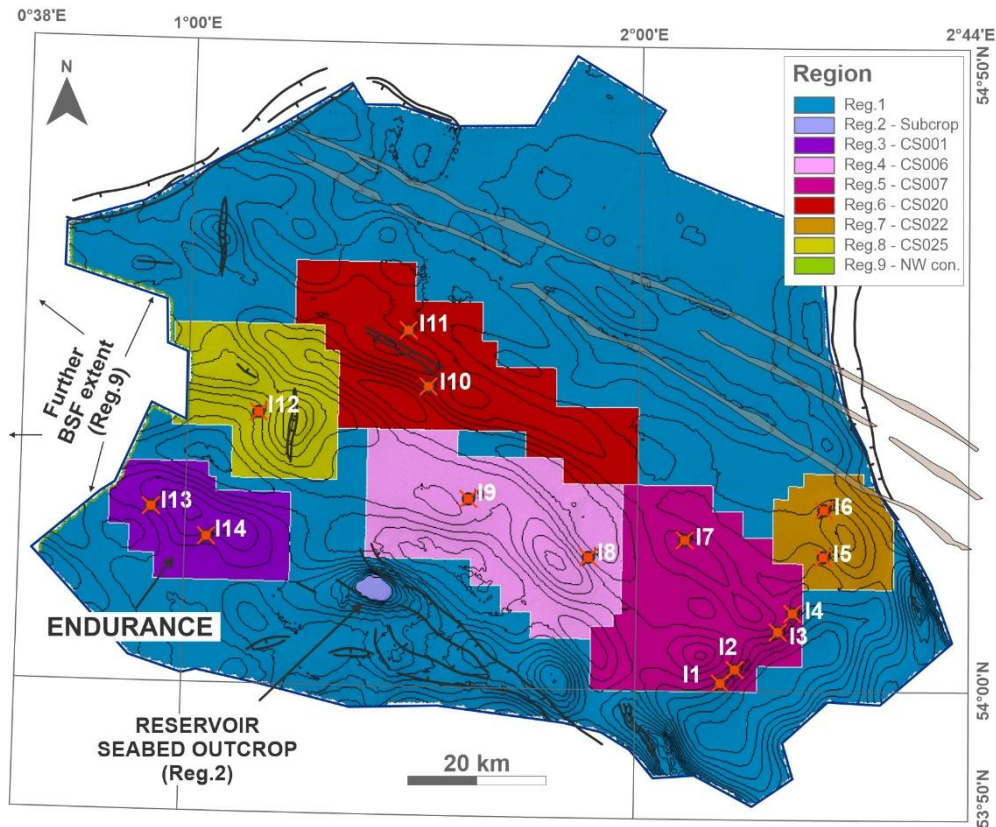


Fig. 3.14 Reservoir region (i.e. fluid in place region) corresponding to the gross reservoir (R.1), approximate seabed subcrop (R.2), CO₂ storage licenses (R.3 to R.8), and approximation of BSF connected region extending toward the northwest (R.9). Red dots indicate the proposed CO₂ injection wells for this study.

The approximate pore volume of each region derived from the base case model is presented in Fig. 3.15. The modelled BSF reservoir comprises the combined volumes of regions 1, 3, 4, 5, 6, 7, and 8, resulting in an estimated total volume of $3.04 \times 10^{11} \text{ m}^3$. The individual pore volumes of these regions are as follows: $1.69 \times 10^{11} \text{ m}^3$, $1.46 \times 10^{10} \text{ m}^3$, $3.19 \times 10^{10} \text{ m}^3$, $3.11 \times 10^{10} \text{ m}^3$, $2.85 \times 10^{10} \text{ m}^3$, $8.42 \times 10^9 \text{ m}^3$, $2.07 \times 10^{10} \text{ m}^3$. To investigate the effect of reservoir connectivity, pore volume multipliers (PVM) were applied to regions 2 and 9, resulting in adjusted pore volumes of $8.89 \times 10^{14} \text{ m}^3$ and $3.44 \times 10^{11} \text{ m}^3$, respectively.

A sensitivity analysis was performed on R.9 by varying its extent and applying PVMs to address uncertainties deriving from the geological setting of the northwestern region. Two additional realisations of the base case model were generated using PVM values of 100

and 1000, denoted as PVM100 and PVM1000. These adjustments produced pore volumes for R.9 of $6.87 \times 10^{10} \text{ m}^3$ and $6.87 \times 10^{11} \text{ m}^3$, respectively. A final sensitivity analysis extended R.9 to include all external cells of the base case model (R.9-all edges), yielding a pore volume of $1.45 \times 10^{12} \text{ m}^3$. This analysis aims to explore the regional impact of an extended connected aquifer on pressure dissipation, providing insights into potential connectivity and its influence on reservoir dynamics.

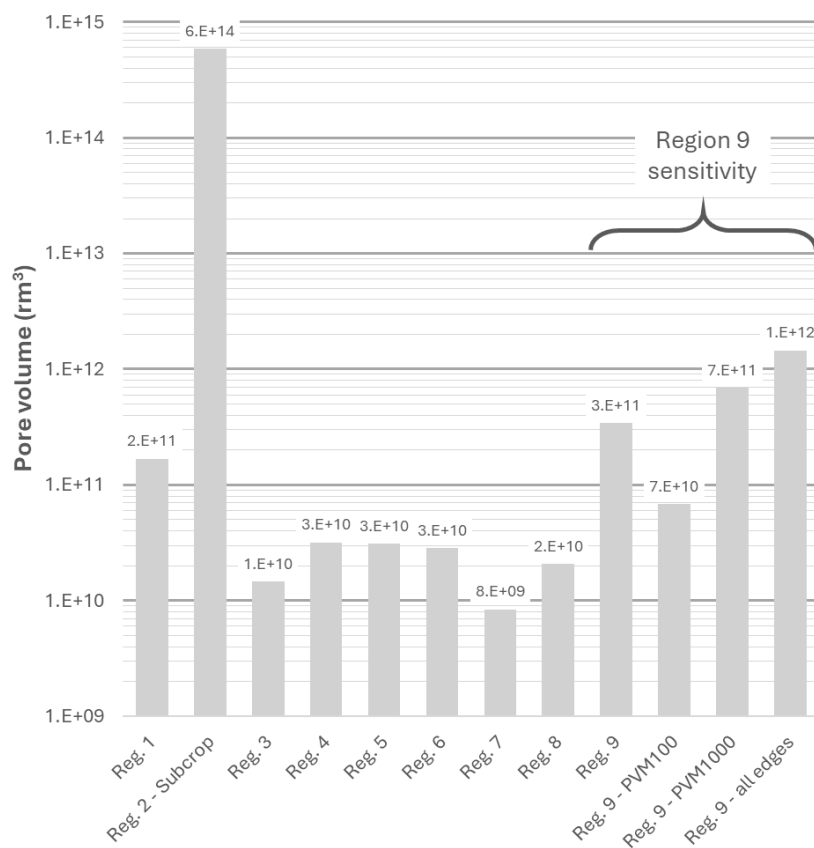


Fig. 3.15 Region pore volumes resulting from the base case reference model (see 3.3.4). R.2 represents the pore volume generated to investigate reservoir connectivity with the North Sea due to the reservoir seabed subcrop. Regions 9 pore volumes indicate volume generated for the sensitivity studies investigating reservoir connectivity with the northwestern region. R.9 refer to the pore volume in the base case model, R.9-PVM 100 and R.9-PVM 1000 are the pore volumes to investigate uncertainties in the pore volume estimations of the northwestern region, R.9-all edges is the pore volume generated to investigate reservoir connectivity along entire lateral side of the model. The modelled BSF reservoir is composed of regions 1, 3, 4, 5, 6, 7, 8 and has an approximate volume of $3 \times 10^{11} \text{ m}^3$.

Dynamic connectivity within the reservoir system further complicates CO₂ storage in the BSF. While structural traps may enhance storage capacity, unexpected connections can lead to migration beyond the containment area. Properly characterizing these connections is crucial to prevent leakage and optimize efficiency. Brine displacement during CO₂ injection poses environmental risks, as saline waters may displace into overlying strata or the seabed with ecological consequences that need further investigation. Rigorous impact assessments and proactive measures to manage brine migration are necessary during and after injection. This approach provides a framework for addressing uncertainties in boundary transmissibility and reservoir connectivity, essential for enhancing the accuracy of pressure and plume migration models in large-scale CO₂ storage projects.

3.4 Numerical CO₂ Flow Simulation

Precise numerical modelling of CO₂ injection is essential for evaluating the viability, effectiveness, and safety of large-scale CCS endeavours. Models created for the BSF saline aquifer aim to capture the intricate interplay between geological and operational variables that impact CO₂ interactions and storage potential across large regions. To navigate these complexities, this research utilizes numerical reservoir modelling with ECLIPSE 100 (SLB, 2023), which is designed to assess both short-term injection performance and long-term containment behaviour across various geological and operational scenarios.

Fifteen simulation scenarios (Tab. 3.2) have been developed to examine the key variables that influence storage efficiency. These variables encompass boundary conditions, reservoir pressure, geological heterogeneities, and injection strategies. The scenarios establish a robust framework for evaluating the dynamic behaviour of CO₂ within the brine-saturated reservoir of the BSF. This formation is characterized by extensive lateral continuity, good permeability, and structural closures that are favourable for CO₂ trapping, which endows it with significant storage potential. Nevertheless, this potential is impeded by factors such as intraformational mudstones, faulting, and halite-cemented layers. These complications may disrupt CO₂ migration pathways and complicate pressure management.

The numerical model integrates a combination of static and dynamic approaches to address uncertainties associated with reservoir properties and heterogeneities. It is structured around the comparison of multiple case models that progressively incorporate specific refinements. This process allows for more accurate predictions of reservoir behaviour and enhances the reliability of simulation results. This comprehensive approach facilitates a nuanced understanding of CO₂ storage dynamics, offering valuable insights into the storage potential and operational risks associated with the BSF.

Nb	Grid	Petrophysical Model	Scenario	Boundary Transmissibility	Description	Name
1		1	Homogeneous	2 OPEN	Homogeneous model with median value from Tab.1	HOMO
2				CLOSED	Confined aquifer	BSCS_CLSD
3				1 OPEN	Aquifer transmissibility at the seabed subcrop	BSCS_OPEN_SEABED
4					Aquifer transmissibility with northwestern region	BSCS_OPEN_NW
5					REFERENCE MODEL	BSCS_OPEN
6					Simulation of over-activity with 42 injector wells	BSCS_OPEN_42W
7		2	Base Case		Overpressured reservoir (0.592 psi/ft)	BSCS_OPEN_OP
8	1			2 OPEN	17 leaky wells added to the simulation	BSCS_ABAND
9					Region 9 extended to all reservoir edges	BSCS_OPEN_FULL
10					Region 9 - pore volume multiplier of 100	BSCS_OPEN_PVM100
11					Region 9 - pore volume multiplier of 1000	BSCS_OPEN_PVM1000
12		3			Horizontal correlation length - 5 x 3.4 km	LONG
13		4	Heterogeneous	2 OPEN	Horizontal correlation length - 2.5 x 1.7 km	MID
14		5			Horizontal correlation length - 1 x 0.7 km	SHORT
15	2	6	Structural Sensitivity	2 OPEN	Base case properties distribution	BSCS_VMOD

Tab. 3.2 Description of the 15 simulation scenarios developed in this study. Boundary transmissibility indicates a confined aquifer (CLOSED; i.e. no flow at the boundary), open aquifer at one location (1 OPEN; i.e. flow transmissibility at the boundary) or two locations (2 OPEN; i.e. flow transmissibility at the seabed subcrop and region NW of Endurance see Fig. 3.2b). For the detailed explanation of the scenarios see chapter 3.4.4.

3.4.1 Numerical Errors and Simulation Uncertainties

Simulation of CO₂ injection in saline aquifers often relies on black-oil models (Kolster et al., 2018). These models provide a simplified yet effective framework that reduces the runtime to one-fourth of that required by the compositional model (Hassanzadeh et al., 2008), for evaluating multiphase fluid flow. However, inherent limitations arise when these models are employed in reservoirs characterized by considerable salinity gradients and temperature variations, such as those found in the BSF. These limitations primarily result from the inability of black-oil models to accurately encapsulate the intricate thermodynamic interactions among CO₂, formation brine, and reservoir rock, which are critical for precisely predicting fluid behaviour under variable reservoir conditions.

To establish the CO₂-brine model, the ECLIPSE 100 reservoir simulator was utilized. This simulator incorporates a black oil framework, with pressure, volume, and temperature (PVT) properties computed in accordance with the methodology proposed by Hassanzadeh et al. (2008). This approach presents a pragmatic means of addressing the phase behaviour of CO₂ under reservoir conditions, while ensuring computational efficiency for extensive simulations. Despite the robustness of this numerical approach, it is imperative to recognize and mitigate several sources of error and uncertainty that are intrinsically linked to the modelling process.

Significant uncertainties arise from the representation of fluid-rock interactions and the calibration of PVT data related to CO₂-brine systems. For instance, variations in salinity gradients and temperature can substantially affect the solubility and density of CO₂, which in turn influences the migration of plumes and the evolution of pressure within the reservoir.

This subsection examines the primary sources of numerical errors and uncertainties associated with CO₂ injection simulations, with a specific emphasis on the challenges imposed by fluctuations in salinity and temperature within black oil modelling. By methodically addressing these limitations, the research aims to improve the reliability and predictive accuracy of numerical simulations.

3.4.1.1 Salinity and temperature limitations in the black oil modelling

Salinity exerts a considerable influence on the density and viscosity of the formation brine, and on the solubility of CO₂ in it. In the BSF, elevated salinity levels ranging between 130,000 and 300,000 ppm have been documented (Bentham, 2006; Gibson-Poole et al., 2024; Ketter, 1991; Ritchie and Pratsides, 1993; Smith et al., 2011; Warren and Smalley, 1994). Increased salinity diminishes the solubility of CO₂, thereby reducing its capacity for dissolution. Furthermore, salinity gradients can give rise to complex fluid flow dynamics, including convective mixing and salt precipitation, which may subsequently impact both injectivity and long-term migration. It is crucial for numerical modelling to consider these variables to avoid overestimating storage efficiency and underestimating risks associated with caprock integrity and CO₂ migration.

As observed in the BSF discoveries and studies (Bifani, 1986; Gibson-Poole et al., 2024; Ketter, 1991; Ritchie and Pratsides, 1993), reservoir temperatures generally vary from 55°C to 70°C. These temperature variations profoundly impact CO₂ phase behaviour, influencing its mobility and interactions with the formation brine. Additionally, the geothermal gradient in the larger Silverpit Basin is noted to be between 25–35°C/km (Gammer et al., 2011; Hollinsworth et al., 2022; James et al., 2016; Noy et al., 2012; Patruno et al., 2024; Smith et al., 2011), emphasizing the thermal diversity in the region while also taking into consideration the depth variations of the reservoir. It is crucial to thoroughly factor in these thermal influences in numerical models to guarantee precise predictions of CO₂ behaviour under reservoir conditions.

Temperature and salinity influence the density and viscosity of CO₂, affecting its state as a gas, liquid, or supercritical fluid at different pressures. Black oil models, which depend on constant PVT properties, simulate these transitions with reduced accuracy especially in reservoirs with significant expansion therefore presenting high fluctuations in temperature and salinity gradient. This limitation can lead to uncertainties in plume migration estimation and pressure distribution over a long period. Due to limited information and the need to reduce simulation runtime (Hassanzadeh et al., 2008), in this study a black-oil model has been used, recognising the limitations of not being able to model a non-isothermal system or a system with salinity gradients, in order to simplify

the simulations and enable them to be completed for this large volume model in a reasonable timeframe.

To address these limitations in the calculations, enhanced modelling approaches are recommended for future studies. These include the use of Equation of State (EOS)-based compositional models, which can more accurately simulate the effects of salinity and temperature on CO₂-brine interactions. Calibration with site-specific data, such as brine composition and thermal gradients, is essential to improve the reliability of simulation outputs. Additionally, sensitivity analyses should be conducted to quantify the impact of salinity and temperature uncertainties on key performance metrics, including injectivity and storage efficiency.

In summary, while black oil models provide a practical starting point for CO₂ flow simulation, their limitations in handling salinity and temperature variations necessitate careful adaptation and calibration. Incorporating these factors is crucial to ensure accurate more predictions of CO₂ behaviour and risk assessment in the BSF.

3.4.2 Simulation Settings

3.4.2.1 PVT, Relative Permeability and Properties Section

The accurate representation of pressure-volume-temperature (PVT) properties and relative permeability is critical in numerical modelling of CO₂ storage, as these parameters govern the interactions between CO₂, brine, and reservoir rock (Bachu, 2015; Juanes et al., 2006; Mathias et al., 2013a; Pruess et al., 2003). CO₂ behaviour within the BSF is highly sensitive to reservoir pressure and temperature conditions due to its lateral and vertical extent. At depths exceeding 800 m, CO₂ transitions into a supercritical state, significantly increasing its density and reducing its viscosity (Benson and Cook, 2005). These properties influence the mobility of CO₂ and its interaction with the formation brine. Accurate modelling requires detailed PVT data calibrated to the specific geothermal and pressure regimes of the BSF.

Another key parameter is rock compressibility. This is a fundamental parameter influencing the response of a reservoir to CO₂ injection. It describes the ability of the

reservoir rock to deform under stress, which impacts pressure buildup, fluid flow, and storage capacity. Understanding rock compressibility is critical to predicting injection performance and ensuring the structural integrity of the storage site. Rock compressibility (C_r) quantifies the change in pore volume as a function of pressure. It is expressed mathematically (SLB, 2023) as:

$$C_r = \left(\frac{dV}{dP} \right) / V_p$$

where V_p is the pore volume, and dV and dP are the changes in pore volume and pressure, respectively. Rock compressibility quantifies the change in pore volume as a function of pressure. In CO₂ storage operations, compressibility influences pressure dynamics, storage efficiency, and reservoir integrity. High compressibility accommodates pressure changes, reducing the risk of caprock failure, but may lead to deformation in less consolidated zones. Conversely, low compressibility can exacerbate pressure buildup, particularly in faulted or compartmentalized reservoirs. Well-cemented zones exhibit lower compressibility, while halite-cemented intervals may act as semi-rigid barriers. Previous studies applied compressibility of about $5.6 \times 10^{-5} \text{ bar}^{-1}$ (e.g. Williams et al., 2013).

In this study, physical parameters such as PVT and relative permeability (Fig. 3.16) obtained from James et al. (2016), were utilized to establish the simulations. Similarly, rock compressibility and density value (James et al., 2016) were applied. This study reports of a rock compressibility of $55.679 \times 10^{-6} \text{ bar}^{-1}$ and density at surface conditions for brine and CO₂ of 1152.2 kg m^{-3} and 1.8678 kg m^{-3} , respectively.

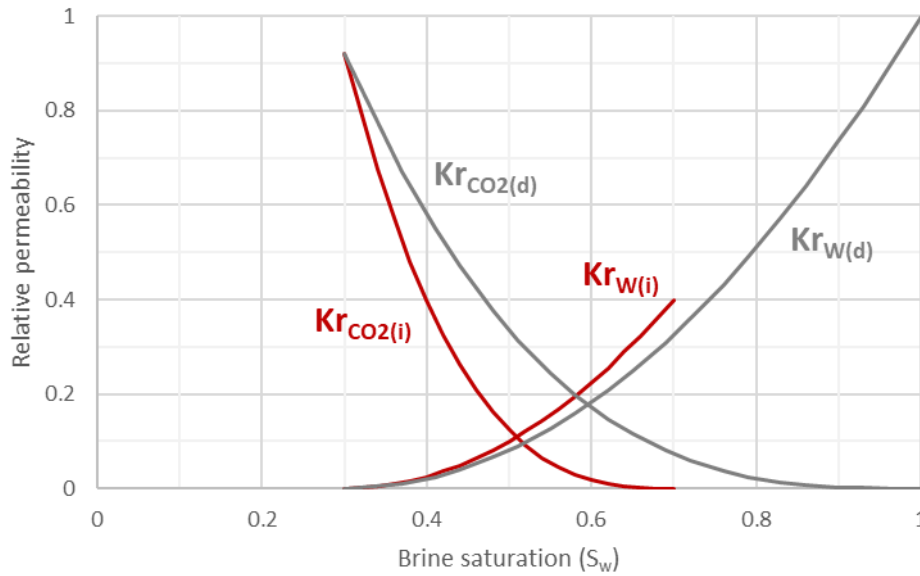


Fig. 3.16 Saturation curves from (James et al., 2016). Drainage (d, grey curves) and imbibition (i, red curves) relative permeability curves for water (Kr_w) and CO₂ (Kr_{CO_2}).

3.4.2.2 Reservoir Pressure

Advancements in numerical simulations for CO₂ storage demand a precise definition of reservoir pressure, crucial for injectivity, containment, and storage viability. Accurate characterization of reservoir pressure is essential for predicting pressure build-up and evaluating injectivity, key for safe and efficient injection strategies. Effective reservoir pressure management is vital for successful CO₂ storage. For the BSF, this requires an integrated approach combining advanced numerical modelling with a thorough assessment of geological uncertainties.

It has been observed that the BSF reservoir is primarily characterized by hydrostatic pressure (Noy et al., 2012), with gradients typically ranging from 100.7 to 104 bar/km (0.46 psi/ft) (Noy et al., 2012; Williams et al., 2013). Fracture pressure, which delineates the maximum permissible pressure prior to jeopardizing caprock integrity, is generally estimated at 75% of the lithostatic pressure, corresponding to 215 to 225 bar/km (Noy et al., 2012). These parameters serve as operational constraints that guide the design and implementation of CO₂ injection strategies. Numerical models play an essential role in

simulating pressure dynamics, analysing the effects of injection rates, and assessing how reservoir characteristics and boundary conditions influence pressure distribution.

In this study, the reservoir has been modelled as hydrostatically pressured for the sake of simplicity (Noy, 2012). Data obtained from leak-off tests and measurements of formation fluid pressure (Noy, 2012; Williams, 2014; Patruno, 2024) indicate that reservoir pressure generally aligns with or slightly exceeds the hydrostatic gradient, thereby providing a foundation for the base-case model. Furthermore, a plasticity fault failure gradient of 0.592 psi/ft, as reported by Williams et al. (2014), is applied as a scenario denoting upper-case conditions, reflecting situations indicative of overpressure within the BSF aquifer. Elevated pressure gradients may run the risk of critical pressure thresholds being exceeded, consequently diminishing injectivity and increasing the risk of caprock failure.

3.4.2.3 Boundary Conditions

Boundary conditions significantly influence the dynamics of CO₂ injection and storage in geological formations (Bergmo et al., 2011; Birkholzer et al., 2009; Birkholzer and Zhou, 2009; Nicot, 2008; Williams et al., 2013). An accurate definition of reservoir boundaries is fundamental to ensuring reliable numerical simulation and effective operational planning. Boundary conditions are typically categorized as closed, open, or semi-open. Closed boundaries represent impermeable conditions (i.e. no transmissibility) where fluid or pressure transfer is restricted both vertically and laterally, as seen in reservoirs sealed by faults, halite layers, or other compartmentalizing structures. Open boundaries allow fluid and pressure exchange (i.e. transmissibility) with adjacent formations, simulating regional aquifer connectivity. Semi-open boundaries exhibit partial communication, influenced by features such as semi-permeable faults or heterogeneous caprocks, or the non-transmissibility of only specific edges in the model. Therefore, the selection of boundary conditions has significant implications.

Observations from previous studies (e.g., Williams et al., 2013) demonstrate that closed boundaries lead to higher pressure build-up, reducing injectivity and increasing risk of caprock failure. Conversely, open boundaries facilitate pressure dissipation, improving injectivity but possibly increasing lateral plume migration. Semi-open boundaries result

in mixed behaviours, necessitating careful modelling to predict their impacts accurately. These conditions not only govern fluid flow and pressure dynamics but also determine the overall storage capacity of the reservoir, with potential implications for regulatory decisions making on large-scale activities (Birkholzer and Zhou, 2009). The hydrogeologic responses of both the near-field and far-field aquifer can be significantly affected by interference between multiple storage sites, underscoring the need for detailed boundary characterization and management.

In the Silverpit Basin, the BSF exhibits a diverse range of boundary conditions due to its geological complexity. Structural features such as faults (e.g. Fig. 3.6 and Fig. 3.10) and salt walls often result in compartmentalized behaviour (Mears et al., 2025), while lateral connectivity varies across the formation depending on depositional setting and permeability changes (Ambrose et al., 2008; Chadwick et al., 2004; Gershenzon et al., 2015). Vertical sealing is primarily ensured by low-permeability overlying layers such as shale, anhydrite, and halite, like those present within the Haisborough Gp (Fig. 3.6), which restrict upward migration of CO₂ and brine. Lateral transmissibility depends on aquifer connectivity and structural features, which facilitate fluid and pressure migration. Incorporating these geological characteristics into numerical models is essential for simulating realistic pressure and flow dynamics and evaluating the effects of boundary conditions.

This study focused on reservoir transmissibility to the seabed subcrop (R.2), to the northwestern region (R.9)(Fig. 3.11), and to lateral edges of the model, evaluating the effects of both transmissible and impermeable conditions. Additional connected pore volume was simulated by applying a pore volume multiplier of 1×10^7 to R.2 (Fig. 3.14) and of 500 to R.9. The R.2 multiplier was implemented to simulate the substantial volume present in the North Sea, while the R.9 multiplier attempt to approximate the estimated volume of the northwestern region. Additionally, the limitations in reconstructing the northwestern portion of the reservoir (i.e., R.9; Fig. 3.14) and aquifer bounding features, were addressed by conducting a sensitivity extending transmissibility across all lateral edges of the model to account for uncertainties in the representation of bounding structural features such as faults, salt walls, and erosional truncations. The characterization of transmissibility in these areas remains challenging.

Sensitivity analyses (Tab. 3.2) were conducted to compare scenarios with closed (CLOSED), semi-open (1 OPEN, 2 OPEN), and open (2 OPEN FULL) boundaries. In the CLOSED scenario, the reservoir had no transmissible boundary. The 1 OPEN scenario considered transmissibility at either the seabed subcrop (Region 2) or the northwestern region (Region 9). The 2 OPEN scenario allowed transmissibility at both Regions 2 and 9, while the 2 OPEN FULL scenario extended transmissibility to all lateral edges of the model. The base case model (De Luca et al., 2025) was employed for these evaluations, while the homogeneous, heterogeneous, and secondary grid were consistently run with transmissibility at both regions.

These analyses provide critical insights into how boundary conditions influence CO₂ storage performance and safety in the BSF. Effectively addressing boundary conditions is essential for optimizing storage operations and ensuring the reliability of CO₂ containment frameworks.

3.4.3 Injection Strategy

Effective placement of injection wells is critical for optimizing CO₂ injectivity and ensuring efficient utilization of reservoir capacity in geological CO₂ storage operations (Michael et al., 2010; Noy et al., 2012; Williams et al., 2013; Zhou et al., 2010). The spatial arrangement of wells must account for geological heterogeneities, reservoir pressure limitations, and operational constraints, ensuring the sustainability and safety of storage operations. The spatial arrangement of wells significantly influences pressure management and storage efficiency. Maintaining a minimum distance between injection sites is essential to mitigate pressure buildup and prevent overlapping pressure zones (Zhou et al., 2010). This spacing ensures even distribution of injected CO₂, reducing the risk of seal breach or caprock failure due to excessive pressure. The number of injection wells required for a storage project depends on several factors, including reservoir permeability, target injection rates, and economic considerations. Average injection rates for commercial-scale operations are estimated at 1–2 Mt/yr per well in the North Sea (Bentham et al., 2017; Chadwick, 2013; Hosa et al., 2011; Mathias et al., 2013b). Recent plans for the Endurance site propose an injection rate of 4 Mt/yr distributed across five

wells starting in 2027 (BP, 2023; Gibson-Poole et al., 2024), supporting studies indicating the feasibility of higher injection rates (Agada et al., 2017; Noy et al., 2012; Williams et al., 2013).

The base-case scenario of this study involves 14 vertical injection wells distributed across six licenses in the BSF (Fig. 3.1 and Fig. 3.15). Each well is modelled to inject 1 Mt/yr over a 50-year operational timeframe, with a maximum of two wells deployed at larger sites (e.g. Endurance, Bunter 36). To assess the response of the aquifer to higher injection rates (Agada et al., 2017; Noy et al., 2012; Williams et al., 2013), an alternative simulation with 42 wells (Scenario No. 6; Fig. 3.17) was developed, evaluating the behaviour of the aquifer under regional stress conditions. Injection is assumed to commence simultaneously across all sites in these simulations. Kolster et al. (2018) demonstrated that injection timing has minimal impact on overall injectivity; instead, reservoir depth and permeability are the primary determinants. Phased deployment of injection sites, aligned with evolving storage demands, is a feasible strategy. This approach reduces upfront infrastructure costs and ensures a gradual ramp-up of operational capacity.

To maximize containment efficiency and enhance structural trapping, wells were strategically placed along the flanks of BSF domes, minimizing the risk of lateral migration and caprock weakening (Williams et al., 2013). In addition to the constrain defined by the injection rate, injection operations were constrained by a bottom-hole pressure limit set at 75% of the lithostatic pressure gradient, which is estimated at 225 bar/km, from leak-off test data (Agada et al., 2017; Kolster et al., 2018; Noy et al., 2012). This conservative pressure threshold prevents caprock fracturing and ensures long-term reservoir integrity. Automated systems dynamically adjust injection rates in response to reservoir pressure fluctuations, optimizing performance while maintaining safety. Injection intervals were restricted to the 4th–20th modelled layers, thereby reducing stress on the caprock. This strategy leverages geological knowledge to maximize injection efficiency while mitigating potential risks. Local geological heterogeneities, including halite cementation and lateral facies changes, present challenges to injectivity and storage capacity. Due to the limitations of the grid resolution proposed in this study, which cannot capture these fine-scale details, site-specific analyses are recommended to define optimal

injection intervals. These tailored assessments are essential to address these complexities and ensure the effectiveness of CO₂ storage operations in the BSF.

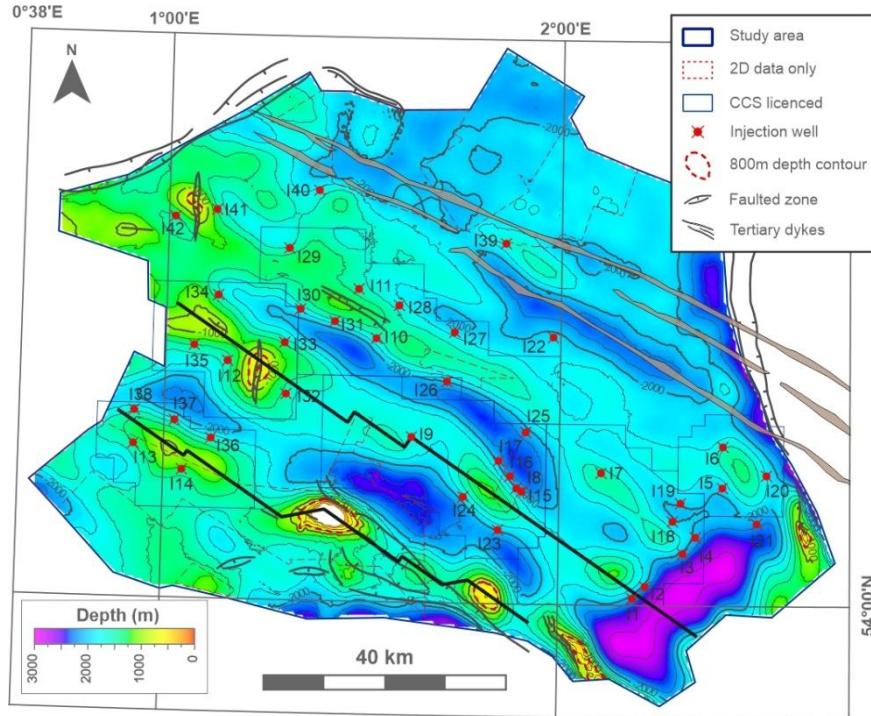


Fig. 3.17 Alternative injection strategy for scenario No.6 (see Tab. 3.2), threefold increase compared to the base case. Black lines indicate location of the pressure profile shown in Fig. 3.27 (rightmost profile) and Fig. 3.28 (leftmost profile), respectively.

3.4.4 Simulation Scenarios

The fifteen simulation scenarios (Tab. 3.2) were categorized based on the sensitivity investigations addressed in this study. A concise description of each scenario is provided below.

Scenario 1: A simple homogeneous model using Grid 1 (Equation 1), and porosity and permeability median values (Tab. 3.1), was developed as a baseline for comparison with the reference scenario. The reference case employs a normal distribution algorithm to distribute petrophysical values. This model features transmissibility in two regions: Region 2 and Region 9.

Scenario 2: A confined aquifer model (i.e., no transmissibility at the boundaries) based on Grid 1, with the base-case petrophysical model (De Luca et al., 2025). This model uses the Sequential Gaussian Simulation (SGS) algorithm to normally distribute the median porosity. Horizontal permeability is defined as a function of porosity (Fig. 3.12).

Scenario 3: An open aquifer model using Grid 1, with transmissibility restricted to the seabed subcrop (R.2). The base-case petrophysical model is applied.

Scenario 4: An open aquifer model using Grid 1, with transmissibility restricted to the northwestern boundary (R.9). The base-case petrophysical model is applied.

Scenario 5: The reference case, utilizing Grid 1 and the base-case petrophysical model, with transmissibility applied to both R.2 and R.9.

Scenario 6: The reference model simulating high-intensity injection activity with 42 injector wells.

Scenario 7: The reference model with reservoir pressure increased to 0.592 psi/ft (Patruno et al., 2024), simulating overpressure conditions of the aquifer.

Scenario 8: The reference model augmented with 17 leaky wells. Leakage is simulated by assigning a permeability value of 0.001 mD along these wells.

Scenario 9: Transmissibility is simulated along the lateral edge of the reservoir, extending R.9 to encompass the entire reservoir.

Scenario 10: The reference model is used to investigate the sensitivity of available pore space in the northwestern margin, where seismic data coverage is lacking. A pore volume multiplier of 100 is applied to R.9 to estimate its impact.

Scenario 11: Building on Scenario 10, the pore volume multiplier is increased to 1000 to evaluate the effect of a significantly larger available pore space.

Scenario 12: A heterogeneous model based on Grid 1, with a long variogram correlation length (5 km in the X direction), and transmissibility applied to both R.2 and R.9.

Scenario 13: A heterogeneous model based on Grid 1, with a medium variogram correlation length (2.5 km in the X direction), and transmissibility applied to both R.2 and R.9.

Scenario 14: A heterogeneous model based on Grid 1, with a short variogram correlation length (1 km in the X direction), and transmissibility applied to both R.2 and R.9.

Scenario 15: A sensitivity scenario addressing structural uncertainties using Grid 2, with transmissibility applied to both R.2 and R.9. This model evaluates the effects of different velocity model realizations on structural configuration.

These scenarios address key variables influencing the short- and long-term behaviour of CO₂ storage, including geological heterogeneities, operational constraints, boundary conditions, and pressure management strategies. By integrating static and dynamic modelling approaches, the simulations provide advanced insights into the feasibility, risks, and optimization opportunities for large-scale CO₂ storage projects in the BSF.

3.5 Simulation Results

This section presents the findings from the reservoir simulation study, focusing on CO₂ saturation, injectivity, and pressure evolution under various sensitivity scenarios. These results provide insights into the dynamic behaviour of the reservoir and highlight the implications of geological, structural, and operational factors for CO₂ storage.

3.5.1 CO₂ Saturation in the Storage Reservoir

The spatial and temporal evolution of CO₂ saturation within the reservoir is a critical metric for understanding plume dynamics and storage efficiency. The reference case scenario (Fig. 3.18) illustrates the behaviour of CO₂ injection and post-injection processes over a 5,050-year simulation timeframe. CO₂ saturation at the top of the reservoir serves as a key indicator, tracking lateral and vertical plume migration.

At the time of Cessation of Injection (COI – i.e. 50 years after the start of injection, SOI), CO₂ plumes extend approximately 5 km from the injection points, exhibiting a roughly

radial pattern. Minor deviations arise due to local petrophysical variations. Within 500 years after COI, the plume stabilises beneath structural traps, with high CO₂ saturation in this area. The leading edge of the plume migrates towards topographic highs, while the trailing edge is constrained by low-permeability zones and residual trapping processes, progressing more slowly over millennia (Fig. 3.18). Migration beyond the license area remains negligible, ensuring containment.

Sensitivity simulations (Fig. 3.19a-o) reveal consistent plume behaviour across homogeneous, heterogeneous, and structural sensitivity scenarios. However, heterogeneous reservoir models (Fig. 3.19g, h, j) exhibit greater plume anisotropy due to preferential migration paths introduced by petrophysical variability. These heterogeneities particularly affect the leading edge of the plume, where low permeability zones act as barriers restricting plume advance.

In the overpressure scenario (Fig. 3.19o), the reduced injectivity leads to a more constrained diffusion pattern, with CO₂ concentrated near the injection points. Similarly, in the scenario with 42 injection wells (Fig. 3.19p), plume geometry reflects increased injection volumes, with plume spread more evenly distributed in areas where structural trap is not well shaped (e.g. wells I19, I22; Supplementary Fig. S3.10; Fig. S3.11).

Post-COI, migration towards structural highs is observed in all scenarios, with CO₂ securely accumulating beneath domal traps by 100 years after COI (Supplementary Fig. S3.10) and for the remaining simulation runtime (Supplementary Fig. S3.11). Across all scenarios, variations in plume extent are minimal, generally less than 1 km, attributable to grid resolution differences.

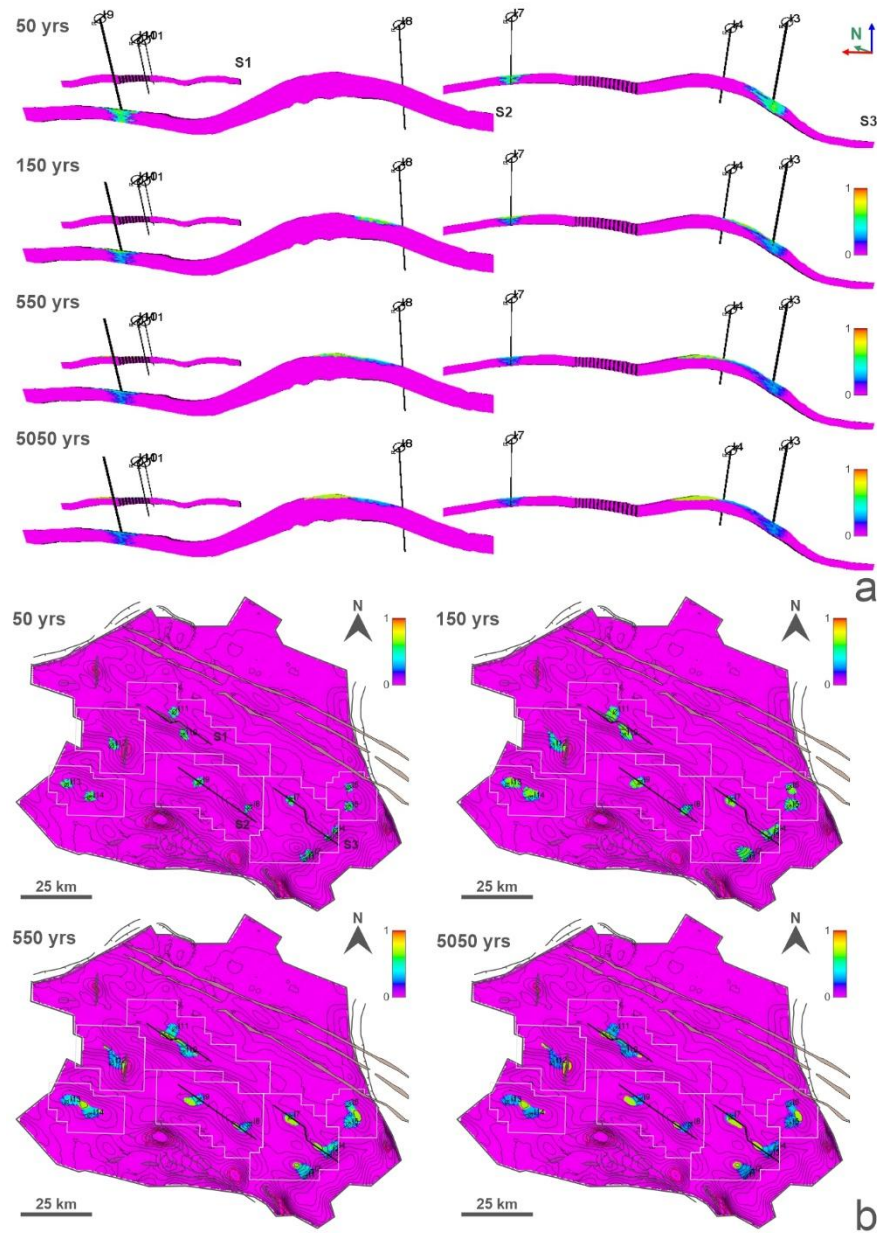


Fig. 3.18 Simulation results for CO₂ saturation of the reference scenario. Dates indicate ages after the start of injection (SOI). White polygons indicate awarded CO₂ storage licenses. Depth contour lines from base case model. Section view (a) location is indicated by the black line on the map (b). Sections have a vertical exaggeration of x3.

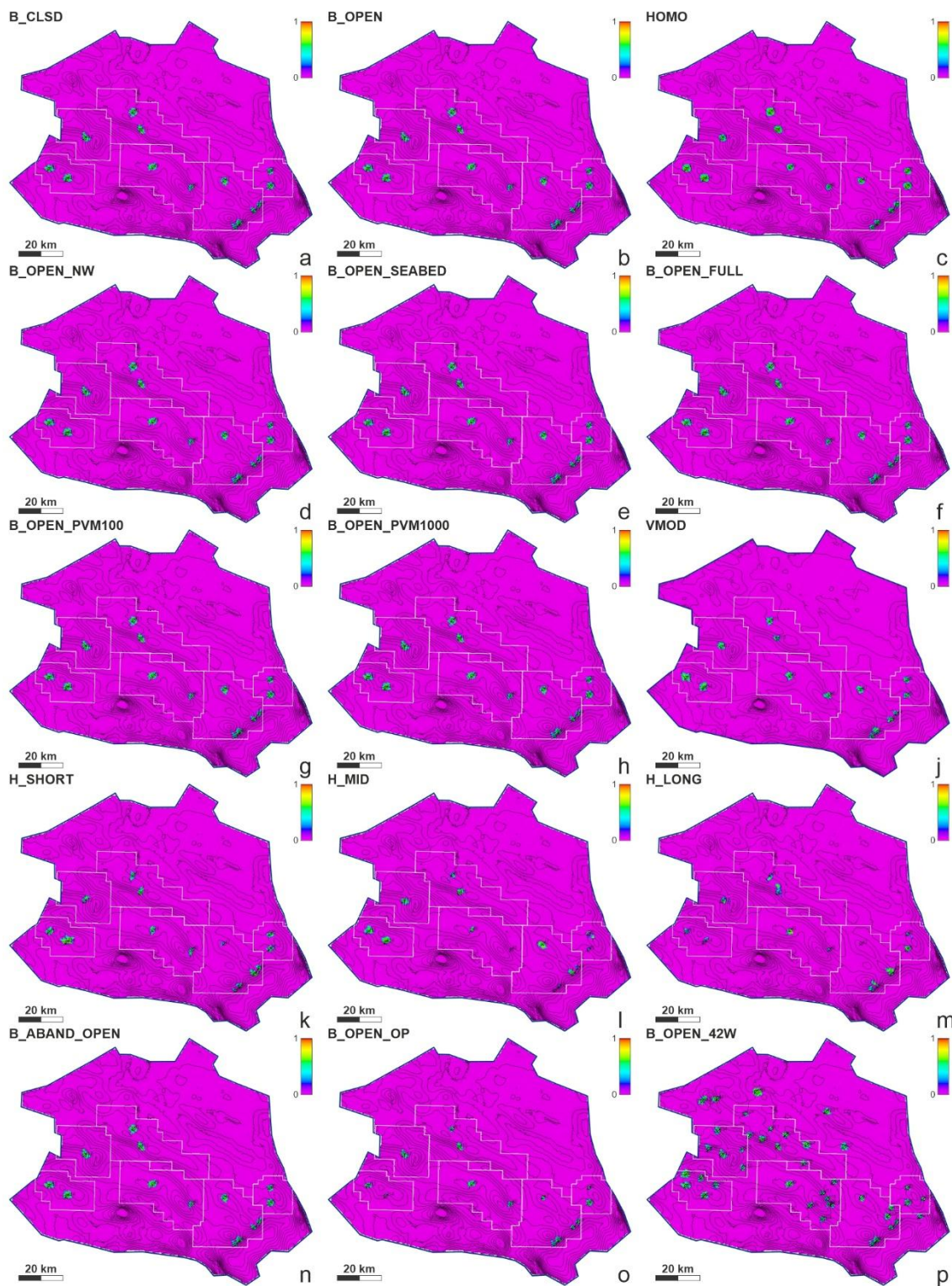


Fig. 3.19 Simulation results for CO₂ saturation, in map view, at the cessation of injection (COI). White polygons indicate awarded CO₂ storage licenses.

Injection rates for the reference model (Fig. 3.20a) remain near maximum capacity, except at well I6, where injectivity decreases near the end of the injection period. In homogeneous reservoir models (Fig. 3.20b), reduced injectivity is observed due to constrained petrophysical properties. In overpressured scenarios (Fig. 3.21a), only well I8 maintains maximum injection rates, with other wells limited by bottom-hole pressure constraints. Similarly, the scenario with 42 injection wells (Fig. 3.21b), shows reduced injectivity after 20 years, with only well I1 maintaining peak rates.

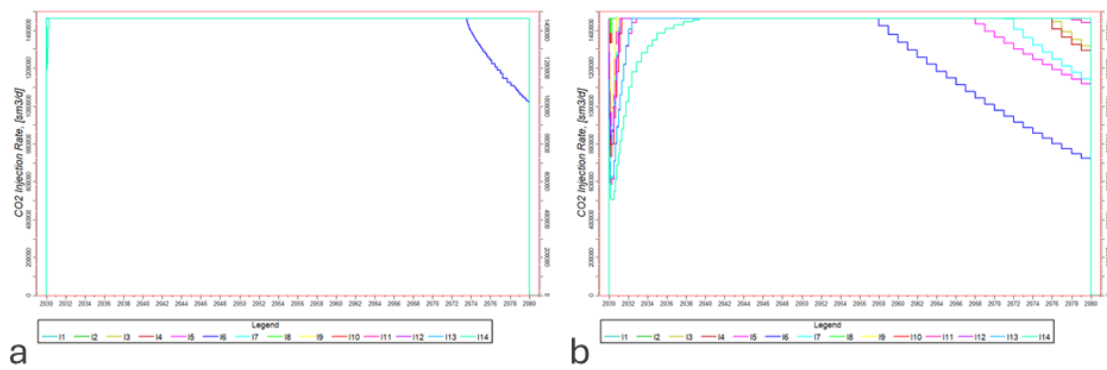


Fig. 3.20 CO₂ injection rate in sm^3/day for the (a) reference scenario and (b) homogeneous scenario.

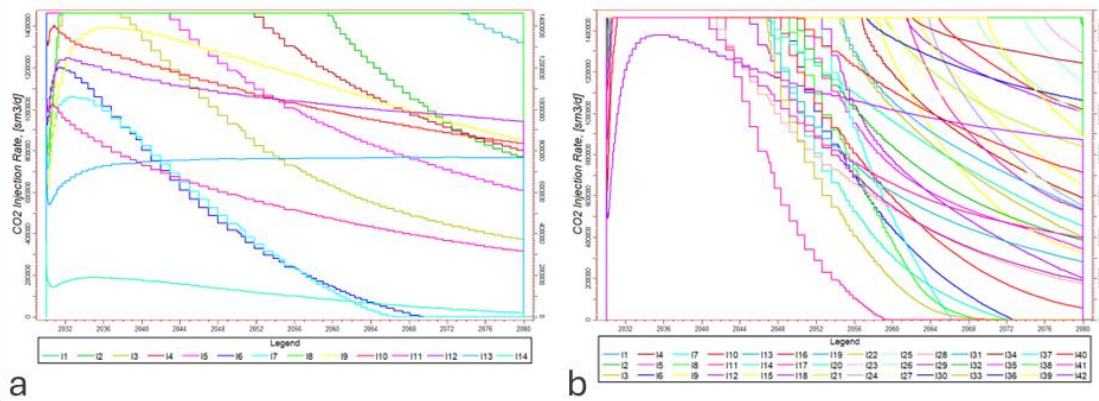


Fig. 3.21 CO₂ injection rate in sm^3/day for the (a) overpressured reservoir scenario and (b) scenario with 42 injection wells.

The total CO₂ injected (Tab. 3.3, Fig. 3.22) for the reference scenario amounts to approximately 700 Mt. Homogeneous models show a minor reduction to 685 Mt, while the overpressured scenario achieves 435 Mt. The scenario with 42 injectors doubles the total injected CO₂ to 1600 Mt, demonstrating the potential for scaling up injection infrastructure.

No.	Scenario	Brine Mass Flux (Mt)			Cumulative CO ₂ Injection Mass (Mt)
		R1 > R2	R1 > R9	R6 > R4	
1	HOMO	985.1	17.8	92.3	685
2	B_CLSD	-	-	-20.1	698
3	B_OPEN_SEABED	1056.1	-	105.9	698
4	B_OPEN_NW	-	352.1	-36.5	698
5	B_OPEN (Ref. scenario)	1028.9	10.0	101.9	698
6	B_OPEN_42W	2412.2	29.0	308.9	1667
7	B_OPEN_OP	577.9	4.8	47.4	437
8	B_ABAND	1027.6	9.9	101.8	698
9	B_OPEN_FULL	828.5	169.7	79.8	699
10	B_OPEN_PVM100	1053.5	-0.1	105.6	698
11	B_OPEN_PVM1000	967.6	45.3	92.3	698
12	H_LONG	1055.5	-0.7	84.4	699
13	H_MID	1039.3	0.9	118.0	699
14	H_SHORT	1032.1	2.1	115.7	698
15	VMOD	956.2	33.7	114.0	698

Tab. 3.3 Cumulative CO₂ injected and brine mass flux between regions in millions of tons at the end of the simulation. R1 indicate the reservoir, R2 refers to the BSF seabed subcrop, R9 represents the sensitivity toward the northwestern region, R6 corresponds to CS020 while R4 is CS006.

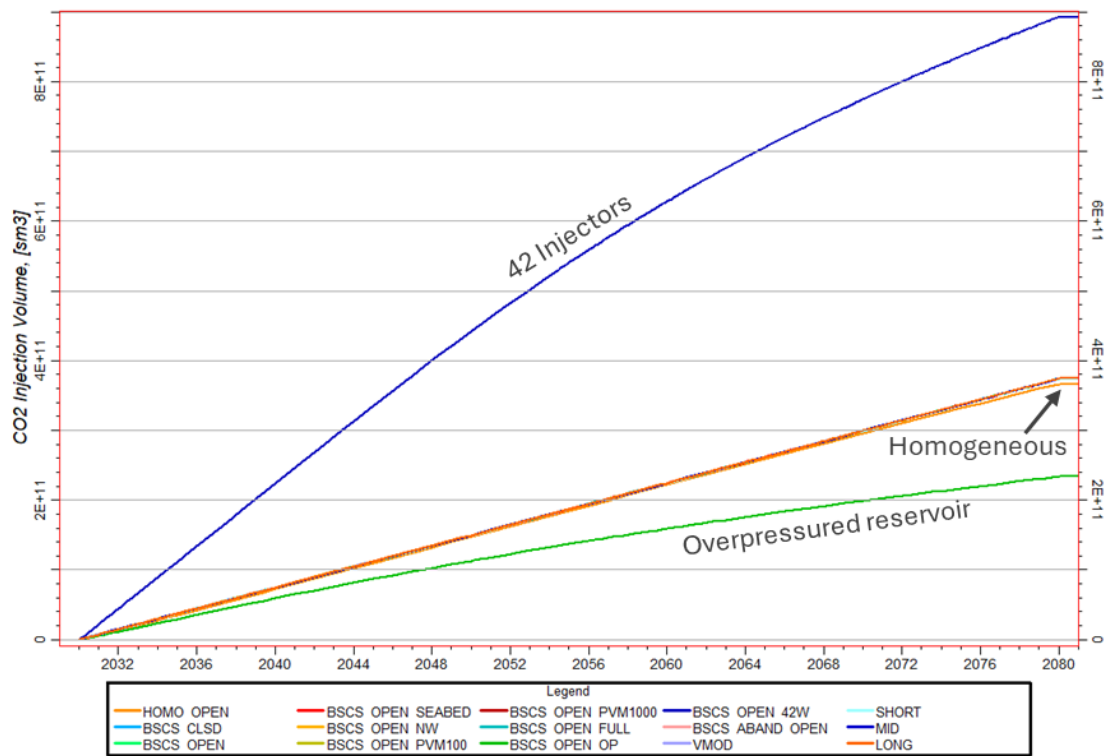


Fig. 3.22 Cumulative CO₂ injection volume over time for each simulation scenario Tab. 3.2. Total injection in using the base case model lies on the same line at approximately 3.73×10^{11} sm³. (corresponding to approximately 700 Mt).

3.5.2 Pressure Evolution

Pressure dynamics exhibit more pronounced variation between scenarios compared to CO₂ saturation, particularly in response to boundary conditions and reservoir properties. Fig. 3.23 illustrates pressure increases 25 years after SOI. The pressure front extends approximately 10–20 km from injection points, with near-well pressure increases of 30–40 bar in the western region (wells I8–I14) and 50–60 bar in the deeper southeastern reservoir (wells I1–I6). The scenario with 42 injection wells (Fig. 3.23p) exhibits the highest-pressure buildup, with near-well increases of 80–90 bar.

Boundary conditions significantly influence pressure behaviour. In the confined reservoir scenario (Fig. 3.23a), pressure fronts extend to the NW boundary, with increases of 20–30 bar. By contrast, semi-open boundaries (Fig. 3.23b) facilitate pressure dissipation, reducing the extent of pressure buildup at the edge. Similar effects are observed in

scenarios with seabed subcrop transmissibility, as illustrated by comparisons between boundary condition sensitivities (Fig. 3.23d, e, g, h).

Petrophysical anisotropies further shape the pressure front. Short correlation lengths (1 km; Fig. 3.23k) result in sharper, more confined pressure fronts, while longer anisotropy ranges (2.5 and 5 km; Fig. 3.23l, m) produce smoother, more extensive pressure diffusion over 20 km larger. These effects are particularly notable in the northeastern region of the model.

After 50 years of injection, pressure fronts reach the model boundaries in all scenarios except the extended pore space scenario (Fig. 3.23f), where additional pore volume limits pressure propagation. The overpressured scenario (Fig. 3.23o) shows a similar diffusion pattern due to reduced injectivity. In the 42-well scenario (Fig. 3.23m), pressures reach 90–100 bar near injection sites (Fig. 3.24p).

Following COI, pressure redistribution occurs across all scenarios (Fig. 3.25). In closed-boundary models (Fig. 3.25a), pressure stabilises at approximately 30 bar after 500 years, with no significant dissipation beyond this period (Supplementary Fig. S3.13a). By contrast, models with transmissible boundaries enable gradual pressure release, returning to near-initial conditions within 5,000 years (Supplementary Fig. S3.12; Fig. S3.13).

Seabed transmissibility facilitates the displacement of formation water, with approximately an average between the various scenario of 1,000 Mt of brine expelled to the seabed during the simulation (Fig. 3.26; Tab. 3.3). This process continues as long as regional reservoir pressures exceed initial levels, though none of the scenarios return to baseline conditions by the end of the simulation.

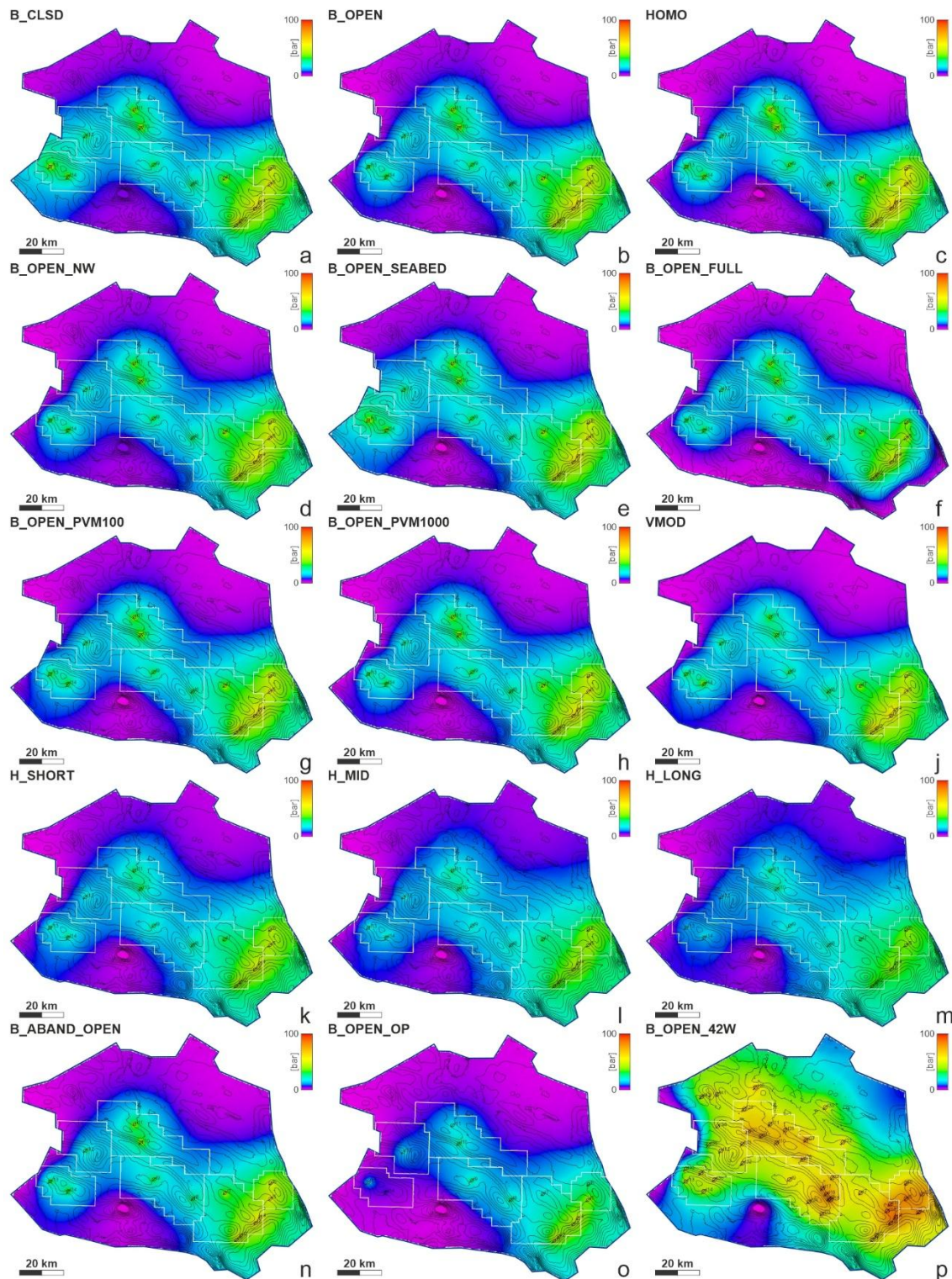


Fig. 3.23 Reservoir pressure increase compared to the initial pressure after 25 years from SOI for each simulation scenarios. White polygons indicate awarded CO2 storage licenses.

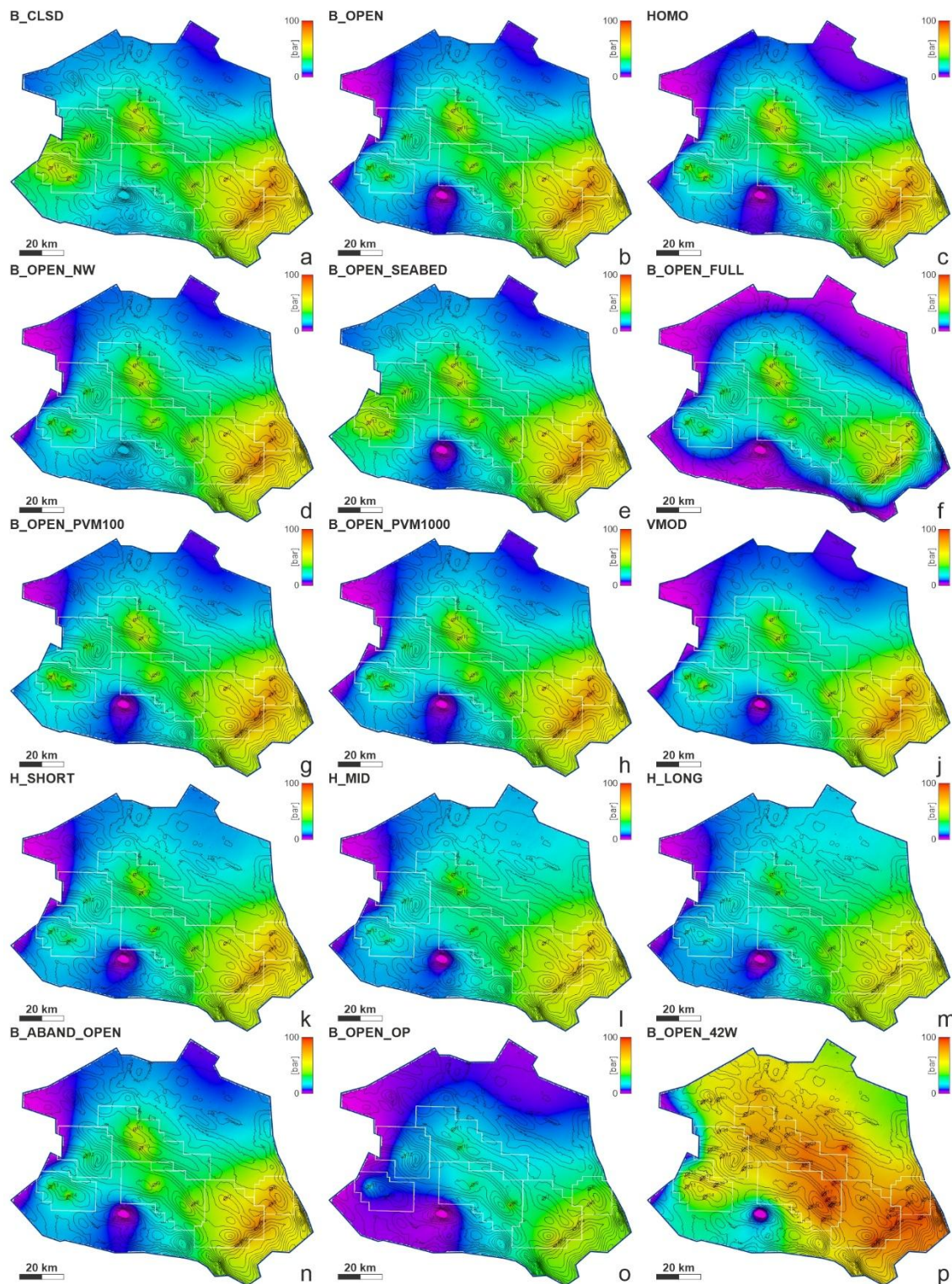


Fig. 3.24 Reservoir pressure increase compared to the initial pressure at COI for each simulation scenarios. White polygons indicate awarded CO₂ storage licenses.

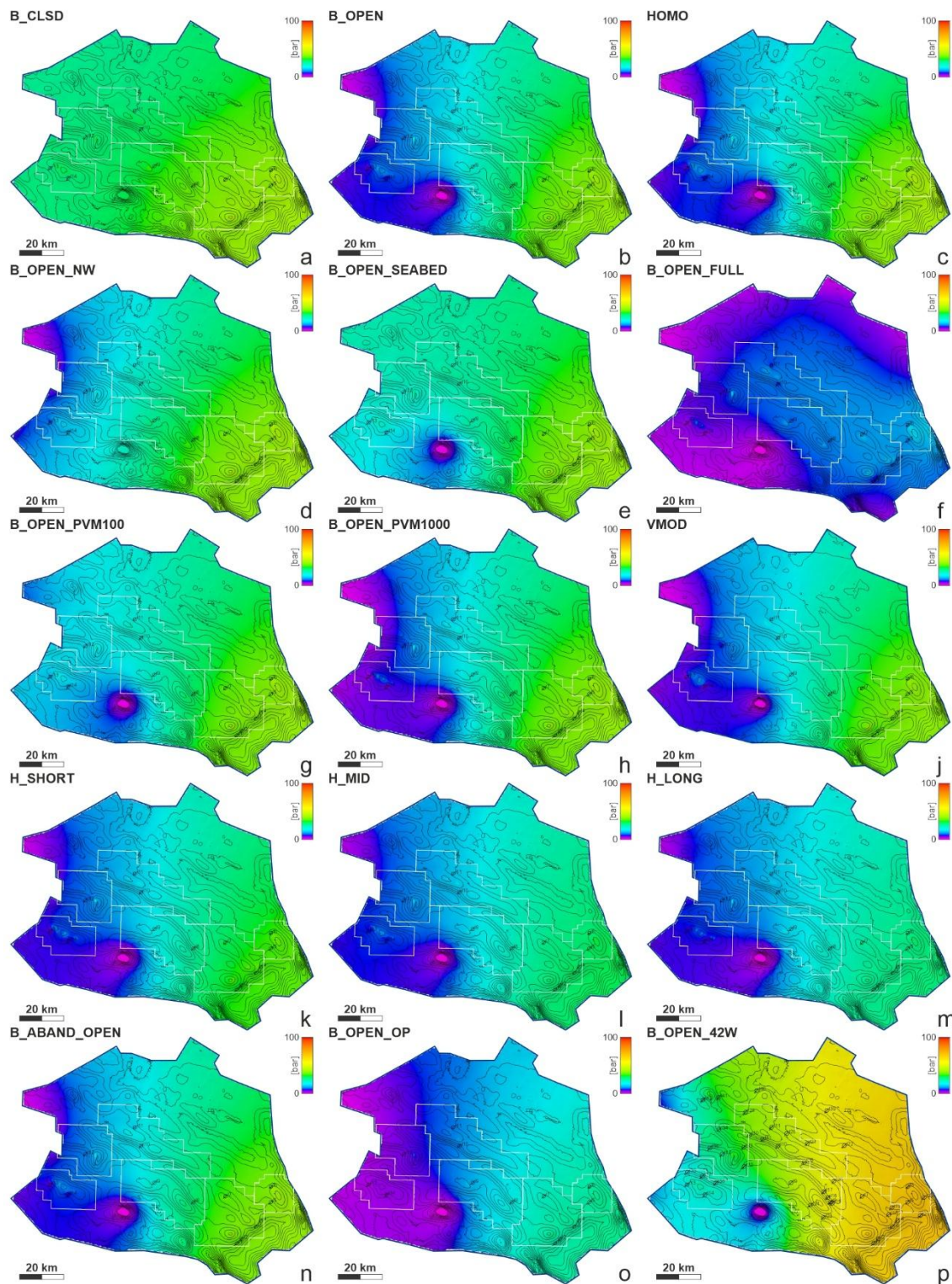


Fig. 3.25 Reservoir pressure increase compared to the initial pressure after 100 years from COI for each simulation scenarios. White polygons indicate awarded CO₂ storage licenses.

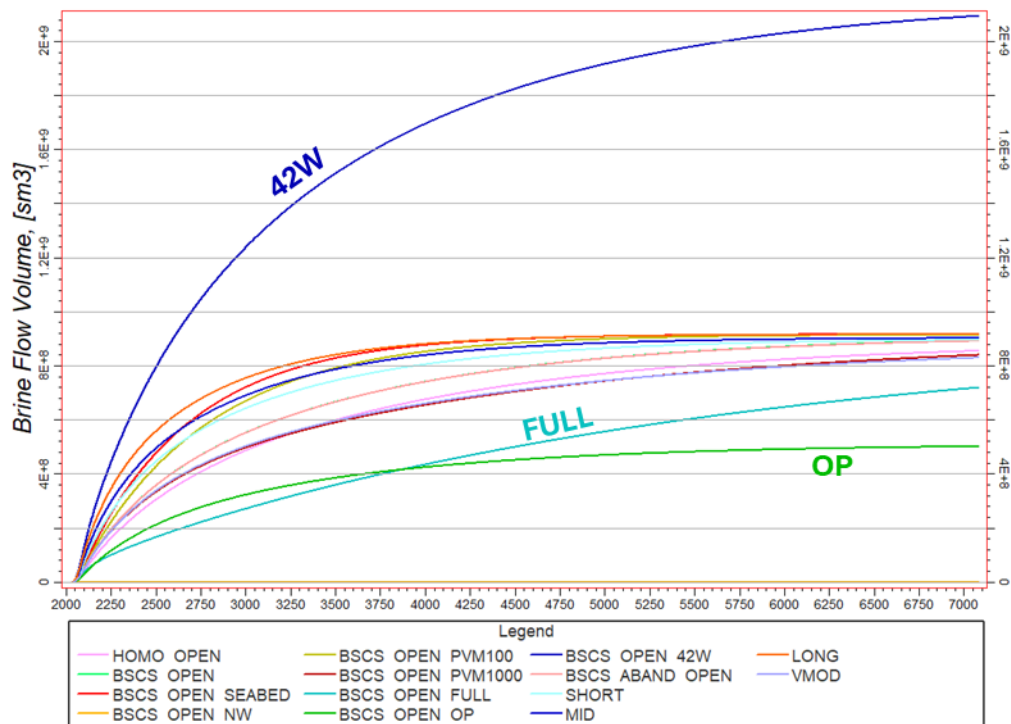


Fig. 3.26 Cumulative brine flow displaced at the BSF seabed subcrop (i.e. inter-region flow, from R.1 to R.2).

3.6 Discussion

The large-scale deployment of CO₂ storage requires a thorough understanding of reservoir behaviour under prolonged injection conditions. The numerical simulation conducted in this study investigated aquifer responses to multiple CO₂ injection activities at a rate of 1 Mt/yr per well over a 50-year period. The key focus was on reservoir injectivity, long-term plume migration, and pressure evolution, considering the impact of geological heterogeneities and inter-regional flow. This discussion explores the influence of these factors on the long-term stability and capacity of large-scale reservoirs, with particular attention to the role of boundary conditions in controlling pressure dynamics within the system.

3.6.1 Pressure Diffusion Effects

Reservoir pressure plays a critical role in the success and safety of CO₂ storage operations (Birkholzer et al., 2009; Birkholzer and Zhou, 2009). In the BSF, pressure management is crucial for assessing storage capacity, maintaining caprock integrity, and mitigating risks associated with overpressure and induced fault reactivation. Pressure increases during injection can exceed critical thresholds, particularly in geologically stressed regions. Without mitigation measures—such as brine production or optimised well placement—caprock fracture risk becomes significant (Agada et al., 2017; Birkholzer et al., 2009; Birkholzer and Zhou, 2009; Buscheck et al., 2012; Kolster et al., 2018; Zhou et al., 2010). Fault reactivation due to pressure changes presents additional risk (Cappa and Rutqvist, 2011a, 2011b; Rutqvist, 2012; Streit and Hillis, 2004; Williams et al., 2016). Faults formed at the crest of the anticline during salt tectonics may be reactivated if pressures exceed their mechanical stability, potentially creating CO₂ leakage pathways. This underscores the necessity of incorporating detailed geomechanical modelling and site-specific fault assessments in future studies before injection operations (Bentham et al., 2013; Williams et al., 2013).

Simulation results indicate that the pressure front extends tens of kilometres from the injection site during the operational phase (Fig. 3.23, Fig. 3.24). The greatest pressure increases, exceeding 50 bar, occur where injectors reach greater depths (Fig. 3.24).

Comparative analysis of different scenarios highlights the role of lateral transmissibility. In the confined model (Fig. 3.24a), a 30-bar pressure increase is observed at the northern boundary, which coincides with the complex fault system of the North Dogger fault zone (Fig. 3.2a). This necessitates careful evaluation of distant fault reactivation risks, as fault stability can be compromised even by minor pressure increases of 15–50 bar (Williams et al., 2016). Similarly, pressure buildup of 30–60 bar (Fig. 3.24) is observed near the southern and eastern Silverpit bounding faults and salt walls (Fig. 3.2a). Sensitivity analysis (Fig. 3.24g, h) shows that increasing the pore volume of the northwestern region by an order of magnitude (i.e., from 10^{10} to 10^{11} m³ Fig. 3.15), reduces boundary pressure by 10–20 bar, alleviating stress in that area.. These findings highlight the need for careful regional-scale assessment of saline aquifers targeted for CO₂ storage.

Comparison of different time-to-depth conversion methods (Fig. 3.24b, j) shows negligible differences in regional-scale pressure diffusion, though the greater reservoir depth in grid 2 results in lower pressure buildup at the injection site (Fig. 3.24j).

Larger lateral permeability (Fig. 3.24m) provides both advantages and risks. Such framework enables to reduce pressure build-up at the injection locations; however, the elongated permeability led to increases in far-field pressure effects. A pressure buildup of 10-15 bar is generated over 30 km from the injection sites (Fig. 3.24m). Similar effects are observed in the northwestern region comparing the reference scenario (Fig. 3.24b) with homogeneous scenario (Fig. 3.24c). The lower permeability in the homogeneous model limits pressure front expansion, mitigating impacts on the northern boundary.

Post-injection pressure redistribution is controlled by boundary conditions. The presence of a transmissible seabed subcrop facilitates continuous pressure relaxation (Fig. 3.25, Supplementary Fig. S3.12; Fig. S3.13, b-c, e-o), whereas confined aquifers allow only regional redistribution (Fig. 3.25, Supplementary Fig. S3.12; Fig. S3.13, a, d). Regional pressure dynamics are further elucidated in Fig. 3.27, where four boundary connectivity scenarios are compared. Deeper reservoir regions exhibit higher pressure buildup (e.g. wells I1 and I2 – 70 bars), while shallower regions experience lower pressure buildups (e.g. wells I12 – 35 bars). In the confined scenario (Fig. 3.27a), pressure steadily increases during the injection phase and then redistributes, achieving equilibrium 500 years post-COI at about 32-34 bar above the initial pressure. In contrast, the open scenarios (Fig. 3.27b) allows continuous pressure relaxation, reducing long-term pressure buildup near I12 by approximately 8-10 bars. Additionally, the continuous flow at the seabed subcrop facilitates ongoing aquifer pressure relaxation for centuries after COI.

Simulations isolating individual boundary connections (i.e. connectivity only NW of Endurance anticline, Fig. 3.27c; and connectivity only at seabed subcrop, Fig. 3.27d) reveal that pore space availability in the near-well area significantly reduces pressure buildup during injection period, while seabed subcrop connectivity contributes with a sustained pressure dissipation over millennia. Long-term regional pressure gradients are therefore controlled by the imposed connectivity at the boundary, driving overpressure below anticlines caused by the presence of mobile CO₂ (e.g. Fig. 3.27b, d; at 5000 yrs,

18-45-65-89 km), highlighting the importance of boundary transmissibility for large-scale CO₂ storage.

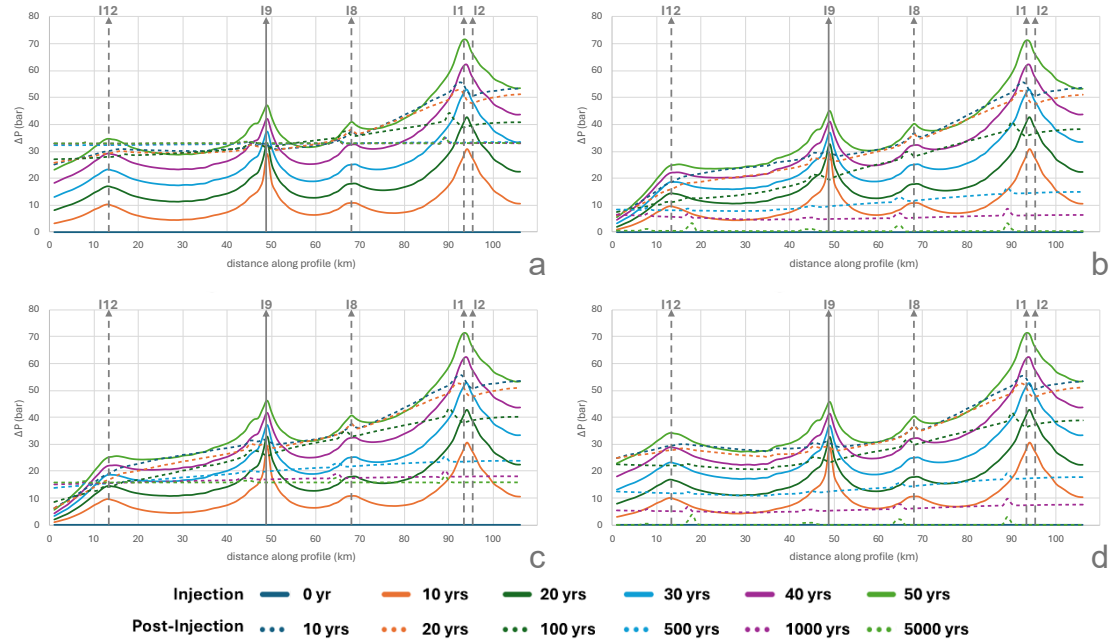


Fig. 3.27 Pressure increase along rightmost profile highlighted in Fig. 3.17 demonstrating the effects of injected CO₂ and boundary conditions under different scenarios: (a) closed boundary (i.e. no flow at boundaries), (b) two open boundaries of the reservoir (i.e. flow at the seabed subcrop and northwestern region), (c) flow connection only at the northwestern region, and (d) flow connection only at the seabed subcrop. Solid lines represent timestep during the injection period, while dotted lines indicate post-injection timestep. Vertical lines mark wells that intersect the profile (solid) or that are projected onto it (dashed).

3.6.2 Impact of Boundary Conditions: Outflows and cross-flows

The evolution of the CO₂ plume and pressure footprint strongly influences storage efficiency. It has been noted that during injection, pressure spreads rapidly, far exceeding the CO₂ plume spatial extent due to hydrodynamic forces (Bachu, 2015). Post-injection, pressure dissipates quickly at the injection point, while the CO₂ plume migrates under buoyancy forces until immobilisation by capillary and solubility trapping. Over time, dissolution reduces the plume footprint, potentially accelerated by convective mixing.

As observed, such pressure behaviour led to the development of regional pressure gradient (Fig. 3.27) mostly controlled by boundary transmissibility and variation in reservoir depth. These regional gradients impact CO₂ plume migration within the reservoir. Although limited by coarse grid resolution, simulations indicate slight plume redirection of less than 1 km. The structural configuration of the BSF, with the characteristic four-way dip closures, enhances containment efficiency and structural trapping within the Silverpit Basin. However, local geological heterogeneity can modify plume migration, particularly during injection, when viscous forces dominate, pushing CO₂ beneath low-permeability baffles that may extend beyond structural spill points.

Consequently, if a constant pressure is assumed to be maintained at the seabed subcrop, pressure continues to increase in regions far from injection sites for 500 years post-COI (Fig. 3.28), even as pressure at the injection points decline. However, such behaviour underscores the importance of considering regional scale connectivity that impact pressure at long distances and changes over long periods of time.

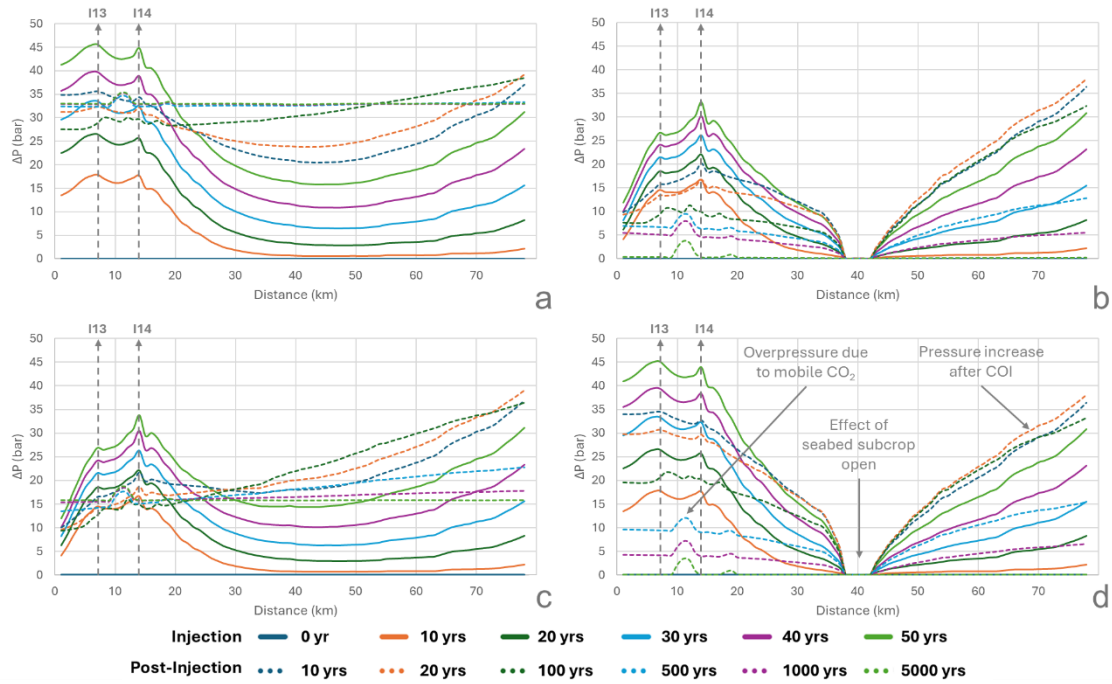


Fig. 3.28 Pressure increase along leftmost profile highlighted in Fig. 3.17 that interest the BSF seabed subcrop, demonstrating the effects of injected CO₂ and boundary conditions under different scenarios: (a) closed boundary (i.e. no flow at boundaries), (b) two open boundaries of the reservoir (i.e. flow at the seabed subcrop and northwestern region), (c) flow connection only at the northwestern region, and (d) flow connection only at the seabed subcrop. Solid lines represent timestep during the injection period, while dotted lines indicate post-injection timestep. Vertical dashed lines mark wells that are projected onto the profile.

Furthermore, such regional gradient enables continuous brine displacement where transmissibility at the seabed is allowed. Plot illustrated in Fig. 3.29 shows the amount of brine expelled (i.e. cumulative flow) from the reservoir through the boundaries over 5,000-year period. It can be noted with interest that the highest brine expulsion rate (i.e. flow rate at the boundary) is about 3,400 sm³/day (approximately 3,900 ton/day, or 21,400 barrel/day) occurring 14 years after COI. Hence, the pressure effect is being felt over a long period, and brine is still being expelled from the system 5,000 years later at about 1% (approx. 39 sm³/day, or 45 ton/day) of the maximum flow rate. Consequently, the 890×10^6 sm³ (1,000 Mt) of brine displaced into the sea is equivalent to only about 3.5 % of the total mass of injected CO₂. Therefore, that means that 96.5 % of the volume occupied by the CO₂ has been taken up by compressibility effects and by dissolution of CO₂ into the formation brine rather than fluid displacement outside the BSF reservoir.

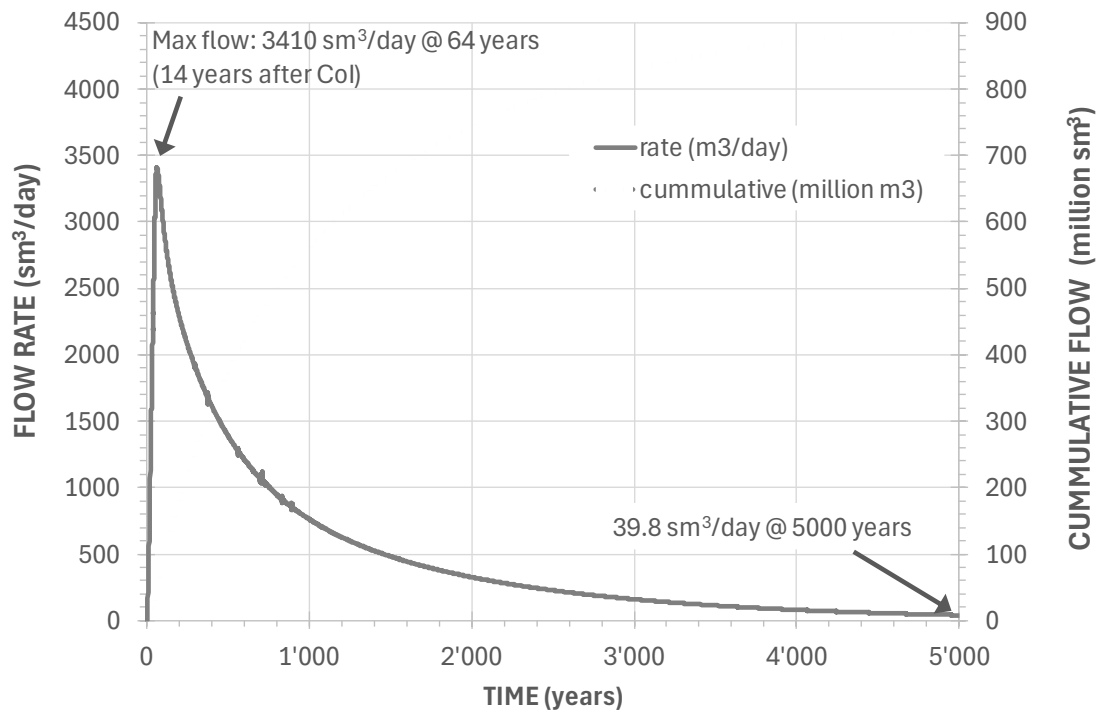


Fig. 3.29 Brine flow rate and cumulative flow at the reservoir seabed subcrop for the reference scenario, highlighting the occurrence of the peak of flow rate (approximately 3,900 ton/day, or 21,400 barrel/day) at 14 years after COI. Continuous flow occurs over millennia decreasing to about 45 ton/day at 5,000 after COI.

Finally, the changes in boundary connectivity generating regional pressure gradients also reflect on internal aquifer hydrogeological flows (Fig. 3.30). Different boundary conditions produce variations in the inter-region flows (i.e. flows between CO₂ storage licenses) showing alternative flow direction or generating inversion in hydrogeological flow. For example, in the reference scenario the brine flow is moving from R.6 to R.4 (light green curve in Fig. 3.30). Conversely, in the confined reservoir brine flow is directed from R.4 to R.6 (pale blue curve in Fig. 3.30). Such variations are represented by an inflection point (qualitatively marked with circles in Fig. 3.30) along cumulative brine flow curves which represent relative maxima and minima. In contrast to what might be intuitively imagined, the inflection point (i.e. reverse flow direction) occurs at different times depending on the geological model. Moreover, except for scenarios No. 2, No.4 and No.6 (i.e. confined, 42-wells, and connected only toward NW) where only one inflection point is observed, in the other scenarios, changes in flow direction seem to happen twice at different time intervals. For example, in the reference scenario, a first

flow inversion occurs after about 35 years from SOI, subsequently, another inversion occurs about 16 years later.

Such behaviour reinforces the need for further investigation prior to planning of CO₂ injection operations, not only at the field scale but also at the broader regional scale.

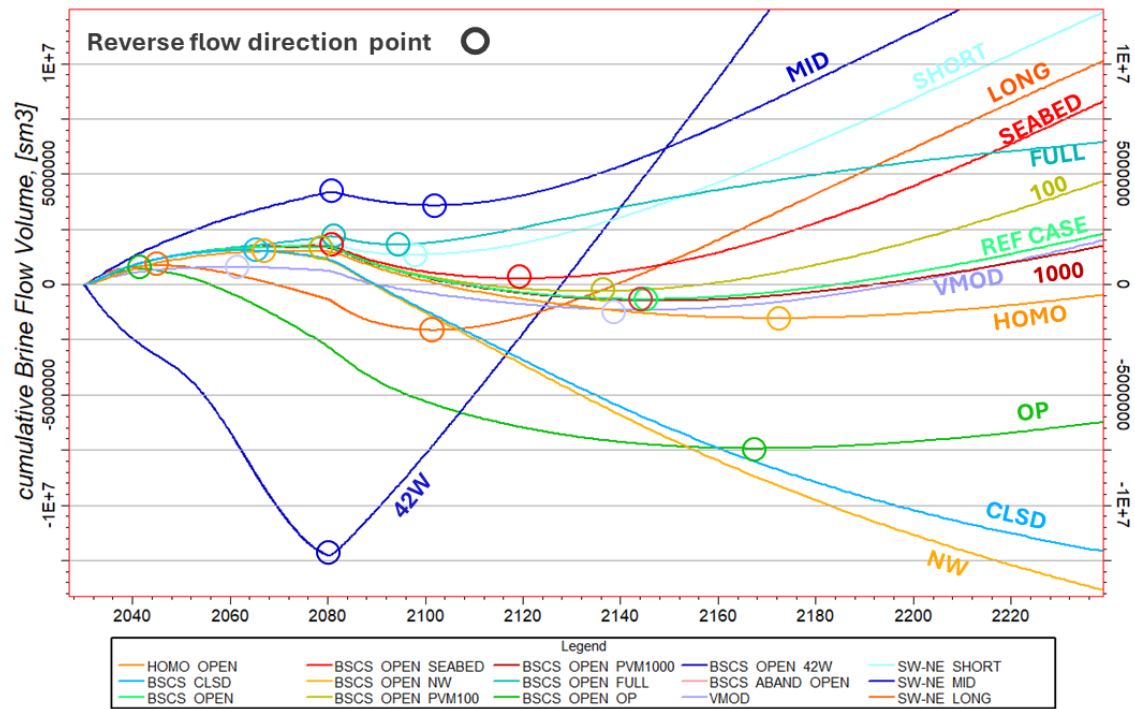


Fig. 3.30 Cumulative brine volume flowing from R.6 to R.4. Circles indicate time when the brine flow turns in the opposite direction (i.e. from R.4 to R.6).

3.6.3 CO₂ Plume Migration

Simulation results suggest that CO₂ plume migration continues for decades to centuries post-COI before stabilising beneath structural traps, with the majority of movement occurring subsequent to the COI (Fig. 3.19, Supplementary Fig. S3.10; Fig. S3.11). Consistent with findings from previous studies (Agada et al., 2017; Kolster et al., 2018; Noy et al., 2012; Williams et al., 2013), initial plume dispersion is approximately radially symmetric around the injection well, regardless of the imposed boundary conditions (Fig. 3.18; Fig. 3.19). After COI, buoyancy forces prevail over viscous forces, driving CO₂

towards the caprock structure that controls its long-term migration (Supplementary Fig. S3.10, Fig. S3.11). This behaviour reflects the buoyant nature of supercritical CO₂, which seeks high-permeability pathways and accumulates at structural traps beneath impermeable caprocks. Hence, the definition of the top reservoir structure, with reservoir heterogeneity, becomes of primary importance to understand the long-term migration of the CO₂ plume. The comparative analysis of two different structural grid realizations shows negligible differences in terms of migration. These results are influenced by the imposed injection location and the injected CO₂ mass, suggesting that a larger amount of CO₂ is required to promote migration over spill points. In this regard, the domal shape of traps seen in BSF within the Silverpit Basin is favourable for allowing CO₂ storage operations.

The injection framework in this study facilitates the storage of approximately 700 Mt of CO₂ in the reference scenario and 1,600 Mt of CO₂ in the 42-well scenario (Tab. 3.3). The overpressure scenario, which represents a conservative case with a more stringent pressure constraint, permits the injection of 435 Mt of CO₂.

During the injection phase, the imposed vertical heterogeneity significantly influences plume behaviour, as viscous forces exert greater influence than gravitational forces. This interplay enhances the plume dispersing beneath low-permeability baffles (Fig. 3.18a), thereby enhancing the mechanism of residual trapping. Post-COI, buoyancy-driven migration occurs over centuries, with limited impact from boundary conditions. Plume evolution is predominantly controlled by reservoir geometry, gravitational forces, and residual pressure gradients. These findings emphasise the need for pressure management and long-term containment assessments in CO₂ storage projects.

3.7 Conclusions

This study provides a comprehensive assessment of the potential for large-scale CO₂ storage within the Bunter Sandstone Formation (BSF) of the Silverpit Basin, in the Southern North Sea. Through an integrated approach combining static geological modelling and dynamic numerical simulation, key insights have been gained into the

geological framework, storage complex integrity, reservoir connectivity, pressure diffusion, and CO₂ plume migration. The findings underscore the viability of the BSF as a long-term CO₂ storage site while identifying critical uncertainties that must be addressed to ensure safe and effective containment. These results contribute to a broader understanding of regional-scale CO₂ sequestration and highlight key factors influencing the feasibility of large-scale CO₂ storage in the region.

The structural and depositional characteristics of the BSF make it a promising candidate for CO₂ sequestration. The extensive regional coverage of the formation, its well-defined structural closures, and the presence of overlying sealing formations within the Haisborough Group enhance its storage potential. However, limitations in defining reservoir property variations, including porosity and permeability heterogeneities, may significantly influence injectivity and plume migration at the field scale and require further investigation. Therefore, site-specific modelling is essential to evaluate potential migration beyond the structural trap.

The integrity of the storage complex is a key factor in determining the long-term security of CO₂ containment. The presence of faults and dykes, along with the potential for undetected sub-seismic faults, may compromise caprock effectiveness in certain areas. While the primary seal, the Röt Halite Member, demonstrates strong lateral continuity, the potential for fault-related leakage and fault reactivation necessitates further analysis, particularly considering observed pressure evolution within the region. Additionally, the subcrop of the BSF at the seabed presents a critical risk for brine displacement, requiring detailed monitoring strategies to assess the impact of formation brine on seawater. Determining whether brine displacement poses an environmental risk or provides benefits for storage operations is essential.

Numerical flow simulations indicate that CO₂ injection induces notable pressure evolution, with varying impacts depending on boundary conditions and reservoir connectivity. The sensitivity analysis of boundary transmissibility highlights the importance of pressure management to prevent over-pressurisation and potential seal failure. Scenarios with open boundary conditions, particularly towards the northwestern region, suggest that an extended connected aquifer could facilitate pressure dissipation

during injection operations. Pressure diffusion over tens of kilometres posing interference risk between neighbouring injection sites must also be considered when scaling up CO₂ storage operations across the region. However, uncertainties regarding the connectivity of the BSF across its regional extent remain a key challenge for accurate pressure modelling.

CO₂ plume migration patterns are strongly influenced by the structural configuration and reservoir heterogeneities. The simulations reveal that plume movement occurs predominantly in the post-injection period and is largely controlled by the dip and shape of the top reservoir structure. Site-specific and intraformational barriers must be evaluated to incorporate this risk into the model. The presence of high-permeability pathways enhances lateral migration, while low-permeability layers act as baffles, potentially leading to plume compartmentalisation. These findings underscore the necessity of detailed site-specific characterisation to optimise well placement and injection strategies.

Overall, this research advances the understanding of large-scale CO₂ storage dynamics in the BSF and provides a framework for future site development. Key recommendations include the need for high-resolution geomechanical assessments to evaluate fault stability over large distances, detailed refinement of petrophysical models to reduce heterogeneity uncertainties, and the implementation of real-time monitoring systems to track pressure evolution and brine displacement.

The modelling results highlight that, while the Bunter Sandstone offers substantial storage potential, the impact of boundary conditions on CO₂ migration and pressure evolution remains a critical factor. The extent of pressure communication across faults and stratigraphic barriers significantly influences the efficiency and security of storage. Further refinement of boundary conditions in numerical models will enhance predictive accuracy and support decision-making for commercial-scale CCS deployment.

Finally, this study reaffirms that the successful implementation of CO₂ storage in the Bunter Sandstone Formation requires an integrated approach that combines geological characterisation and advanced numerical simulation not only at the field scale but also at the wider basin scale. Future research should focus on refining reservoir characterisation by integrating high-resolution seismic data to refine geological structures, improving

dynamic modelling approaches, and evaluating long-term geochemical interactions between reservoir brine and seawater. These efforts will be essential for ensuring the viability of CCS as a key component of CO₂ mitigation strategies, not only in the UK Continental Shelf but also in other regionally extensive saline aquifers identified for CCS operations.

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Chapter 4

Using Large-scale CO₂ Injection Simulations to Evaluate Integrity of Abandoned Wells: A Case Study from the Silverpit Basin, Southern North Sea (UK)

Abstract

The integrity of abandoned wells in geological carbon storage sites is a critical factor influencing containment security and long-term storage feasibility. Legacy wells, many of which were drilled and abandoned prior to the establishment of stringent regulations, pose potential leakage risks due to cement degradation, casing corrosion, and mechanical failures.

This study evaluates the integrity of abandoned wells in the Silverpit Basin, Southern North Sea (UK), using pressure calculations obtained from large-scale CO₂ injection simulations. Well-abandonment schematics, casing collapse risk assessment, and plug setting depth evaluation were integrated with numerical simulation results to quantify the impact of pressure perturbations on legacy wells. A representative dataset of 17 wells was analysed, revealing significant variations in abandonment conditions, including disparities in cement plug placement, casing integrity, and the presence of well barrier elements. Casing collapse and plug depth setting assessments indicate that elevated injection pressures can induce mechanical failure in structurally compromised wells, particularly those with extensive corrosion or inadequate abandonment plugging. Long-

term pressure build-up scenarios suggest that additional remediation measures may be necessary for some wells to prevent potential leakage.

Advanced monitoring technologies, regulatory enforcement, and improved abandonment practices are essential to ensure that legacy wells do not compromise the long-term viability of CO₂ storage operations in the Silverpit Basin and similar mature basins worldwide.

4.1 Introduction

The necessity for geological CO₂ storage arises from the increasing global imperative to mitigate climate change by reducing atmospheric CO₂ concentrations (IEA, 2021a; IPCC, 2021b; ZEP, 2019). Carbon capture and storage (CCS) has been identified as a viable strategy to achieve this goal, mostly with depleted oil and gas reservoirs and deep saline aquifers serving as potential storage sites (Bachu, 2003; Benson and Cook, 2005). However, the selection of these sites is complicated by the presence of legacy wells, which pose significant risks to long-term containment integrity (Carroll et al., 2016; Gasda et al., 2004; IEAGHG, 2009; Zhang and Bachu, 2011).

Many abandoned wells in these regions were drilled and decommissioned before the implementation of modern regulatory frameworks for CCS development. Furthermore, standards and regulations have evolved over the years, resulting in varying abandonment conditions depending on the time of implementation and local standards (IEAGHG, 2009). Consequently, their integrity may be compromised due to outdated abandonment techniques, cement degradation, casing corrosion, and mechanical failure (Bai et al., 2016; Carroll et al., 2016; Gasda et al., 2004; IEAGHG, 2009; Romdhane et al., 2022; Scherer et al., 2005; Tiong et al., 2019; Zhang and Bachu, 2011). The integrity of these wells is a critical factor in determining the feasibility and safety of CO₂ storage projects, as they can serve as potential leakage pathways for stored CO₂ and formation brine (Celia et al., 2005; Duguid et al., 2017; Scherer et al., 2005).

The study area extends approximately throughout the entire Silverpit Basin (De Luca et al., 2025) in the Southern North Sea (UK), a mature hydrocarbon-producing region

identified as a potential site for CCS (Fig. 4.1)(BP, 2023; Hollinsworth et al., 2022). This region is characterised by numerous legacy wells, many of which were abandoned decades ago, presenting unique challenges for ensuring CO₂ containment integrity (IEAGHG, 2009). By contrast, the presence of halite formations within the sealing intervals (De Luca et al., 2025; Hollinsworth et al., 2022) provide reliable conditions to promote CCS operations as they show creeping effects as highlighted by findings in the Schooner field (Loizzo et al., 2024).

Quantitative studies have demonstrated that leakage risks are significantly higher in mature sedimentary basins with extensive hydrocarbon production histories (Celia et al., 2005; Gasda et al., 2004). For instance, in the Alberta Basin, Canada, spatial analysis has revealed that CO₂ injection projects could interact with hundreds of legacy wells, amplifying the risk of containment loss (Celia et al., 2005; Gasda et al., 2004). Similar concerns have been raised for the Southern North Sea, where legacy well integrity assessment is pivotal for developing CO₂ storage sites (Das et al., 2024). The Silverpit Basin, in particular, has been the focus of recent studies evaluating its suitability for long-term CO₂ storage (BP, 2023; Heinemann et al., 2012; Noy et al., 2012; Williams et al., 2013). While most of these wells are plugged with cement during abandonment, the well structure may still provide possible pathways for CO₂ leakage (Carroll et al., 2016; Gasda et al., 2004; Vrålstad et al., 2019) and some of them may lack of proper well barrier elements (WBE) that ensure containment (NORSOK, 2013). Additionally, whether it is a depleted hydrocarbon field or a saline aquifer, CO₂ injection into geological formations generates pressure perturbation (Noy et al., 2012; Williams et al., 2013). Such perturbation of the reservoir pressure will move further from the injection sites (Williams et al., 2013) therefore affecting surrounding legacy wells producing uncertainties in the capacity of legacy wells to sustain pressure build-up.

This study evaluates the integrity of abandoned wells located in the proximity of CCS sites, focusing on reconstructing abandonment schematics, assessing casing collapse risk, evaluating abandonment plug depths, and analysing their implications in relation to large-scale CO₂ storage operations.

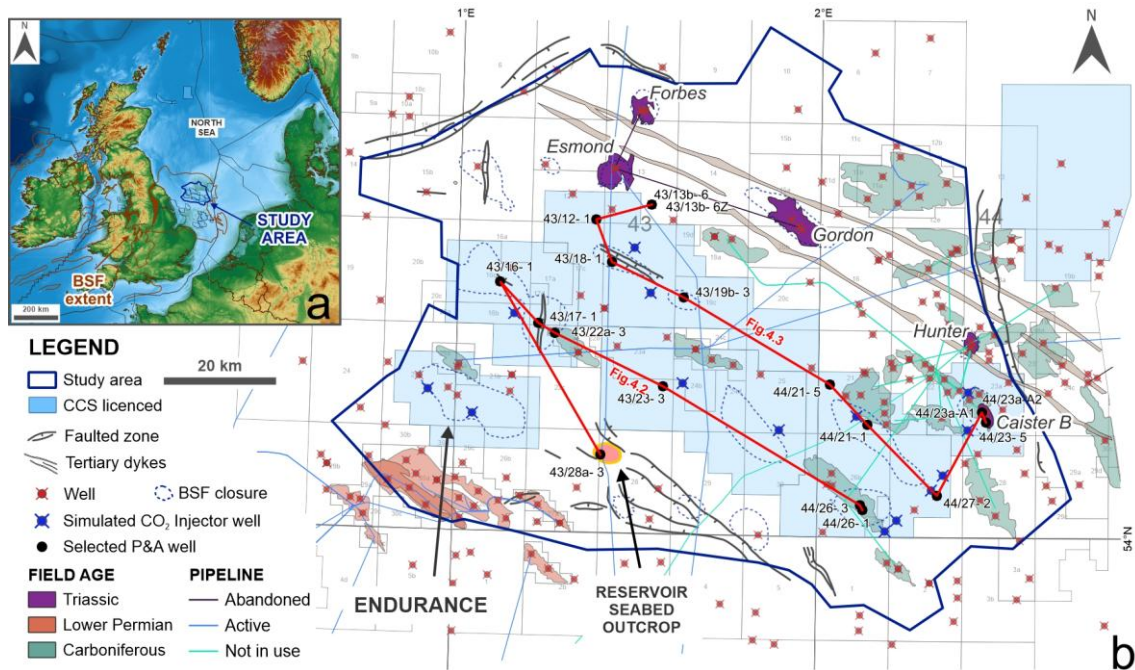


Fig. 4.1 (a) Location map of the study area. (b) Key elements within and surrounding the area of interest extending approximately across the entire Silverpit Basin. The study area indicates the extension of the model developed to run the CO₂ flow simulation.

4.2 Well Abandonment

The primary objective of permanent well abandonment is to establish long-term isolation of permeable and hydrocarbon-bearing formations, safeguarding underground resources by preventing contamination of potable water sources in shallow layers and mitigating the risk of surface leakage (IEAGHG, 2009; Khalifeh and Saasen, 2020; NORSOK, 2013; Vrålstad et al., 2019). Abandonment operations are designed to restore the integrity of the subsurface condition that has been altered by the perforation of wellbores. In offshore oil and gas operations, plug-and-abandonment (P&A) procedures constitute a critical component of well decommissioning, ensuring long-term well integrity and preventing fluid migration that could lead to environmental contamination (Khalifeh and Saasen, 2020; Vrålstad et al., 2019).

Wells serve as direct conduits between storage formations and overlying aquifers or the surface. Potential leakage mechanisms encompass microannuli between casing and cement or cement and formation, fractures within the cement sheath, corrosion-induced

breaches in casing integrity, and chemical degradation of well materials due to interactions with injected CO₂ (Gasda et al., 2004; Scherer et al., 2005; Tiong et al., 2019; Zhang and Bachu, 2011). The likelihood of leakage is contingent upon factors such as well age, employed abandonment methodology, the original cement quality, and stress conditions (Bai et al., 2016; Carroll et al., 2016; Zhang and Bachu, 2011).

The long-term integrity of wells in CCS projects faces challenges that can be broadly categorised into cement degradation, casing corrosion, and geomechanical creep of surrounding formations, where geological conditions allow it (Bai et al., 2016; Carroll et al., 2016; Loizzo et al., 2024, 2017; Zhang and Bachu, 2011). Cement, which functions as the primary sealing material in abandoned wells, is particularly susceptible to chemical interactions with CO₂, leading to carbonation and associated permeability alterations (Carroll et al., 2016; Tiong et al., 2019). Empirical evidence suggests that the dissolution of calcium hydroxide and the transformation of calcium silicate hydrate into amorphous silica significantly compromise cement integrity (Scherer et al., 2005). The extent of cement degradation depends on multiple factors, including CO₂ partial pressure, temperature, brine composition, and exposure duration (Tiong et al., 2019). The carbonation process can initially reduce permeability by forming calcium carbonate, but prolonged exposure often leads to leaching and increased porosity as dissolution progresses (Scherer et al., 2005). This degradation is further exacerbated in dynamic wellbore environments where thermal and mechanical stresses induce micro-annuli formation, creating preferential pathways for CO₂ migration (Loizzo et al., 2017; Vrålstad et al., 2019).

Furthermore, steel casing in abandoned wells is vulnerable to corrosion when exposed to CO₂-rich fluids, with the presence of formation brine exacerbating the degradation process. CO₂-rich fluids react with steel, forming iron carbonate (FeCO₃), which can either act as a protective scale or deteriorate under certain geochemical conditions (Bai et al., 2016; Zhang and Bachu, 2011). This can result in the thinning of the casing wall and the creation of potential leakage pathways (Gasda et al., 2004; Romdhane et al., 2022; Zhang and Bachu, 2011). Corrosion-induced weakening of the casing, combined with cement debonding at the casing-cement or cement-formation interfaces, significantly increases the risk of leakage (Carroll et al., 2016).

Geomechanical processes, particularly the creep behaviour of formations such as halite and shale, may contribute to self-sealing mechanisms by exerting radial stress on the casing-cement interface, potentially mitigating leakage risks (Fjær et al., 2023; Kristiansen et al., 2018; Loizzo et al., 2024, 2017). However, the efficacy of such self-sealing depends on the specific properties of the formation and the prevailing stress conditions. Furthermore, geomechanical creep in formations such as halite or ductile shales can lead to time-dependent deformation, exerting stress on the wellbore structure and potentially reopening sealed pathways (Kristiansen et al., 2018; Loizzo et al., 2024; Wang and Samuel, 2016). These interrelated degradation mechanisms highlight the necessity for advanced CO₂-resistant cements, improved abandonment strategies, and long-term monitoring to mitigate well integrity risks in CCS projects.

Remediation strategies for compromised wells typically involve re-plugging with advanced cement formulations, casing repairs, and the implementation of alternative sealing technologies. Innovations such as polymer-based barriers and microbial-induced mineralisation present promising avenues for enhancing well integrity in the long term (Vrålstad et al., 2019; Williams et al., 2009). Additionally, re-entering wells for targeted intervention may be required in cases where prior abandonment measures prove inadequate (Torsaeter et al., 2024).

Ensuring the long-term integrity of plugged and abandoned wells is imperative for the viability of CCS projects. Effective regulatory frameworks, continuous monitoring, and the integration of emerging technologies into abandonment strategies are necessary to mitigate risks associated with well integrity failures. The interplay between cement chemistry, geomechanical behaviour, and corrosion processes underscores the need for multidisciplinary approaches in designing and implementing P&A operations that guarantee the containment of stored CO₂ over geological timescales.

4.2.1 Abandonment Status and Phases

The regulatory framework and best practices governing abandonment procedures are outlined in key guidelines such as the UK regulatory frameworks and the NORSOK D-

010 standard for the North Sea region, ensuring compliance with environmental and industrial standards (IEAGHG, 2009; Khalifeh and Saasen, 2020; Nelson and Guillot, 2006; NORSOK, 2013). The following description is based on such report and standards.

According to definitions from the NSTA (NSTA, 2022) and other reports, well development begins with the drilling phase. Various well statuses provide insight into different stages of a wellbore operational lifecycle. A well is considered spudded when the drill first penetrates the ground or seabed, or, in the case of a sidetrack, when new formation is drilled after the P&A operations of a part of the original wellhole. After drilling, a well can either be operational or temporarily shut-in. A Completed shut-in wellbore is an active well that has undergone completion activities but remains closed at the tree valves or subsurface safety valve, typically with the intention of re-opening after a period exceeding 90 days. Three P&A statuses exist: suspension, temporary abandonment, and permanent abandonment. Each requires distinct well-integrity measures to prevent leakage and ensure regulatory compliance. A Suspended wellbore is one that is either plugged (AB1 or AB2) or remains inactive or under maintenance but well equipment has not been removed. A Plugged wellbore has been temporarily sealed with a plug rather than a permanent isolation barrier, effectively isolating the well through the subsurface safety valve and tree valves.

Temporary Abandonment involves the removal of well control equipment, with the intention to re-enter the well at a later date which shall be within 3 years if monitoring is not involved. Different regulatory authorities have their own requirements with respect to the maximum period of temporary abandonment. Permanent Abandonment is a well status, where the well is abandoned with the intent not to be used or re-entered again. The first stage of abandonment, Abandoned Phase 1 (AB1), ensures permanent reservoir isolation by placing a robust barrier material that fully seals all producing or injecting zones, making the section below the barrier inaccessible. Depending on operational needs and well conditions, the tubing may remain in place or be partially or fully removed.

In Abandoned Phase 2 (AB2), all required permanent isolation barriers are installed and verified, including environmental barriers. This phase ensures complete segregation of intermediate zones with flow potential. If tubing remains, partial retrieval may be

necessary to enable proper barrier placement. Typical operations in this phase involve isolating liners, milling or removing casing, and placing cement or other sealing materials to prevent cross-communication between geological formations. A wellbore at this stage is considered fully isolated, requiring no further intervention for decommissioning. However, the well origin—the point where the well penetrates the seafloor for offshore wells—and any conductor above it may still require removal.

The final stage, Abandoned Phase 3 (AB3), represents the full decommissioning of the wellbore. This includes the removal of the well origin and any conductor above it, ensuring that no remaining infrastructure is left at the surface or seabed. At this stage, the wellbore is permanently abandoned, preventing any future re-entry or use. Upon completion, the wellbore is officially removed from the well examination scheme.

Understanding these classifications ensures adherence to regulatory requirements and industry best practices, particularly in the North Sea region, where wellbore integrity is paramount for environmental protection and safety compliance.

4.2.2 Well Barrier Elements

The decommissioning of wells, known as P&A, is a crucial operation aimed at restoring caprock function to prevent leakages from potential inflow zones, reservoirs, or other permeable formations (IEAGHG, 2009; Khalifeh and Saasen, 2020; NORSOK, 2013). To achieve this, well barrier elements (WBEs) are systematically combined and verified to establish a well barrier envelope (Fig. 4.2). On the Norwegian Continental Shelf, the regulatory standard mandates a two-barrier concept, requiring each barrier to be a cross-sectional barrier that extends across the full well diameter (Khalifeh and Saasen, 2020; NORSOK, 2013).

A well barrier system comprises primary and secondary barriers designed to prevent uncontrolled fluid migration (NORSOK, 2013). Depending on well-operation scenarios, these barriers consist of various materials, including cement plugs, mechanical plugs, annulus cements, drilling fluids, valves, casings and creeping formations (ISO, 2017a; Khalifeh and Saasen, 2020; NORSOK, 2013). The requirements governing well

barriers—such as length, material selection, and verification—are detailed in standards such as NORSOK D-010 and ISO16530 (ISO, 2017a; NORSOK, 2013). According to this standard, a well barrier envelope must:

- Withstand the maximum differential pressure and temperature it may encounter;
- Be verified through leak testing, function testing, or other validation methods;
- Ensure that no single failure of a barrier or WBE leads to uncontrolled release of fluids;
- Be capable of being re-established in the event of failure;
- Maintain integrity throughout the lifetime of the well;
- Be independent of other well barrier envelopes whenever feasible.

Four main types of well barriers exist (Fig. 4.2 – ISO, 2017a; Khalifeh and Saasen, 2020; NORSOK, 2013):

- the Primary Well Barrier is the first line of defence, preventing flow from the reservoir or inflow zones. It is in direct contact with the pressure of the reservoir and must endure the pressure and stresses of the formation;
- the Secondary Well Barrier serves as a backup in case of primary barrier failure. It must also withstand reservoir pressure (or any overlying formation capable of flowing) and must operate independently of the primary barrier;
- the Crossflow Well Barrier prevents fluid migration between distinct formations within the overburden, or between different reservoirs where isolation has been deemed necessary;
- the Surface (Environmental) Plug isolates the well from the external environment, preventing contamination from annular fluids.

The two-barrier philosophy is a fundamental principle in well integrity management, requiring two independent barriers to isolate formations. According to NORSOK (2013), these barriers must be designed such that failure of one does not compromise the other. However, in cases where formations have limited or no flow potential, a risk assessment may justify reducing the required number of barriers.

Each WBE contributes to forming a well barrier envelope but does not independently prevent flow. For a WBE to be qualified, it must meet the Element Acceptance Criteria (NORSOK, 2013), ensuring long-term integrity, low permeability, chemical stability, proper bonding to tubulars, and sufficient resistance to mechanical loads.

Commonly used WBEs in P&A include:

- Annulus Cement – Provides zonal isolation along the wellbore;
- Casing – Maintains well structure and containment;
- Cement Plug – Creates a permanent seal within the well;
- In-Situ Formation – Naturally occurring creeping formations can act as self-sealing barriers.

The required lengths of WBEs are dictated by well conditions and regulatory standards:

- Annulus Cement must be continuous and verified through acoustic logs, displacement calculations, or pressure tests. The minimum length is generally 100 m above a casing shoe or 200 m if the next section penetrates an inflow zone.
- Cement Plugs must be at least 100 m in open hole conditions or 50 m in cased hole settings with mechanical support.
- Creeping Formations are increasingly recognized as effective WBEs, particularly in formations with high ductility. Verification requires demonstration of continuous contact over a defined length.

The verification of WBEs is essential for long-term integrity. Cement integrity is typically assessed using acoustic (i.e. sonic and ultrasonic) logs, while cement plugs are verified through tagging and pressure testing. Tagging ensures that the plug is structurally sound, whereas pressure testing confirms its sealing capability.

Ensuring the integrity of permanently abandoned wells is critical for environmental safety and regulatory compliance. The use of multiple, independently verified well barrier elements, adherence to the two-barrier philosophy, and continuous advancements in sealing materials and verification methods contribute to the robustness of P&A practices. As industry practices evolve, incorporating alternative WBEs and improved verification

techniques will further enhance long-term well integrity, particularly in the context of CO₂ storage and other subsurface applications.

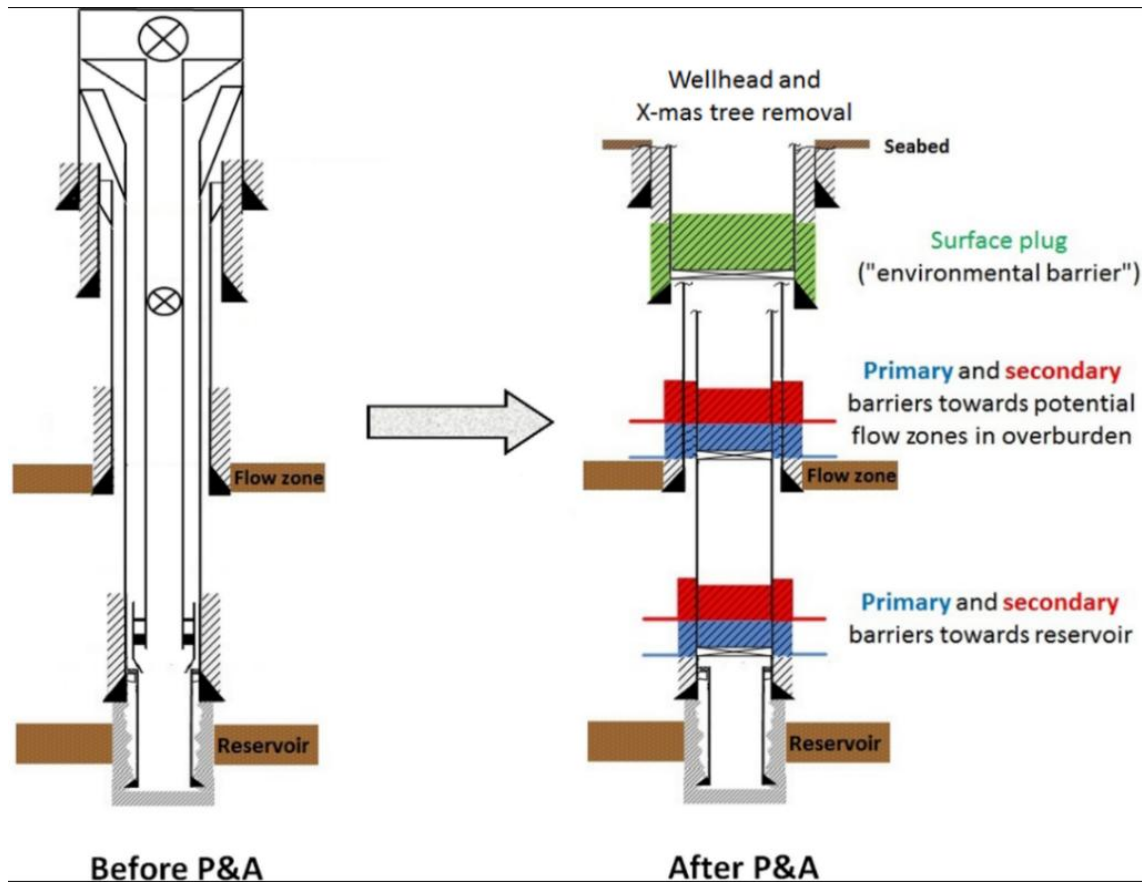


Fig. 4.2 Simplified schematic of a well before (left) and after P&A (right). After (Vrålstad et al., 2019). Colour coding of primary (blue) and secondary (red) barrier and surface plug (green) are based on NORSOK (2013).

4.3 Data and Methods

Based on the available data (NSTA, 2024b), the study area comprises approximately 400 wells (Fig. 4.1), which were spudded beginning in the mid-1960s (Fig. 4.3). The majority of drilling activity occurred between the 1980s and 1990s, with around 120 wells located within designated CO₂ storage licence areas (Fig. 4.3). These wells are categorised as 113 exploration wells, 72 appraisal wells, and 211 development wells (NSTA, 2024b), each exhibiting distinct status classifications (Tab. 4.1). Notably, over 234 wells—the

majority—are assigned the AB3 status (Fig. 4.4), indicating their final decommissioning and the removal of associated infrastructure.

Well Origin Status	Operational Status	Completion Status	No.
Present	Constructing	Drilling	2
	Constructed	Completed (Operating)	50
		Completed (Shut In)	44
	Suspended	Plugged	10
		AB1	30
		AB2	26
Decommissioned	Decommissioned	AB3	234

Tab. 4.1 Actual status of 396 existing wells within the study area based on the wellbore information from NSTA (2024b).

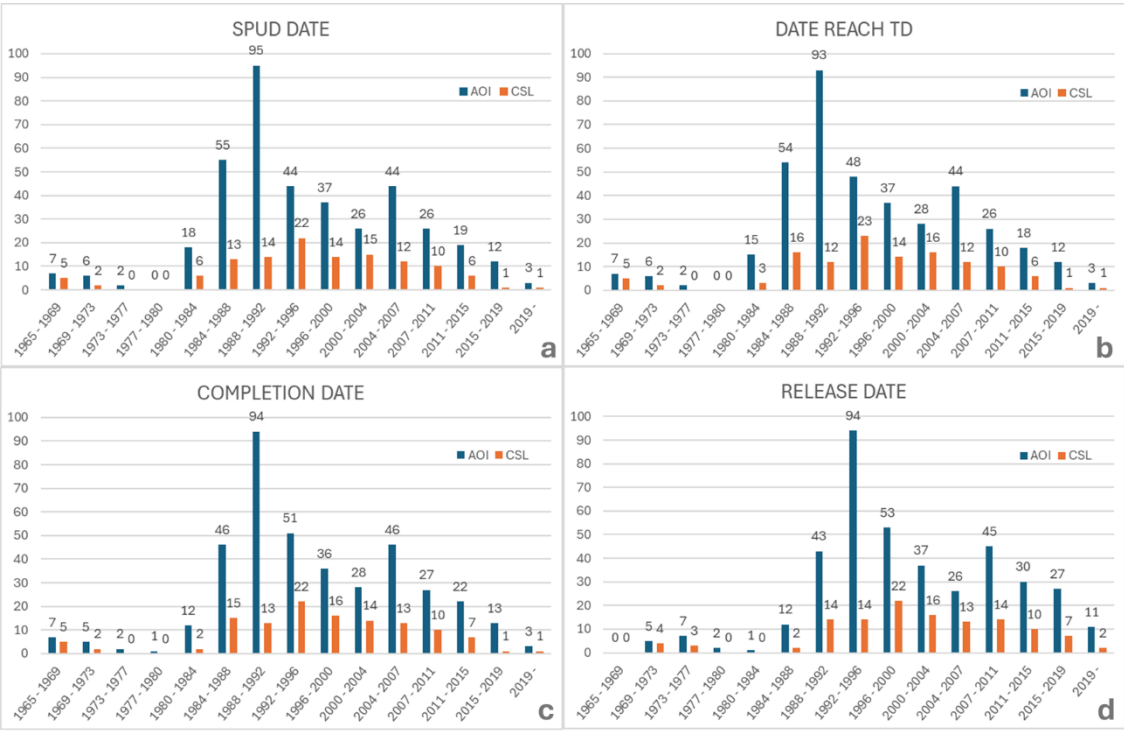


Fig. 4.3 Date relative to operational progressions of existing well within the study area as reported by the NSTA (2024b) dataset. (a) Spud date, (b) date when reached total drilled depth, (c) date of completion, and (d) release date of the document for well within the entire study area (AOI) and only within the CO₂ storage licenses (CSL).

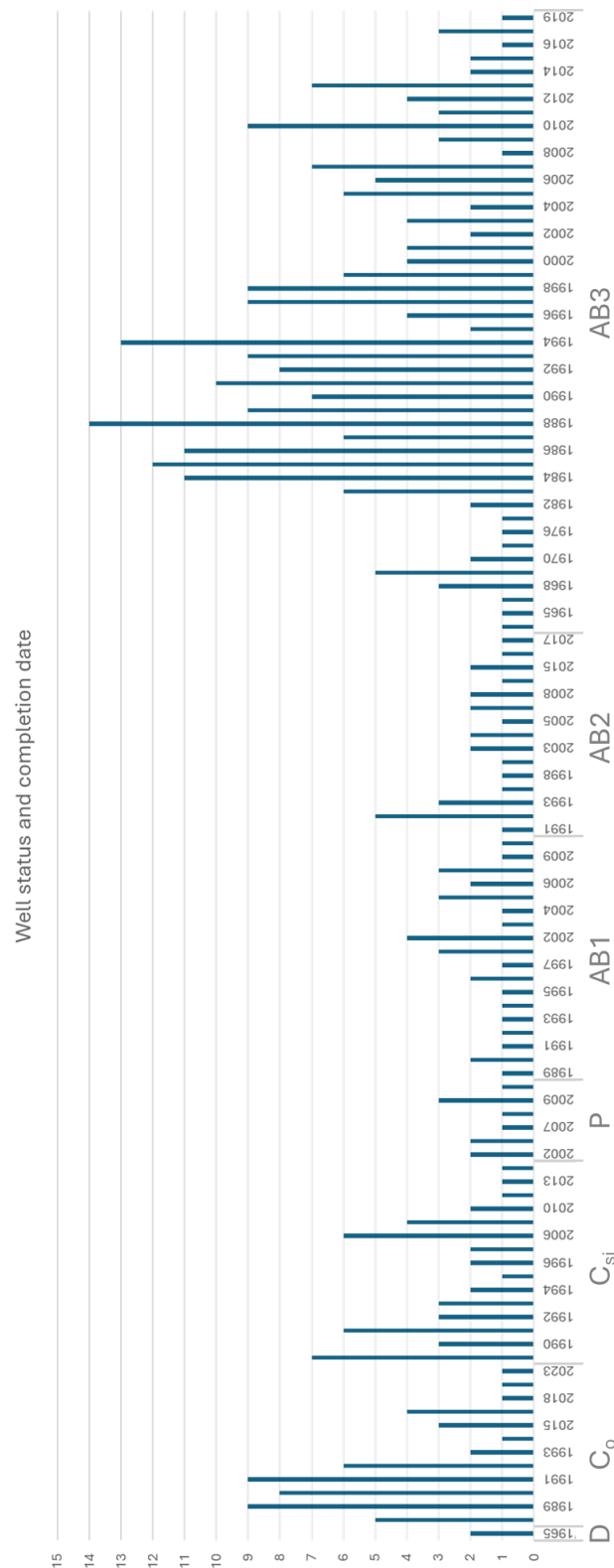


Fig. 4.4 Histogram plot indicating well status and completion date of wells within the study area. The majority of the wells are in AB3 phase. Abbreviations: D, drilling; Co, Completed operating; Csi, completed shut in; P, plugged; AB2, abandoned phase 2; AB3, abandoned phase 3.

To assess the integrity of these legacy wells, a comprehensive dataset was compiled, integrating well-log data, cement sonic and ultrasonic logs, abandonment schematic, drill daily reports and other available documentation. From this dataset, a representative subset of 17 wells (Tab. 4.2) was selected for detailed investigation based on multiple criteria, including abandonment date, which ranged from early legacy wells to recent closures, well location to ensure varied reservoir conditions, targeted reservoir, and casing design and cement plug configurations to capture a broad spectrum of well integrity scenarios. Priority was given to wells situated in proximity to CO₂ accumulation zones, including those within Bunter domes and migration pathways, as indicated by previous numerical simulations presented in Chapter 3. The availability of well documentation was also a key selection factor, enabling the reconstruction of abandonment conditions, completion settings, and well integrity indicators.

A thorough review of available well documentation revealed significant variations in data quality. Some wells featured extensive, well-maintained records spanning hundreds of pages (e.g. wells 44/23a-A1, 44/23a-A2), while others exhibited substantial information gaps due to poor reporting practices (e.g. wells 43/12-1, 43/16-1).

No.	Well name	Spud Date	Completion Date	Aband Date	Survey	Target Interval	Type	Abandonment status @BSF
1	43/28a-3	29/02/1969	06/04/1996	06/04/1996	v	C	Dry	@ subcrop location
2	43/16-1	20/09/1969	-	29/09/1969	v	T	Dry	Open hole
3	43/17-1	25/03/1969	-	05/04/1969	v	T	Dry	Plugged open hole
4	43/22a-3Z	10/03/2010	29/06/2010	27/09/2010	d	C	Gas	13 3/8" w/cement
5	43/23-3	27/05/1994	-	11/06/1994	v	T	Dry	Plugged open hole
6	44/26-3	20/08/1987	22/01/1988	?	v	C	Gas	13 3/8" + 9 5/8" w/cement
7	44/26-1	30/04/1968	16/05/1968	?	v	T	Dry	Plugged open hole
8	43/13b-6Z	08/12/2010	10/01/2011	13/01/2011	d	C	Gas	Plugged 13 3/8" w/cement
9	43/12-1	24/02/1984	-	09/05/1984	v	C	Dry	9 5/8"
10	43/18-1	29/07/1986	29/10/1986	29/10/1986	v	C	Gas	13 3/8" + 9 5/8" possibly cemented
11	43/19b-3	02/12/1994	14/12/1994	15/12/1994	v	T	Dry	Plugged open hole
12	44/21-5	17/06/1989	04/09/1989	08/09/1989	v	C	Dry	13 3/8" + 9 5/8" w/cement
13	44/21-1	07/07/1965	19/09/1965	26/09/1965	v	C	Dry	9 5/8"
14	44/27-2	20/04/1988	-	15/07/1988	v	C		13 3/8" + 9 5/8"
15	44/23a-A1	10/04/1992	07/05/1993	01/07/2019	v	T	Gas	9 5/8" w/cement, plugged @seal
16	44/23a-A2	08/05/1992	14/07/1992	01/07/2019	v	C	Gas	13 3/8" + 9 5/8" w/cement
17	44/23-5	20/09/1985	21/01/1986	27/01/1986	v	T		13 3/8" + 9 5/8" w/cement

Tab. 4.2 Selected well for the study indicating spud, completion, abandonment dates and abandonment condition at the BSF reservoir interval. Survey indicates whether is a vertical (v) or deviated (d) well targeting the Carboniferous (C) or Triassic (T) interval.

These records facilitated the reconstruction of well schematics, particularly regarding well-barrier depth, casing design, cement placement, and abandonment plug configurations. Information concerning casing grades, weights, threads, and the placement of cement plugs was extracted wherever available. However, the absence of cement sonic and ultrasonic logs in many abandonment wells constrained the evaluation of annular sealing quality and the integrity of formation-cement-casing bonding.

The abandonment schematics of the selected wells were reconstructed and systematically analysed to delineate WBEs as defined by the NORSOK D-010 standard (NORSOK, 2013). These schematics were illustrated in two correlation panels (Fig. 4.5 and Fig. 4.6). Additionally, a summary of UK abandonment guidelines, as outlined in the IEAGHG (2009) report, was incorporated into the study. This report reflects mid-1990s UK regulations for suspension and abandonment. While more recent guidelines are available through the Offshore Energies UK (OEUK) "Guidelines for the Abandonment of Wells," access to these documents was not possible. As a result, well barriers were defined using the NORSOK D-010 standard (NORSOK, 2013).

A key objective of this study was to quantify the risk of casing collapse in legacy wells. This was achieved by calculating casing collapse resistance at the BSF reservoir interval in accordance with international standards for casing properties (ISO, 2017b). External casing was considered when two casing were encountered at the reservoir. The safety factor (F_s) was defined as the ratio of casing collapse resistance to reservoir pressure, where values greater than 1.1 indicate safe conditions, values between 1.0 and 1.1 suggest a potential risk of collapse, and values below 1.0 signify imminent collapse. Reservoir pressure values were derived from numerical simulations (De Luca et al., 2025) at decadal intervals from the start of CO₂ injection. The calculations incorporated casing properties such as weight, grade, and yield stress to determine collapse limits and coefficients following API equations (ISO, 2017b). The outside diameter-to-thickness (OD/t) ratio was also computed, where OD represents pipe external diameter and t the wall thickness (i.e. nominal thickness). Given the lack of data on drilling and abandonment fluids, a conservative worst-case scenario was assumed, wherein internal pressure calculations were based on a standard gravity ($SG=1$) water column. Furthermore, sensitivity to

evaluate possible degree of corrosion were imposed by reducing wall thickness of 0 (i.e. no corrosion), 5, 10 and 15 %.

The integrity of abandonment plugs was evaluated in relation to their proximity to designated storage sites, with a particular focus on their ability to retain CO₂ under varying subsurface conditions. This assessment involved determining the capacity of cement plugs to sustain a CO₂ column by computing the Minimum Safe Abandonment Depth (MSAD – i.e. minimum setting depth in Khalifeh and Saasen, 2020). The MSAD represents the shallowest depth at which the formation withstands the maximum anticipated pressure without being fractured. As the secondary plug is a backup to the primary plug, the MSAD is the shallowest depth where the top of the secondary permanent plug can be placed. This parameter is essential in assessing the long-term stability of abandonment plugs under evolving reservoir conditions.

To facilitate MSAD calculations, a MATLAB-based algorithm was refined to interpolate results based on several parameters, including the depth of the first plug installed above the reservoir top, the pressure at the reservoir top at both the initiation and cessation of injection (De Luca et al., 2025), and a temperature gradient of 33.2 °C/km (Patruno et al., 2024), with a seabed temperature of 10 °C. The model also incorporated CO₂ density variations under relevant pressure-temperature conditions. This computational framework enabled a robust evaluation of the structural resilience of abandonment plugs and provided insights into their long-term performance in a dynamic storage environment.

4.4 Results of Abandonment Conditions

The analysis of the selected wells reveals substantial variability in abandonment conditions and the overall well-integrity (Tab. 4.3). The reconstructed schematics (Fig. 4.5 and Fig. 4.6) provide a detailed visualization of the diverse abandonment configurations, which range from open-hole abandonment to plugged open-hole designs, as well as single and double casing completions. Some wells exhibit annular cements (e.g. 44/26-3, 44/21-5), while others lack documented evidence of cementation (e.g. 43/18-1,

44/27-2), particularly at critical intervals such as the reservoir and caprock (Fig. 4.5 and Fig. 4.6).

Casing sizes at the reservoir interval (Tab. 4.3) predominantly consist of either 13 3/8" (e.g. 43/22a-3) or 9 5/8" (e.g. 44/21-1) for wells with single or double casing. The exception is well 43/28a-3, which is located at the reservoir seabed subcrop and features also a 30" conductor pipe and 20" surface casing, reflecting its unique placement and geological context (Fig. 4.5 and Fig. 4.6). The casing grades in these wells are primarily N-80 and P-110, which are designed for high-pressure environments, yet long-term durability remains a concern, particularly under prolonged exposure to CO₂-rich fluids

Seven of the 17 wells present cement plugs placed at the BSF depth, two of them are placed within the Haisborough Gp (Tab. 4.3, Fig. 4.5, Fig. 4.6). In four of five open-hole wells, a cement plug is present at the reservoir level, with lengths ranging between 150 and 350 m (Tab. 4.3). However, well 43/16-1 lacks documented evidence of a cement plug, making it impossible to verify its effectiveness in preventing leakage. The majority of cementing operations utilized Class G cement, a standard material for wellbore sealing (IEAGHG, 2009). Despite this, in 5 of the 12 wells (Fig. 4.5 and Fig. 4.6), it was not possible to confirm the presence of annular casing cement at the reservoir interval due to missing or incomplete records (e.g., wells 43/12-1, 43/18-1).

Among the wells analysed, well 43/13b-6Z stands out as having the most robust primary barrier. This well features a cement plug exceeding 600 m, extending from the Haisborough Group (i.e. sealing interval) to the Bunter Shale Formation (i.e. underlying reservoir unit), providing an extensive and continuous seal. Additionally, this well contains external casing cement, further reinforcing its long-term integrity. The presence of such a well-defined cement barrier significantly enhances the containment potential for CO₂ storage, contrasting with other wells where abandonment measures appear less comprehensive.

Well Name	Size (in)	Weight (lb/ft)	Grade	Thread	Wall Thickness (inches)	Plug Length (m)	Abandonment Status @ BSF depth
43/28a-3	30"	203		RL4S			@ subcrop location

43/28a-3	20"	133	X-56	RL4S	0.635		@ subcrop location
43/16-1	-	-	-	-	-		Open hole
43/17-1	-	-	-	-	-	317	Plugged open hole
43/22a-3(Z)	13 3/8"	72	L80	DINO VAM	0.514		1 csg cmtd
43/23-3	-	-	-	-	-	149.7	Plugged open hole
44/26-3	13 3/8"	68	N80	BTC C95	0.48		2 csg cmtd
44/26-1	-	-	-	-	-	292.6	Plugged open hole
43/13b-6Z	9 5/8"	53.5	VM95SS	Vam top	0.545	616.9	Plugged 1 csg cmtd
43/12-1	9 5/8"	47	N80	BT+C	0.472		1 csg
43/18-1	13 3/8"	68	N80	Buttress	0.48		2 csg cmtd
43/19b-3	-	-	-	-	-	355.1	Plugged open hole
44/21-5	13 3/8"	72	N80	Buttress	0.514		2 csg cmtd
44/21-1	9 5/8"	47	P110		0.472		1 csg
44/27-2	13 3/8"	72	N80		0.514		2 csg
44/23a-A1	13 3/8"	61	K55	Buttress	0.43	315.5	Plugged caprock 1 csg
44/23a-A2	13 3/8"	72	P110	Buttress	0.514	361.1	2 csg cmtd
44/23-5	13 3/8"	72	N80	Buttress	0.514		2 csg cmtd

Tab. 4.3 Summary of abandonment conditions at the BSF reservoir depth indicating casing properties and plug setting.

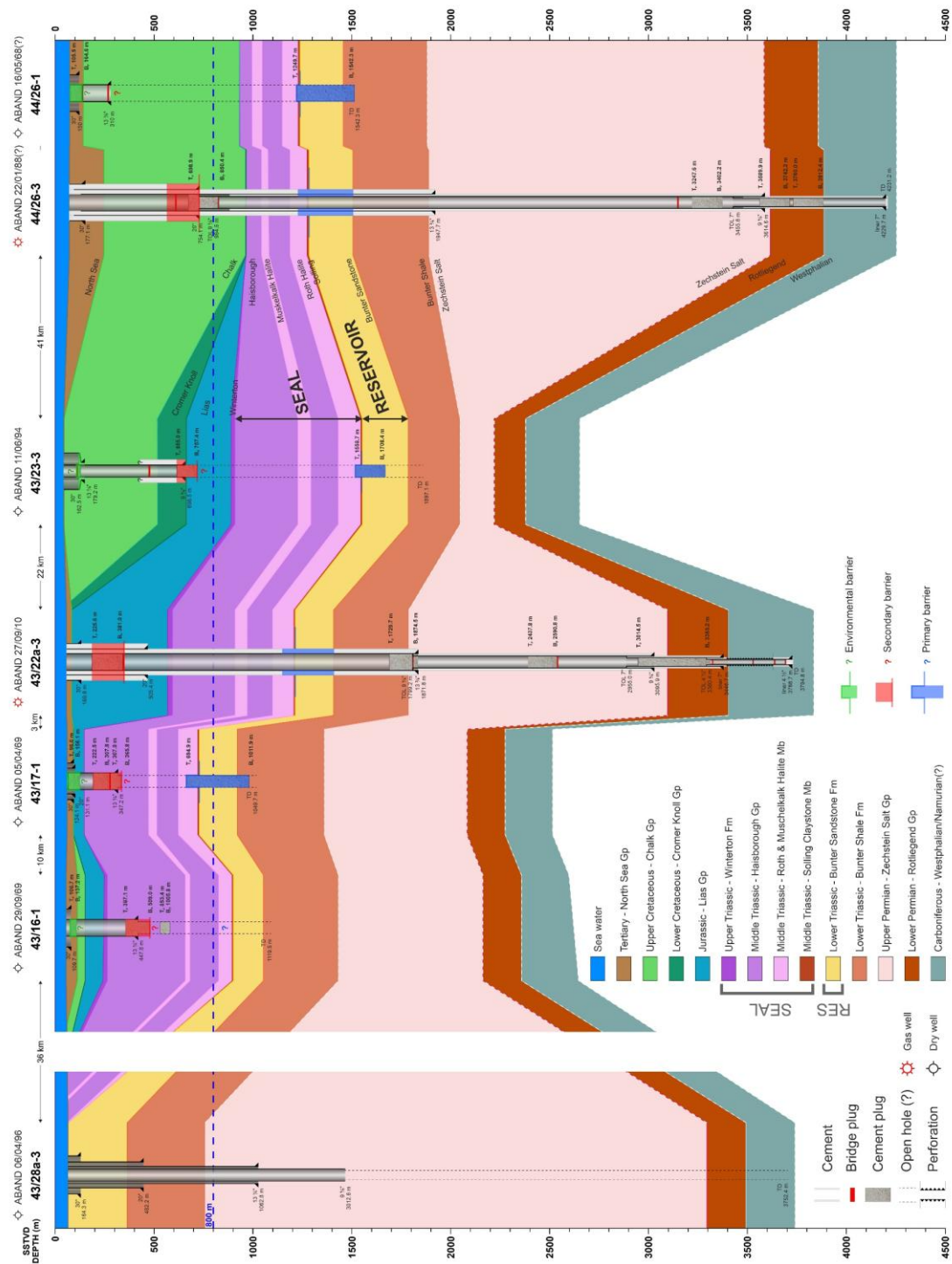


Fig. 4.5 Well section panel representing abandonment conditions of wells over simplified stratigraphy. Question marks indicate uncertainties in the identification of WBE (i.e. top of cement or cement plugs). Dashed lines at the formations boundaries approximate stratigraphic setting based on the interpretation of seismic data by De Luca et al. (2025). See Fig. 4.1 for location.

4.4.1 Casing Evaluation

The analysis of casing collapse risk across the evaluated wells highlights a range of probabilities for structural failure, strongly influenced by injection conditions, reservoir pressure evolution, and casing corrosion. This assessment was conducted exclusively on wells where casing pipes were present along the reservoir interval, with calculations focusing on the external casing in cases where two casings were present (e.g., well 44/26-3). Fig. 4.5 and Fig. 4.6 illustrate the progressive evolution of collapse risk for each well under different scenarios, as proposed in Chapter 3, tracking conditions from the onset of CO₂ injection at initial reservoir pressure (i.e. at start of injection period) through subsequent increments every ten years, up to the maximum reached reservoir pressure (i.e. at end of injection period). These analyses were performed for corrosion levels of 0%, 5%, 10%, and 15%, allowing for a comprehensive evaluation of casing integrity under varying degradation rates.

The results indicate that collapse risk is significantly elevated in high-pressure scenarios, particularly under conditions of imposed overpressure in the reservoir (scenario OPEN_OP) and intensive injection activity with 42 injectors (scenario OPEN_42W). In these cases, well 44/26-3 exhibits collapse risk from the very beginning of the injection phase at 15% corrosion, with failure becoming apparent again after 20 years of injection (Fig. 4.5). At 10% corrosion, collapse is slightly delayed, occurring after 30 to 40 years of injection. In all other scenarios, collapse occurs only at 15% corrosion, appearing approximately 20 years into the injection period.

A higher susceptibility to collapse is observed in well 43/18-1 (Fig. 4.5), where casing failure occurs more rapidly across all scenarios. In OPEN_OP and OPEN_42W, collapse is evident after 10 and 20 years of injection, even when casing corrosion is not present. When corrosion is introduced at 5%, failure begins to emerge after 40 years, while in all tested cases with 10% or 15% corrosion, collapse occurs immediately at the start of injection.

This well also provides insight into the impact of geological heterogeneity (Chapter 3) on casing integrity. The LONG scenario, which represents a petrophysical model with a greater correlation length and extended high-permeability pathways, exhibits a delayed

collapse compared to the SHORT and MID scenarios, and even more significantly compared to the homogeneous model (i.e. HOMO). This suggests that pressure dissipation in heterogeneous formations can mitigate stress concentrations on the casing, delaying structural failure.

The most critical failure conditions are observed in well 44/21-5, where collapse occurs in every scenario. Without corrosion, casing collapse is projected within 20 to 30 years from the start of injection. When 5% corrosion is introduced, failure accelerates to occur within 10 years, while at 10% and 15% corrosion, structural collapse is immediate at the onset of injection. This highlights the severe risk posed by corrosion in high-pressure injection settings and underscores the necessity of enhanced casing protection and long-term integrity monitoring.

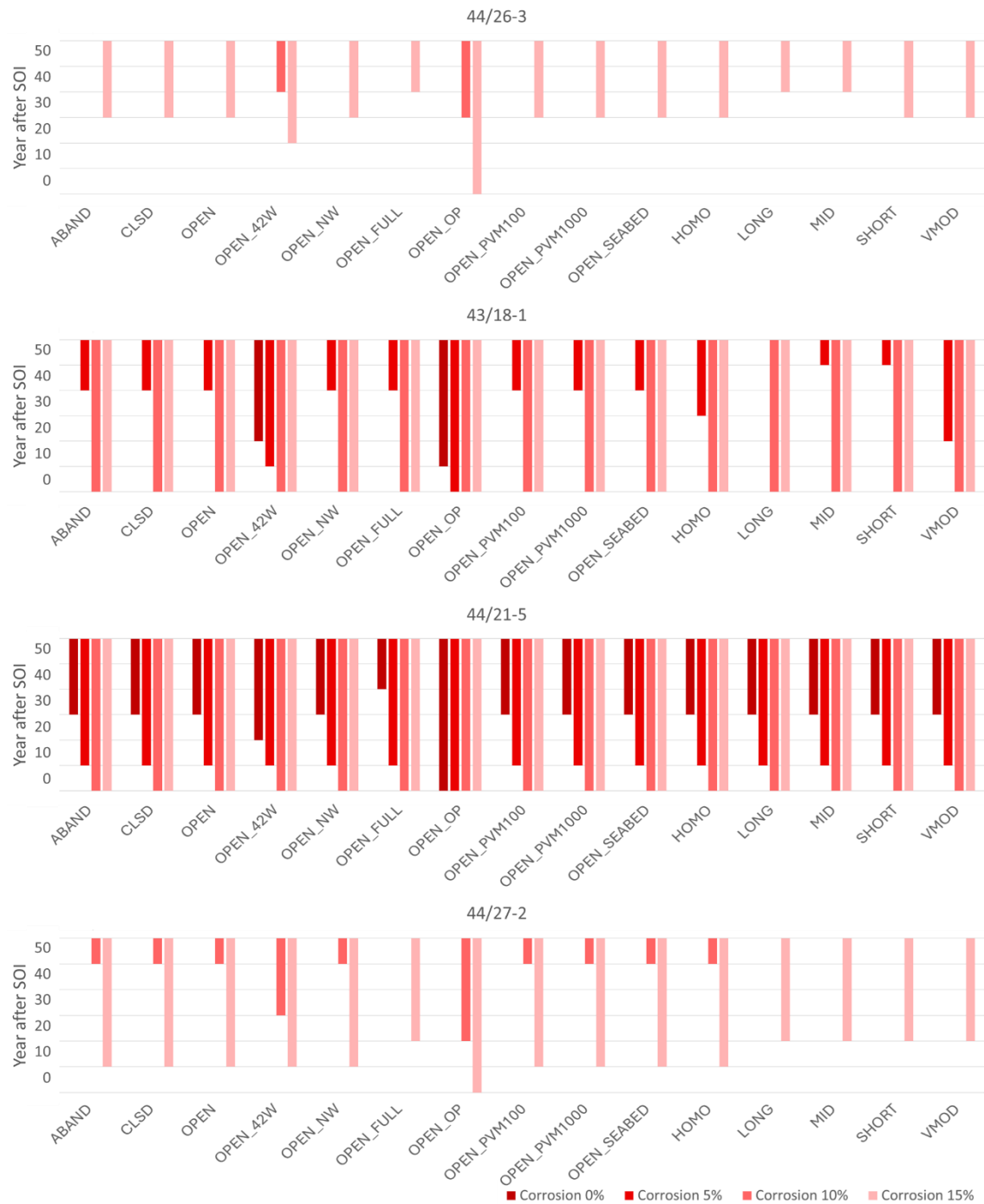


Fig. 4.7 Casing collapse risk evaluation for each scenario presented in Chapter 3, at 0, 10, 20, 30, 40 and 50 year of injection, for 0, 5, 10 and 15 % of casing corrosion (i.e. thinning of wall thickness).

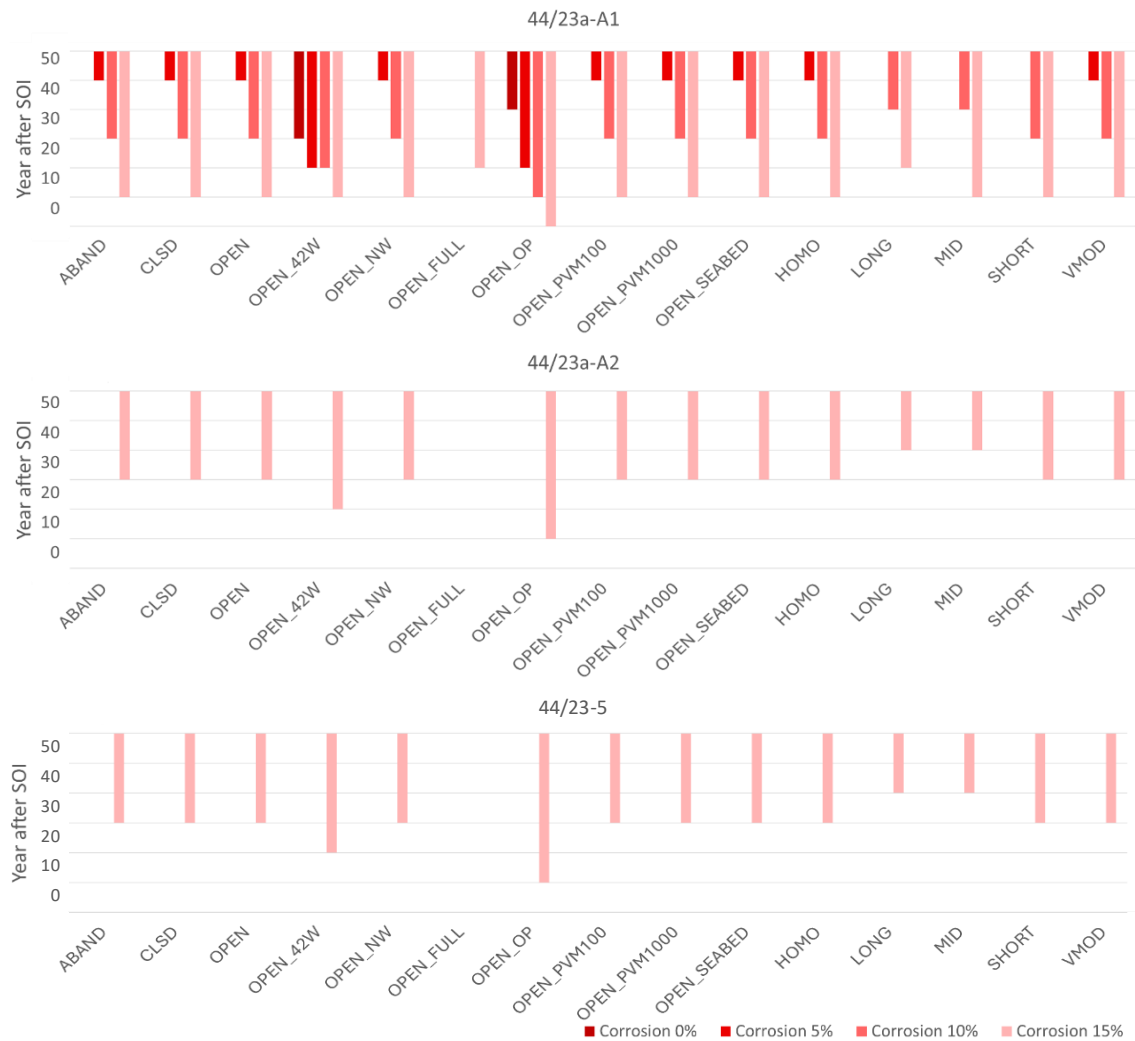


Fig. 4.8 (Continued) Casing collapse risk evaluation.

4.4.2 Cement Plugs Assessment

The effectiveness of well barriers in ensuring long-term containment relies on multiple factors, including the quality of cement placement, the presence of annular seals, and the depth of abandonment plugs. To assess the ability of these barriers to withstand pressure variations induced by a CO₂ column accumulating within a compromised wellbore, the Minimum Safe Abandonment Depth (MSAD) was calculated for each well (Tab. 4.4). This evaluation considered key parameters such as reservoir pressure, temperature gradients, and plug depth, allowing for a comparison between existing abandonment configurations and safety requirements.

The analysis indicates that the depth of abandonment cement plugs varies widely across the examined wells (Fig. 4.6 and Tab. 4.4), ranging from approximately 100 m for environmental abandonment plugs, such as in wells 44/21-1 and 43/12-1, to depths exceeding 1800 m for primary barriers, as observed in well 43/13b-6Z. The lengths of these plugs range from 100 to 350 m (Tab. 4.4), with only three of the twelve wells having casing at the reservoir level exhibiting a cement plug that functions as a primary barrier.

Given that the reservoir pressure values required in the calculations were derived from numerical simulations (De Luca et al., 2025) uncertainties exist regarding the precise depth of the reservoir in each model scenario. To address this, MSAD was calculated for both the actual reservoir depth recorded in well logs and the depths estimated in the geological models (Chapter 3). The differences between the two datasets were found to be within approximately ± 50 m (Tab. 4.4).

By comparing the differences between MSAD and actual plug depth (dZ), results indicate that five wells, including 44/26-3, 43/13b-6Z, 43/18-1, 44/23a-A1 and 44/23a-A2, have cement plugs positioned above the MSAD threshold, suggesting a high likelihood of maintaining containment integrity with the initial pressure conditions (Tab. 4.4). Generally, wells with cement plugs placed at the reservoir or caprock intervals exhibit the most favourable conditions for containment. However, three of these wells (i.e. 44/26-3, 44/23a-A1 and 44/23a-A2), exhibit an opposite trend when considering the higher pressure reached at the cessation of injection (Tab. 4.4). In these cases, the MSAD exceeded the actual plug depth by more than 400 m in well 44/26-3 and between 150 to 200 m in wells 44/23a-A1 and 44/23a-A2. This raises concerns about the ability of these wells to withstand long-term pressure variations and potential CO₂ migration pathways under post-injection conditions.

Further comparison of dZ values at the start and cessation of injection provides additional insights into the risks associated with inadequate abandonment conditions. Wells with poorly placed abandonment plugs, meaning those unable to withstand the pressure exerted by a full CO₂ column, show a variation (Δ) in dZ ranging from approximately 200 m to 750 m. The smallest variation is observed in well 43/22a-3Z, where dZ increases from 245 m at the start of injection to 440 m at the cessation of injection, indicating

relatively stable conditions despite the pressure increase. In contrast, the largest dZ variation is found in well 44/27-2, where dZ ranges from approximately 900 m to 1600 m, highlighting a significant vulnerability in its ability to maintain long-term containment.

4.5 Discussion

The assessment of well integrity within the Silverpit Basin has revealed substantial variability in abandonment conditions, casing stability, and the effectiveness of well barriers. The dataset, encompassing well schematics, casing configurations, and abandonment reports, has provided significant insight into the long-term reliability of these wells located close to CCS sites. Discrepancies in cement placement, casing design, and potential corrosion risks emphasize the necessity for a comprehensive evaluation of their suitability for containment. The analysed wells exhibit a wide range of completion and abandonment histories, with some presenting robust isolation measures while others pose potential risks for CO₂ leakage. The integrity of these wells is strongly influenced by the quality of abandonment procedures, particularly the placement and condition of cement plugs and casing, which ultimately affect their ability to withstand pressure variations induced by large-scale CO₂ injection.

4.5.1 Casing Integrity and Collapse Risk

The Casing stability is a key factor in ensuring well integrity, especially during the operational phase, with corrosion posing a considerable challenge. CO₂-rich fluids react with steel casing to form iron carbonate (FeCO₃), which, under certain geochemical conditions, can lead to gradual degradation, reducing casing thickness and increasing permeability over time (Bai et al., 2016; Carroll et al., 2016; Zhang and Bachu, 2011). A combination of casing thinning, cement debonding, and mechanical stress at casing-formation interfaces further exacerbates the risk of structural failure (Carroll et al., 2016).

The analysis of casing collapse risk reveals substantial variability in structural integrity, influenced by reservoir pressure build-up and casing corrosion. High-pressure injection scenarios, such as OPEN_OP and OPEN_42W, significantly increase the likelihood of collapse. For instance, well 44/26-3 experiences immediate collapse at 15% corrosion and delayed failure at 10% corrosion after 30–40 years of injection. Moreover, other wells such as wells 43/18-1 and 44/21-5 exhibit even greater susceptibility, with failure occurring within 10–20 years, even in the absence of corrosion.

Geological heterogeneity plays a significant role in mitigating or exacerbating collapse risks. The LONG scenario, which represents extended high-permeability pathways, results in delayed collapse compared to the SHORT and MID scenarios (Fig. 4.5 and Fig. 4.6). This suggests that pressure dissipation in heterogeneous formations can alleviate stress concentrations on the casing, delaying structural failure. However, in cases such as well 44/21-5, where casing failure occurs within 30 years under non-corrosive conditions and accelerates to just 10 years with moderate corrosion, the risk of collapse becomes a major concern. Such structural failures can create extensive leakage pathways, significantly compromising well integrity. This underscores the critical need for continuous monitoring to detect early signs of deterioration and implement timely interventions. The observed heterogeneity in well abandonment conditions underscores the necessity of a case-by-case evaluation when selecting legacy wells for carbon storage projects. While some wells exhibit robust sealing mechanisms, others present uncertainties due to missing documentation or potential deficiencies in cement placement. These variations highlight the importance of detailed integrity assessments and possible remediation measures to ensure the long-term containment of injected CO₂.

4.5.2 Cement Plugs Integrity and Well Barriers

The analysis of cement plug depth suggests that, in many cases, reliance is placed on secondary barriers (e.g. well 43/22a-3, 44/26-3, 43/18-1), which may not provide adequate containment under evolving pressure conditions. MSAD calculations indicate that although minor discrepancies exist between well data and model-derived depths, these differences, which remain within ± 50 m, do not significantly alter the overall assessment of cement plug stability. However, the absence of plug depth documentation for well 43/16-1 prevents a full evaluation of its sealing capacity, highlighting the need for alternative assessment on poorly documented abandonment.

The absence of section milling operations above the reservoir interval suggests that cement plugs may not have fully bonded with the casing and surrounding formations, potentially leading to leakage pathways over time. Shrinkage and micro-annuli formation remain key concerns, particularly in wells where cement plugs were placed under less

controlled conditions (i.e. aged abandonment relaying on less regulations). Furthermore, inadequate annular cementation introduces additional uncertainty regarding the reliability of well barriers, as poorly cemented annuli may allow for fluid migration along the wellbore (Scherer et al., 2005; Vrålstad et al., 2019; Zhang and Bachu, 2011). Such operations were not fully addressed in this work and require to be further investigated.

Creeping formations have been increasingly recognised as effective well barrier elements, providing a natural and long-term sealing mechanism for abandoned wells. Their ability to exert radial stress on wellbores facilitates the gradual closure of potential leakage pathways, significantly reducing the risk of CO₂ migration over time (Loizzo et al., 2024, 2017; Wang and Samuel, 2016). The NORSOK D-010 standard (NORSOK, 2013) explicitly acknowledges creeping formations as a viable barrier element, provided they meet stringent verification requirements. Specifically, the formation must exhibit continuous hydraulic sealing capability over a minimum interval of 50 m, with integrity validated through sonic and ultrasonic logs and pressure testing to confirm its ability to withstand anticipated differential pressures. This regulatory inclusion highlights the growing confidence in the sealing capacity of creeping formations, particularly in mechanically favourable lithologies such as halite and shales. Successful applications in various geological settings demonstrate their effectiveness as a complementary or even primary barrier. Their ability to bond directly to casing or annular cement enhances long-term well integrity (Loizzo et al., 2024), while also reducing the need for costly mechanical interventions such as section milling or perf-wash-cement operations.

Integrating creeping formations into well integrity strategies could provide a cost-effective and environmentally sustainable alternative to conventional plug-and-abandonment methods. This is especially relevant in formations with favourable mechanical properties, such as the Solling Claystone Mb and Röt Halite Mb, which serve as the first sealing formations above the BSF reservoir within the studied area (Loizzo et al., 2024). The ability of these formations to gradually close microannuli and mitigate cement degradation further underscores their role in ensuring the integrity of legacy wells in CCS projects. By optimizing well abandonment strategies to incorporate these formations, operators could enhance long-term containment while minimizing the need for costly interventions.

4.5.3 Regulatory and Operational Challenges

The findings from this study highlight critical regulatory and operational challenges that must be addressed to ensure the long-term integrity of abandoned wells. One of the primary concerns is the lack of acoustic logs for cement verification, which introduces uncertainty regarding the effectiveness of well barriers. Without cement acoustic logs, the extent of casing-cement-formation coupling remains unclear, increasing the risk of micro-annuli formation and potential CO₂ migration pathways.

The absence of section milling operations above the BSF reservoir further compounds this issue, as unperforated casing may prevent proper plug adhesion, diminishing the effectiveness of abandonment barriers.

Another key challenge is the high susceptibility of certain wells to casing collapse under increased injection pressures. Wells in high-pressure injection zones, such as 44/21-5 and 43/18-1, exhibit elevated collapse risks due to pressure buildup from nearby injection activities. This necessitates continuous monitoring to detect early signs of casing deformation or failure. Furthermore, casing integrity remains vital for long-term well security, with corrosion, mechanical deformation, and annular cementation all being critical factors that should be incorporated into future well integrity assessments.

The variability in well integrity across the Silverpit Basin underscores the necessity for detailed integrity assessments as a prerequisite for CCS site selection. While some wells exhibit sufficient barriers to prevent CO₂ migration, others require intervention or further assessment to ensure long-term containment. The results suggest that wells with plugs positioned below the MSAD at the cessation of injection may require potential remediation to prevent future leakage risks. The large variations in dZ across different wells further indicate that site-specific abandonment strategies are required to account for reservoir pressure evolution and long-term containment objectives.

The findings from this study highlight the importance of robust abandonment practices, continuous monitoring, and site-specific risk assessments for ensuring the long-term viability of CCS operations. Inadequate plug placement, lack of cement verification, and casing corrosion all contribute to potential failure points that could compromise well

integrity. While some wells are well-sealed under initial conditions, the pressure build-up over time presents a considerable risk for those with suboptimal abandonment configurations.

4.6 Conclusion

The evaluation of well integrity in the Silverpit Basin has revealed substantial variability in abandonment conditions, casing stability, and the effectiveness of well barriers, highlighting key challenges for large-scale CCS operations. The study demonstrated that many legacy wells exhibit uncertainties in cement plug placement, casing integrity, and corrosion susceptibility, factors that could compromise long-term containment. Casing collapse assessments indicate that certain wells, particularly 44/21-5 and 43/18-1, exhibit elevated casing collapse risks under high-pressure injection scenarios, with structural failure occurring within 10 to 30 years depending on corrosion levels, especially when corrosion is increased.

Geological heterogeneity influences collapse timing, with pressure dissipation in permeable formations delaying structural failure, while less permeable scenarios experience sharper stress gradients, accelerating collapse. The absence of cement acoustic logs in multiple wells introduces further uncertainty, as inadequate cementation may create leakage pathways along the annulus.

The assessment of abandonment cement plugs indicates that in several wells, plug depths do not meet the Minimum Safe Abandonment Depth (MSAD) required to withstand reservoir pressure variations, particularly at the cessation of injection. Wells where the MSAD threshold exceeds the actual plug depth may require further evaluation and potential remediation to prevent long-term leakage risks. While secondary barriers provide additional containment, reliance on them alone may not be sufficient under evolving pressure conditions and may be inadequate to withstand the accumulation of CO₂ in the abandoned wells over time. The absence of section milling in most wells suggests that cement plugs may not have fully bonded with casing and formations, reducing their sealing effectiveness.

Despite these challenges, creeping formations emerge as a promising natural sealing mechanism particularly for the well with open hole abandonment. The Röt Halite Mb has the potential to exert radial stress on wellbores, gradually closing microannuli and the hole section mitigating CO₂ migration risks.

These findings underscore the critical need for comprehensive well integrity assessments in CCS site selection. Prioritizing but not limiting to wells with verified cement seals and casing stability, implementing enhanced monitoring techniques, and integrating natural sealing mechanisms where applicable can improve long-term containment security. Addressing the risks associated with inadequate plug depths and casing collapse is essential to ensure that legacy wells in the Silverpit Basin and similar mature basins do not compromise the viability of large-scale CCS operations not only because of CO₂ accumulation but also because pressure perturbation will represent an early concern that can impact containment safety. By implementing proactive well integrity assessments, CCS operators can mitigate containment risks and enhance the long-term feasibility of CO₂ storage initiatives.

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Chapter 5

Final Remarks and Future Work

5.1 Thesis Summary and Conclusions

This thesis has explored the feasibility and implications of large-scale geological CO₂ storage in the North Sea, focusing on regional-scale characterisation and assessment of storage sites. The study incorporated gravity and magnetic modelling, static and dynamic simulations of CO₂ injection, and an evaluation of well integrity in the context of carbon capture and storage (CCS). The research was structured into three key analytical components presented in Chapters 2, 3, and 4, leading to the following major conclusions:

1. (Chapter 2) Evaluation of crustal settings through gravity and magnetic modelling

The Greater East Shetland Platform and its intra-platform basins were assessed using gravity and magnetic forward modelling techniques. The results provided new insights into the subsurface geological framework, demonstrating that these underexplored basins possess favourable geological characteristics for CO₂ storage. Key findings include:

- The identification of Mesozoic intra-platform basins with substantial sedimentary thickness suitable for CCS activities.
- Integration of seismic data with gravity and magnetic modelling highlighted structural complexities that influence the distribution of potential storage reservoirs.
- The estimated gross CO₂ storage capacity of the region ranges between 170 and 640 Mt, suggesting substantial storage potential, though further data acquisition and modelling are required to refine site-specific parameters.

2. (Chapter 3) Static modelling and dynamic simulation of regional-scale CO₂ injection

The research then focused on the Silverpit Basin in the Southern North Sea, evaluating its suitability for multiple large-scale CO₂ injection scenarios. The primary storage target, the Bunter Sandstone Formation (BSF), was modelled to assess pressure evolution, plume migration, and reservoir behaviour under different injection strategies. Key findings include:

- A comprehensive static and dynamic model covering ~9000 km² was developed, incorporating petrophysical parameters, boundary conditions, and multiple injection scenarios.
- Simulation results indicate that the BSF can safely store up to 750 Mt of CO₂. However, managing regional pressure build-up is critical to avoid potential interactions between injection sites.
- Brine displacement and pressure perturbations could lead to long-term effects such as slow brine migration towards the seabed, requiring careful monitoring and mitigation strategies.
- Localised heterogeneities in permeability and geological structures affect CO₂ plume migration, reinforcing the need for field-scale refinement to improve accuracy.

3. (Chapter 4) Well-integrity assessment of plugged and abandoned wells

Considering the history of hydrocarbon production in the Silverpit Basin since the mid-1960s, an evaluation was performed on the integrity of abandoned wells to identify potential leakage risks and other impacts related to P&A wells linked to CCS activities. The assessment centred on seventeen wells with diverse abandonment conditions. Key findings include:

- Many abandoned wells were not initially designed to coexist with CCS activities; therefore the integrity of their barriers is a crucial factor in long-term containment.

- Casing collapse risk was identified in seven wells, particularly those with 13 3/8" casing in the reservoir interval, due to lateral pressure increases caused by CO₂ injection over time.
- Cement plug depths in some wells were shallower than the minimum safe abandonment depth (MSAD), increasing the risk of CO₂ migration along the wellbore.
- Regulatory frameworks for well abandonment have evolved over time, leading to inconsistencies in barrier placement and long-term containment strategies.

4. Overall Conclusions and Implications

This thesis underscores the importance of a regional-scale approach in CCS site selection and risk assessment. The findings demonstrate that:

- Multi-method integration, including geophysical modelling, dynamic simulations, and well integrity analysis, is essential for a comprehensive evaluation of CO₂ storage potential.
- The Greater East Shetland Platform basins and the Silverpit Basin provide significant storage opportunities, but site-specific challenges must be addressed before large-scale deployment.
- Pressure management, well integrity, and long-term monitoring are critical factors in ensuring the safe and effective implementation of CCS in these regions.

The next section will discuss recommendations for future research, building on these findings to refine storage strategies and enhance risk mitigation approaches.

5.2 Recommendations for Future Investigations

5.2.1 Impact of Regional Gradients

The influence of regional gradients on CO₂ storage performance remains an area requiring further investigation. The presence of a significant salinity gradient across the Silverpit Basin, ranging from 180,000 to 300,000 ppm (Noy et al., 2012), suggests variability in CO₂ phase behaviour and buoyancy effects. Higher salinity levels lead to increased brine density, potentially altering CO₂ migration pathways and dissolution rates. Additionally, the impact of the geothermal gradient on storage integrity must be evaluated, as temperature variations influence CO₂ solubility and pressure distributions. Furthermore, the role of pre-existing fluid flow patterns caused by regional stresses should be examined to determine their contribution to impact regional pressure gradients and, therefore CO₂ migration. A comprehensive analysis incorporating basin-scale simulations and high-resolution subsurface data is essential to refine predictions of CO₂ behaviour under these complex gradient conditions.

5.2.2 Contribution of Underlying and Sealing Formations in Pressure Dissipation

The role of underlying and sealing formations in pressure dissipation remains a critical uncertainty in CO₂ storage modelling. Models developed in this, and other studies predominantly assume impermeable boundaries; however, even low-permeability formations, such as shales and mudstones, can significantly influence pressure migration as a function of their areal extent. The Solling Claystone and the Bunter Shale formations likely exhibit permeability values in the range of 10^{-3} to 10^{-4} (Armitage et al., 2016; Spain and Conrad, 1997), which could substantially impact pressure dissipation over large surface areas. Future simulations should incorporate realistic permeability values to better predict pressure behaviour. Additionally, targeted petrophysical characterisation and advanced numerical modelling are necessary to refine assessments of pressure dissipation and enhance long-term storage security.

5.2.3 Impact of Further Geological Heterogeneities

Geological heterogeneities, including depositional facies variations, fault structures, and stratigraphic baffles, play a crucial role in containment efficiency. The risk of fault reactivation due to injection-induced pressure changes is particularly concerning in domal structures, where subseismic fault systems may exist (Bentham et al., 2013; Williams et al., 2014). Accurately quantifying fault permeability variations is essential to assess potential CO₂ leakage pathways and pressure dissipation mechanisms. Additionally, horizontal baffles within the storage formation can significantly alter fluid flow dynamics, leading to localised pressure build-ups and complex plume migration patterns. Therefore, detailed field-scale modelling is suggested. Further research should also explore the transmissibility factor and the extent of reservoir subcrop locations to better understand their influence on the displacement of formation brine at the subcrop, as highlighted in this study.

5.2.4 Simulations and Modelling Tools

The choice of simulation tools is crucial for improving CO₂ storage predictions. Current models rely predominantly on Darcy law for flow simulation; however, integrating Young-Laplace formulations would enable a more accurate representation of capillary pressure thresholds, eliminating the need for explicit permeability input. Additionally, incorporating chemical tracers into models can provide insights into brine composition changes and enhance the understanding of salinity gradients at outcrop locations. The application of seismic inversion techniques and attribute analysis can aid in the characterisation of near-well heterogeneities, improving model calibration. Future research should focus on the integration of multi-physics approaches, combining fluid dynamics, geomechanics, and geochemical interactions to develop a more comprehensive framework for evaluating CO₂ migration and storage security under realistic subsurface conditions.

5.2.5 Impact of Hydrocarbon Fields

The presence of hydrocarbon fields within the study area introduces additional complexities to CO₂ storage performance. Interactions between CO₂ and residual hydrocarbons may enhance plume migration due to reduced density and viscosity effects. In particular, depleted gas fields in the eastern region are underpressured, potentially influencing regional pressure relaxation and affecting CO₂ containment. The compressibility of residual gas must be considered, as it may contribute to pressure fluctuations and unintended migration pathways. Additionally, the potential for CO₂ dissolution into hydrocarbons and subsequent phase behaviour alterations requires further experimental and numerical investigations. Future work should include such parameters coupled with compositional simulation to quantify these interactions and assess their implications for long-term CO₂ storage stability.

5.2.6 Near-well Uncertainties

Near-wellbore processes play a crucial role in determining injectivity and storage efficiency. CO₂ injection in high-salinity reservoirs can lead to brine evaporation and halite precipitation, reducing porosity and permeability in the near-well region (Badejo et al., 2024; Ogundipe et al., 2024b, 2024a). This phenomenon is particularly relevant at high injection rates, where dry-out zones develop, exacerbating salt deposition. However, feedback mechanisms, including brine re-saturation and self-healing processes, may mitigate some of these effects. Understanding the balance between injection rate, gravity segregation, and capillary forces is essential to optimising well performance. Such parameters should be included to evaluate the injectivity which thereby will impact the pressure diffusion in the region.

5.2.7 Wellbore Risk Mitigation

Ensuring wellbore integrity is fundamental to the success of CCS projects, as compromised wells pose a significant risk of leakage and environmental contamination.

Chemical interactions between CO₂, brine, and wellbore materials can lead to cement and casing degradation, ultimately threatening long-term containment. Studies have demonstrated that CO₂-saturated brine induces cement carbonation, forming zones of altered material that may extend up to several metres over thousands of years (Carroll et al., 2016). However, field investigations suggest that mechanical integrity, including proper cement placement and casing bonding, plays a more crucial role in preventing leakage than chemical degradation alone (Duguid et al., 2017). One of the primary concerns is the development of fractures and annular pathways, which significantly increase permeability and create potential conduits for CO₂ migration. In addition, creeping formations such as halite and mudstone have been found to contribute to well integrity by exerting radial stress that can close micro-annuli and restore sealing capacity (Loizzo et al., 2024). Given these challenges, future research should prioritise in-situ monitoring techniques, including non-invasive geophysical methods, and explore advanced wellbore sealing materials such as self-healing cements and geochemically reactive barriers (Romdhane et al., 2022). These innovations will be critical in mitigating both chemical and mechanical degradation effects, ensuring the long-term security of geological CO₂ storage sites.

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Appendix

Supplementary Material C.2

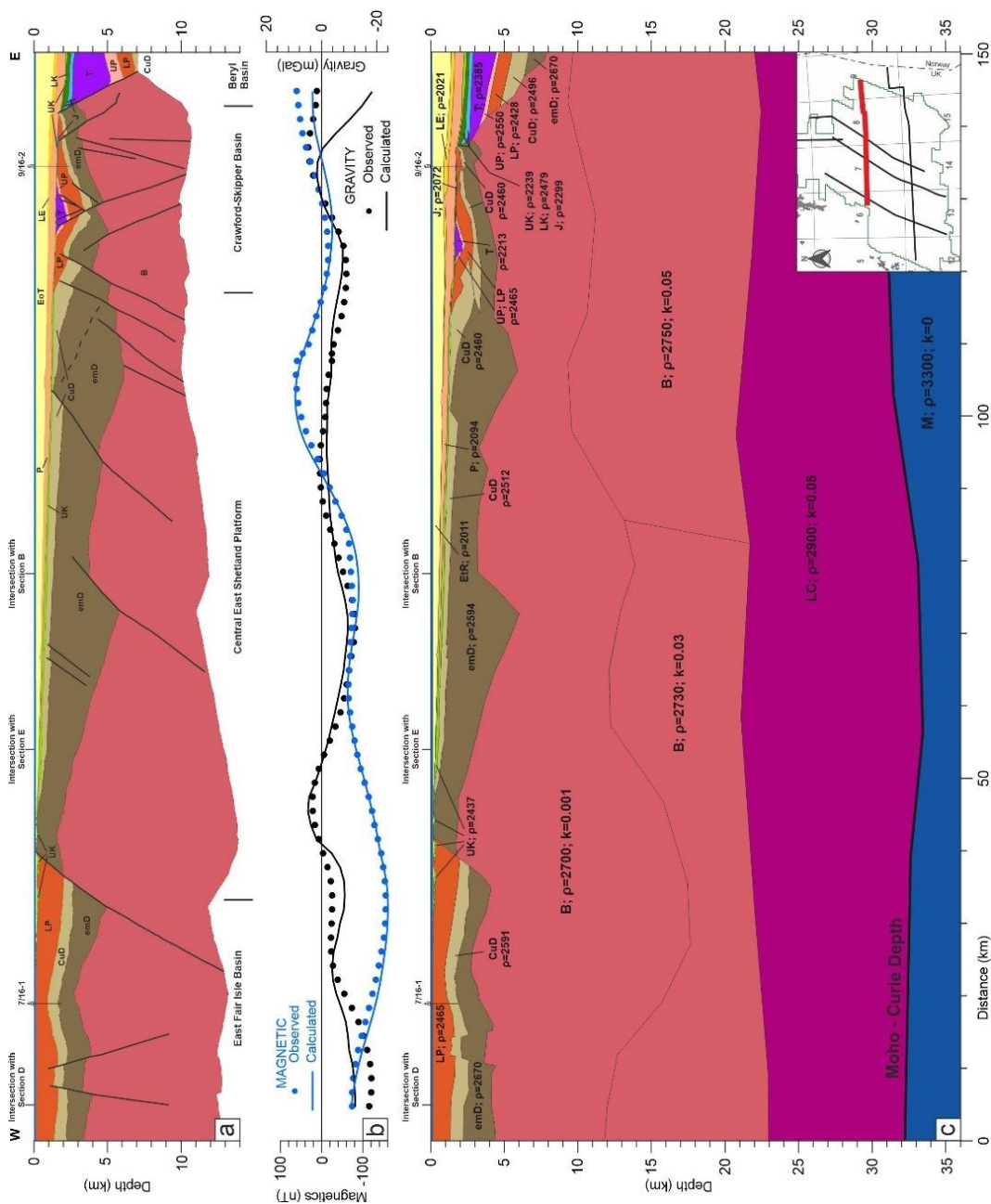


Fig. S2.1 Gravity and magnetic anomalies model across the Section C (seismic line name: 024A024 Extra-B). (a) Depth-converted section. (b) Anomaly curves best fitting. (c) 2D integrated forward model. Modelled density (ρ) and magnetic susceptibility (k) values are given for each block in the lower panel. Bathymetry across the modelled profile ranges mainly between 50 and 150 m. Label abbreviations are the same of those shown in Tab. 2.1. In the inset, the thick red line shows the extent of the modelled section while the green line represents the extent of the modelled gravity and magnetic anomaly grids.



Fig. S2.2 Gravity and magnetic anomalies model across the Section D (seismic line name: OA16ESP00039A032). (a) Depth-converted section. (b) Anomaly curves best fitting. (c) 2D

integrated forward model. Modelled density (ρ) and magnetic susceptibility (k) values are given for each block in the lower panel. Bathymetry across the modelled profile ranges mainly between 50 and 150 m. Label abbreviations are the same of those shown in Tab. 2.1. In the inset, the thick red line shows the extent of the modelled section while the green line represents the extent of the modelled gravity and magnetic anomaly grids.



Fig. S2.3 Gravity and magnetic anomalies model across the Section E (seismic line name: OA16ESP00109A011). (a) Depth-converted section. (b) Anomaly curves best fitting. (c) 2D integrated forward model. Modelled density (ρ) and magnetic susceptibility (k) values are given for each block in the lower panel. Bathymetry across the modelled profile ranges mainly between 50 and 150 m. Label abbreviations are the same of those shown in Tab. 2.1. In the inset, the thick

red line shows the extent of the modelled section while the green line represents the extent of the modelled gravity and magnetic anomaly grids.

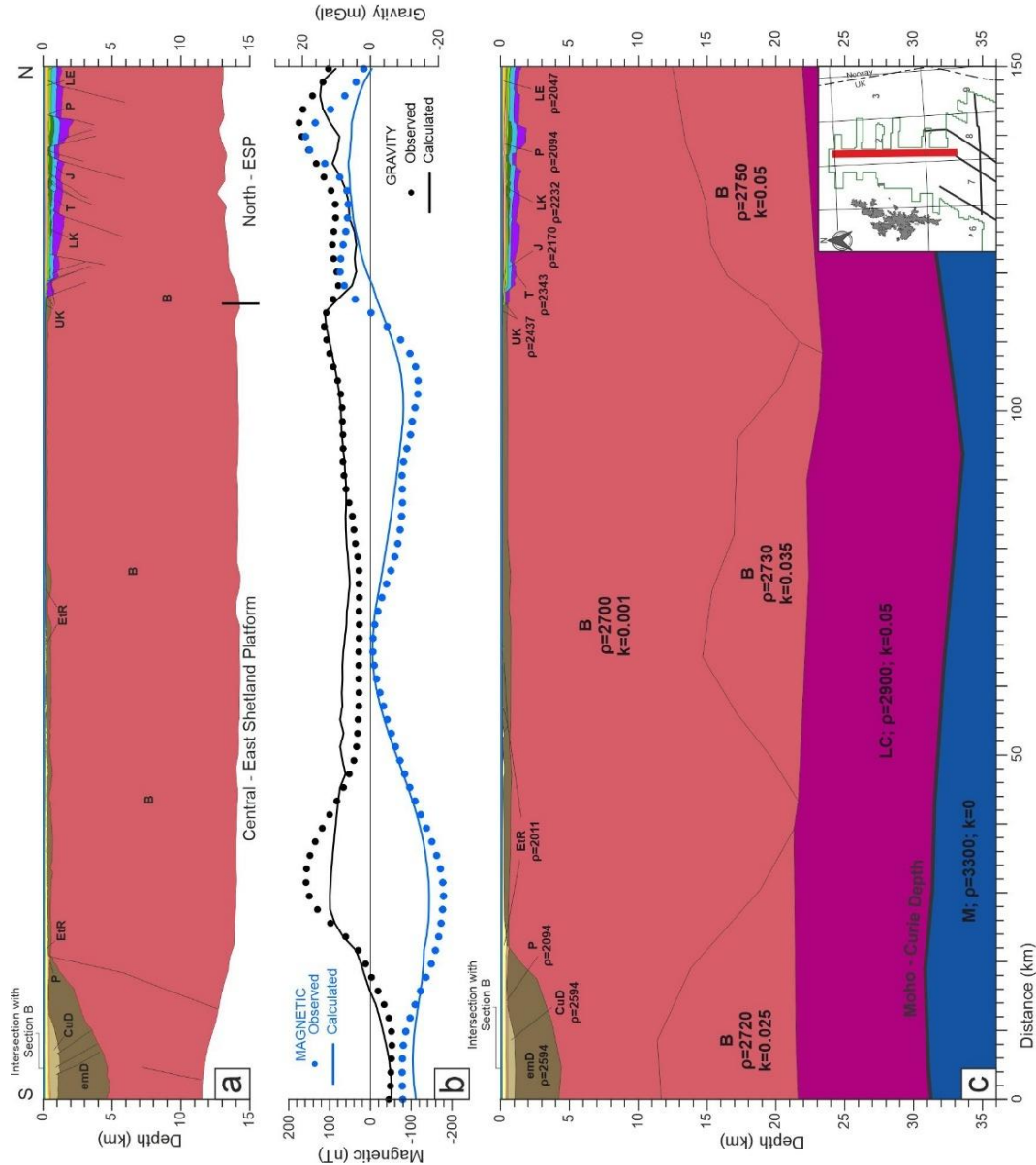


Fig. S2.4 Gravity and magnetic anomalies model across the Section E (seismic line name: OA16ESP00091A093). (a) Depth-converted section. (b) Anomaly curves best fitting. (c) 2D integrated forward model. Modelled density (ρ) and magnetic susceptibility (k) values are given for each block in the lower panel. Bathymetry across the modelled profile ranges mainly between 50 and 150 m. Label abbreviations are the same of those shown in Tab. 2.1. In the inset, the thick red line shows the extent of the modelled section while the green line represents the extent of the modelled gravity and magnetic anomaly grids. ESP, East Shetland Platform.

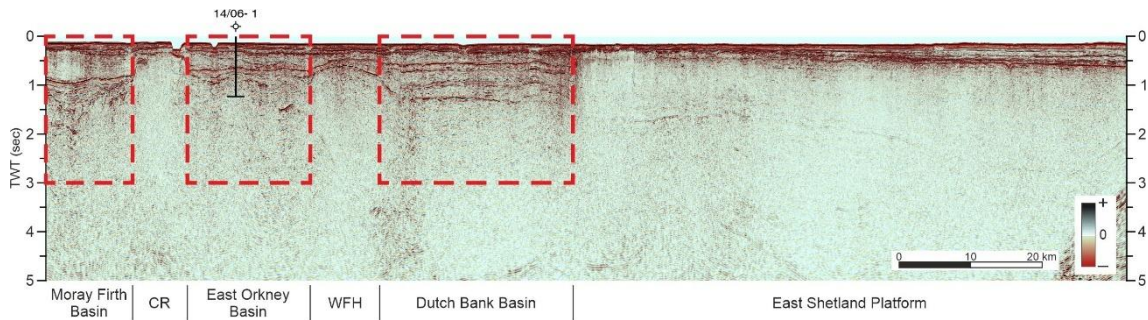


Fig. S2.5 2D seismic reflection profile of Section E (seismic line name: OA16ESP00109A011) from the PP162DGOGA survey (NSTA, 2022). Red dashed polygons enclose areas with thick sedimentary sequences. See Fig. 2.4b, Fig. 2.5c, Fig. 2.5d for location. CR, Caithness Ridge; WFH, West Fladen High.

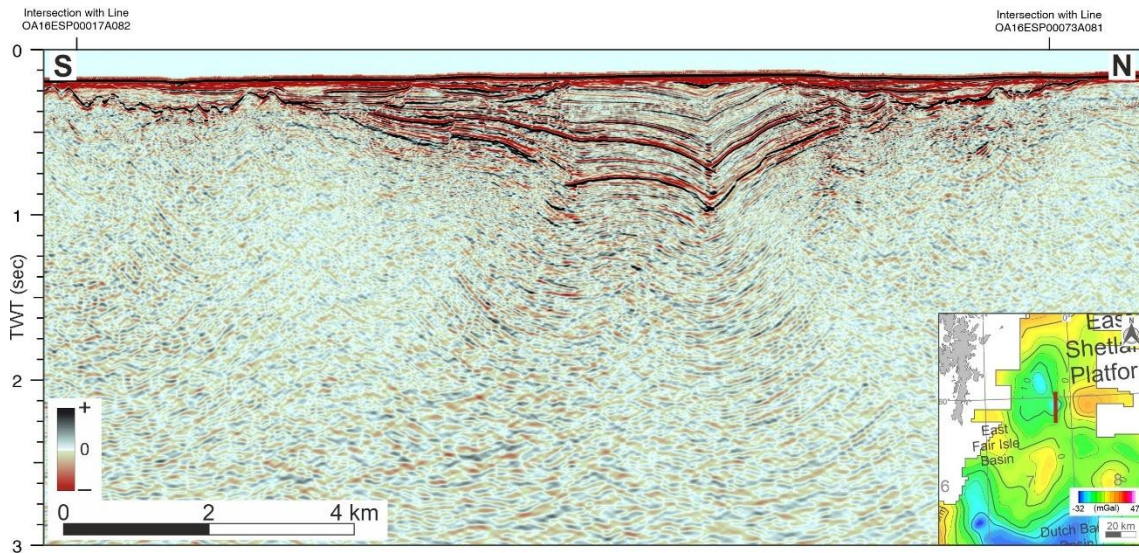


Fig. S2.6 Part of OA16ESP000090A076 seismic profile from the PP162DGOGA survey (NSTA, 2022). Local gravity low associated with local-scale sedimentary basin of inferred Mesozoic sediments northeast of the East Fair Isle Basin. Red bold line in the inset locates the showed profile, overlying the Bouguer total gravity anomaly shown in Fig. 2.4.

Supplementary Material C.3

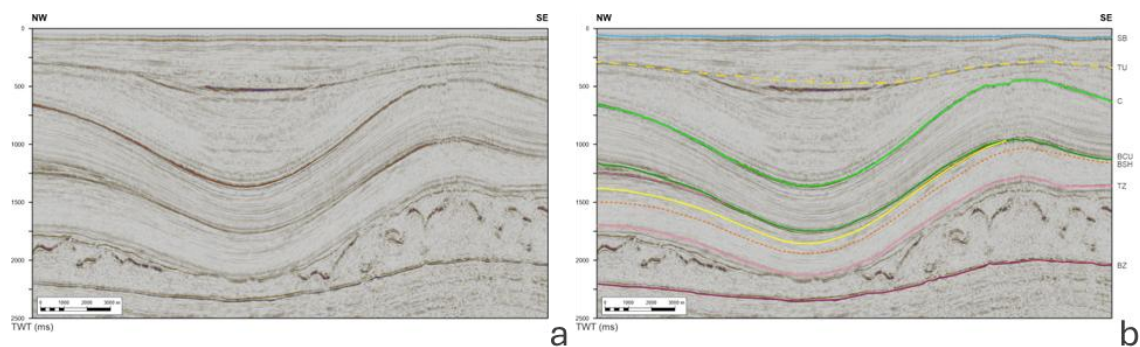


Fig. S3.7 (a) uninterpreted and (b) interpreted seismic section illustrating BSF reservoir erosional truncation by the BCU unconformity in the southeastern part of the Silverpit Basin. See Fig. 3.2b for location.

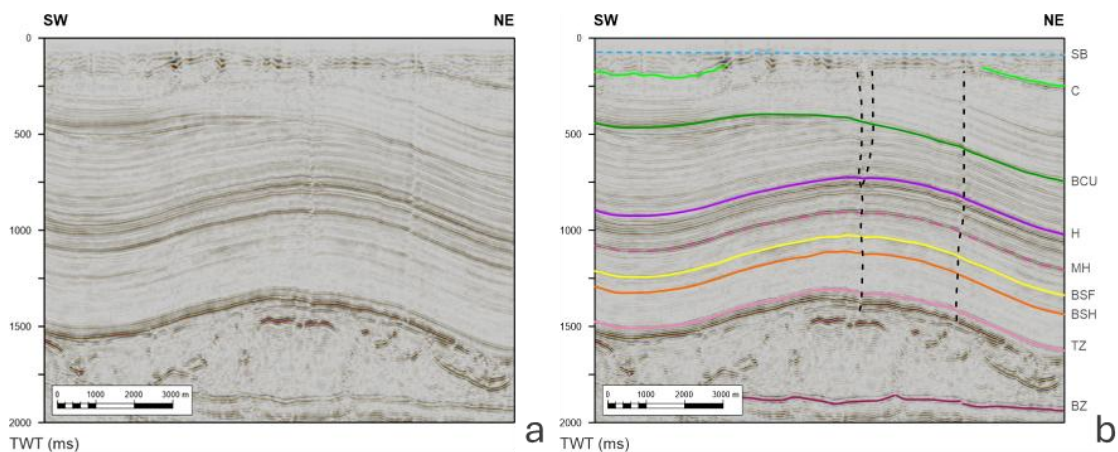


Fig. S3.8 (a) uninterpreted and (b) interpreted seismic section illustrating possible gas chimney in the northwestern part of the Silverpit Basin. See Fig. 3.2b for location.

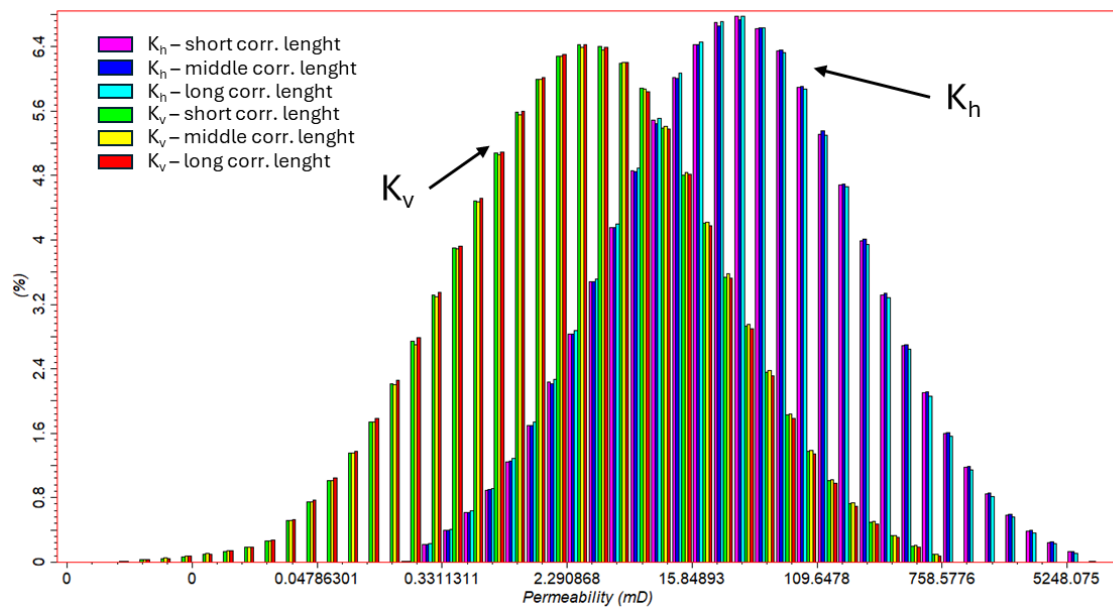


Fig. S3.9 Histogram plot of the horizontal (K_h) and vertical (K_v) permeability.



Fig. S3.10 CO₂ saturation 100 years after Cessation of Injection (COI).

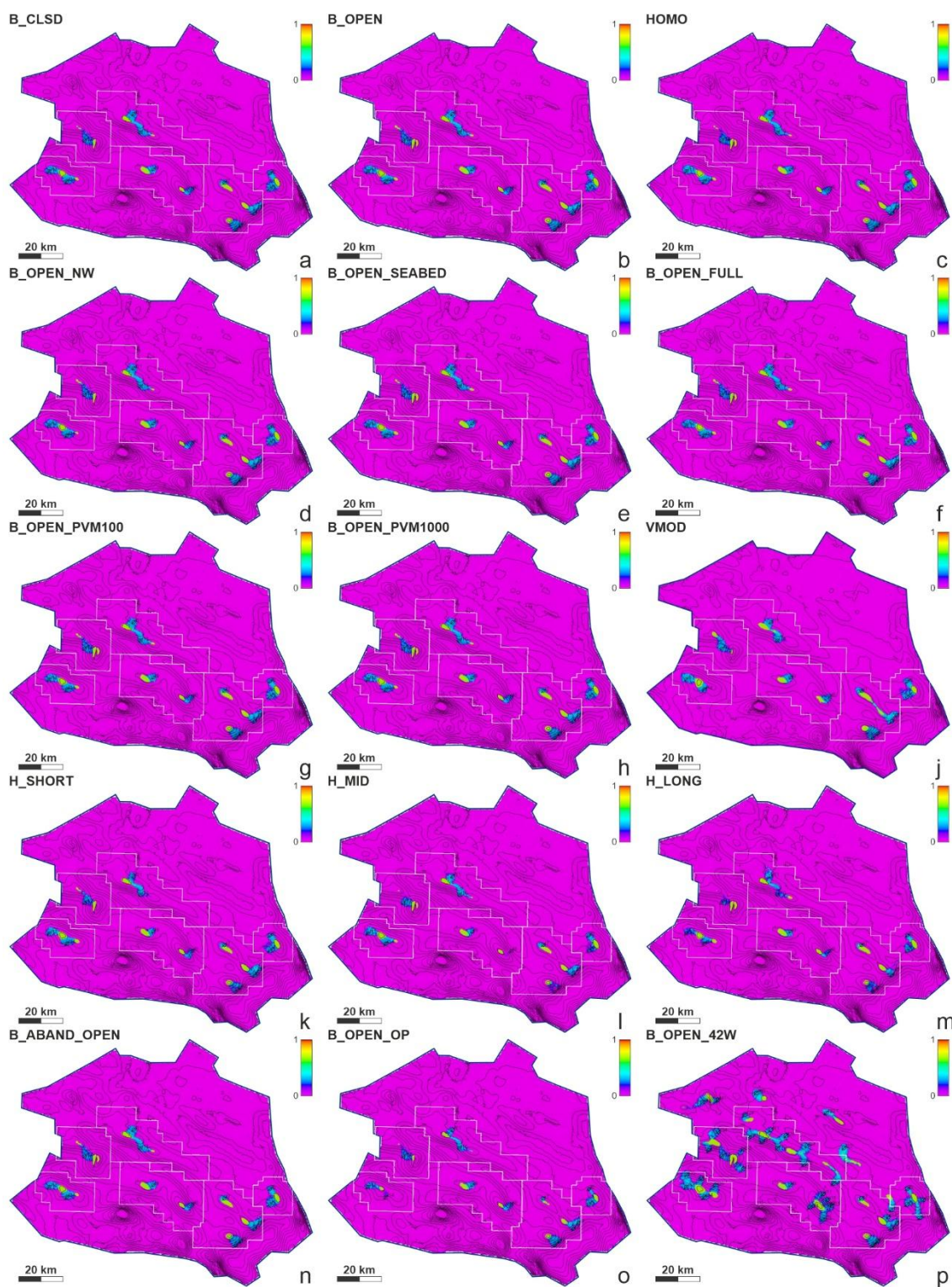


Fig. S3.11 CO₂ saturation 5000 years after Cessation of Injection (COI).

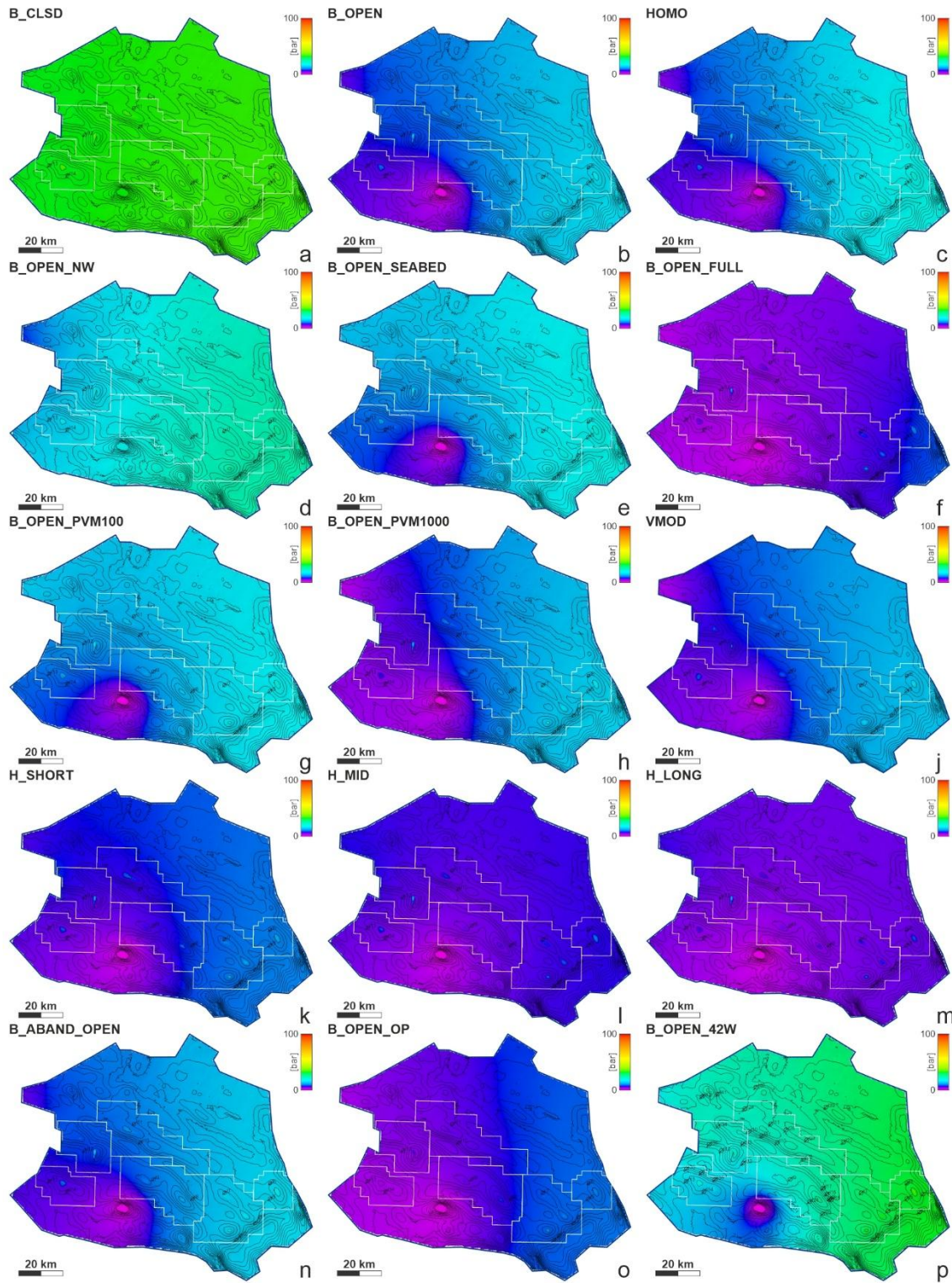


Fig. S3.12 Reservoir pressure increase compared to the initial pressure after 500 years from COI for each simulation scenarios. White polygons indicate awarded CO₂ storage licenses.

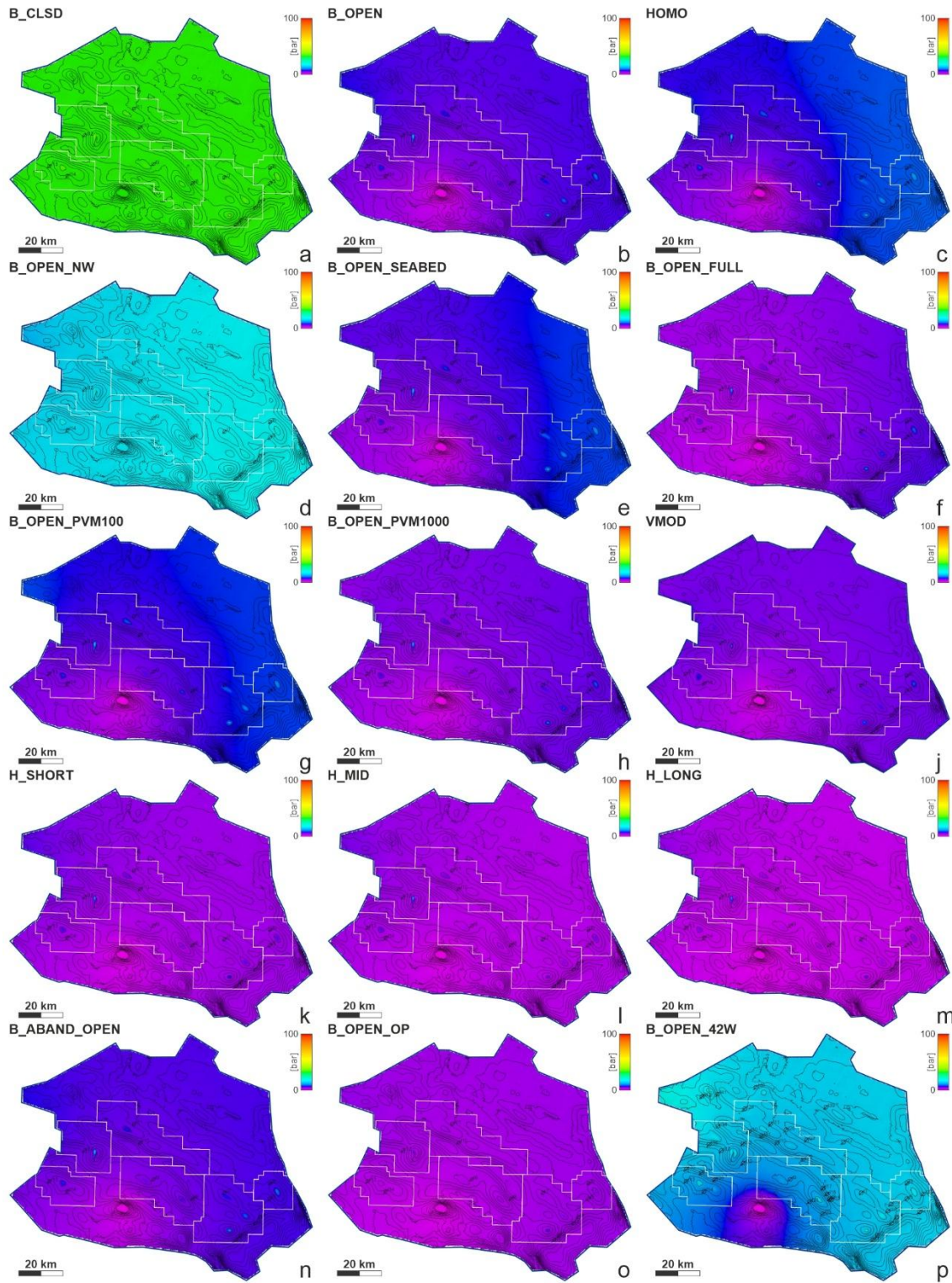


Fig. S3.13 Reservoir pressure increase compared to the initial pressure after 5000 years from COI for each simulation scenario. White polygons indicate awarded CO₂ storage licenses.

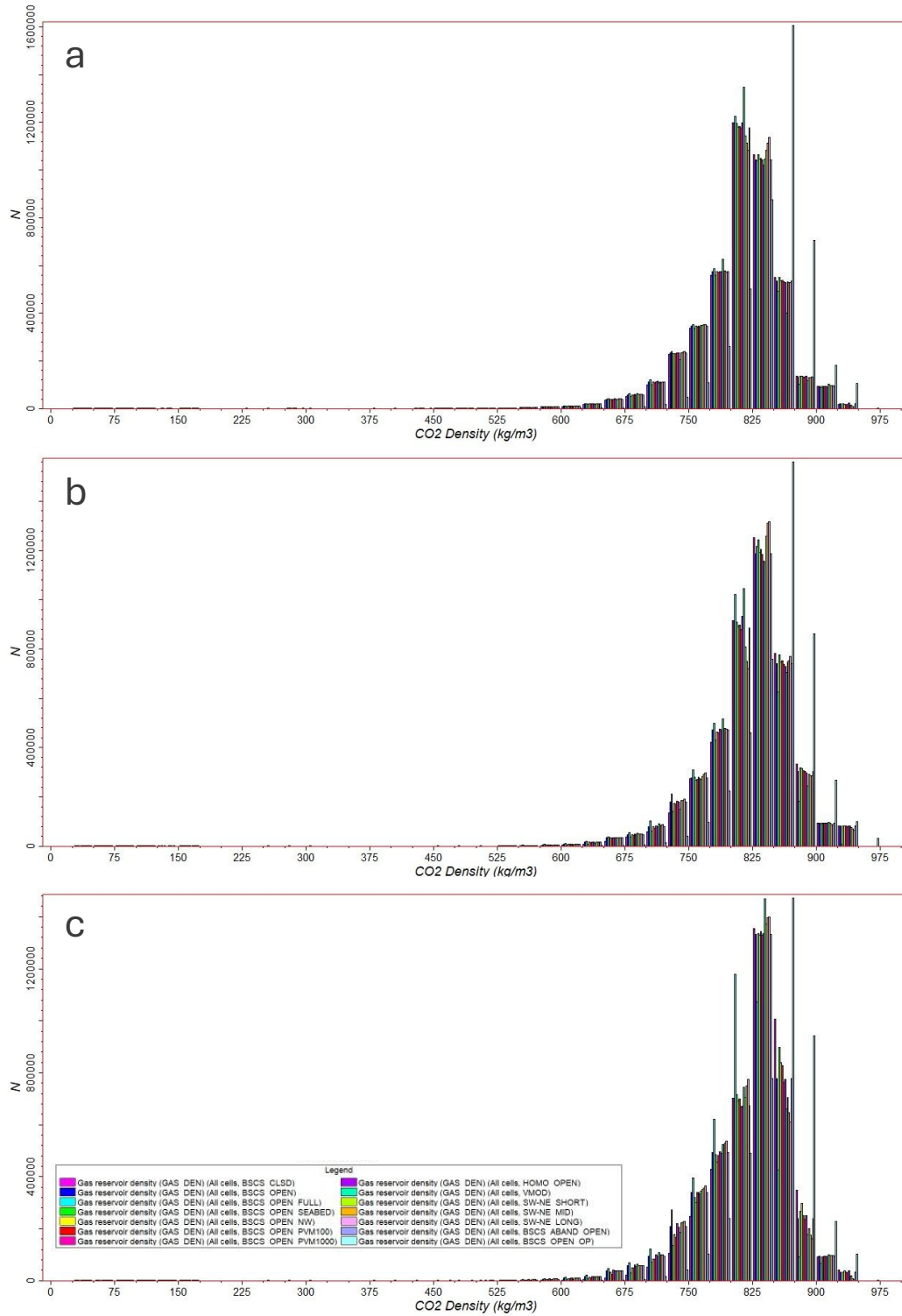


Fig. S3.14 CO₂ density distribution in reservoir conditions at (a) 25, (b) 50, and (c) 150 years post-SOI for each simulation scenario. The majority of cells exhibit a density between 800 and 850 kg m⁻³ for these times.

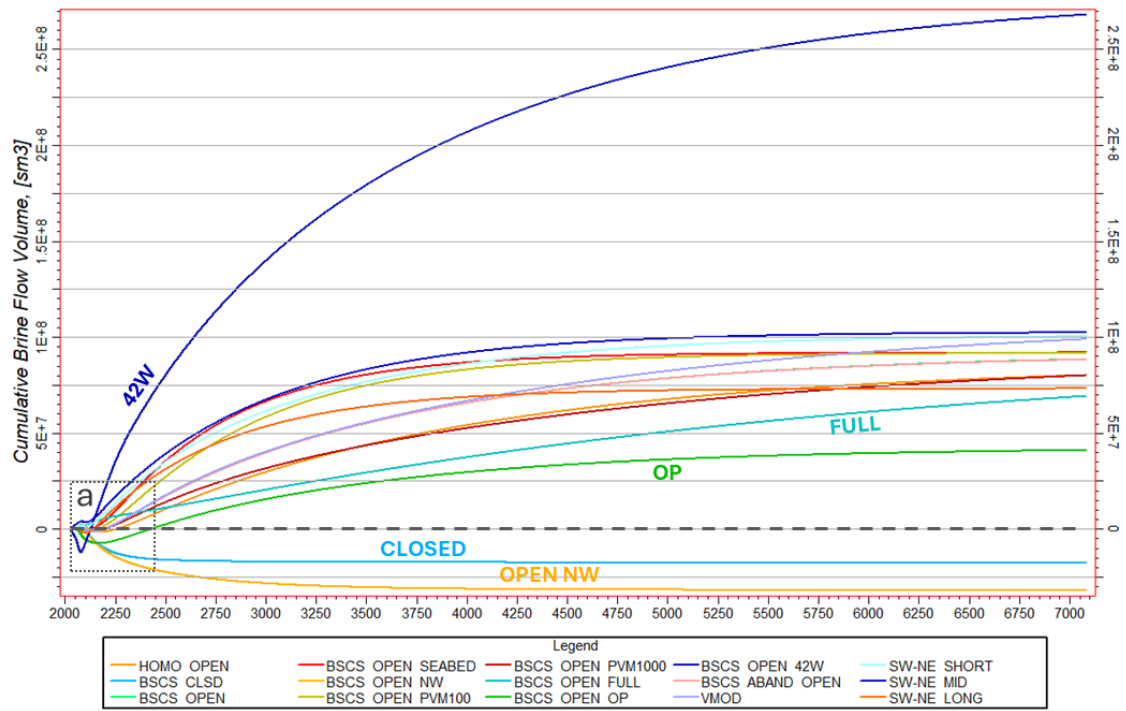


Fig. S3.15 Cumulative brine volume flow from R.6 to R.4 over the entire simulation period for each simulation scenario. (a) indicates the extension of Fig. 3.30.

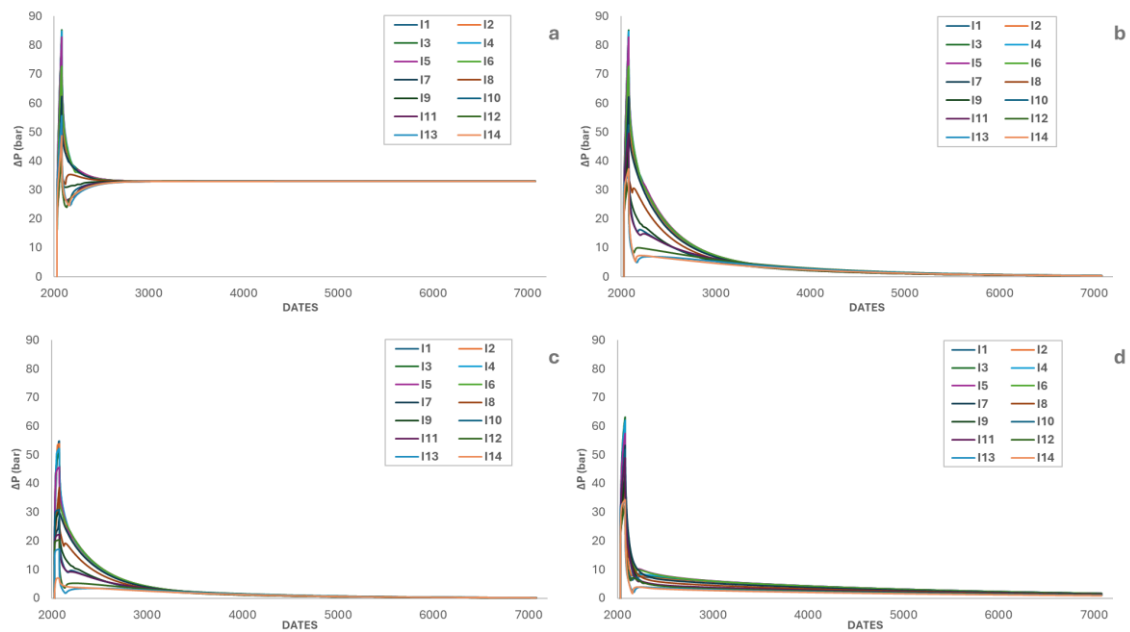


Fig. S3.16 Pressure increases over time at the top-reservoir depth (i.e. uppermost cell) injection point for (a) confined, (b) reference, (c) overpressured and (d) fully connected scenarios.

Scenario	Injection well	Depth (m)	Lithostatic pressure		Pressure limit		
			(MPa)	(psia)	(MPa)	(psia)	(bar)
Grid 1	I1	2037.1	45.83	6648	34.38	4986	344
Grid 1	I2	1999.5	44.99	6525	33.74	4894	337
Grid 1	I3	1985.9	44.68	6481	33.51	4861	335
Grid 1	I4	1986.0	44.69	6481	33.51	4861	335
Grid 1	I5	1836.5	41.32	5993	30.99	4495	310
Grid 1	I6	1577.5	35.49	5148	26.62	3861	266
Grid 1	I7	1454.2	32.72	4746	24.54	3559	245
Grid 1	I8	1890.1	42.53	6168	31.90	4626	319
Grid 1	I9	1629.2	36.66	5317	27.49	3987	275
Grid 1	I10	1566.5	35.25	5112	26.43	3834	264
Grid 1	I11	1410.2	31.73	4602	23.80	3451	238
Grid 1	I12	1407.6	31.67	4593	23.75	3445	238
Grid 1	I13	1331.6	29.96	4345	22.47	3259	225
Grid 1	I14	1183.2	26.62	3861	19.97	2896	200
Grid 1	I15	1941.6	43.69	6336	32.76	4752	328
Grid 1	I16	2033.6	45.76	6636	34.32	4977	343
Grid 1	I17	1970.6	44.34	6431	33.25	4823	333
Grid 1	I18	1864.4	41.95	6084	31.46	4563	315
Grid 1	I19	1895.5	42.65	6186	31.99	4639	320
Grid 1	I20	1717.0	38.63	5603	28.97	4202	290
Grid 1	I21	2070.6	46.59	6757	34.94	5068	349
Grid 1	I22	2055.3	46.24	6707	34.68	5030	347
Grid 1	I23	1906.8	42.90	6223	32.18	4667	322
Grid 1	I24	1796.3	40.42	5862	30.31	4396	303
Grid 1	I25	2010.5	45.24	6561	33.93	4921	339
Grid 1	I26	1915.0	43.09	6249	32.32	4687	323
Grid 1	I27	1811.9	40.77	5913	30.58	4435	306
Grid 1	I28	1619.6	36.44	5285	27.33	3964	273
Grid 1	I29	1492.6	33.58	4871	25.19	3653	252
Grid 1	I30	1682.9	37.87	5492	28.40	4119	284
Grid 1	I31	1577.9	35.50	5149	26.63	3862	266
Grid 1	I32	1400.4	31.51	4570	23.63	3427	236
Grid 1	I33	1382.9	31.12	4513	23.34	3385	233
Grid 1	I34	1440.2	32.40	4700	24.30	3525	243
Grid 1	I35	1305.2	29.37	4259	22.03	3194	220
Grid 1	I36	1623.9	36.54	5299	27.40	3975	274
Grid 1	I37	1681.9	37.84	5489	28.38	4116	284
Grid 1	I38	1581.8	35.59	5162	26.69	3871	267
Grid 1	I39	1616.3	36.37	5275	27.28	3956	273
Grid 1	I40	1661.0	37.37	5420	28.03	4065	280
Grid 1	I41	1304.6	29.35	4257	22.02	3193	220
Grid 1	I42	1330.4	29.93	4342	22.45	3256	225
Grid 2	I1	2332.2	52.47	7611	39.36	5708	394
Grid 2	I2	2186.2	49.19	7134	36.89	5351	369
Grid 2	I3	2024.9	45.56	6608	34.17	4956	342
Grid 2	I4	1983.8	44.64	6474	33.48	4855	335
Grid 2	I5	1822.8	41.01	5948	30.76	4461	308
Grid 2	I6	1600.6	36.01	5223	27.01	3917	270
Grid 2	I7	1496.9	33.68	4885	25.26	3664	253
Grid 2	I8	1929.1	43.40	6295	32.55	4721	326
Grid 2	I9	1655.8	37.26	5403	27.94	4053	279
Grid 2	I10	1548.3	34.84	5053	26.13	3789	261
Grid 2	I11	1365.0	30.71	4454	23.03	3341	230
Grid 2	I12	1502.8	33.81	4904	25.36	3678	254
Grid 2	I13	1285.4	28.92	4195	21.69	3146	217
Grid 2	I14	1131.7	25.46	3693	19.10	2770	191

Tab. S3.1 Injection well depth, lithostatic pressure and bottom hole pressure limit of the wells used in the study for each grid and scenario.

