Assessment of the Geological Storage Potential of Carbon Dioxide in the Mid-Atlantic Seaboard: Focus on the Outer Continental Shelf of North Carolina

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Dissertation submitted to the faculty of the Virginia Polytechnic Institute and State University in partial fulfillment of the requirements for the degree of

Doctor of Philosophy
In
Mining Engineering

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March 25th 2019
Blacksburg, Virginia

Keywords: Carbon dioxide, geological storage, offshore storage, seismic interpretation, reservoir simulation, storage capacity

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ABSTRACT

In an effort to mitigate carbon dioxide (CO_2) emissions in the atmosphere, the Southeast Offshore Storage Resource Assessment (SOSRA) project has for objective to identify geological targets for CO_2 storage in two main areas: the eastern part of the Gulf of Mexico and the Atlantic Ocean subsurface. SOSRA's second objective is to estimate the geological targets' capacity to store up to 30 million metric tons of CO_2 each year with an error margin of ±30%. As part of this project, the research presented here focuses on the outer continental shelf of North Carolina and its potential for the deployment of large-scale offshore carbon storage in the near future.

To identify geological targets, workflow followed typical early oil and gas exploration protocols: collecting existing datasets, selecting the most applicable datasets for reservoir exploration, and interpreting datasets to build a comprehensive regional geological framework of the subsurface of the outer continental shelf. The geomodel obtained can then be used to conduct static volumetric calculations estimating the storage capacity of each identified target. Numerous uncertainties regarding the geomodel were attributed to the variable coverage and quality of the geological and geophysical data. To address these uncertainties and quantify their potential impact on the storage capacity estimations, dynamic volumetric calculations (reservoir simulations) were conducted. Results have shown that, in this area, both Upper and Lower Cretaceous Formations have the potential to store large amounts of CO_2 (in the gigatons range). However, sensitivity analysis highlighted the need to collect more data to refine the geomodel and thereby reduce the uncertainties related to the presence, dimensions and characteristics of potential reservoirs and seals. Reducing these uncertainties could lead to more accurate storage capacity estimations. Adequate injection strategies could then be developed based on robust knowledge of this area, thus increasing the probability of success for carbon capture and storage (CCS) offshore projects in North Carolina's outer continental shelf.

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GENERAL AUDIENCE ABSTRACT

Since the industrial revolution, a significant increase in the anthropogenic emissions of greenhouse gases has been observed worldwide. The rise in concentration of these gases in the atmosphere, specifically carbon dioxide (CO_2), has been linked to an increase in the average temperature on Earth, what is commonly known as global warming. To mitigate the emission of anthropogenic CO_2 in the atmosphere and consequently limit its impact on Earth's climate, Carbon Capture and Storage projects (CCS) have been developed on various scales. In this type of project, CO_2 is captured from an emitting source (e.g., power plants), then transported via pipelines and stored in deep geological formations. In the United States, onshore CCS projects have demonstrated the technical feasibility of such projects. However, controversies associated with public acceptance and mineral ownership make expansive onshore CCS project development complicated. For these reasons, the U.S. Department of Energy (DOE) has been investigating offshore locations for the deployment of large-scale CCS projects. Southeast Offshore Storage Resource Assessment (SOSRA) is a project sponsored by the U.S. DOE to assess the storage potential of the eastern part of the Gulf of Mexico and the Atlantic Ocean as a first step towards the development of large-scale offshore storage of CO_2.

The state of North Carolina was identified as an adequate candidate for CO_2 offshore storage due to its location on the Atlantic coast and its elevated CO_2 emissions from the power plants on its coastal plains. However, as exploration conducted on the outer continental shelf of North Carolina has been minimal, published information regarding the subsurface of this area remains limited to this date. To ensure the safe, long-term storage of CO_2 in this area, an extensive study was needed to select suitable geological formations and determine the storage capacity of each identified target. The research described here aimed to identify such geological targets and estimate the CO_2 storage capacity of North Carolina's outer continental shelf

DEDICATION

This dissertation is dedicated to my two biggest fans, my husband Douglas and my father Fulvio.

ACKNOWLEDGEMENTS

I would like to thank my advisor Dr. Nino Ripepi for giving me the opportunity to work and study at Virginia Tech and for guiding me in my research for the last three years allowing me to complete this dissertation.

I would also like to acknowledge the U.S. Department of Energy for funding this project (under contract DE-FE0026086).

I would also like to thank my committee members for accepting to be a part of my research team and for providing guidance throughout my time at Virginia Tech. Your feedbacks helped me enlarged my perspectives on my project and led to the dissertation I am proud of today.

A special thank you to Charles Schlosser, who has been the best research partner I could have asked for. I learned a lot from him and I am very grateful I had the chance to work with him on this challenging project. You made me a real engineer Charlie.

Another special thank you to Andrew Parent, the geologist of the team, who tremendously helped me achieve my goals this last year and shared my passion for Disney World. We'll meet again and it will be at Epcot.

I would like to thank my support group at home. I am very fortunate to have an amazing family here in Blacksburg, my husband Douglas, my in-laws Tina and Doug and my cat "daughter" Nini. Thank you all for supporting me through the ups and downs of my doctoral studies, I could not have done it without you.

Finally, I would like to thank my friends here at Virginia Tech: Manuel, Ellie, Jon, Juan, Joe and Aman. If the bond of this group can survive graduate school, then there is nothing stopping us now.

Go Hokies!

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CHAPTER 4 – CO_2 STORAGE CAPACITY ASSESSMENT IN THE OUTER CONTINENTAL SHELF OF NORTH CAROLINA.

INTRODUCTION

The geological storage of CO_2 represents the last step in Carbon Capture and Storage (CCS) projects. The technical feasibility of such projects has proven successful in both onshore and offshore environments. In the state of North Carolina, the anthropogenic emissions of CO_2 could be mitigated with the implementation of large-scale offshore geological storage. However, site selections, prior to the development of such projects, need to be thorough to ensure the large storage capability of identified targets and the provision of a safe and efficient CO_2 injection over a long period of time.

Chapter 1 – *Review of CO_2 Geological Storage Mechanisms and the Potential of the Atlantic Ocean for Commercial Development,* prepares readers with an understanding of the geological requirements used to select a potential injection site. This section also presents the mechanisms responsible for the safe, long-term sequestration of CO_2 in geological formations. A description of reservoirs suitable for CO_2 storage and the thermodynamic in-situ conditions (pressure and temperature) required to store supercritical CO_2 are discussed. Past oil and gas exploration campaigns have provided some insight on the subsurface of the Mid-Atlantic continental shelf, and geological information published after these campaigns was collected in this chapter to provide an overview of the regional stratigraphic framework of this area.

Chapter 2 – *Assessment of Geophysical Data Quality and Coverage for the Continental Shelf of Virginia and North Carolina,* focuses on the selection of a publicly available dataset suitable for reservoir exploration. This chapter describes the methodology followed to assess the geological and geophysical data coverage and quality in the Mid-Atlantic and, more specifically, offshore Virginia and North Carolina. The objective of this section is to provide an overview of the potential application for each dataset and its associated limitations. To identify potential

reservoirs, a large variety and density of data is needed. Even though past exploration and academic campaigns produced extensive data, the usefulness of that data in the context of reservoir exploration had to be determined to select the most applicable datasets to identify potential targets for CO_2 storage. Typically, the depth of penetration and vertical resolution of seismic data are critical parameters to image deep reservoirs. Characterizing the geometry of a potential target depends highly on the density of data in an area of interest. Lastly, well coverage is an important element to consider during exploration, as it can provide essential elements regarding lithologies and reservoir parameters. All of these aspects were analyzed and discussed in Chapter 2.

Chapter 3 – *CO_2 Reservoir Identification and Estimation of Storage Capacity of the Outer Continental Shelf of North Carolina Based on Seismic Stratigraphy and Onshore Correlations*, continued the study discussed in Chapter 2. The data selected in the previous chapter was interpreted to build an updated regional geological framework of the outer continental shelf of North Carolina. This chapter focuses on correlating major stratigraphic units interpreted in onshore wells to mapped sequence boundaries interpreted on 2D seismic reflection data. The objective of this correlation is to build a geomodel and estimate the CO_2 storage capacity of each identified target. Seismic stratigraphy can be used to distinguish stratigraphic units at various scale, depending on the resolution of the seismic data, and can produce predictions of sandstone (reservoir) and shale (seal) presence. With the correlation of these predictions to core data from wells located on the coastal plain of North Carolina, sandstone and shale formations can be extrapolated and mapped to produce isopachs of potential reservoirs and seals across the continental shelf. Basic volumetric calculations can be conducted by using isopach maps and by estimating the porosity of each potential reservoir. Another objective of this

chapter was to highlight the high uncertainty related to the interpretation and consequently on the storage capacity estimations.

Chapter 4 – *CO_2 Storage Capacity Assessment in the Outer Continental Shelf of North Carolina* addresses the uncertainty identified in Chapter 3 by conducting dynamic volumetric calculations to determine the impact of highly uncertain parameters on the storage capacity. One of the main challenges determined in Chapters 2 and 3 was the inability to image and map lateral stratigraphic traps due to the limited resolution of the seismic data. To address this issue, dynamic calculations had to be conducted on two types of aquifers: confined and open. In the confined aquifer, the objective was to optimize the storage capacity while managing any pressure buildup in the aquifer, thus preventing any geomechanical failures in the borehole and in the formation (risk of leakage). In an open aquifer, where pressure buildup represents less of a concern, plume extension needs to be managed to prevent unwanted migration of saltwater or CO_2 towards the coastal plain, which would limit the risk of freshwater contamination. First, this chapter focuses on the effect of reservoir dimensions, heterogeneity and compressibility of a confined saline aquifer on the CO_2 storage capacity. Then, the focus shifts towards the effect of permeability, porosity and net-to-gross ratio on plume extension after a long period of CO_2 injection. This chapter concludes with a comparison between the storage capacity results obtained with the static approach to the ones obtained with the dynamic approach.

Based on the research conducted in these four chapters, recommendations were made for the continuing exploration of North Carolina's outer continental shelf.

CHAPTER 1 – REVIEW OF CO_2 GEOLOGICAL STORAGE MECHANISMS AND THE POTENTIAL OF THE ATLANTIC OCEAN FOR COMMERCIAL DEVELOPMENT.

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ABSTRACT

Since the industrial revolution, the ever-growing emission of greenhouse gases in the atmosphere has led to an abnormal worldwide increase in global temperatures, also known as "global warming." Carbon dioxide (CO_2) anthropogenic emissions have been identified by the scientific community as one of the main factors responsible for global warming and climate change (Anderson, Hawkins, & Jones, 2016). While the extent and accuracy related to the projections of climate change facing mankind is still being debated by the scientific community, a worldwide effort to reduce CO_2 emissions in the atmosphere is taking place to limit global warming.

One avenue investigated to mitigate these emissions is carbon capture and storage (CCS). As many storage scenarios are possible, this paper focuses on the potential of geological storage of CO_2 in saline aquifers located on the Mid-Atlantic's continental shelf (Offshore Virginia and North Carolina). The deployment of large-scale CO_2 injection projects offshore requires a detailed understanding of the geology and physical boundaries of any possible storage sites to ensure the long-term and safe trapping of CO_2 in the subsurface. A thorough literature review was conducted to assess the conditions required to safely inject CO_2 into the subsurface of the Mid-Atlantic, along with the mechanisms allowing the injected CO_2 to be trapped indefinitely in

these deep reservoirs. Furthermore, the literature also provided a regional geological framework of the subsurface of the Mid-Atlantic Ocean, illuminating potential storage locations within the study area (P. M. Brown, Miller, & Swain, 1972; Poag, 1979).

1. INTRODUCTION: CARBON DIOXIDE, GLOBAL WARMING AND CARBON CAPTURE AND STORAGE

The United Nations Climate Change Conference held in 2015 set the worldwide objective to limit the increase in global temperature to 2°C, compared to pre-industrial temperatures. Steadily increasing temperatures have risen by 0.6°C since 1980. Therefore, to meet these goals, emissions of greenhouse gases (GHG) such as CO_2 need to be drastically reduced or mitigated in the near future (Anderson et al., 2016). The impact of industry innovation and new policies to reduce CO_2 emissions have already shown positive results in recent years. In the U.S., for instance, GHG emissions decreased by 2.7% from 2015 to 2016 (EPA, 2018).

The direct capture of CO_2 from various industries or power plants (gas and coal-fired) could be recycled for other industrial processes or transported and stored in deep geological formations (Blunt, 2010). Geological storage takes multiples forms, as it can occur in deep saline formations, depleted oil and gas reservoirs, and unmineable coal seams (NETL, 2007; D. Zhang & Song, 2014). Producing fields have also used the injection of CO_2 for secondary production. Enhanced oil recovery (EOR) uses gas flooding (CO_2) to stimulate the production of a field (Blunt, 2010) after primary production. This process is also known as carbon capture, utilization and storage (CCUS).

The onshore storage of CO_2 in deep saline aquifers, as well as depleted reservoirs, represents a valuable opportunity for large-scale CO_2 storage projects due to their large storage capacity

(NETL, 2007). In the U.S., an extensive volume of pore space in different types of reservoirs (mostly sedimentary rocks) has the potential to store from 2,020 to 14,220 gigatons of CO_2 (NETL, 2007; Orr Jr, 2004). Onshore projects have already been developed in the U.S., such as the Illinois Basin-Decatur field test, which injected over 1 million metric tons of CO_2 into the Mount Simon sandstone formation. Other successful projects, such as the Cranfield project in Mississippi and the Citronelle project in Alabama, provided valuable insight for substantial carbon storage in the future (NETL, 2007).

Despite its implicit capability, onshore storage projects can be challenging due to their locations near populated areas. Rigorous geological characterization for site selection, as well as extensive monitoring during and after injections phases, is necessary to limit the risk of unwanted gas leaks to the surface or shallow aquifers and to prevent surface deformations or induced seismicity. Offshore storage represents an important positive alternative because of its distance from populated areas and the associated absence of land and mineral ownership in these locations (NETL, 2007). However, the monitoring of these projects should remain a priority; some innovations in the monitoring domain are necessary to provide similar levels of monitoring capabilities to offshore projects (Reilly, 2008).

On the East Coast, more specifically in North Carolina and Virginia, emissions of CO_2 in 2016 ranged between 100 and 120 million metric tons of CO_2 per year with all sectors combined (residential, commercial, industrial, transportation, power plants, etc.) (EPA, 2018). These states are good candidates for offshore geological storage due to their location near the Atlantic Ocean. The Mid-Atlantic subsurface could host large-scale development of CCS with the capture of CO_2 from nearby industries and/or power plants, followed by the transport and offshore geological storage in distant deep saline aquifers.

Past oil and gas exploration campaigns conducted in the Mid-Atlantic identified the Baltimore Canyon Trough as a possible host for oil and gas reservoirs. Despite the attempt of these campaigns to find hydrocarbons in the region, multiple dry boreholes, drilled onshore and in the North Atlantic region, made the campaigns commercial failures at the time (Keer, 1988). However, in the Carolina Trough, offshore from North and South Carolina, no stratigraphic test was ever drilled, despite the hydrocarbon potentiality identified by geologists at the time (Carpenter, Amato, & Journal, 1992). In the case that hydrocarbons are found present in the Carolina Trough, CCUS could be considered in the Mid-Atlantic, as well.

2. OFFSHORE GEOLOGICAL STORAGE OF CARBON DIOXIDE

Similar to onshore projects, site selection represents a crucial element determining the success of a geological storage project. The presence of suitable reservoir rocks and multiple trapping mechanisms is essential for this type of project. Other identified criteria should also be considered for proper site selection and storage capacity estimations, such as basin activity (tectonic, geothermal, and hydrostatic gradients) and the presence of natural resources (i.e., oil and gas, coal, salt deposits, etc.) (S Bachu, Adams, & management, 2003).

Reservoir rocks suitable for CO_2 storage are, for the most part, clastic sedimentary rocks such as consolidated sandstone or carbonates. These reservoirs not only need to possess adequate porosity to provide sufficient pore volume and storage capacity, but also high permeability to allow storage efficiency through CO_2 injectivity (S Bachu et al., 2003). Sand deposits are considered the most valuable target for onshore and offshore storage, due to their high porosity (≈30%) and high permeability (≈100mD to 1D).

Prior to selecting a reservoir, defining the injection depth zone should be completed. Typically, supercritical CO_2 is injected in reservoirs that can maintain its supercritical state (minimum pressure of 7.38 MPa and temperature of 31.1°C) (S Bachu et al., 2003). Typical geothermal (25°C/km) and hydrostatic gradient 10.516 kPa/m (Sam Holloway, 1997) put the injection window at a minimum depth of 800 meters below the sea floor. However, these gradients are site dependent and can vary greatly, impacting the thermodynamic state of CO_2 in the reservoir (D. Zhang & Song, 2014). Supercritical CO_2 has a gas behavior that can fill a large volume of pore space in a reservoir but also has a liquid-like density ranging from 200 to 900 kg/m^3 (under different temperature), making it less dense than formation water (S Bachu et al., 2003). These properties allow CO_2 to migrate within the reservoir. The density difference between CO_2 and brine creates buoyancy forces that cause upward migration of supercritical CO_2 in the reservoir (Espinoza & Santamarina, 2017). Therefore, trapping mechanisms are necessary to prevent unwanted migrations of CO_2 outside the reservoir (vertically and laterally).

The main trapping mechanisms considered for regional assessment are stratigraphic and structural trapping. These traps provide geological boundaries, confining the reservoir and preventing any fluid migration out of the confined formation. These formations are seals making the reservoir a closed system. Stratigraphic traps are low permeability rocks located at the top and bottom of the reservoir (Vail, 1987). Other types of stratigraphic traps include the following: a) a reservoir pinching out in a less permeable formation (depositional pinch out); b) channels of sandstone surrounded by low permeability rocks (incised valley); c) alluvial fans (in the basin) in a low permeability formation; and d) high porosity carbonate reefs also in low permeability formations. Shales are typically considered ideal seals for stratigraphic trapping due to their low permeability. Structural trappings may include various types of complex geometries, such as

non-conductive faults or anticlines and salt domes create by tectonic activity. A combination of both structural and stratigraphic traps are needed for safe and lengthy CO_2 storage projects (Busch, Amann-Hildenbrand, Bertier, Waschbuesch, & Krooss, 2010).

Seals are critical components of safe CO_2 storage projects and prevent major leakages from the reservoir over long periods of time (Olabode & Radonjic, 2013). Evaluating the integrity of caprocks presents one of many challenges associated with site selection. Shales should preserve their sealing integrity, and the pressure increase associated with it, both during the injection phase (short-term) and also over a long period of time (after injection) to resist the buoyancy forces responsible for the upward migration of CO_2 in the reservoir (hydrodynamic trapping) (Espinoza & Santamarina, 2017; D. Zhang & Song, 2014). Shales' ductility provides the capability to resist these forces and limit the creation of permeable pathways (fractures) (Skerlec, 1999a). The ductility of shales can be determined by analyzing shale density from cores in the laboratory or can be derived from well density logs. Skerlec (1999) proposed that shale with a density higher than 2.1 g/cm^3 is susceptible to go through brittle failure under increased stress (such as CO_2 injection) and would consequently lose its seal integrity. In general, shales' ductility decreases with depth in most sedimentary basins. Therefore, shale ductility should be taken into account while defining the injection zone, to ensure the presence of an adequate seal.

Other trapping mechanisms exist within the reservoir at the pore scale. Capillarity, or residual trapping, renders CO_2 immobile by trapping CO_2 bubbles in the reservoir pores and disconnecting these bubbles from the mobile phase (Gershenzon, Ritzi, Dominic, Mehnert, & Okwen, 2017; Krevor et al., 2015; D. Zhang & Song, 2014). The mobility of CO_2 depends on the relative permeability of the rock to water and CO_2 (wettability and interfacial tension) (Krevor et al., 2015; Valle, Rodríguez, Grima, & Martínez, 2018) and on the capillarity pressures and fluid

saturations (Al-Menhali & Krevor, 2014; Al-Menhali, Niu, & Krevor, 2015; De Dios et al., 2016; dos Santos, Trevizan, & Martins; Valle et al., 2018). These parameters are properties of specific rock types. Capillary trapping takes place after the injection phase, when water reenters the pore (imbibition) (Iglauer, 2018; Krevor et al., 2015; Valle et al., 2018), and it also occurs during injection in heterogeneous reservoirs as snap-off trapping in smaller pores (Gershenzon et al., 2017). Multiple studies showed that the impact of residual or capillary trapping can be important for CO_2 storage, but it highly depends on changes in permeability curves and therefore on rock properties under reservoir pressure (Akbarabadi & Piri, 2013; Stefan Bachu, 2013; Burnside & Naylor, 2014; De Silva & Ranjith, 2012; Juanes, Spiteri, Orr, & Blunt, 2006; Valle et al., 2018).

While CO_2 migrates upward due to density differences, also known as natural convection (Neufeld et al., 2010; Riaz & Cinar, 2014; Slim, Bandi, Miller, & Mahadevan, 2013), some of the supercritical CO_2 is immobilized by capillary trapping while another fraction dissolves in brine (De Silva & Ranjith, 2012). CO_2 dissolution in brine (formation water) represents another type of trapping, with a rate depending on the salinity of the formation water, pressure and temperature conditions in the reservoir, and the efficiency of the convective transport (Stefan Bachu, 2015; Riaz & Cinar, 2014; Rumpf, Nicolaisen, Öcal, & Maurer, 1994; Spycher & Pruess, 2005). The dissolution of CO_2 in brine increases the density of the mixture and therefore enhances diffusion in the reservoir. This process attenuates the upward migration of CO_2 and increases storage efficiency (CO_2 and water become one phase) (Metz et al., 2005; D. Zhang & Song, 2014). However, the impact of this process is minimal compared to the other type of trapping mechanisms during the injection phase (≈1%) and therefore is of limited importance for storage capacity estimation (Stefan Bachu, 2015).

Following the dissolution of CO_2 in brine, the formation of carbonate minerals can occur as a result of the precipitation of ion species within the reservoir. This process, known as mineralization, is considered very slow compared to physical and capillarity trapping mechanisms (De Silva & Ranjith, 2012; Metz et al., 2005).

The 2005 Intergovernmental Panel on Climate Change (IPCC) report highlighted the trapping contribution over time scale (Figure 1). In an injection project time-scale (less than 100 years), physical trapping remains the most important factor for safe geological storage, followed by capillarity trapping. CO_2 dissolution and mineralization are lengthy processes which increase storage safety over long periods of time (Metz et al., 2005).

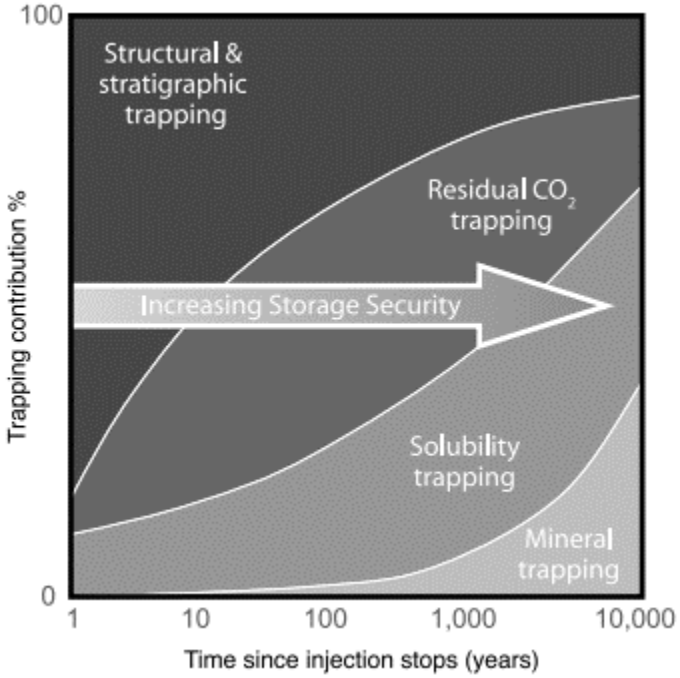

Figure 1 Storage Mechanisms Contribution Over Various Time-Scale (Metz et al., 2005)

All these mechanisms are responsible for the feasibility and safety of any geological storage project (onshore and offshore). However, assessing the presence and extent of seals as well as the reservoir properties (porosity, permeability) in offshore settings constitutes more economical

and technical challenges than onshore settings. These challenges are responsible for the limited data available, basing storage assessments heavily on results from other field tests and on geological assumptions.

3. STORAGE RESOURCE AND CAPACITY ASSESSMENT IN SALINE AQUIFERS

Large-scale projects launched in recent years confirm that offshore storage in saline aquifers can be successful and maintain safety standards. The Sleipner project in the North Sea is a successful example of feasibility of CCS in offshore settings. Since 1999, this site has captured and stored 1 million tons of CO_2 per year in a sandstone aquifer known as the Utsira Formation. The active plume monitoring (4D seismic, gravimetric, electromagnetic surveys) conducted at the Sleipner site ensures the safe, continuous injection of CO_2 in the Utsira Formation and provides updated reservoir properties, thereby reducing uncertainties and ameliorating storage predictions (Singh et al., 2010). However, in early stages of offshore storage projects, data availability is extremely limited, allowing substantial uncertainty to be associated with storage capacity assessment. Various methodologies were developed to quantify the storage potential of selected sites, leading to a wide range of storage resources and capacity estimations for specific sites. The U.S. Department of Energy (DOE) refers to *resource* assessment as the pore volume available for storage in a given formation, whereas the *capacity* refers to the actual volume that could be stored by commercial injection of CO_2. A capacity assessment takes into account technological as well as economic constraints associated with a site at a specific time (Goodman et al., 2013).

Static volumetric calculations are commonly used for prospective storage resource assessments as a limited amount of data is needed. This straightforward method requires an estimated bulk volume of the targeted formation, a representative porosity and a predetermined storage efficiency factor (Jin et al., 2012). This efficiency factor was introduced to take into account multiple factors (such as reservoir heterogeneities), which would reduce the actual pore volume available for CO_2 storage. This coefficient can be estimated with multiple methods, as described in Table 1, and depends on the rock types present in the formation. (Goodman et al., 2013; Goodman et al., 2011).

Table 1 Methodologies for Efficiency Factors Estimations

Method	Year	Volumetric Approach	Boundary	Traps	Factors Influencing the Efficiency
CSLF	07	x	Open	Structural, Stratigraphic	Field
US-DOE	08-09	x	Open	Structural, Hydrodynamic	Generic
US-DOE	10-12	x	Open	Structural, Hydrodynamic	Lithology
USGS	10-13	x	Open	Buoyant Forces, Residual	Permeability
Szulczewski et al.	12	x	Open and Closed	Residual, Solubility	Formation Type
Zhou et al.	08	x	Closed	Compressibility	Compressibility

(Goodman et al., 2013)

The U.S.-DOE methodology (Goodman et al., 2013; Goodman et al., 2011) is commonly used in academic research for storage resource estimations in saline aquifers and follows Equation 1.

$$G(CO2) = A * h * \emptyset * \rho * E \qquad (1)$$

With:

G (CO_2): estimated storage capacity of CO_2 in GT

A: total area of the geologic formation

Ø: porosity of the geologic formation

ρ: density of supercritical CO_2

E: CO_2 storage efficiency factor in saline aquifer

During the preliminary stages of any storage resource assessment, static volumetric calculations are preferred, but the uncertainty associated with these calculations should be clarified in order to avoid the overestimation of storage potential.

Dynamic volumetric calculations can be conducted when more information related to the site is available. Dynamic modelling refers to analytical methods that take into account changes in the reservoir from pressure and temperature variation during the injection of supercritical CO_2. Reservoir simulation is considered the most developed analytical method for capacity estimation, as all trapping mechanisms mentioned above are considered in the calculation while taking into account pressure and temperature variations (Hortle, Michael, & Azizi, 2014; Jin et al., 2012). Reservoir modelling allows saline aquifers' geometry and heterogeneities to be calibrated through model and grid cells sizing (Jin et al., 2012; Nazarian, Cavanagh, Ringrose, & Paasch, 2014; Thibeau et al., 2014; M. Zhang, Zhang, & Lichtner, 2017). Depending on the geological setting, boundary conditions can be applied. In a case of a confined aquifer, no-flow boundary conditions are applied, making the aquifer a closed system with top and bottom confining layers and lateral boundaries. For this type of reservoir, pressure management is considered a priority, to prevent any geomechanical failures (fracturation or fault activation) in the reservoir and the confining unit which could lead to leakage of CO_2 (Gorecki, Ayash, Liu, Braunberger, & Dotzenrod, 2015; Jin et al., 2012; Zhou, Birkholzer, & Technology, 2011). The injection rate and rock compressibility are parameters that condition the level of pressure buildup in the reservoir. Reservoir simulations permit the testing of pressure buildup under various injection rates and compressibility values to determine which injection scenario should be implemented to enhance storage capacity and prevent large pressure buildup (Jin et al., 2012). In the case of semi-closed aquifers, lateral boundaries are still considered present; however, the top and bottom confining

unit show variable permeability, allowing fluid infiltration in the confining units. For this type of scenario, sensitivity analysis can be conducted in the reservoir simulator to estimate the leakage rate out of the reservoir through the variable seal's permeability (Thibeau et al., 2014; Zhou, Birkholzer, Tsang, & Rutqvist, 2008). Open aquifers, on the other hand, have lateral boundaries located a distance from the well; therefore, constant pressure boundary conditions can be used. For this type of open aquifer, plume management should be considered to avoid long-distance lateral migrations of CO_2 after reaching the top seal (Jin et al., 2012). For any type of aquifer described above, reservoir simulation should only be used for local grids at a selected site and not for regional capacity estimation, as computational time for reservoir simulation would be too extensive for large-scale (regional) projects (Williams, Chadwick, & Vosper, 2018; M. Zhang et al., 2017).

Static and dynamic calculations are both valuable at different times in a CO_2 injection project. Storage *resource* assessment via static calculation requires a limited amount of data. However, the methodology used for regional storage resource assessment conditions the obtained results and the uncertainty associated with it. Dynamic modelling requires more understanding and knowledge of the study area but can provide a corrected *capacity* estimation of a prospective reservoir at a local scale.

4. POTENTIAL SITES FOR OFFSHORE STORAGE IN THE MID-ATLANTIC

As previously mentioned, offshore North Carolina and Virginia shows a large potential for CCS. However, the subsurface of the continental shelf of North Carolina and Virginia remains vastly unknown, primarily because few exploration campaigns have been conducted in this area due to limited oil and gas prospects. During the 1970s and 1980s, oil and gas companies, as well

as academia, showed increased interest in the Mid-Atlantic. Exploration campaigns collected 2D seismic reflection surveys (multichannel seismic data) and drilled deep and shallow penetrating wells all across the Atlantic continental shelf. For some of the wells located offshore or on the coastal plain of North Carolina and Virginia, geophysical logs and core analysis are available, providing information about lithologies and geological ages. However, petrophysical data is limited, so porosity and permeability distribution in the Mid-Atlantic is highly uncertain.

Previous studies of the subsurface of the Atlantic region have been conducted and highlight two main basins for their oil and gas potential within the Mid-Atlantic (P. M. Brown et al., 1972; Hathaway et al., 1976; K. O. Emery, 1972; Perry Jr, Minard, Weed, Robbins, & Rhodehamel, 1975; Poag, 1979; Schlee, 1977; Scholle, 1977): the Baltimore Canyon Trough (BCT), which extends from the shores of New Jersey to Virginia, and the Carolina Trough (CT), which lies between North Carolina and South Carolina. The Manteo Prospect, located between the BCT and the CT, should also be investigated for its oil and gas potential, which could be associated to CCUS (Meekins, 1999).

The interpretation of seismic data conducted in these studies relied on few available surveys. Since then, more recent surveys have been released to the public. Available seismic surveys cover both of these basins with variable density. The coverage is considered dense for the outer shelf and shelf edge but sparse on the slope and deep basin (Sullivan, Lehr, & Sackett, 2015). Deep penetrating wells were only drilled in the BCT, leaving the CT unexplored. Although these oil and gas exploration campaigns were deemed unsuccessful, they did provide valuable information needed to define the regional framework of these basins but not enough data to identify potential reservoirs, seals and other stratigraphic and structural traps. The interpretation

of newer seismic surveys could refine this stratigraphic framework and lead to the identification of regional targets for large-scale CO_2 storage.

Previous research showed that the upper and lower cretaceous formations are located at depths within the injection zone previously defined. Based on the interval velocities estimated and the seismic interpretation conducted in the BCT, formations between top Maastrichtian and top Hauterivian (presented in Figure 2) which are located on the continental shelf of Virginia and North Carolina should be between the depth of 800m and 2000m (Klitgord & Schneider, 1994).

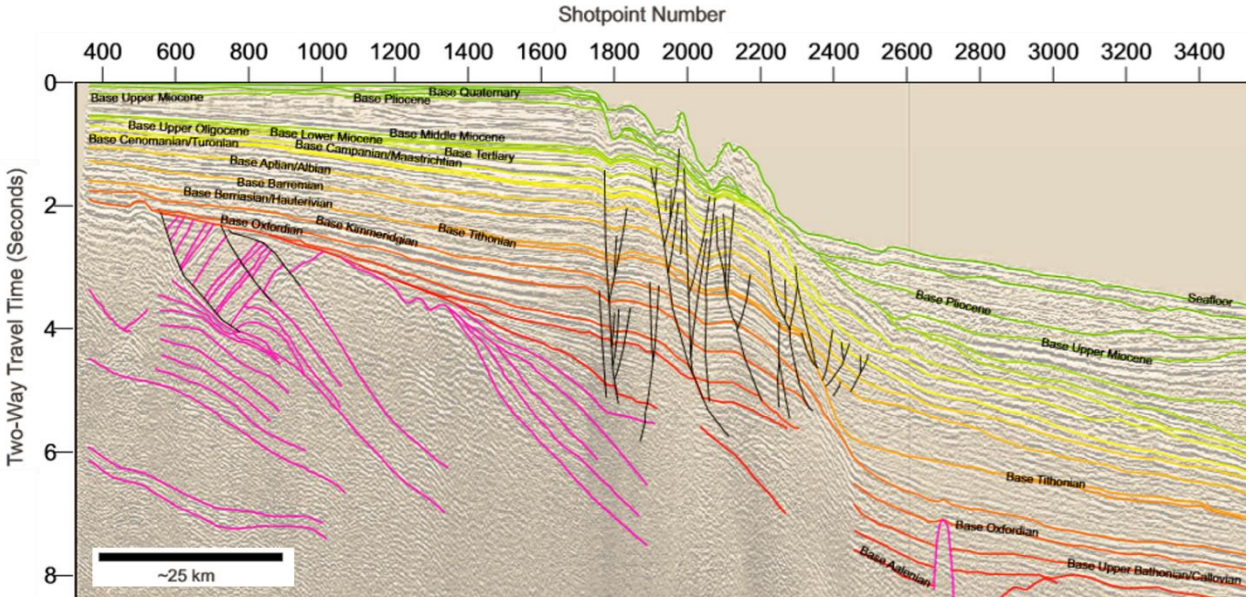

Figure 2 Seismic Profile (in Two-Way-Time) of Line 28 (Survey C-1-78)located in BCT. The Seismic Horizons are Derived from (Klitgord & Schneider, 1994).

Well logs from onshore and offshore wells confirm the presence of thick sandstone deposits as well as carbonates and shales in the upper and lower Cretaceous intervals (P. M. Brown et al., 1972). The absence of deep-penetrating wells offshore from Virginia and North Carolina represents the main challenge, as lithology correlations cannot be established between the coastal plain and the outer continental shelf. Any type of reservoir prediction in the Mid-Atlantic will rely heavily on seismic stratigraphy and on the identification of analogue basins in other parts of

the world. Substantial uncertainty associated with seismic stratigraphy can be reduced by the public release of more data in the future, through the collection of modern seismic data (3D or 4D), and by drilling stratigraphic tests on the Mid-Atlantic continental shelf.

CONCLUSION

Past and ongoing projects have shown that offshore storage of CO_2 could be crucial in the mitigation of atmospheric CO_2 emissions. Storage trapping mechanisms are well understood and show that offshore storage is feasible and safe if monitoring systems are deployed to detect leakage and subsurface deformations. Offshore geological storage of CO_2 presents major advantages over onshore storage, such as greater storage potential in unpopulated areas. However, site characterization prior to site selection is more challenging in an offshore environment. The identification of prospective targets over large areas necessitates an extensive amount of data coverage. The subsurface of the Mid-Atlantic remains unknown due to poor data coverage over this area; therefore, site selection and reservoir characterization is extremely challenging. To pursue the storage and capacity assessment in the Mid-Atlantic, a thorough review of the data available in this area is needed to determine the limitations, possibilities, and uncertainties regarding these assessments.

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CHAPTER 2 - ASSESSMENT OF GEOPHYSICAL DATA QUALITY AND COVERAGE FOR THE CONTINENTAL SHELF OF VIRGINIA AND NORTH CAROLINA

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This work is in preparation to be submitted at the *Carbon Management Technology Conference* to be published in the SPE journal.

ABSTRACT

Increases in atmospheric carbon dioxide (CO_2) since the 1950's are primarily attributed to anthropogenic emission sources. To limit the negative impacts of these emissions, multiple projects related to Carbon Capture and Storage (CCS) have been developed to study potential mitigation strategies, including permanent geologic storage of CO_2. This work represents the first step toward investigating potential geological storage of CO_2 off the coast of Virginia and North Carolina ("Mid-Atlantic") as part of Phase I of the Southeast Offshore Storage Resource Assessment (SOSRA). The purpose of this work was to reduce the dataset volume of publically available 2D seismic reflection surveys and geophysical logs to that which was most applicable to reservoir identification in the Mid-Atlantic. To this end, the variable quality and degree of data coverage in the study area were analyzed and quantified to provide an objective basis of comparison. Because most of this data was collected in the 1970's to 1980's, field acquisition parameters, such as source volume and streamer length, were compared to that of modern equipment and practice, as they directly affect the quality and usefulness of the data. To illustrate this effect, a frequency analysis was performed to estimate the vertical resolution of the vintage 2D seismic data. The results indicate a correlation between the acquisition parameters (source volume and streamer length) and the vertical resolution. On the basis of the findings of this work,

Phase II of the SOSRA project will continue this investigation by performing seismic interpretation of the selected data to define potential geological targets for CO_2 sequestration and their limitation. Reservoir simulations will then provide volumetric calculations on the potential of each reservoir.

1. INTRODUCTION

Following the BP oil spill in the Gulf of Mexico, a political decision was made to cancel the five-year (2012-2017) offshore leasing program in the Atlantic (Eilperin & Mufson, December 2nd 2010). A ban on offshore drilling is still currently active, however, a shift in the political climate recently opened the discussion for new leasing program in the Atlantic.

Carbon capture and permanent geologic carbon storage is an important potential strategy for stabilizing anthropogenic CO_2 emissions and establishing a sustainable low-carbon energy system (Benson & Orr, 2008; Metz, 2005). The United States Environment Protection Agency (EPA) estimated in 2014 that the rate of CO_2 emission in the U.S increased by almost 10 percent since 1990 (U.S-Environmental-Protection-Agency, 2015). There is a global trend among policy makers to investigate available technologies for capture and storage of anthropogenic CO_2. Onshore geological sequestration of CO_2 has been assessed for deep saline formations, depleted oil and gas reservoirs, unmineable coal seams, and basalt and ultramafic rock reservoirs (Boot-Handford et al., 2014; Goldberg, Kent, & Olsen, 2010; Gozalpour, Ren, & Tohidi, 2005; Michael et al., 2010; Orr, 2009; White et al., 2005). Even though offshore geological sequestration of CO_2 has been proposed for decades (Brewer, Friederich, Peltzer, & Orr, 1999; Metz, 2005), the development of CCS projects in the U.S. have only been conducted in onshore settings mostly due to technical and economic constraints.

This paper focuses on the methodology for selecting geophysical and geological data to support the assessment of carbon storage resource in the Mid-Atlantic region (offshore Virginia and North Carolina). This area presents a high interest for CO_2 storage due to the presence of fossil fuel power plants located on the coastal plain region, making it a good candidate for carbon capture and storage (CCS) technologies. Figure 1 displays the Mid-Atlantic and the estimation of CO_2 emissions by power plants in proximity to the study area.

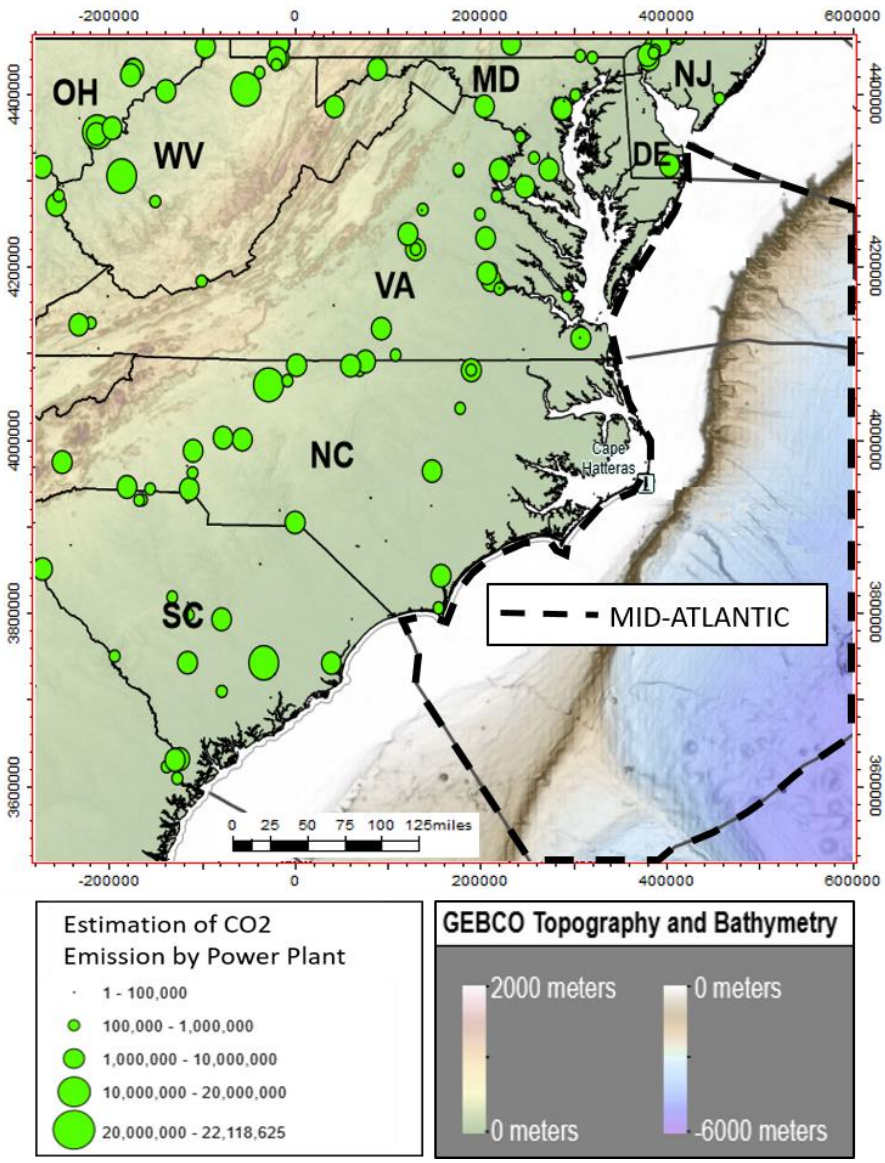

Figure 1. Mid-Atlantic Study Area

2. METHODOLOGY

Vintage geological and geophysical data (2-D seismic reflection surveys, well logs and other relevant geological information) were collected then analyzed to determine the usefulness of each dataset for the purpose of this study. All the data used for this study are publically available and can be downloaded via BOEM and the U.S Geological Survey (USGS) websites and other sources presented in Table 1. The geological and geophysical data analyzed were acquired over a 118-year period (from 1896 to 2014). Despite the commercial failure of these campaigns, the data collected still provides the greatest insight into the structural geological framework across the Atlantic margin. The release of proprietary data to the public is regulated by § 550.197 and dictates the release time of geophysical and geological data in BOEM possession. Processed geophysical data can be released after 25 years whereas, unprocessed or raw geophysical data can only be release after 50 years. Geological data can be release to the public after 10 years (BOEM, 2018). Only the final selection of data publically available at the time of writing this paper was illustrated in this paper.

Table 1 Sources of Publically Available Data Located in the Mid-Atlantic Study Area

DATA SOURCE	MCS SEISMIC	WELL INFO	SEISMIC VELOCITY SURVEYS	SEISMIC REFRACTION SURVEYS	SINGLE- CHANNEL AND/OR HIGH-RESOLUTION SEISMIC	MULTIBEAM BATHYMETRY	GRAVITY AND/OR MAGNETICS	GEOLOGIC MAPS OR GIS DATA
BOEM/BSEE	X	X	X					X
CEUS-SSC				X			X	X
DGS		X						X
DMME								X
IODP/ODP/DSDP		X	X					X
LDEO ASP	X				X			
NGDS		X						
NOAA NGDC	X	X	X	X	X	X	X	
USGS, including NAMSS	X	X	X			X	X	X
UTIG ASP	X				X			
WHOI	X				X			

Source: (Fugro, 2015). Note: Central and Eastern United States Seismic Source Characterization for Nuclear Facilities (CEUS-SSC), Delaware Geological Survey (DGS), Integrated Ocean Drilling Program (IODP), National Geothermal Data System (NGDS), Woods Hole Oceanographic Institution (WHOI), University of Texas Institute for Geophysics (UTIG)

Multiple criteria were used to compare the quality of the dataset and to assess the data coverage over the study area, reducing the volume of the dataset to the most applicable seismic surveys and well logs.

2.2 Data Coverage

There are no deep-penetrating wells in the waters of Virginia and North Carolina. Only shallow-penetrating wells have been drilled and are of limited use for exploration purposes (Atlantic Slope Project and AMCOR wells). To provide well control for the study, eleven onshore and offshore deep-penetrating wells located outside of the study area have been selected to help assess the potential for carbon storage in the Mid-Atlantic.

The second step was to identify seismic lines within an acceptable proximity to the previously selected wells. This will help establish well ties that are essential for interpreting seismic data. The most useful strike and dip lines were selected and the distance between these lines and wells were quantified.

Regarding the seismic data, an assessment of the line spacing used for each survey was conducted to determine if the areal coverage of a survey was sufficient to identify potential geological targets for CO_2 sequestration. The line spacing represents a limiting factor that impacts how the survey is used. Regional surveys will be used to obtain a regional geological framework of the study area, while surveys with tight line spacing will be used to identify the geometry of potential reservoirs. These surveys were then classified as regional, semi-regional or exploration scale surveys.

2.3 Data Quality

Publically available well folios and other publications provided useful information, such as the identification of formation tops and analysis of core data. Most of the well data can only be accessible in the literature, and therefore the logs had to be digitized to assess the quality of the well logs and the degree of detailed information they provide. The geophysical logs obtained for most of the deep-penetrating wells are comparable to those collected in modern exploration campaigns for standard petrophysical analysis.

Seismic data in the study area is extremely dense and assessing the quality of these data was an important task to perform as shown on Figure 1. A preliminary study was conducted to categorize the extent of processing applied to the data (i.e. pre-stack, stacked, migrated). Seismic lines covering the study area and presenting sufficient quality for this study also needed to be migrated or stacked to be adequate for seismic interpretation. Seismic lines were categorized according to their processing steps and represented on maps (Figure 2).

Following this preliminary study, another step was taken to assess the quality of the data covering the study area. Since the oil and gas exploration campaigns in the Atlantic, field equipment technologies have evolved. Comparing seismic acquisition parameters and equipment used in modern and vintage surveys helps determine if the data used in this study is up to current standards for reservoir exploration (Landrø & Amundsen, 2010). The equipment used for seismic data acquisition has a high impact on the obtained seismic profiles. The field parameters are chosen based on the objectives of the survey and the location but also on economic constraints (Knapp & Steeples, 1986). Field parameter information for each survey were collected, with a focus on the seismic source (number and volume of air guns' array) and the streamer length. A larger source volume produces higher dominant frequencies at deeper

intervals, which in turn produces higher resolution seismic data. Likewise, a higher number of air guns and a longer streamer length produces a higher CDP (common-depth-point) fold, which in turn produces a higher signal-to-noise ratio. Therefore, larger source volumes, higher air gun count, and longer stream length are desirable for imaging the deep subsurface. Tables have been created to display the distribution of each parameter and their variations from survey to survey.

Lastly, the vertical resolution of the seismic data is a crucial element influencing the usefulness of a seismic survey for reservoir identification. Interpreting reflectors on seismic profiles highly depends on the experience of the interpreter but also the format (paper or digital) and the resolution of the data (R. Sheriff, 1992). Assessing the vertical resolution of the data determines the limitations of the interpretation. The vertical resolution refers to the minimum distance between two geological interfaces that can be detected (one reflector), the limit of detectability D, or the minimum thickness between the top and bottom of a geological unit necessary to visualize two different reflectors on the seismic profile, the limit of separability S (R. E. Sheriff & Geldart, 1995). This element is crucial for the seismic interpreter as it will determine the ability to detect thin-beds which could represent potential reservoirs or seals. The limit S and limit D are empirical methods that provide a reliable approximation of the vertical resolution. Both of these limits are dependent of the wavelength (Equation 2 and 3) which can be deduced from the seismic frequency (Equation 1). The one-quarter acoustic wavelength ($\lambda/4$) (Equation 2) represents an adequate approximation of the minimum thickness necessary to observe two reflectors for two geological interfaces (R. Sheriff, 1992) or the limit of seperability. Whereas, one-thirtieth of the wavelength ($\lambda/30$) approximates the minimum thickness for a geological bed to be detected on seismic data as one reflector which is the limit of detectability *D* (Equation 3) (A. R. Brown, 2011).

A frequency analysis was conducted to determine the minimum, maximum and dominant frequency for one representative seismic trace and time interval for each survey. The trace and time window were selected to avoid poor quality sections and complex geometries (slopes and fault zones). The frequencies were then used to calculate the limit of separability *S* and limit of detectability *D*. The interval velocities assumed for this analysis are broad approximation of shallower section's velocities (2000m/s) and deeper section's velocity (5000m/s) (Ö. Yilmaz, 2001).

$$\lambda = \frac{V}{f} \quad (1)$$

Where λ is the wavelength (m), V interval velocity (m/s) and f frequency (Hz).

$$S = \frac{\lambda}{4} \quad (2)$$

Where S is the limit of separability (m)

$$D = \frac{\lambda}{30} \quad (3)$$

Where D is the limit of detectability (m)

Multiple methods can be used to extract the dominant frequency from a seismic trace. In this study, two methods commonly used by the geophysics community were implemented and compared (Barnes, 1993). The seismic traces are discrete, real-valued two-way-time t_i and amplitude A_i pairs. Although processed amplitudes are typically unitless, they depict the mechanical energy of the seismic wave relative to an arbitrary zero value. The original signal was then decomposed into discreet, complex-valued frequency f_i and amplitude-time $\tilde{A}_i$ pairs through the discreet Fourier transform (DFT) (Equation 5) (Frigo & Johnson, 2005). Again,

although the transformed amplitude-time is unitless, it depicts the signal content associated with each frequency. Because the signal content is a complex number, the complex magnitude or absolute value was used to define the magnitude of the signal content (Equation 6). Method 1 extracted the dominant frequencies ($f_{dom}^{(1)}$) by calculating the average -frequency weighted by the signal content. (Equation 7) (Barnes, 1993).

$$DFT\{t_i, A_i\} = \{f_i, \tilde{A}_i\} \quad (4)$$

$$|\tilde{A}_i| = \sqrt{Re(\tilde{A}_i)^2 + Im(\tilde{A}_i)^2} \quad (6)$$

$$f_{dom}^{(1)} = \frac{\sum_i |\tilde{A}_i| f_i}{\sum_i |\tilde{A}_i|} \quad (7)$$

The second method used to extract dominant frequencies also used modified amplitude (signal content) (Equation 4, 5 and 6). However, for this method, the dominant frequency ($f_{dom}^{(2)}$) represents the average of the squared frequency weighted by the amplitude (Barnes, 1993).

$$f_{dom}^{(2)} = \sqrt{\frac{\sum_i |\tilde{A}_i| f_i^2}{\sum_i |\tilde{A}_i|}} \quad (8)$$

Both methods are considered valid to approximate dominant frequencies and therefore quantify the vertical resolution on 2D seismic reflection profile.

All these steps led to a detailed data quality assessment, which aimed to reduce the dataset volume to the most appropriate data to conduct a regional assessment of the carbon storage potential of offshore Virginia and North Carolina.

3. RESULTS

3.1 Well Data

3.1.1 Data Inventory

Eleven onshore deep-penetrating wells located in Virginia and North Carolina's Coastal Plain were selected. Previous studies (Sunde & Coffey, 2009) showed that onshore wells could help correlate the stratigraphy of the coastal plain to offshore sediments on the continental shelf. Formation tops for the eight wells located in North Carolina, as well as for three in Virginia, were obtained from P. M. Brown et al. (1972). The remaining wells located in the coastal plain of Virginia (Delmerva Peninsula) have not been analyzed in this publication and no information related to their well tops were found. Tables 2 and 3 show the onshore wells selected in the coastal plain of North Carolina and Virginia and other helpful information collected throughout the study.

Table 2 Onshore Wells Selected in the Coastal Plain of North Carolina

Well	Latitude	Longitude	Date	Datum (ft)	Hole Depth (ft)	Digital Logs	Raster Logs
Twiford #1	36.3028	-75.925	1965	12	4,553	SP, GR, RES	VEL
Kellog #1	36.1172	-75.8528	1969	17	5,140	SP, GR, RES	VEL, Mudlog
Hatteras Light	35.25	-75.5292	1946	24	10,054	SP, RES	-
Esso #2	35.7035	-75.598	1947	21	6,332	SP, RES	-
Mobil #2	35.4389	-75.5764	1965	24	8,386	SP, GR, DRHO	VEL, RES, DIP, RHOB
Mobil #1	35.9986	-75.8667	1965	24	5,270	SP, GR, RES, DRHO	VEL, DIP, RHOB
Marshall Collins #1	35.8833	-75.6708	1965	14	6,295	SP, GR	VEL, RES
Etheridge# 1	35.9241	-75.6768	1969	26	6,049	SP, RES	-

Source : (P. M. Brown et al., 1972; Reid, DePoy, Taylor, & Simons, 2011)

Table 3 Onshore Wells Selected in the Coastal Plain of Virginia

Well	Latitude	Longitude	Date	Datum (ft)	Hole Depth (ft)	Digital Logs	Raster Logs
Norfolk Water Works	36.8722	-76.2	1896	15	2,567	-	Lith. Log
Bush Development Corp.	36.8667	-75.9808	1964	10	1,593	-	SP RES SPR Lith. Log
E.G. Taylor	37.8842	-75.5168	1971	53	6,269	GR TEMP	GR SP RES RHOB DRHO VEL Lith. Log

Source : (P. M. Brown et al., 1972; Gohn, Koeberl, Miller, & Reimold, 2009)

Oil and Gas exploration wells were also added to the study. Their relatively short distance from the study area could lead to ties to seismic lines located in the study area. Shell

Baltimore Rise 93-1 is the closest well selected. This well is located offshore Delaware. As one well might be insufficient to build a robust interpretation, six other industry wells, also located in the North-Atlantic were collected. These wells are important because there are deep penetrating wells, carrying valuable information for this study. Geophysical logs are available for each of these wells.

Table 4 displays the wells selected for this study, their location, main characteristics and the geophysical logs available.

Table 4 Industry Wells Selected and Analyzed

Well Location	Latitude	Longitude	Date	Datum (ft)	Water Depth (ft)	Hole Depth (ft)	Digital Logs
Shell 93-	37.89306	-73.7358	1984	48	5,013	17,740	SP, GR, SFL, ILM, ILD, DT, DTL
Shell 372-1	38.60028	-72.9369	1984	48	6,952	11,631	SP, GR, SGR, SFL, ILM, ILD, DT, DTL, RHOB, DRHO, NPHI
Shell 586-1	38.40528	-73.2175	1983	48	5,838	16,000	SP, GR, SFL, ILM, ILD, DT, DTL
Shell 587-1	38.38111	-73.1644	1983	48	6,448	14,470	SP, GR, SFL, ILM, ILD, SN, DT
Tenneco 495-1	38.46639	-73.3775	1979	88	355	18,300	SP, GR, SFL, ILM, ILD, DT, RHOB, DRHO, NPHI
Cost B-2	39.37555	72.73444	1976	90	298	16039	DRHO, DIP, VEL, SFL, NPHI
Cost B-3	38.91694	72.77277	1979	42	2686	15820	DRHO, DIP, VEL, SFL, NPHI

Source: (Amato, 1987; Amato & Simonis, 1979; G. Edson, 1987; G. M. Edson, 1986; U.S.-Geological-Survey) Note: Spontaneous Potential Log (SP), Gamma Ray Log (GR), Single Point Resistivity Log (SPR), Density Correction Log (DRHO), Resistivity Log (RES), Sonic Log (VEL), Bulk Density Log (RHOB), Spherically Focused Log (SFL), Deep Induction Resistivity (ILD), Medium Induction Resistivity (ILM), Dipmeter (DIP), Neutron Porosity Log (NPHI), Delta Time (Interval Transit Time) Log (DT)

3.1.2 Data Coverage and Quality

The data collected demonstrated that well coverage is insufficient due to the lack of deep penetrating wells in the study area as well as in the south of the study area. To provide offshore well control, more data located at the north of the study area were included in the study. To establish seismic well ties, the closest seismic lines to onshore and offshore wells were identified and reported in this paper.

Assessing the quality of onshore well logs turned out to be a difficult task due to the absence of digitized logs for deeper section of most wells. Well logs had to be digitized from paper copies prior extracting any information and this process impaired the quality of the data. However, the digitized logs (Gamma Ray, Resistivity, Neutron, Sonic and Density logs) for both onshore and offshore wells are still commonly used and would provide good information to the interpreter. Well folios publically available describing petrophysical analysis from cores represent the larger source of information and will be useful for seismic interpretation and reservoir characterization.

3.2 Seismic Data

3.2.1 Data Inventory

Twenty-seven seismic surveys were collected from previously mentioned sources and Table 7 displays the surveys selected for this project. The number of lines and line-metrics is also shown on Table 7.

Table 5 Seismic Survey Selected for this Study

Permit or Survey	Year	Client/Research Team	Acquisition Company	Number of Seismic Lines		Approximate Kilometers Acquired	
				Entire Survey	Study Area	Entire Survey	Study Area
E14-75	1975	Western Geophysical	Western Geophysical	33	5	4,340	227
E16-76	1976	Offshore Atlantic Group	Digicon	42	33	5,386	3,726
E02-77	1977	Atlantic Offshore Group	Digicon	29	0	10,341	0
BGR79	1979	BGR	Prakla-Seismos	21	4	4,763	434
E01-80	1980	South Atlantic Group	Geosource	159	57	6,625	1,866
E-02-82	1982	Mid-South Atlantic Group	Geosource	274	113	8,597	3170
E-02-80	1980	South Atlantic Group	Digicon	106	39	3,665	807
E-04-82	1982	Shell	Shell	40	13	2,009	534
E-03-88	1988	Texaco	GECO	29	17	731	467
E-07-81	1981	Chevron	Digicon	12	12	294	294
E-11-82	1982	ARCO	ARCO	92	46	2,395	1250
E-01-75	1975	USGS	Digicon	7	3	2,406	485

Source: (Fugro, 2015)

3.2.2 Data Quality

This assessment of the quality of the seismic data was conducted to determine the purpose of each dataset. Part of the data will be used to construct a regional geological framework. The rest of the dataset will be interpreted to identify potential reservoirs for carbon sequestration. For the

reasons mentioned in the methodology section of this paper, the acoustic source volume, the number or air guns and the streamer length, were analyzed to assess the quality of the data compared to modern equipment.

The first field parameter analyzed was the acoustic source volume (air gun array volume). This parameter corresponds to the sum of all the air guns in an array. This is a crucial parameter for exploration, as it determines the strength of the signal. Nowadays, sources (air guns in most cases) array volumes ranges between 3,000 and 8,000 cubic inches (Landrø & Amundsen, 2010). For vintage surveys, in general, the source volume is smaller for older surveys and increases in size over time.

The second parameter analyses in the number of air guns used for each survey. Modern surveys typically used array of 18 to 48 guns whereas vintage surveys used 14 to 25 air guns. This represent a limiting factor for the signal to noise ratio as it decreases the CDP fold or trace gather. Table 10 shows the number of air guns used and the range of acoustic source volumes used for the collection of each survey as well as the pressure associated with it.

Table 6 Acoustic Source Parameters for each Survey Selected in the Mid-Atlantic

Survey	Client	Contractor	Year	Acoustic Source		
				Number of Guns	Volume (Cubic Inches)	Pressure (psi)
E14-75	Western Geophysical	Western Geophysical	1975	Aquapulse	Unknown	Unknown
E16-76	Offshore Atlantic Group	Digicon	1976	18	1700	Unknown
E02-77	Atlantic Offshore Group	Digicon	1977	Unknown	1,700	Unknown
BGR79	BGR	Prakla-Seismos	1979	"U-Type" Airgun Tuned Array	1430	1430
E01-80	South Atlantic Group	Geosource	1980	14	2682	1850
E02-80	South Atlantic Group	Digicon	1980	25	2220	1700 to 1800
E07-81	Chevron	Digicon	1981	25	Unknown	1800
E02-82	Mid-South Atlantic Group	Geosource	1982	14	3060	1800 to 2000
E04-82	Shell	Shell	1982	Unknown	Unknown	Unknown
E11-82	ARCO	ARCO	1982	Unknown	5600	Unknown
E03-88	Texaco	GECO	1988	24	6324	Unknown

Source: (U.S.-Geological-Survey)The National Archive of Marine Seismic Surveys (NAMSS)

The last field parameter analyzed was the streamer length. This field parameter can be a limiting factor for depth penetration. As a rule of thumb in exploration seismology, the maximum offset should be a similar value to the depth of the target. Modern seismic design

usually uses streamers that range from six to twelve kilometers (IAGC, 2002). However, in the 70s and 80s, the streamer length used was much shorter (three kilometers long). Most of the surveys collected for this study have short cable length (three kilometers long) and therefore imaging below three kilometers is not possible with these data. One of the survey selected used longer streamers and visualized the deep stratigraphy of the Mid-Atlantic as shown in Table 9 (E-03-88).

Table 7 Streamer Length Used for each Selected Survey in the Mid-Atlantic

SURVEY	CLIENT	CONTRACTOR	YEAR	CABLE LENGTH (m)
E14-75	Western Geophysical	Western Geophysical	1975	3,152
E16-76	Offshore Atlantic Group	Digicon	1976	3,569
E02-77	Atlantic Offshore Group	Digicon	1977	3,569
BGR79	BGR	Prakla-Seismos	1979	3,350
E01-80	South Atlantic Group	Geosource	1980	3,524
E02-80	South Atlantic Group	Digicon	1980	3,561
E07-81	Chevron	Digicon	1981	3,305
E02-82	Mid-South Atlantic Group	Geosource	1982	3,562
E04-82	Shell	Shell	1982	Unknown
E11-82	ARCO	ARCO	1982	2,987
E03-88	Texaco	GECO	1988	5,975

Source: (U.S.-Geological-Survey)The National Archive of Marine Seismic Surveys (NAMSS)

The other important parameter for exploration design is the CDP fold (trace gather), which is influenced by the shot point spacing, receiver spacing and the number of receivers (Equation 9).

$$CDP\ fold = \frac{Receiver\ Spacing * Number\ of Receivers}{2 * Shotpoint\ Spacing} \quad (9)$$

Modern surveys usually obtain CDP fold values higher than 60, however, vintage data used in this study contain CDP fold values ranging between 38 and 48 (Table 9). Low CDP fold values decrease the subsurface imaging possibilities by decreasing the signal to noise ratio. Older surveys typically have lower CDP fold than more recent surveys.

Table 8 CDP Fold for Each Survey Selected in the Mid- Atlantic

Survey	Shotpoint Interval (ft)	Receiver Spacing (ft)	Number of receivers	CDP Fold
E14-75	220	220	48	24
E16-76	338	164/328	48	36
E02-77	330	164/328	48	36
BGR79	164	164	48	24
E01-80	246	246	48	48
E02-80	328	82/164	96	36
E07-81	328	82/164	96	36
E02-82	123	123	96	48
E04-82	100	Unknown	Unknown	Unknown
E11-82	41	82 or 164	60 or 120	144 to 240
E03-88	82	82	240	70 to 95

Source: (U.S.-Geological-Survey)The National Archive of Marine Seismic Surveys (NAMSS)

Another method to determine the data type of each survey is to know which processing steps have been used. The interpreter will determine if processing or reprocessing data are needed for seismic interpretation. The data collected for this study were either depth converted, migrated, stacked, or unprocessed. To identify potential reservoirs, only stacked sections and migrated sections are used by the interpreter. From the twenty-seven surveys collected, 77% were migrated and 76% were stacked. Figure 2 and 3 represent the special distribution of the migrated and stacked seismic lines used for this study within the study area (from the 11 selected surveys).

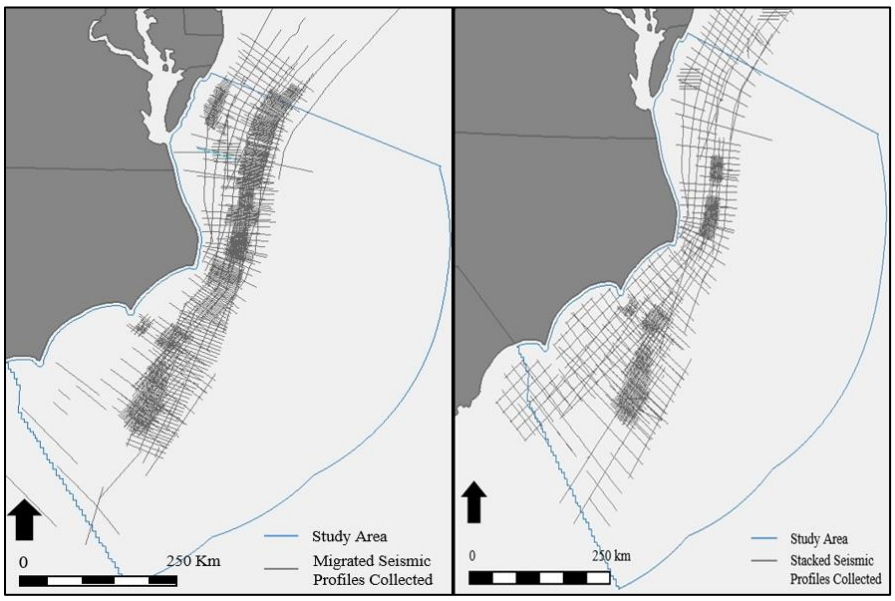

Figure 2 Spatial Distribution of Migrated Section(left) and Stacked Section (right) in the Study Area

The last factor analyzed to assess the quality of the data was the vertical resolution. The limit of separability and detectability were calculated by following the methodology described above. The results are shown in Table 11 and 12.

Low frequencies as well as high frequencies were used to provide a range of limits of detectability and separability for shallow section (low velocities) and deeper section (higher velocities). The results showed that the best vertical resolution appear to be for higher frequencies in shallow section. These results can be easily explained by the frequency being inversely proportional to the wavelength (Equation 1). Higher frequencies lead to shorter wavelength and therefore smaller limit of separability and detectability. Surveys E-11-82 and E-07-81 presents the best vertical resolution. The limit of detectability of survey E-11-82 ranges between 1 meters for low velocity and high frequency zones and 10 meters for high velocity and low frequency zones. Whereas E-16-76 and E-01-75 shows poor vertical resolution. E-16-76 limit of detectability varies between 2 meters and 20 meters for the same two zones mentioned above. These results are consistent with the argument previously made regarding the improvement of field equipment over time and therefore the increasing quality of the data over time. Both of these surveys (E-16-76 and E-11-82) share similar streamer length however, the difference in resolution arise from the use of larger acoustic sources (Table 10) but also a larger final CDP fold (Table 9).

Using maximum and minimum frequencies can provide a “best and worst case” values for the limit of detectability and separability. The same analysis was then conducted by using the dominant frequency extracted by the two methods aforementioned. The first methods provided dominant frequencies ranging from 20 (E-16-76) to 31 Hz (E-11-82) whereas the second method extracted higher overall dominant frequencies ranging from 25 (E-16-76) and 40 Hz (E-11-82).

Both methods confirmed that the frequency ranges are still higher for more recent surveys than for older ones. However, modern data with a dominant frequency around 50 Hz, exceeds the quality of all the vintage data. The limits of detectability where calculated by using both dominant frequency extraction method. Both methods provide a limit of detectability and separability in the same order of magnitude.

This complete analysis showed the importance for the interpreter to know the approximated vertical resolution of the dataset used. Some older surveys such as E-16-76 could participate in the construction of a regional geological framework in the study area however, because of the poor resolution of this survey, reservoir identification and mapping cannot be achieved by using these data. Surveys with higher dominant frequencies and therefore smaller wavelength, should be preferred to identify and characterize reservoir in the study area. Overall, the data quality analysis highlighted that the vintage data collected are of fair to poor quality because of the aforementioned field parameters and processing techniques. As a consequence, the depth of penetration, the resolution and the signal to noise ratio of the data were impaired.

Table 9 Estimation of the Vertical Resolution for High and Low Frequencies in Deep and Shallow Environments (with Interval Velocities of 2000m/s and 5000m/s)

PERMIT OR SURVEY	CHOSEN LINE	LINE TRACE	TIME WINDOW	LINE TYPE	FREQUENCY RANGE		S				D			
					Min (10%)	Max (90%)	Min (10%)		Max (90%)		Min (10%)		Max (90%)	
							V=2000m/s	V=5000m/s	V=2000m/s	V=5000m/s	V=2000m/s	V=5000m/s	V=2000m/s	V=5000m/s
E14-75	we-026_stk	1183	0.5 to 1.5 s	dip	12.7	43.5	39	98	11	29	5	13	2	4
E16-76	MA-032_mig	1005	1s to 2.5s	dip	6.9	32.8	72	181	15	38	10	24	2	5
E02-77	BP-118A_migr	404	0.25s to 1.3s	dip	9	45	56	139	11	28	7	19	1	4
BGR79	bgr79-204a_migr	386	1.5s to 3s	strike	10.9	51.8	46	115	10	24	6	15	1	3
E01-80	56-138_migr	481	0.7s to 1.7s	dip	9.5	41	53	132	12	30	7	18	2	4
E-02-82	PR82-185_migr	134	0.5s to 2s	dip	9.6	40.8	52	130	12	31	7	17	2	4
E-02-80	SA-1142_mig	699	0.5 to 1.8s	dip	8.1	40.5	62	154	12	31	8	21	2	4
E-04-82	18074_migr	247	1s to 2.5s	dip	10.9	42	46	115	12	30	6	15	2	4
E-03-88	88-16-B_migr	2401	0.5s to 1.7s	dip	9.2	43.8	54	136	11	29	7	18	2	4
E-07-81	CSA81-8_migr	199	1s to 2s	dip	13.4	56	37	93	9	22	5	12	1	3
E-11-82	M82-35_migr	601	0.5s to 1.5s	dip	12.5	56.4	40	100	9	22	5	13	1	3
E-01-75	A-243_migr	502	0.7s to 2s	dip	8.4	37.5	60	149	13	33	8	20	2	4

Table 10 Estimation of Vertical Resolution for Dominant Frequencies in Deep and Shallow Environment (With Interval Velocities of 2000/s and 5000m/s)

PERMIT OR SURVEY	CHOSEN LINE	LINE TRACE	TIME WINDOW	LINE TYPE	DOMINANT FREQUENCY		S				D			
					Method 1	Method 2	Method 1		Method 2		Method 1		Method 2	
							V=2000m/s	V=5000m/s	V=2000m/s	V=5000m/s	V=2000m/s	V=5000m/s	V=2000m/s	V=5000m/s
E14-75	we-026_stk	1183	0.5 to 1.5 s	dip	28.25	32.22	18	44	16	39	2	6	2	5
E16-76	MA-032_mig	1005	1s to 2.5s	dip	20.02	24.73	25	62	20	51	3	8	3	7
E02-77	BP-118A_migr	404	0.25s to 1.3s	dip	27.6	34.35	18	45	15	36	2	6	2	5
BGR79	bgr79-204a_migr	386	1.5s to 3s	strike	26.78	34.75	19	47	14	36	2	6	2	5
E01-80	56-138_migr	481	0.7s to 1.7s	dip	24.9	29.12	20	50	17	43	3	7	2	6
E-02-82	PR82-185_migr	134	0.5s to 2s	dip	24.51	32.66	20	51	15	38	3	7	2	5
E-02-80	SA-1142_mig	699	0.5 to 1.8s	dip	25.33	30.87	20	49	16	40	3	7	2	5
E-04-82	18074_migr	247	1s to 2.5s	dip	25.56	29.9	20	49	17	42	3	7	2	6
E-03-88	88-16-B_migr	2401	0.5s to 1.7s	dip	27.33	32.7	18	46	15	38	2	6	2	5
E-07-81	CSA81-8_migr	199	1s to 2s	dip	31.45	39.56	16	40	13	32	2	5	2	4
E-11-82	M82-35_migr	601	0.5s to 1.5s	dip	31.02	39.13	16	40	13	32	2	5	2	4
E-01-75	A-243_migr	502	0.7s to 2s	dip	24.54	31.75	20	51	16	39	3	7	2	5

3.3 Data Coverage

3.3.1 Well Coverage

As mentioned before, the data collected for the SOSRA project have a relatively low quality and represent one of the biggest challenges for the interpreter along with the lack of well control in the region. Wells provide data considered like the ground truth carrying very valuable information for interpretation. Establishing correlation between well-derived data and the interpreted horizons on seismic profile are necessary to complete a reliable interpretation. The appropriate seismic lines to establish these correlations have been selected for both onshore and offshore wells. Regarding the onshore wells, dip lines have been preferred to establish correlation toward offshore Virginia and North Carolina. Seismic lines collected for this study are relatively far from any wells and any correlation would come with an increased uncertainty (Table 14).

Table 11 Onshore Well-Seismic Ties

WELL	SEISMIC SURVEY	SEISMIC LINE	LINE TYPE	LINE PROCESSING	DISTANCE FROM WELL
E.G. Taylor #1-G	E11-82	MAR82-137	Dip	Migrated	35 km
Norfolk Water Works	E03-88	88-16-B	Dip	Migrated	31 km
Norfolk Water Works	E05-86	5-YRE	Dip	Stack	27 km
Norfolk Water Works	E06-79	V105	Strike	Paper (Stack)	32 km
Bush Development Corp	E03-88	88-16-B	Dip	Migrated	13 km
Bush Development Corp	E06-79	V105	Strike	Paper (Stack)	16 km
Twiford #1	E06-79	V104	Oblique	Paper (Stack)	29 km
Kellog #1	VA EDGE	MA-802	Oblique	Paper (Stack)	34 km
State of NC # 1	E14-75	WE-002	Dip	Stack	15 km
State of NC # 1	E16-76	MA-60	Dip	Migrated	17 km
Etheridge #1	E16-76	MA-48	Dip	Migrated	24 km
Etheridge #1	S-1-77	17	Oblique	Stack	18 km
Marshall Collins #1	E16-76	MA-50	Dip	Migrated	27 km
Esso #2	E16-76	MA-54	Dip	Migrated	21 km
State of NC # 2	E14-75	WE-002	Dip	Stack	14 km
State of NC # 2	E14-75	WE-004-1	Dip	Stack	17 km
Hatteras Light	E17-75	DS-13	Dip	Paper (Stack)	4 km
Hatteras Light	E14-75	WE-007-1	Oblique	Stack	6 km

Source: (Fugro, 2015)

Regarding establishing well ties to industry wells, survey E11-77 will be the most useful dataset to achieve this task but also to correlate the ASP wells 13,14 and 15. Migrated sections are preferred as stacked section to establish well ties to improve spatial resolution and removing diffraction patterns. The

survey E11-77 provides good ties for both dip and strike direction. Other lines from various other surveys have also been selected and are displayed on Table 15.

The shallow wells in the study area have lines passing as close as 3 km from them. However due to the poor quality of the data (low resolution), correlating seismic lines to shallow well information may not be possible and therefore might be of little help to the resource assessment.

Table 12 Offshore Oil & Gas Well-Seismic Ties

WELL	SEISMIC PERMIT/SURVEY	SEISMIC LINE	SEISMIC LINE ORIENTATION	SEISMIC SECTION FOR CORRELATION	APPROXIMATE DISTANCE FROM WELL
Shell 93-1	E11-77	MA-191	Dip	Migrated or Depth	1 km
Shell 93-1	S-1-75	10	Dip	Stack	1 km
Shell 93-1	E11-77	MA-112B	Strike	Migrated	1 km
Shell 372-1	E11-77	MA-139	Dip	Migrated or Depth	< 1 km
Shell 372-1	E11-77	MA-116A	Strike	Migrated	< 1 km
Shell 386-1	E11-77	MA-151	Dip	Migrated or Depth	2.5 km
Shell 386-1	BGR-79	203	Strike	Migrated	1.5 km
Shell 386-1	E11-77	MA-112B	Strike	Migrated	1 km
Shell 587-1	E11-77	MA-151	Dip	Migrated or Depth	1.5 km
Shell 587-1	E11-77	MA-116A	Strike	Migrated	< 1 km
Tenneco 495-1	E11-77	MA-153	Dip	Migrated or Depth	1 km
Tenneco 495-1	S-1-77	TD15A	Strike	Stack	< 1 km
Tenneco 495-1	E22-75	5044	Oblique	Stack	< 1 km

Source: (Fugro, 2015)

3.3.2 Seismic Data Coverage

The first method used to assess the coverage was to analyze the line spacing for each survey. At first, regionally spaced 2-D seismic lines were collected. If a “lead” (favorable conditions for hydrocarbon accumulation) was found, more surveys were conducted with tighter line spacing. For this study, each survey was classified as regional, semi-regional or exploration scale based on their line spacing. To be able to image a potential reservoir, exploration scale surveys were necessary. Table 11 shows the line spacing for all the survey in this study.

Table 13 Line Spacing for Surveys in the Study Area

PERMIT OR SURVEY	LOCATION	SURVEY SCOPE	SEISMIC DATA TYPE	NUMBER OF DIP LINES	TYPICAL DIP LINE SPACING (KM)	NUMBER OF STRIKE LINES	TYPICAL STRIKE LINE SPACING (KM)
E16-76	Cape Hatteras, NC to MD	Semi-Regional	Stacked & Migrated	35	15-04	6	10-25
BGR 79	Northern NC to southern NJ	Regional	Stacked & Migrated	0	NA	4	10-25
	NJ	Regional	Stacked & Migrated	8	13-30	3	40-75
E01-80	Currituck Sound Prospect	Exploration	Stacked & Migrated	16	3-2	6	2-5
	Manteo Prospect	Exploration	Stacked & Migrated	23	5-2	7	3-4
E02-80	Currituck Sound Prospect	Exploration	Stacked, Migrated & Depth	8	5-2	2	7
	Manteo Prospect	Exploration	Stacked, Migrated & Depth	22	5-2	2	10-20
E07-81	Manteo Prospect	Exploration	Migrated & Depth	11	2.5-5	1	NA
E02-82	Northern NC to southern MD	Exploration	Stacked, Migrated & Depth	104	1.5	4	13
E04-82	Northern NC & VA	Regional	Migrated & Depth	9	9-30	0	NA
E03-88	Currituck Sound Prospect	Exploration	Migrated	8	5	1	NA
	Norfolk Basin, VA	Exploration	Stacked	7	5	1	NA
E-14-75	Cape Hatteras, NC to Northern SC	Semi-Regional	Stacked	25	10-20	Variable, 3 to 7	10-20
E02-77	Southern NC to GA	Regional	Stacked, Migrated & Depth	22	20-40	7	Variable, 25-50;120-180
E-11-82	Norfolk Basin, VA	Exploration	Migrated	33	2.5	11	3
	Northern NC to Southern MD	Regional	Migrated	5	25-63	3	7-27

Source: (Fugro, 2015)

The data analysis lead to the selection of geophysical and geological data (2D seismic reflection survey and well logs) necessary to pursue the SOSRA project and identify potential

reservoirs for CO_2 storage. The selected data are presented in Figure 3. The study was extended to include offshore industry wells.

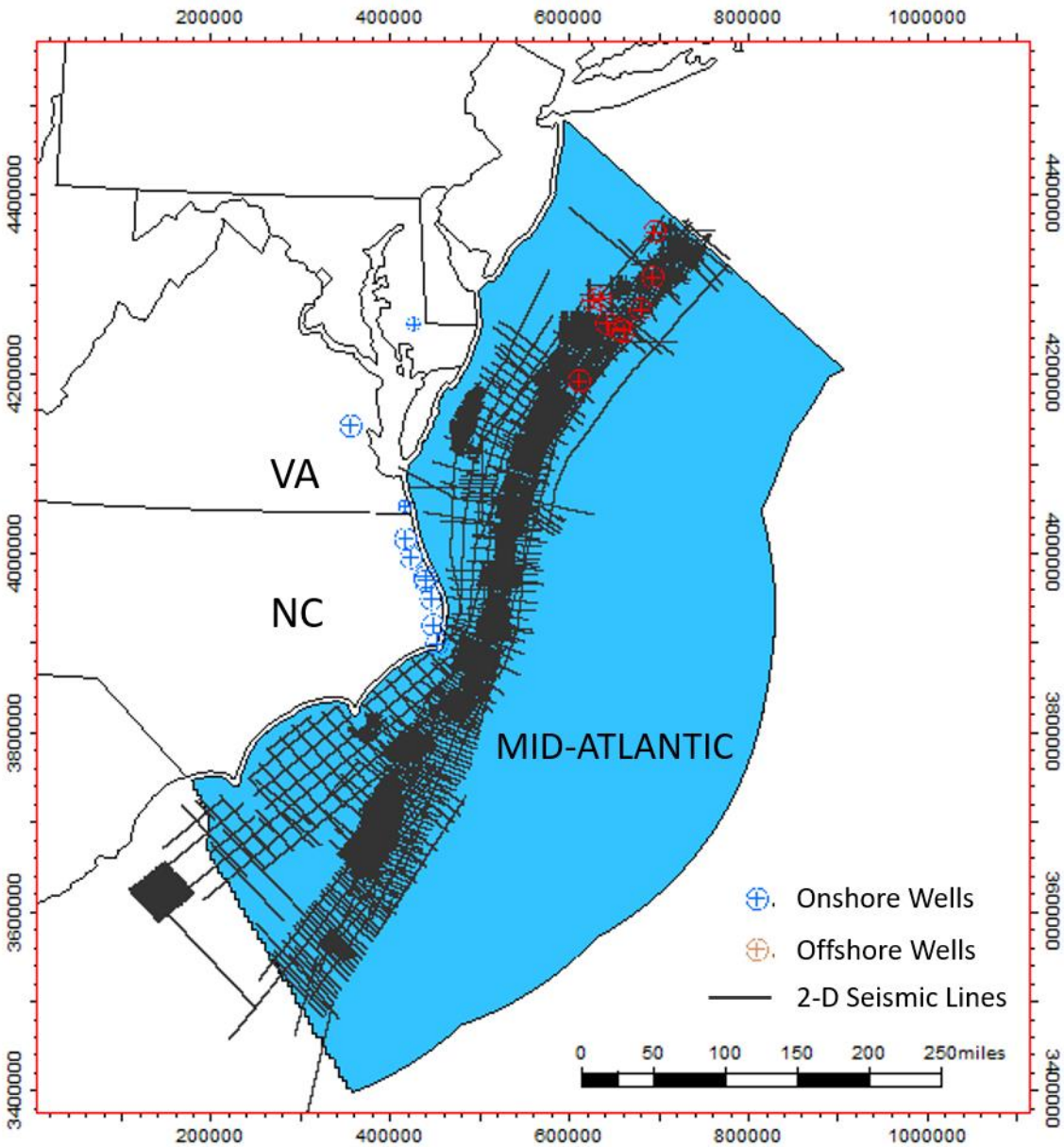

Figure 3 Selected Data in the Mid-Atlantic
(Note: This dataset will be interpreted to identify potential reservoirs suitable for CO2 storage)

DISCUSSION

This study is a review of the publicly available data and their suitability for the identification of reservoirs for CO_2 geologic storage and for oil and gas exploration. This study highlights the limitations of the available data with an emphasis on the quality and coverage of the Mid-Atlantic. The results presented in this publication could orient the development of future exploration campaign towards the collection of modern data in unexplored zones or in area with the most potential for CO_2 storage.

Despite the large volume of data collected in the past, the U.S Atlantic margin's stratigraphy still remain vastly unknown. The absence of modern seismic surveys (3D and 4D) as well as deep-penetrating wells represent the main challenges for reservoir characterization in this region. Some regional seismic interpretations have been conducted by USGS researchers and provided some insights on the regional stratigraphic framework of the continental shelf and slope (P. M. Brown et al., 1972; Poag, 1978, 1979). However, these regional studies do not provide the information necessary to assess the CO_2 storage potential in the Mid-Atlantic. Since the publication of this research, more vintage 2D seismic reflection data may have become publicly available allowing more robust interpretation of this study area.

To identify potential reservoirs for CO_2 sequestration in the Mid-Atlantic, a selection of the best quality data was made to reduce the dataset to the most applicable to this task. This selection was presented in this publication. The dataset doesn't only include good quality. Data considered to be of relatively poor quality, such as E-16-76, were included in this selection due to their ideal location on the shelf of Virginia where the data coverage is otherwise insufficient. Stack lines were also included to the selection for the same reason previously mentioned. During the seismic

interpretation task, it is the interpreter's responsibility to acknowledge the limitation associated with the seismic data and consequently the usefulness of the data.

This research showed the variability in data quality but also the lack of coverage on the proximal part of the shelf of Virginia and North Carolina. This represents a challenge for onshore-offshore stratigraphy correlation. The distance between the closest seismic lines and onshore wells will increase the uncertainty related to the seismic interpretation. Two main surveys are covering this part of the shelf: E-16-76 and E-14-75. Unfortunately, the quality of these lines is relatively poor and consequently any correlation will be associated with a high uncertainty.

In the next phase of the SOSRA project, the presented dataset will be interpreted to identify geological reservoirs suitable for CO_2 storage and reservoir simulation will be conducted to estimate the volumetric capability of each potential target.

CONCLUSION

The Mid-Atlantic continental shelf may represent a better opportunity for CCS than the Gulf of Mexico due to limited tectonic activity. For this reason, the risk associated with CO_2 injection (leakage and migration) could be less in this location. However, to reach the development phase of a large-scale CO_2 injection project, or even to start new oil and gas exploration campaigns, important steps need to be taken. The first step was presented in this paper and showed the necessity to analyze the data already available in the Mid-Atlantic and their usefulness for reservoir exploration.

With the focus turned on the proximal or near-shore part of the continental shelf of Virginia and North Carolina, the seismic data coverage was judged to be sparse and applicable only to regional geological interpretation due to the presence of regional surveys with large line-spacing. The observation of lateral changes in facies at reservoir scale will be uncertain. The quality of the seismic surveys in this zone is also considered to be of low quality with corresponding low vertical resolution.

However, on the more distal part of the shelf, seismic data coverage and quality is improved and may be extrapolated to improve the interpretation of the proximal part of the shelf.

The lack of offshore deep-penetrating wells still remains the biggest challenges of the Mid-Atlantic SOSRA project, as well as a low signal to noise ratio and low vertical resolution in the deeper section of the subsurface. Limited coverage and variable quality of the data will have a great impact on the uncertainty associated with the identification of potential reservoirs for CO_2 storage and therefore it is recommended to conduct a thorough uncertainty analysis during the seismic interpretation task to understand the limitation of the results.

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CHAPTER 3 - CO_2 RESERVOIR IDENTIFICATION AND ESTIMATION OF STORAGE CAPACITY OF THE OUTER CONTINENTAL SHELF OF NORTH CAROLINA BASED ON SEQUENCE STRATIGRAPHY AND ONSHORE CORRELATIONS.

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This work is in preparation to be submitted to the *Interpretation* journal.

ABSTRACT

As part of a global effort to mitigate the emissions of anthropogenic carbon dioxide (CO_2) in the atmosphere, Carbon Capture and Storage (CCS) represents a crucial step in lowering emissions and meeting targets. Geological storage appears to be an ideal last step of CCS following capture and transport of CO_2 , as it does not require major technological advancements (Freund, 2013). Offshore storage might be associated with larger economic challenges, however some major advantages associated with risk management and public acceptance make offshore storage a valuable option for carbon sequestration. This paper focuses on the CO_2 storage potential of the U.S. Mid-Atlantic region, specifically the outer continental shelf offshore North Carolina. 2-D vintage seismic reflection data and publicly available well data were previously analyzed and the most applicable dataset was selected for CO_2 reservoir exploration (Mullendore, Schlosser, Ripepi, & Xu, 2018). Due to the lack of offshore well control in the study area, seismic interpretation relied heavily on seismic stratigraphy to build a regional geological framework. To associate the picked horizons to a geological age and the seismic facies to lithologies, information from samples and core analysis as well as electrical logs of two deep wells located on the coastal plain of North Carolina were used for this study. This analysis

provided geological age to the identified sequences and predicted the location of sandstone (reservoirs) and shale (confining units). This methodology successfully identified potential reservoirs and impermeable seals necessary for CO_2 storage. Early Cretaceous units appear to be a suitable reservoir with adequate net(sand)-to-gross ratio, porosity and permeability, and preliminary results showed that the sandstones within these units could store between 0.9 GT and 10 GT of CO_2. The Lower Cretaceous intervals also showed great potential with estimates of 0.5 GT to 5 GT of storage capacity. The limitations related to the vintage 2D seismic reflection data as well as the challenges associated with the absence of deep-penetrating wells in the study area are discussed in this paper and highlight the extensive uncertainty.

1. INTRODUCTION

Carbon dioxide (CO_2) emissions represent over 80% of all anthropogenic greenhouse gas emissions in the U.S. (U.S-Environmental-Protection-Agency, 2015). These emissions have increased worldwide since the industrial revolution due to the extensive use of fossil fuels, industrial activities, and changes in land-use. High atmospheric concentrations of anthropogenic CO_2 and other greenhouse gases have been affecting the Earth's climate by increasing the rate of global warming causing environmental, economic, and health related consequences around the world (U.S-Environmental-Protection-Agency, 2015). As part of a global effort to reduce CO_2 emissions, multiple projects have been developed to capture and store CO_2 from energy and industrial-related sources (Department of Energy-National Energy Technology Lab (NETL, 2007). Geological storage of CO_2, which consists of injecting CO_2 into a subsurface geological formation at supercritical depth, represents one of the main solutions to efficiently storing CO_2 and minimizing leakage risks (Metz et al., 2005). Despite the increased focus of onshore storage

in deep saline aquifers or coal-bed methane reservoirs, offshore storage may have potential technical advantages, such as larger storage capacity and the ability to control reservoir pressure (NETL, 2007). Other legal advantages related to public acceptance and the absence of offshore mineral rights make offshore storage a more sustainable option (Schrag, 2009).

To investigate the potential for offshore storage in the U.S, the Southeast Offshore Storage Resource Assessment (SOSRA) (SSEB, Retrieved January 24, 2019), a project funded by the U.S Department of Energy (DOE), was created to assess the storage potential of the U.S. Atlantic margin as well as the eastern part of the Gulf of Mexico. Here, we focus on assessing the CO_2 storage potential of the Mid-Atlantic, primarily on the continental shelf of North Carolina. This area could be an adequate candidate for the development of CCS projects due to the proximity of power plants located along the East coast (Figure 1).

These power plants released 51.7 million metric tons of CO_2, which represent almost 50% of the total CO_2 emission budget of North Carolina (120 million metric tons) in 2015 (U.S-Energy-Information-Administration).The storage potential of this area remains unassessed, mostly because of the limited knowledge of the subsurface geology of this area.

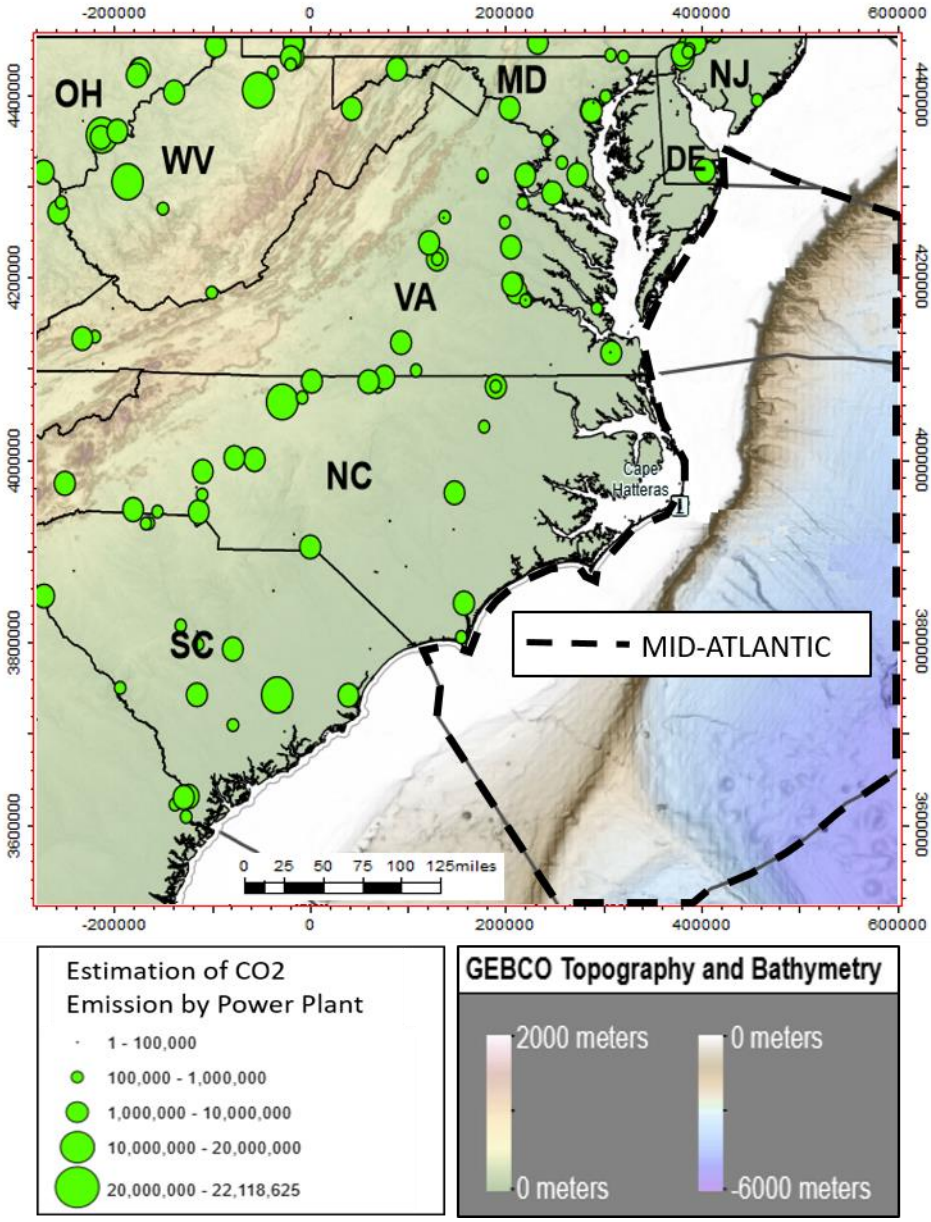

Figure 1 CO_2Emissions of Power Plants Nearby the Continental Shelf of North Carolina (Mullendore, Schlosser, et al., 2018)

No deep-penetrating petroleum exploration wells have ever been drilled offshore North Carolina. Therefore, this resource assessment relies on information provided by wells located on the coastal plain of North Carolina and vintage 2-D seismic reflection data collected during oil and gas exploration campaigns between the 1970s and 1980s, now publicly available. These data were used to establish a basic geological framework of the continental shelf of North Carolina.

Seismic stratigraphy and seismic facies analysis were used to predict sand-prone reservoir and shale-prone (seals) intervals. Seismic sequences were then correlated to well data to quantify the extent character, and quality of potential reservoirs and seals.

Because CO_2 can only be stored under supercritical conditions, only geologic formations within the required conditions of pressure and temperature were considered potential targets. The sequestration of CO_2 in supercritical (or dense) state increases the storage potential as the volume of supercritical CO_2 is less than CO_2 at atmospheric conditions (NETL, 2007). To reach the critical point of CO_2, the reservoir condition should be greater than 1,057 psi with a temperature greater than 31.1ºC. In the Atlantic Ocean, the hydrostatic gradient is typically 1 MPa per 100 meters and the geothermal gradient 25ºC/km (Stefan Bachu, 2000). As a result, potential reservoirs should be buried approximately 800 m below the surface (sea floor) to provide the thermodynamic conditions necessary for CO_2 storage. However, hydrostatic and geothermal gradient can greatly vary within a basin. The geothermal gradient can be affected by the basin activity such as tectonism. This 800 m limit has been widely accepted by the scientific community as an adequate depth threshold for the geological storage of CO_2 (Stefan Bachu, 2000; Sam Holloway, Savage, & Management, 1993; Van der Meer & Management, 1993).

The last boundary condition considered for this study was shale ductility and, therefore, seal integrity. Typically, shales with a density lower than 2.1 g/cm^3 are ductile and can support large amounts of strain before reaching brittle failure and therefore fracturing and losing top seal integrity. Shales with a density higher than 2.1 g/cm^3 can only support limited stress before fracturing, which makes these shales poor seals (Skerlec, 1999b). Density logs were not available for the onshore wells used in this study. However, density logs from wells located offshore New Jersey, such as Continental Offshore Stratigraphic Test (COST B-2), were available and

provided information to assess the brittle/ductile transition. Thick shales appeared to become denser than 2.1 g/cm^3 below 6,500 feet or approximately 2,000 meters. Therefore, below this depth, shales should not be considered adequate seals for carbon sequestration as they risk brittle failure and leakage.

By taking into account these boundary conditions, reservoirs below 800 m were identified and mapped, as well as seals above 2,000 m. These isopachs maps were used to conduct volumetric calculations to assess the storage potential of each identified reservoir. The volumes were calculated by following the method developed by DOE-NETL (Department of Energy-National Energy Technology Lab) to estimate the storage capacity of CO_2 in saline aquifers and is presented in Equation 1 (Goodman et al., 2011).

$$G(CO2) = A * h * \emptyset * \rho * E \qquad \text{Equation (1)}$$

With:

G (CO_2): estimated storage capacity of CO_2 in GT
A: total area of the geologic formation
h: stratigraphic thickness of reservoir interval(s)
Ø: porosity of the geologic formation
ρ: density of supercritical CO_2
E: CO_2 storage efficiency factor in saline aquifer

Geologic units interpreted as potential targets for CO_2 storage were given a net sand and net shale ratio as well as porosities calculated from core analysis of the Hatteras Light Esso No. 1 (NC-DNR-1-46) well and applied to the study area. Due to the lack of offshore wells, and the extrapolation of onshore data to the continental shelf, a high uncertainty is associated with this resource assessment and will be discussed hereafter.

2. GEOLOGICAL FRAMEWORK OF OFFSHORE NORTH CAROLINA: LITERATURE REVIEW

The lack of exploratory wells on the continental shelf of North Carolina represents one of the main reasons the regional stratigraphy of this area still remains broadly unknown. A thorough literature review was conducted to gather the most valuable information from previous studies which had the potential to guide this research.

The study area covers the southern Baltimore Canyon Trough and the northern part of the Carolina Trough. The southern part of the Baltimore Canyon Trough was described by Poag (1979) and Brown and Swain (1972; 1947) (Figure 2).

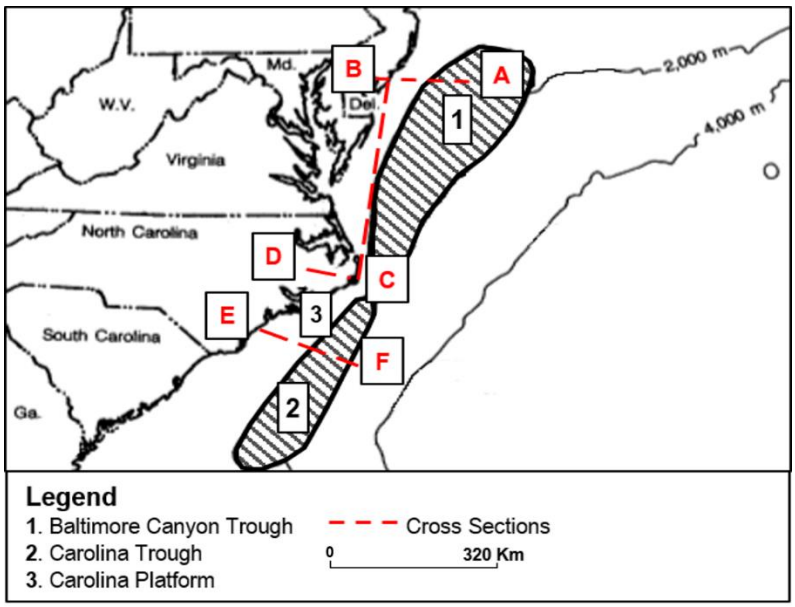

Figure 2 Major Basins Covering the Continental Shelf of North Carolina (Carpenter & Amato, 1992)

2.1 Baltimore Canyon Trough

The basic geological framework of the Baltimore Canyon Trough (BCT) is presented in Figures 3 and 4. According to these interpretations, and the aforementioned boundary conditions, potential targets could be located within the Upper and Lower Cretaceous strata. Lower

Cretaceous formations (Albian-Barremian) of the northern BCT are mostly non-marine, dominated by sand (fine, medium and coarse-grained) and shales, and are believed to be associated with the Potomac Group (Scholle, 1977). Lower Cretaceous strata in COST B-2 extend from approximately 2,500 m to 3,000 m deep (Scholle, 1977). Upper Cretaceous strata is interpreted to be more marine than the Lower Cretaceous. COST B-2 penetrated shallow Upper Cretaceous marine sandstone, shale and limestone. In the southern part of the trough, Esso No. 1 highlighted the same pattern of marine-dominated units in the Upper Cretaceous strata and nonmarine in the Lower Cretaceous (Poag, 1979).

Figure 3a shows these strata dipping seaward (A-B cross section) with a structural high of the trough on the coastal plain of Maryland and a southward dip of the Upper and Lower Cretaceous strata from Maryland to the coastal plain of North Carolina (B-C). This structural high was attributed to a possible igneous intrusion (Mattick, Foote, Weaver, & Grim, 1974). At the Esso No. 1 well, the Lower Cretaceous was encountered at a depth of 1,400 m and the Upper Cretaceous at a depth of 900 m. Therefore, it appears that both intervals should be within the acceptable depth for carbon storage below the North Carolina shelf. To avoid unwanted migration of CO_2 towards the coastal plain of North Carolina, the presence of a trapping mechanism is necessary. Based on the study of onshore wells, previous interpretations (Mattick et al., 1974) showed the presence of landward pinchout within the Cretaceous strata, which could indicate the presence of stratigraphic trapping within the Cretaceous interval. These traps were not identified on seismic data due to the limited vertical resolution of the data but were observed by correlating offshore wells to onshore wells in the BCT. Stratigraphic traps below the coastal plain are common in passive margin settings and exist adjacent to the BCT and CT (Holmes,

Breza, & Wise, 1987; Kraft, Sheridan, & Maisano, 1971; Libby-French, 1984; Mattick et al., 1974).

A significant amount of work has focused on the stratigraphy of the coastal plain of North Carolina and its aquifer system (Bonini & Woollard, 1960; Spangler, 1950; Swain, 1947). Correlation between the coastal plain and the continental shelf is possible. Sundee and Coffey (2009) defined the CT as a transition zone between siliciclastic-dominated facies to the north (BCT) and carbonate-dominated facies to the south (Southeast Georgia Embayment). COST B-2 lacks a significant carbonate component and shows a clear dominance of siliciclastic facies. However, southward, the presence of carbonates in Esso No. 1 as well as Pamlico Sound Esso No. 2 (1-47) is far greater, suggesting that CT strata represent a mixed carbonate-siliciclastic system that extends basinward below the continental shelf (Sunde & Coffey, 2009).

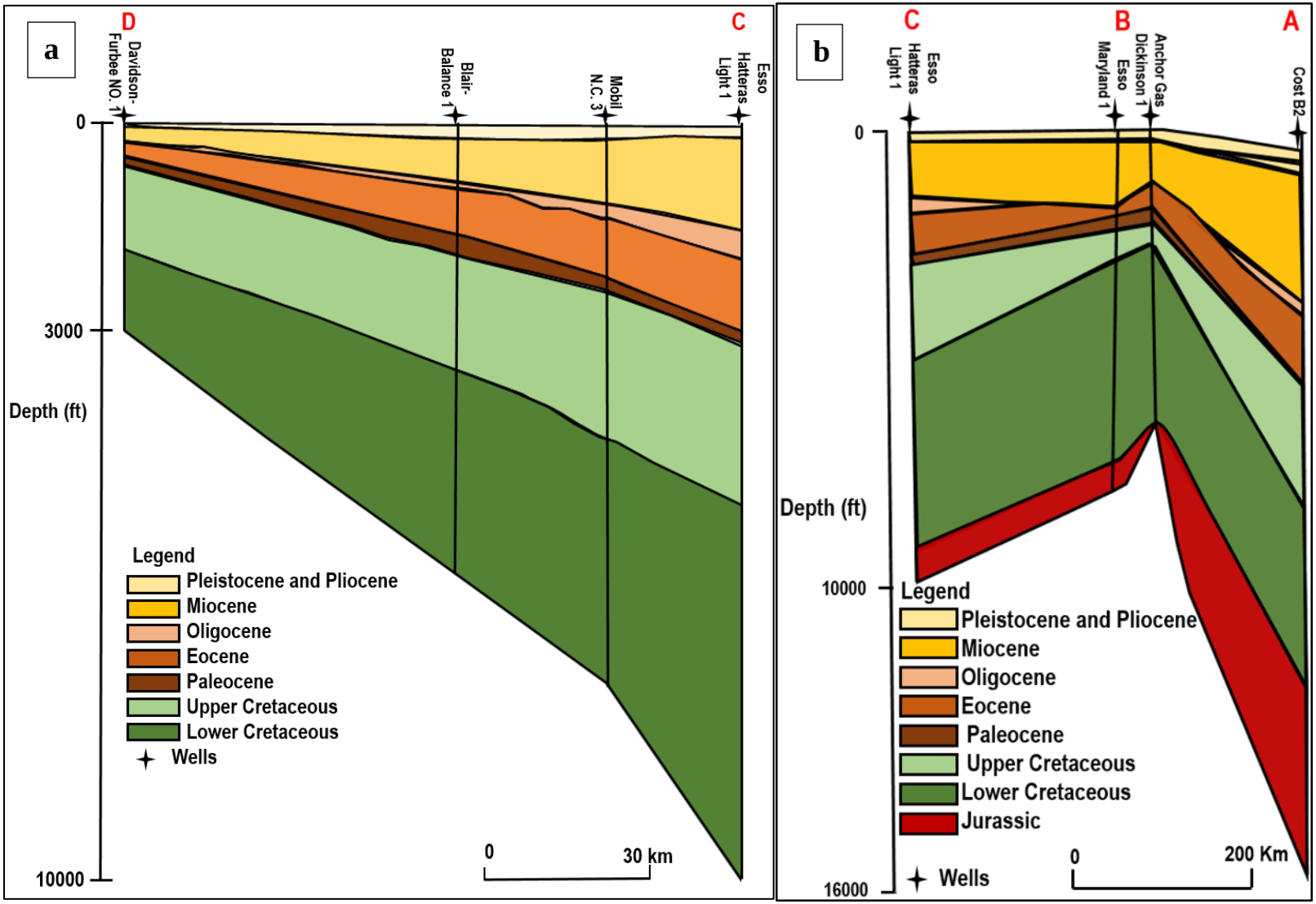

Figure 3 a) Schematic Cross Section Representing the Stratigraphic Seaward Dipping on the Coastal Plain of North Carolina between Davidson Furbee 1 and Hatteras Light Esso 1 Well) b) Schematic Cross Section between Four Wells from the Coastal Plain of North Carolina to Offshore New-Jersey (Poag, 1979).

2.2 Carolina Trough

Unlike the BCT, no basement-penetrating wells have been drilled in the Carolina Trough (CT). Previous studies assessed the oil and gas potential of this area (Carpenter & Amato, 1992; Dillon et al., 1982). These studies depended heavily on correlating onshore wells drilled into the coastal plain of North Carolina with offshore exploration (COST GE-1, Southeast Georgia Embayment; Shell 93-1, northern BCT) and scientific ocean drilling (DSDP 105, 524, 603) boreholes along with seismic data.

This basin is considered to be more structurally complex than any other basin in the U.S Atlantic continental shelf, mostly due its high degree of deformation as a result of salt diapirism (Carpenter & Amato, 1992). The underlying basement is relatively thin, affording rapid early subsidence of the basin and a transition from rift phase to drift phase at ~175 Ma (Dillon et al., 1982). A succession of syn-rift (Triassic-Jurassic) sedimentary rocks underlying shallow-water carbonates are interpreted from seismic reflection (Dillon et al., 1982). Carbonate deposition decreased in the Early Cretaceous, giving way to clastic sedimentation which dominated throughout the Cretaceous. Normal faults are predominant throughout the CT and can easily be identified on seismic data. These major faults are interpreted to be the consequence of movement of salt diapirs illustrated in Figure 4 (Carpenter & Amato, 1992).

Multiple potential reservoirs were interpreted by Carpenter et al (1992) as potential oil and gas targets in the CT. Complex structure could provide some advantages over the southern BCT for carbon storage as various trapping mechanisms were identified on seismic data. We focus primarily on the Carolina Platform and the most landward part of the CT where salt structures are not observed. Carpenter and Amato (1992) suggest that potential reservoirs could be present on shelf anticline traps, in siliciclastic formations wedging out on the carbonate

platform or other formations landward (Figure 4). Risk of leakage is much higher in the CT than BCT. The presence of regional faults may represent a valuable asset for carbon storage by providing a structural trap and preventing unwanted migration of CO_2 but could also be the source of unwanted leakage. Fault permeability represents one of the most challenging parameters to assess as it is site-specific and depends heavily on in-situ flow data, stress, and lithologies (Nicol et al., 2017).

The BCT, CT, and Carolina Platform could be adequate locations for geological storage of CO_2 within the study area. Since the completion of this study, more 2-D seismic reflection surveys have been released to the public, and more robust interpretations can be made to assess the storage potential of the outer continental shelf of North Carolina.

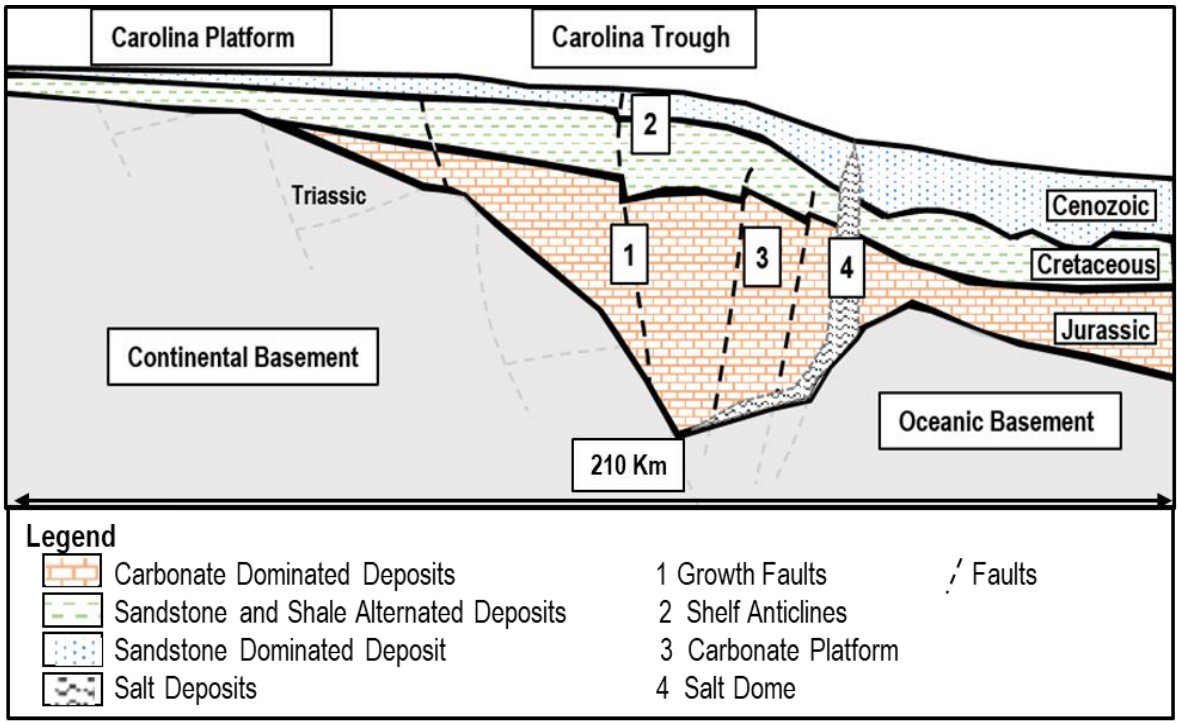

Figure 4 Schematic Cross Section of the Carolina Platform and the Carolina Trough Offshore North Carolina (Carpenter & Amato, 1992)

3. GEOPHYSICAL DATASET

For the purpose of this study, no additional dataset was collected in the study area. All the results presented here are based on the interpretation of 2-D seismic reflection data collected during oil and gas exploration from 1970-84 (Figure 5) and stratigraphic test wells located on the coastal plain of North Carolina. The majority of the data are publicly available and were acquired from the Bureau of Ocean and Energy Management website as well as the United States Geological Survey (USGS) database . Five seismic surveys covered the majority of the study area and are interpreted and discussed here (Table 1). To gain well control, information from two onshore stratigraphic test wells (Hatteras Light Esso No. 1, Pamlico Sound Esso No. 2 hereafter Esso-1, Esso-2 respectively) were extracted (Table 2).

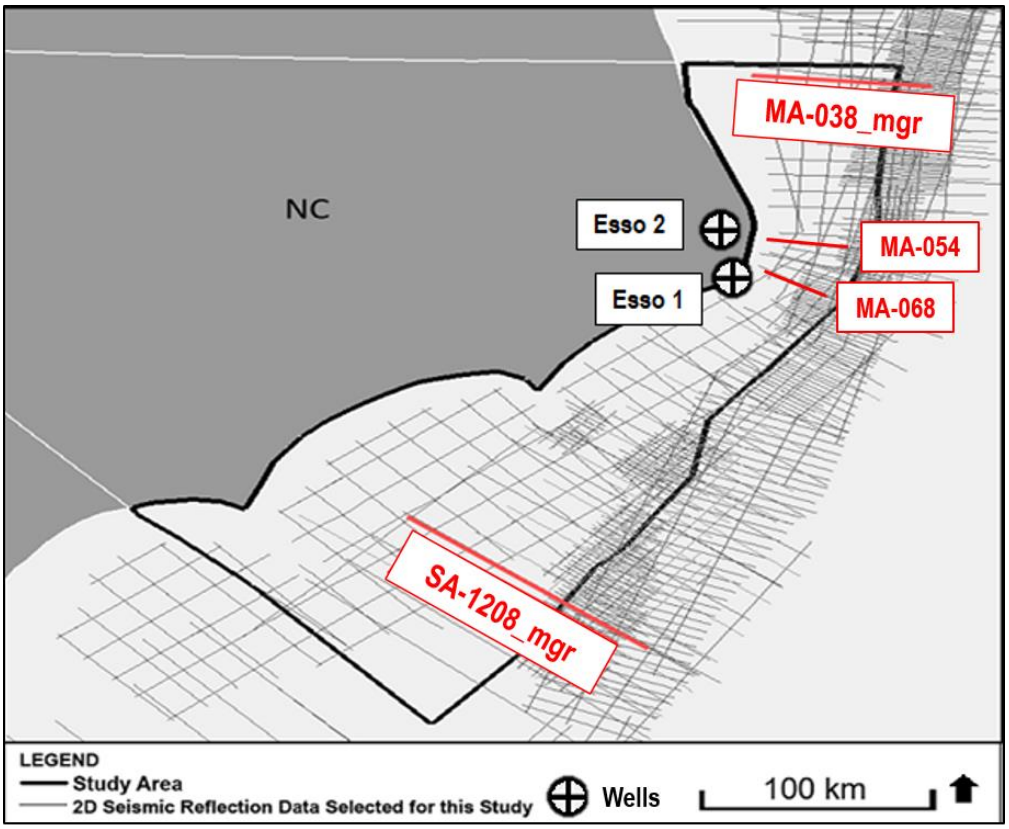

Figure 5 2D Seismic Reflection Data and Onshore Wells Distribution in the Study Area (NAMSS)

Table 1 2D Seismic Reflection Survey Collected for this Study (Bureau-of-Ocean-and-Energy-Management, 2009)

PERMIT OR SURVEY	LOCATION	SURVEY SCOPE	SEISMIC DATA TYPE	NUMBER OF DIP LINES	NUMBER OF STRIKE LINES
E16-76	Cape Hatteras, NC to MD	Semi- Regional	Stacked, Migrated	35	6
E02-80	Currituck Sound Prospect	Exploration	Stacked, Migrated	8	2
	Manteo Prospect	Exploration	Stacked, Migrated	22	2
E02-82	Northern NC to southern MD	Exploration	Stacked, Migrated	104	4
E-14-75	Cape Hatteras, NC to Northern SC	Semi- Regional	Stacked	25	3 to 7
E02-77	Southern NC to GA	Regional	Stacked, Migrated	22	7

Table 2 Stratigraphic Tests Located on the Coastal Plain of North Carolina (Bureau-of-Ocean-and-Energy-Management, 2009; Swain, 1947)

Well	Latitude	Longitude	Date	Datum (ft)	Hole Depth (ft)	Digital Logs
Hatteras Light	35.25	-75.52917	1946	24	10,054	SP, RES
Esso #2	35.70351	-75.59795	1947	21	6,332	SP, RES

Overall, the seismic dataset is of variable quality, typically from fair to poor (Mullendore, Schlosser, et al., 2018). Each seismic survey was collected independently and, therefore, acquisition and processing parameters varied between surveys. Seismic mis-ties are highly probable when different surveys are correlated and used together. To prevent any potential seismic direct mis-ties, calibration prior to mapping and interpretation was done to display identical amplitude polarities and avoid changes in amplitude scaling. No synthetic seismograms were constructed for well-seismic correlation due to the absence of digitized geophysical logs of Esso-1 and Esso-2.

4. SEISMIC INTERPRETATION: SEISMIC STRATIGRAPHY AND SEISMIC-WELL TIES

4.1 Seismic stratigraphy

Seismic stratigraphy has commonly been used by exploration geologists to predict the distribution and characteristics of potential reservoirs and seals at both regional and reservoir scale. This method has been used to identify hydrocarbon reservoirs and can similarly be used to

characterize reservoirs for carbon storage. Seismic stratigraphy provides a basic regional geological framework by identifying depositional sequences and the boundaries associated with them (conformities and unconformities). Recognizable elements can be observed on seismic data such as stacking pattern, reflector terminations and changes in seismic facies (Mitchum Jr, Vail, & Thompson III, 1977). By applying the principles of seismic stratigraphy, major units can be highlighted and prediction of sand and shale-prone zones can be achieved (Miller et al., 2017). In marine systems, particularly prograding/aggrading deltaic systems that developed on passive margins, patterns associated with specific system tracts can be observed and contribute to the prediction of sand- and shale-prone intervals (Posamentier, Jervey, & Vail, 1988; Posamentier & Vail, 1988). The vertical resolution constitutes one major limitation for seismic stratigraphy as it reduces the detectability and resolution of some strata (R. E. Sheriff & Geldart, 1995). However, the presence of two wells on the coastal plain of North Carolina represents a highly valuable asset. Seismic-well ties are established to correlate the identified sequence boundaries to formation tops deduced from well logs. Well data also allow seismic facies-lithology correlations and confirm the lithofacies predictions made by seismic stratigraphy. The workflow followed for this study is presented in Figure 6.

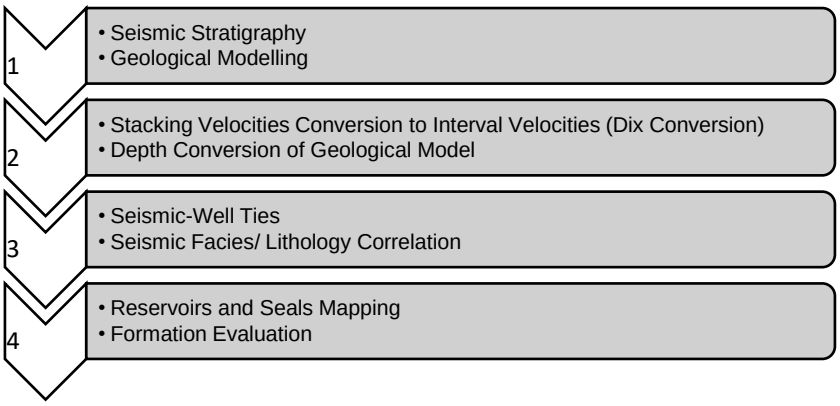

Figure 6 Seismic Interpretation Workflow

Ten sequence boundaries were identified and mapped across study area, typically. Two seismic profiles, representative of the south of the BCT and CT respectively, are shown in Fig. 7 and 8. This interpretation is consistent with past interpretations, as the same patterns were observed by Brown et al. (1972) and Poag (1979). Major growth faults were not identified in the BCT but were present in the CT. The transition zone between siliciclastic-dominated and carbonate-dominated strata cannot be observed on the outer continental shelf of North Carolina due to the limited vertical resolution of the data.

4.2 Depth Conversion from stacking velocities

Onshore wells did not provide any information regarding interval velocities. However, stacking velocities for three major surveys were available and downloaded from the BOEM website (NAMSS). To convert the geologic model from two-way time (TWT) to depth, a velocity cube was created by using stacking velocities. These velocities were first converted to interval velocities using the Dix conversion (Dix, 1955). This method can be considered accurate for horizontal layers with limited offsets but loses its accuracy for dipping layers and complex geometries (Öz Yilmaz, 2001). The interpretation of the stratigraphy of the outer continental shelf of North Carolina shows an overall shallow dip and overall low structural complexity. Therefore, the Dix conversion was considered acceptable for this study. It is important to note that some uncertainty can be associated with this type of conversion. The interval velocity profile for line SA-1208_migr shot point 1052 is showed below on Figure 9. The time window displayed in this figure is representative of the time between the sea floor and the acoustic basement on the continental shelf.

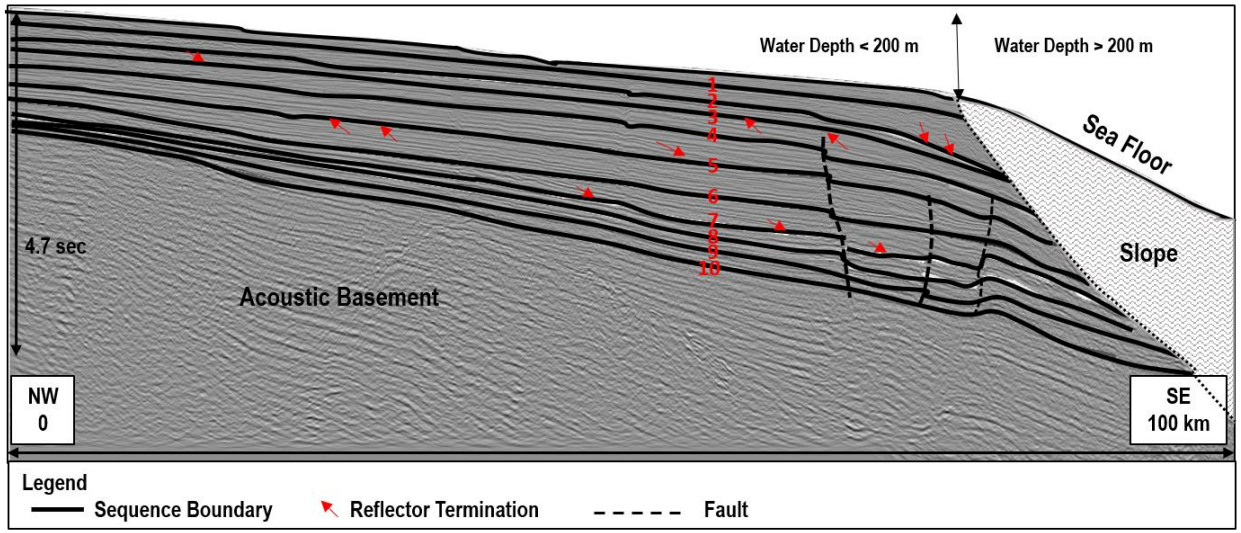

Figure 7 SA-1208 Interpretation

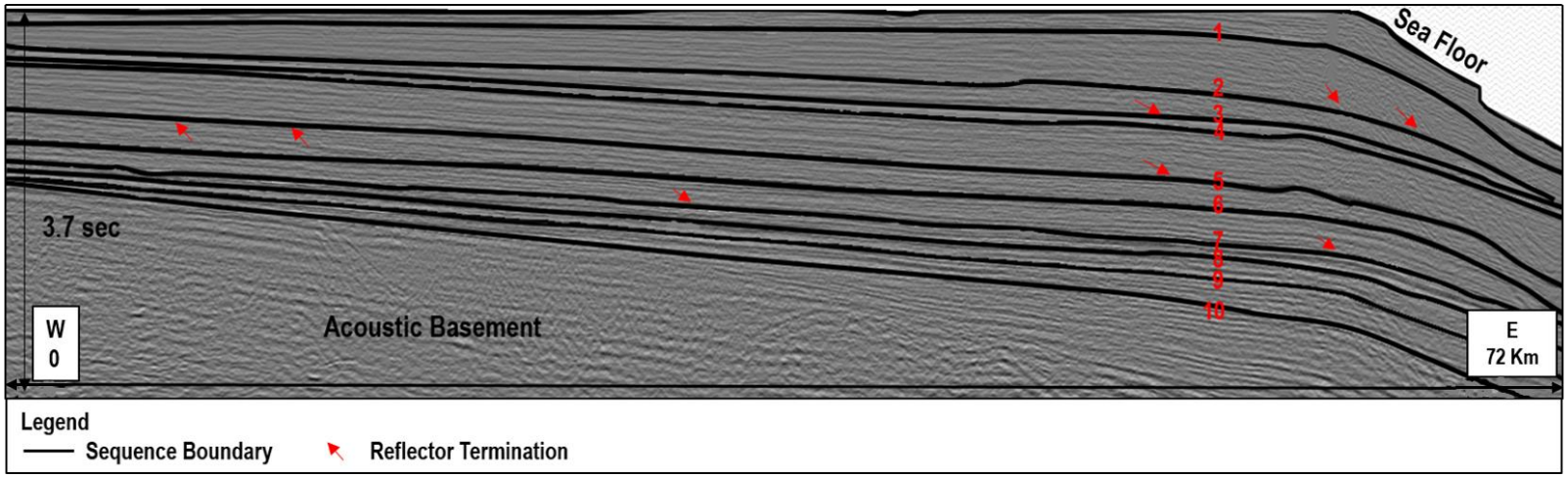

Figure 8 MA-068 Interpretation

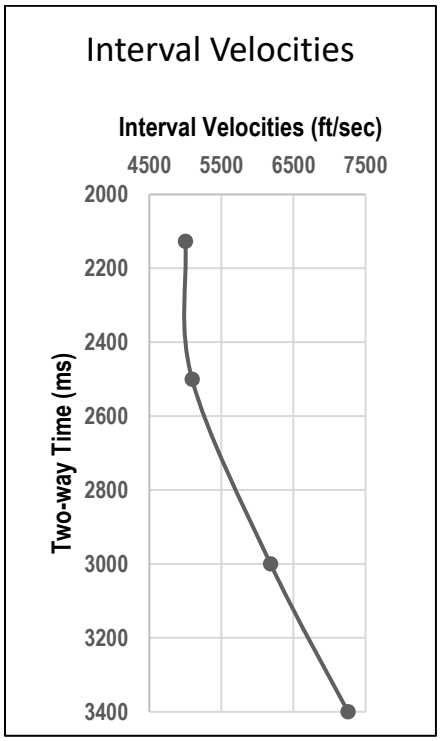

Figure 9 Interval Velocity Profile of Line SA-1208 at Shot Point 1052 (from stacking velocities downloaded on the NAMSS website)

4.3 Seismic-Well Ties

The digital well logs for the onshore wells used here are not publicly available. However, some publications provided valuable information to aid in seismic-well ties (Spangler, 1950; Sunde & Coffey, 2009; Swain, 1947). Formation tops and corresponding lithologies were digitized and correlated to the nearest onshore lines formation tops described in Swain (1947) were tied to major sequence boundaries. Tying these regionally-extensive boundaries to formation tops provided geological ages to each unit. Formations of early Jurassic to Pleistocene can be successfully correlated to the closest line and extended through the entire study area (Figure 10 and 11). An attempt to link seismic facies to lithologies showed limited success due to the vertical and horizontal resolution of the data which did not allow an in-depth analysis of the seismic facies variation.

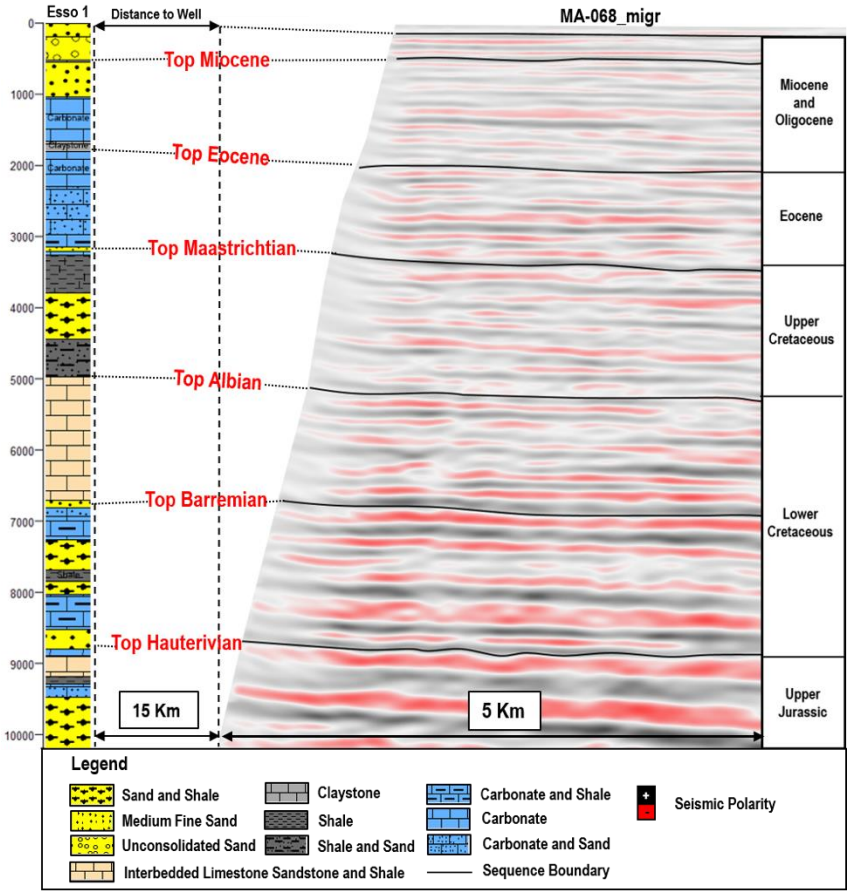

Figure 10 Correlation of Hatteras Light Esso 1 Formation Tops to the Sequence Boundaries Identified on Profile MA-068 (Lithologies from Swain, 1947)

Successful correlations increased the confidence in the seismic interpretation and were used to quality control each picked horizons. Esso-1 penetrated 10,054 ft of sedimentary rocks including the entire Upper and Lower Cretaceous and Upper Jurassic. Esso-2 penetrated into the Lower Cretaceous at 6,410 ft (Swain, 1947). From these wells, seven horizons were successfully tied surfaces mapped across the continental shelf.

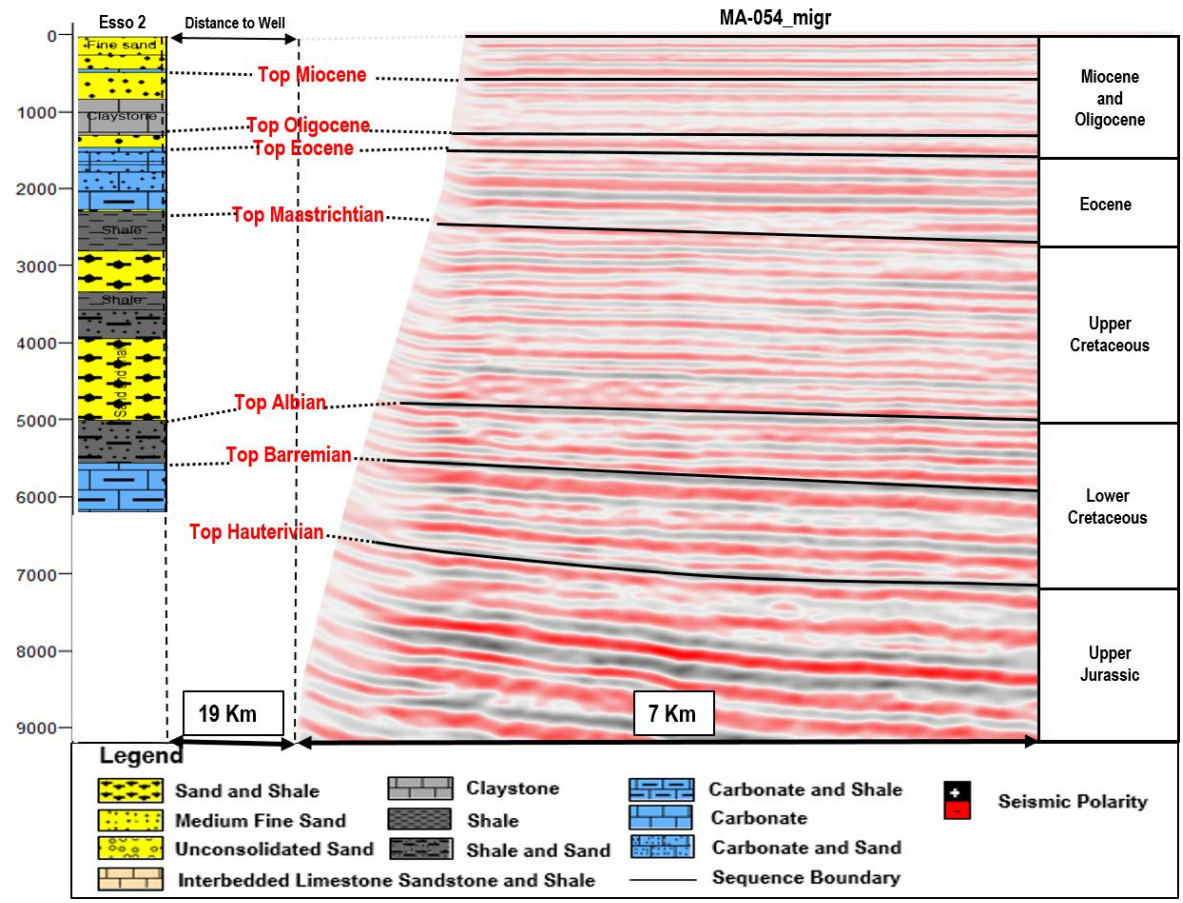

Figure 11 Correlation of Esso 2 Formation Tops to the Sequence Boundaries Identified on Profile MA-054(Lithologies from Swain, 1947)

5. RESERVOIR IDENTIFICATION

5.1 Boundary Conditions

Carbon storage in geologic formations can only be achieved by injecting supercritical CO_2 into a thick, porous and permeable reservoir. These reservoirs also have to be bounded vertically and laterally, by impermeable seals to prevent migration of CO_2. Temperatures and bottom hole pressures collected from Esso-1 (Swain, 1947) suggest that storage of supercritical CO_2 is possible in the Upper and Lower Cretaceous formations on the outer continental shelf of North Carolina. However, due to the potential loss of seal integrity related to shale ductility at

depth, the Lower Jurassic was not considered in this study. Interpretation of the Upper Jurassic formation showed that this unit is buried below 6,500 ft (2,000 m) and therefore any seals adjacent to reservoir targets may be prone to brittle failure and potential leakage.

5.2 Thickness Maps

Three major units were identified within the Cretaceous interval: 1) Maastrichtian to Albian (Upper Cretaceous), 2) Albian to Barremian (Lower Cretaceous) and 3) Barremian to Hauterivian (Lower Cretaceous). The geological ages of each formation top were obtained from Esso-1 and Esso-2. Thickness maps (isopachs) were created for each interval (Figure 12,13,14).

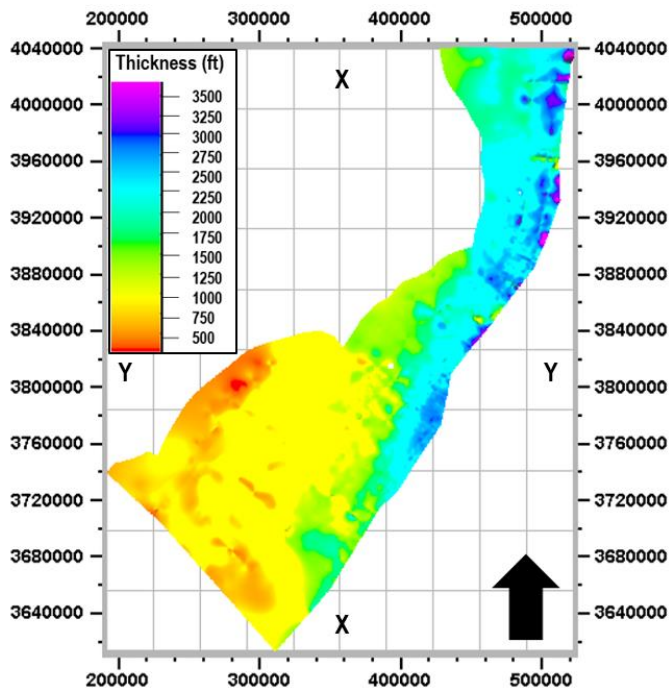

Figure 12 Thickness Map of the Upper Cretaceous Strata (From Maastrichtian to Albian)

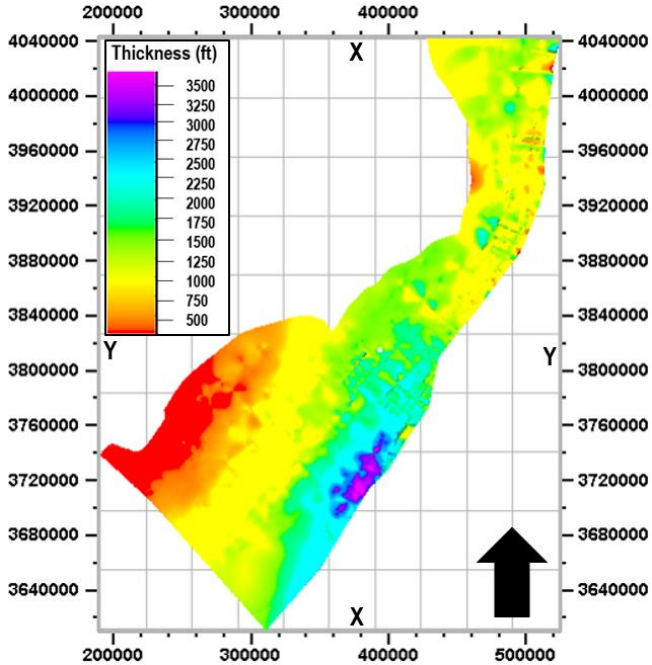

Figure 13 Thickness Map of Lower Cretaceous Strata (From Albian to Barremian)

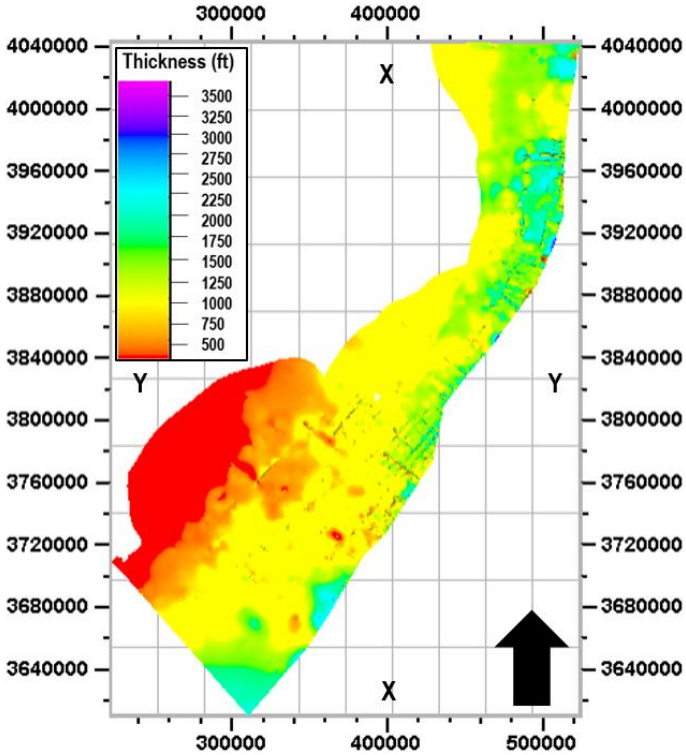

Figure 14 Thickness Map of Lower Cretaceous Strata (From Barremian to Hauterivian)

Each interval shows potential for CO_2 sequestration due to the presence of thick interbedded sandstones (reservoirs) and shales (seals). Reflectors for the upper limit of Maastrichtian, Albian and Barremian cannot be traced below the Onslow Bay. These reflectors may wedge out landward which would indicate the presence of some potential stratigraphic traps. Another explanation could be the poor seismic resolution of the stacked, unmigrated lines acquired from Onslow Bay, limiting the detectability and resolution of some geologic units.

In general, it appears that thickness of all three target intervals increases basinward. The thickness maps show that the upper Cretaceous unit thickens toward the north of the study area, whereas the Albian unit becomes thinner towards the North Carolina-Virginia border. The Barremian unit maintains similar thickness throughout the study area.

5.3 Formation Evaluation

Onshore well logs are not publicly available and therefore reservoir parameters such as porosity, permeability, and net to gross cannot be directly deduced or calculated from well data. Spangler (1950) provided porosity and permeability of major sand units identified in the Esso No. 1. However, no information is available regarding the shales and carbonates encountered in the same well. This location in the Mid-Atlantic can be complicated to assess due to the lack of basement-penetrating or deep exploration wells offshore, but also due to the distance to other wells located in the Atlantic (COST B-2, B-3, GE-1). As mentioned before, the shelf of North Carolina represents a transition zone between a siliciclastic-dominated shelf to the north and more carbonate-dominated to the south. COST GE-1 in the South Georgia Embayment and COST B-2 in the BCT (New Jersey), highlight the differences in lithologies between the two areas. Therefore, these distant wells cannot be used reliably to provide reservoir parameters for the three units interpreted in the CT. The lateral and vertical variation in seismic facies is not

easily observable on seismic data and therefore identifying the extent of the transition zone is problematic. Onshore wells are the only reliable source of subsurface information in this area.

Esso-1 provided porosity and permeability of sand units located between 3,657 feet and 7,191 feet (Swain, 1947). No information regarding the shale and carbonate intervals were collected in this publication and were just broadly described by Spangler (1950). Porosity and permeability vary greatly within the sand bodies located at the Esso-1 well. No strong relationship between porosity or permeability with depth is apparent. However, the average porosity is slightly higher in the upper Cretaceous than lower Cretaceous and higher permeability values can be found in the lower Cretaceous. Due to the absence of deep wells, the porosity and permeability obtained from Esso-1 will be extended to the rest of the study area to estimate the storage potential of each geological unit.

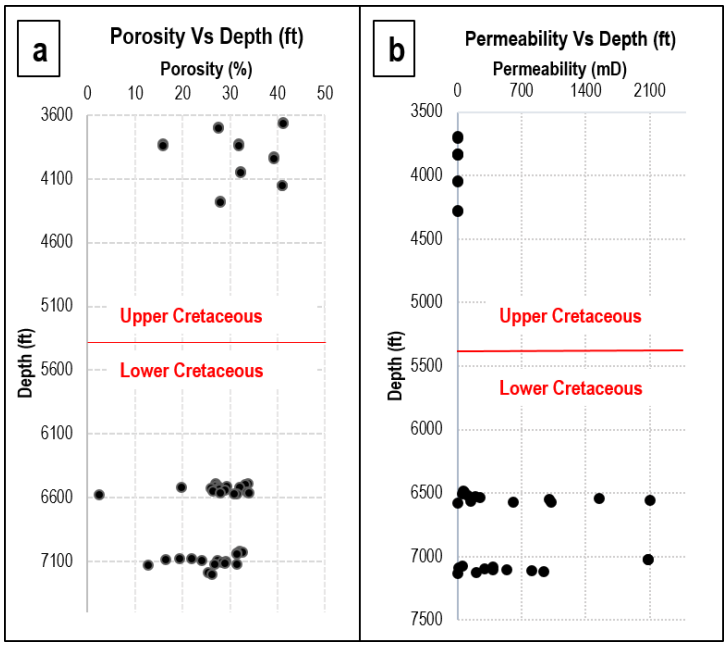

Figure 15 Hatteras Light Esso 1 Cores and Samples Analysis Results: a) Porosity Vs Depth b) Permeability Vs Depth (Swain, 1947)

Measured sandstone intervals, shale and limestone are presented in Table 3; these bulk percentages were used to calculate the net-to-gross ratio of reservoir to seal. Only sandstone intervals were considered potential reservoirs (conventional) as carbonate's porosity and permeability were not estimated by previous studies and therefore presented larger uncertainties than sandstone formations. It appears that multiple reservoirs and seals are present within each unit. Between 3,600 ft and 4250 ft, the upper Cretaceous unit identified in some recent publications as the Pleasant Creek Formation (Self-Trail, Prowell, & Christopher, 2004) and as the Black Creek formation in older publications (Richards, 1950; Spangler, 1950) shows great potential for CO_2 storage due to high-porosity sandstone within this interval. This formation is bounded at the top by the Shepherd Grove Formation and at the bottom by the Collins Creek Formation, both dominated by thick shale (Self-Trail et al., 2004). In the Lower Cretaceous formation, carbonates are more abundant, but thick sand intervals are still present, especially the Patuxent Formation, 200 ft thick sandstone at 7,000 ft. The Patuxent Formation is also described as the bottom of Tuscaloosa Formation by Richards (1950).

Table 3 Lithologies Distribution in the Upper and Lower Cretaceous at Esso 1

Formation	% Sand	% Shale	% Limestone
Maastrichtian	37	53	10
Albian	24	38	38
Barremian	27	38	35

6. ESTIMATION OF CARBON STORAGE POTENTIAL

Based on the net-to-gross calculated from the literature, volumetric calculations were conducted for the three main target intervals identified here. Net-to-gross values were given to each interval and were extended across the study area. The model did not take into account

lithofacies changes within the study area, mostly because of the lack of data in other parts of the seismic polygon.

The volume of each reservoir was calculated and used to estimate the storage capability for the three identified reservoirs (methodology described above). An average porosity based on the core analysis described in Swain (1947) was used. The density of 700 kg/m^3 for supercritical CO_2 was used for the calculation. The storage efficiency refers to that of saline formations in clastic reservoirs described in Goodman et al. (2011). This coefficient represents the fraction of pore volume that will realistically be occupied by carbon dioxide. Probabilities show that this coefficient can range between 0.5% and 5.4% (10th and 90th percent probability) Goodman et al. (2011). The value for 50th percentile was also added to the calculations. The results are presented in Table 4.

Table 4 Carbon Storage Potential of the Upper and Lower Cretaceous Formations on the Outer Continental Shelf of North Carolina

							Storage Coefficient			Storage Potential (Gt)		
Formation	**Volume (m3)**	**Area (m2)**	**Net Sand**	**Net to Gross**	**Density (kg/m3)**	**Porosity**	P10	P50	P90	P10	P50	P90
Maastrichtian	2.27E+12	4.66E+10	0.37	0.9	700	0.32	0.005	0.02	0.054	**0.94**	**3.76**	**10.16**
Albian	2.55E+12	4.64E+10	0.24	0.8	700	0.25	0.005	0.02	0.054	**0.54**	**2.14**	**5.78**
Barremian	2.83E+12	4.52E+10	0.27	0.8	700	0.35	0.005	0.02	0.054	**0.94**	**3.75**	**10.12**
										2.41	**9.65**	**26.05**

DISCUSSION

This paper assessed the storage potential of CO_2 of the outer continental shelf of North Carolina by identifying potential reservoirs and confining units and provided estimations of the volume of CO_2 that could potentially be stored in these reservoirs. The Upper and Lower Cretaceous intervals were identified as possible targets due to their optimal burial conditions and

the presence of thick sandstone deposits (reservoirs) and shales (seals). The volumetric calculation conducted by following the DOE guidelines showed that the storage potential of the Upper Cretaceous is between 0.9 and 10 gigatons (GT) of carbon, and the Lower Cretaceous between 0.5 and 5 Gt in the upper part and 0.9 to 10 GT in the lower part. All three reservoirs cumulated could store up to 26 GT of CO_2. These results are a broad estimation of the storage potential of this area.

However, large uncertainties are associated with these numbers. First, the vintage data interpreted for this study had variable origins and quality. For each survey, the acquisition and processing parameters varied and therefore influence the quality of the data. By law, the release of processed data to the public happens after a 25-year period; however, unprocessed data gets release after a period of 50 years. Therefore, reprocessing seismic data in this area will only be possible after the release of raw data in the near future. Moreover, 2D seismic reflection data are typically used to construct a regional framework of basins but are considered insufficient to predict with some accuracy the presence of reservoirs and confining units. The quality but also the coverage of 2D seismic data limits the extent of the interpretation. 3D surveys or 2D surveys with tight line-spacing are necessary to reduce the uncertainty related to the interpretation. The vintage data used for this study allowed identification of major sequence boundaries and faults but the resolution does not allow the detectability of sub-sequences and, therefore, potential reservoirs. The predictions made in this paper relied heavily on published studies that described the various lithologies encountered in two wells on the coastal plain of North Carolina and provided some reservoir parameters such as porosity and net-to-gross ratio (Swain, 1947 and Spangler, 1950). Well logs for these two wells were not released to the public and core samples were not available, preventing any newer interpretation of these data. The absence of deep

penetrating wells on the outer continental shelf of North Carolina represents the most challenging aspect of this assessment. The CT has been interpreted as a transition between siliciclastic-dominated deposits and carbonate-dominated deposits and therefore some lateral changes in lithologies are expected to be occurring in this area. However, seismic profiles did not show obvious changes in seismic facies pattern due to the poor resolution of the data. For that reason, lithologies were assumed unchanged within units across the study area maintaining the same net-to-gross ratios and porosities.

All the reasons mentioned above increased the uncertainty associated with the interpretation presented in this paper and therefore in the estimation of carbon storage potential of the outer continental shelf of North Carolina.

By reprocessing data as well as collecting additional data in this location such as 3D seismic and stratigraphic test wells, reservoir prediction could be drastically improved, and the uncertainty related to the storage potential of the study area reduced.

CONCLUSION

In an attempt to reduce the emission of CO_2 in the atmosphere, the geological storage of CO_2 could represent an important part in the development of CCS projects. Offshore storage is currently being investigated for long-term project as it offers considerable advantages over onshore storage. On the East coast of the United States, the capture of CO_2 from emitting power plants could be coupled to the transport and geological storage in the subsurface of the Atlantic Ocean and provide long-term solution to reduce the emission of CO_2 (DOE-NETL, 2015). This study identified potential reservoirs in the upper and lower Cretaceous formations on the outer continental shelf of North Carolina (from Maastrichtian to Hauterivian) but also some regional

confining units. These intervals qualify for carbon storage as both are buried below the 800 meters' supercritical threshold of CO_2. Each interval shows great potential for carbon storage however volumetric calculation represents a broad approximation of the regional storage potential due to the limitation associated with the vintage data and lack of deep-penetrating wells. The U.S DOE has for goals to store 30 megatons of CO_2 per key focus area such as the Mid-Atlantic seaboard. Reservoir simulation needs to be conducted to estimate the time frame necessary to reach this goal. A wide range of injection scenarios need to be tested to optimize the storage of CO_2 in each identified reservoir.

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CHAPTER 4 – CO_2 STORAGE CAPACITY ASSESSMENT IN THE OUTER CONTINENTAL SHELF OF NORTH CAROLINA.

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This work is in preparation to be submitted to the *International Journal of Greenhouse Gas Control.*

ABSTRACT

To mitigate the emissions of CO_2 in the atmosphere, the implementation of Carbon Capture and Storage (CCS) technologies was identified as necessary by the Intergovernmental Panel on Climate Change (IPCC). The geological storage of CO_2 plays a large part in the success of CCS. Some successful projects such as the Sleipner facility in the North Sea demonstrated the feasibility of large-scale offshore geological carbon storage in saline aquifers. In the United States, the potential for offshore storage of CO_2 is currently being investigated in some key areas such as the Atlantic Ocean and the Gulf of Mexico. This paper focuses on the potential of the Mid-Atlantic planning area and specifically the outer continental shelf of North Carolina. In a previous publication (Mullendore, Parent, Schlosser, & Romans, 2018) the Upper Cretaceous Formation was identified at suitable for sequestration of supercritical CO_2. A storage resource assessment was conducted by following the DOE-NETL approach and concluded that #GT of CO_2 could potentially be stored in this area (Goodman, Sanguinito, & Levine, 2016). This paper presents the results of a storage capacity assessment and a comparison to a refined storage resource assessment previously published allowing the calculation of an effective efficiency factor proper to this area. Reservoir simulations tested various injections strategies (variable number of wells and CO_2 flowrates) in both open and confined system settings to optimize the

long-term storage of CO_2 while limiting regional pressure build-up and long-distance plume migration in the aquifer. Due to the limited data available in this location, high uncertainties were associated with the identification and characterization of sandstone reservoirs and their associated parameters. In an effort to understand these uncertainties, a sensitivity analysis was conducted to determine the effect of reservoir dimensions and petrophysical properties on the storage capacity and plume extension. This study showed the feasibility of large-scale storage projects in this area, however, reservoir geometries and parameters highly impact storage capacity predictions. In confined aquifer (with the presence of lateral boundaries), to prevent geomechanical failures, the pressure build-up should remain below the estimated fracture pressure (270 bars). This boundary condition impacts the possible injections strategies and therefore the storage capacity estimations. In an open system, the objective was to contain the plume to a limited area and results showed the importance of net-reservoir ratios and properties to plume migration predictions. The recommendation that can be made after this research is that to accurately assess the potential storage capacity of the Mid-Atlantic, additional data need to be collected to reduce the large uncertainty presented in this publication.

1. INTRODUCTION

Since the industrial revolution, anthropogenic activities have contributed to the increase of CO_2 emissions in the atmosphere to reach the alarming concentration of 401 ppm in 2015 (U.S-Environmental-Protection-Agency, 2015). This increased concentration was for the most part attributed to the combustion of fossil fuel as a primary source of energy. Each year, the power plants located in the state of North Carolina emits approximately 100 MT of CO_2 in the atmosphere (U.S-Energy-Information-Administration). The location of North Carolina (NC) on

the coast of the Atlantic Ocean makes it an adequate candidate for the deployment of CCS and more specifically for large-scale offshore geological storage of CO_2. The continental shelf of NC remains for the most part unexplored, however, a previous study highlighted the large storage potential of sandstone intervals in the Upper Cretaceous Formation (between the depth of 1,030 and 1,440 meters) (Mullendore, Parent, et al., 2018) and the potential presence of thick shale deposits acting as seals and providing stratigraphic traps to the reservoir. Laterals boundaries were not identified by this study and therefore both cases of open and confined system must be investigated.

The Department of Energy (DOE) has for objective to store up to 30 MT of CO_2 each year in identified targets which would lead to the impactful mitigation of anthropogenic emissions in NC (-30%) (U.S.-Department-of-Energy). To assess the feasibility of such objective in this location, an extensive geological knowledge of the study area is needed to design injection strategies to optimize the storage of CO_2 while maintaining safety requirements. Only a limited amount of data is available in this area and therefore multiple reservoir dimensions and parameters were tested to provides a range of storage capacity estimations.

In a confined system, limiting a local and regional pressure build-up should be a priority to prevent geomechanical failures and leakage of CO_2 over time. In this paper, various injection strategies were tested on a homogeneous and heterogeneous aquifer to assess the pressure response and its effect on injectivity and consequently on the storage capacity of the aquifer. A sensitivity analysis was then conducted to capture the effect of reservoir dimensions and rock compressibility on these estimations.

In an open system, pressure build-up represents less of a challenge due to the mobility of the water outside the reservoir. However, to prevent the unwanted migration of CO_2 toward the coast

and the contamination of fresh water aquifers, it is crucial to limit the plume migration as much as possible to a restricted area. Limiting this migration also allows to perform long-term seismic monitoring of the plume via repeated 3-D surveys also referred as time-lapse 4D seismic surveys. Reservoir properties were extracted from industry wells located on the coastal plain of NC (Esso-1 and Esso-2) and in the North-Atlantic (COST B-2 and COST B-3) and extended to the study area (Amato & Simonis, 1979; Smith et al., 1976; Spangler, 1950; Swain, 1947). Due to the uncertainty associated with extending these parameters across long distance, a sensitivity analysis was conducted to determine the effect of reservoir property variation such as porosity and permeability. The reservoir (sandstone deposits) thickness also represents an unknown variable at this stage of this investigation and therefore the sensitivity to the net-to-gross ratio on the storage capacity was also investigated.

2. CASE STUDY OF HOMOGENEOUS RESERVOIR

The Upper Cretaceous Formation (UCF) is present all across the Mid-Atlantic continental shelf. The formation's thickness increases basinward to reach a maximum at the shelf break. In this study area, major normal faults can be identified on seismic profiles at the proximity of the shelf break. The absence of information regarding these faults and their potential conductivity suggest an elevated risk level for CO_2 storage on the distal part of the continental shelf. It would be recommended to remain within a 15 km radius from the shore of NC to limit the risk of leakage from the identified faults.

The reservoir simulations presented below focused on a 200 km^2 area, located in the northern part of the Carolina Trough (CT), 10 km away from the shore of NC. A circular grid, with

50x50 grid blocks, was created to model the formation at depth between 1,030 to 1,440 meters below sea floor (SSD).

2.1 Model and Simulation Set-Up

The UCF was divided in 11 zones, each one dominated by a facies: sandstone, shale or carbonates. These ratios were estimated from Esso-1 stratigraphic log presented in P. M. Brown et al. (1972). In this paper, only sandstone reservoirs are considered suitable for carbon storage. These stacked reservoirs are represented by 3 sandstone intervals: Interval 4, 8 and 10, confined by two seals (shales) at the top and the bottom of the formation.

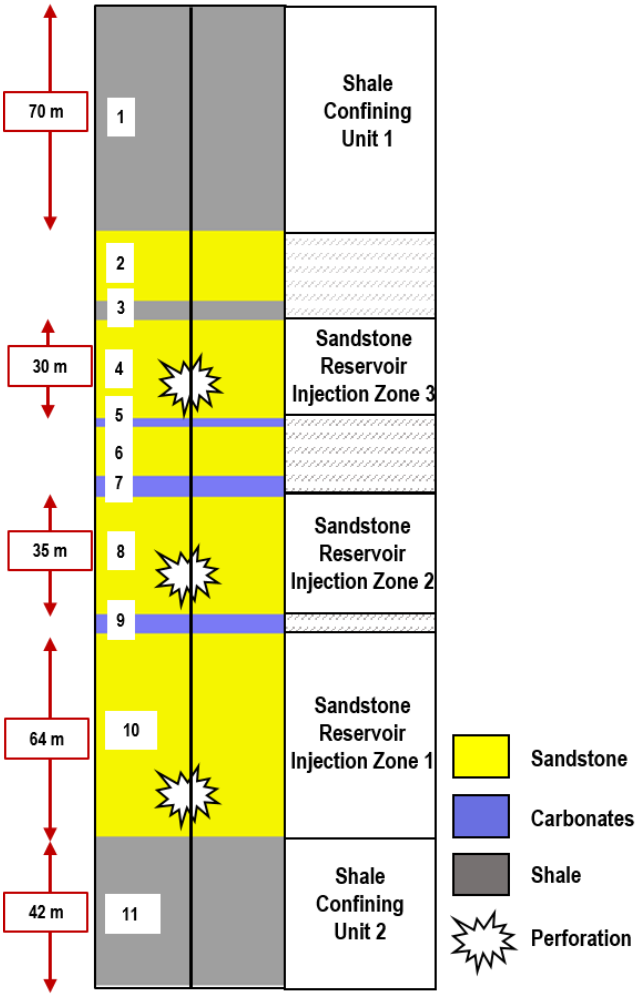

Figure 1 Cross-Section of Geomodel at Injector 1 Representing Reservoirs and Confining Units

Table 1 Facies Distribution in Each Zone of the Geomodel

Facies %	1	2	3	4	5	6	7	8	9	10	11
Sandstone	1	95	0	90	0	95	5	90	0	90	0
Shale	99	5	95	5	5	5	0	5	5	5	99
Carbonate	0	0	5	0	95	0	95	0	95	0	1

In this case, the reservoir was considered homogenous and therefore, average values of porosity, permeability and net-to-gross (NTG) were calculated for each facies, from the core analysis results of Esso-1 and Esso-2, published in Swain (1947). The reservoir parameters are presented in Table 2. Rock compressibility for sandstone was set as $4x10^{-10}$ bars (Zimmerman, 1990) and brine salinity as 10%. To prevent geomechanical failures and preserve borehole stability, a fracture pressure was estimated at 300 bars (30,000 kPa).

Table 2 Petrophysical Properties of Homogeneous Grid

Facies	Porosity	Permeability IJ (mD)	Permeability K (mD)	Net-to-Gross
Sand	0.2	100	10	0.8
Shale	0.3	0.005	0.0005	0.2
Carbonate	0.25	0.02	0.002	0.15

The reservoir initial conditions were based on typical geothermal and hydrostatic gradient, of respectively 25°C/km and 0.1 bars/m. At 1,200 meters, the reservoir temperature was set as 35°C and the pressure as 120 bars.

Each simulation consisted of 50 years' continuous injection of CO_2, with a bottom hole pressure (BHP) limit set as 90% of the estimated fracture pressure (270 bars). The BHP reference depth is located at the bottom of the deepest reservoir (Injection Zone 1). Each interval was perforated and opened at different time during the injection to increase the storage capacity of each interval. During the first 25 years, CO_2 was injected in the lowest interval (Injection Zone 1), then for 15 years in Injection Zone 2 and finally 10 years in Injection Zone 3. This strategy

was developed to optimize the storage of CO_2 in the deepest and thickest interval and prevent large accumulation of CO_2 below Confining Unit 1 which would decrease the risk of leakage. The initial flowrate was set a 1 million metric tons per year (MT) and constrained by the maximum BHP of 270 bars (27,000 kPa). The numbers of wells as well as the well spacing varied for each run to determine which scenario would optimize the storage capacity of CO_2 (Figure 1) and range between 1 to 10 wells with a spacing between 2 to 8 km. Five combinations of wells were tested for each run (1, 2, 3, 5 and 10 injector wells) and are described in Table 3.

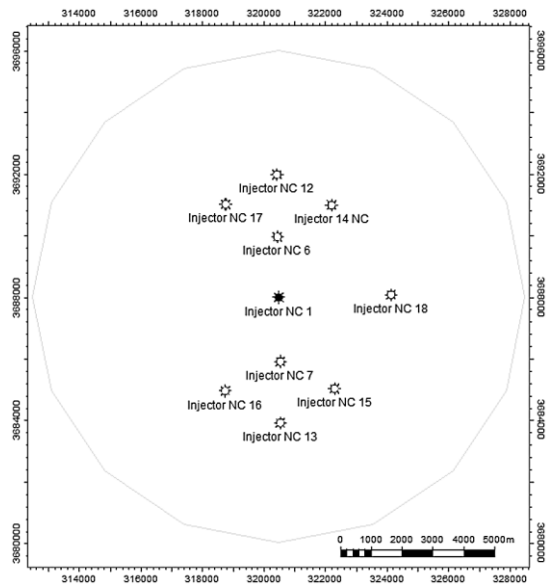

Figure 2 Well Distribution and Spacing on 200 km² Grid

Table 3 Well Combination for Variable Number of Wells Used in Runs

# of Wells in Runs	NC 1	NC 6	NC 7	NC 12	NC 13	NC 14	NC 15	NC 16	NC 17	NC 18
1	x									
2	x	x								
3	x			x	x					
5	x	x	x	x	x					
10	x	x	x	x	x	x	x	x	x	x

2.2 Confined Aquifer Results

To simulate a confined aquifer, a no flow-boundary condition was selected to prevent any fluid migration outside of the reservoir. The storage capacity of a homogeneous confined aquifer was estimated for multiple injection scenarios and a sensitivity analysis was then conducted to determine the effect of reservoir dimensions, well spacing and rock compressibility on the storage capacity.

2.2.1 Storage Capacity Estimation in Homogeneous Aquifer

Five different cases were run on a homogeneous grid. Table 4 describes the estimated storage capacity in this type of aquifer for these five cases with a well spacing of 2 km.

Table 4 Storage Capacity Estimations in a Homogeneous 200 km² Aquifer

Boundary Condition No flow			***200 km² Grid***		
Simulation Scenario	**Target Injection Rate (MT/Year/well)**	**# of Wells**	**Max BHP (bar)**	**Storage Capacity (MT)**	**Injection Rate (MT)/ Year**
Case 1	1	1	266	50	1
Case 2	1	2	270	61	1.22
Case 3	1	3	270	62.6	1.25
Case 4	1	5	70	63.5	1.27
Case 5	1	10	270	64.5	1.29

Only Case 1 maintained the set injection rate for the entire injection period. The results show that the injectivity is greater for Case 1 as increasing the number of wells only increase the storage capacity by 25 to 30% each year. The pressure constraint set at 270 bars, limit the injection for cases with more than one well injecting at the same time for wells spaced 2 km apart. These observations can be explained by the large pressure build-up observed in the aquifer when other wells are added to the simulation. This pressure build-up affects each well, as the BHP reaches its limit early on during the injection. Therefore, to remain below the pressure limit, the injection rate is adjusted in all wells affected by the pressure build-up.

2.2.2 Effect of Well Spacing on Storage Capacity

In the previous section Case 2 was identified as the best-case scenario for multi-wells injection strategies in this type of aquifer (Table 4). However, to potentially increase the storage capacity in this aquifer, the effect of well spacing on the storage capacity was investigated. Scenarios with two wells spaced by 4 km (NC 6 and NC 7) and 8 km (NC 12 and NC 13) were tested (respectively Case 6 and Case 7) and compared to Case 2 (2 km well spacing) (Figure 2).

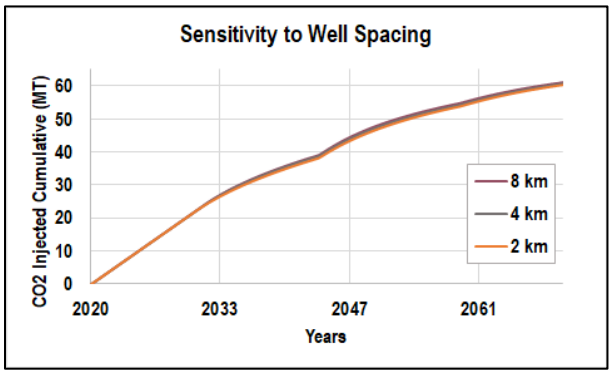

Figure 3 Comparison of Storage Capacity Estimation for Variable Well Spacing (2,4 and 8 km)

Table 5 highlights that the well spacing does not impact the storage capacity in this type of aquifer. The pressure constraint set at 270 bars limits the flowrate of CO_2 for the three different cases presented above and average 0.6 MT/ year per well. These results confirm that the communication of pressure has an effect over long distances (2,4 and 8 km). To prevent geomechanical failures in the borehole and in the aquifer, the flowrate needs to be limited early on for multi-wells injection strategies for any type of well spacing.

2.2.3 Sensitivity to Aquifer Dimensions

Reservoir dimensions were then tested to quantify the effect of variable distance to lateral boundaries on the storage capacity of a confined aquifer. A 100 km^2 and 300 km^2 grid were designed to reduce and extend the reservoir dimensions. Table 6 shows that a reduction of 50 %

of the aquifer size, decreases the storage capacity by 33 to 45%. Whereas, an expansion of the aquifer (300 km^2), increases the storage capacity due to the increase productivity of additional wells (up to 60%).

Table 5 Storage Capacity Estimations in a Homogeneous 100 km² Aquifer

Boundary Condition No flow			*100 km² Grid*			
Simulation Scenario	**Target Injection Rate (MT/Year/well)**	**# of Wells**	**Max BHP**	**Storage Capacity**	**Injection Rate / Year**	**% Variation from 200 km²**
Case 1	1	1	270	33.6	0.67	**-33%**
Case 2	1	2	270	34.5	0.689	**-44.4**
Case 3	1	3	270	34.7	0.693	**-44.6%**
Case 4	1	5	270	34.8	0.696	**-45.2%**
Case 5	1	10	270	35	0.7	**-45.7%**

Table 6 Storage Capacity Estimations in a Homogeneous 300 km² Aquifer

Boundary Condition No flow			*300 km² Grid*			
Simulation Scenario	**Target Injection Rate (MT/Year/well)**	**# of Wells**	**Max BHP**	**Storage Capacity**	**Injection Rate / Year**	**% Variation from 200 km²**
Case 1	1	1	218	50	1	**0%**
Case 2	1	2	270	87	1.74	**+42.6%**
Case 3	1	3	270	93.7	1.87	**+49.7%**
Case 4	1	5	270	102	2.03	**+60.6%**
Case 5	1	10	270	103	2	**+59.7**

These results demonstrate the importance of knowing the reservoir dimension to estimate the storage capacity but also determine which injection strategy should be implemented. In a 100 km^2 aquifer, the injection of less than 1 MT/year appear to be the safest option (maximum flowrate of 0.67 MT/year) whereas on a larger grid (200 km^2 and 300 km^2), injecting 1MT/ year can be done while remaining below the fracture pressure. In the largest aquifer (200 and 300 km^2), a higher flowrate than 1 MT/year can be considered, as the BHP limit was not reached in both cases.

2.2.4 Determination of Maximum Injection Rate in 100 km^2, 200 km^2 and 300 km^2 Aquifers

On the original 200 km^2 aquifer, a different maximum injection rate was tested for the case with the best productivity (Case 1). This case was given a target flowrate of 2 MT per year with the same pressure constraint previously used. These simulations were run to quantify the maximum injection rate a single well can support in variable aquifer geometries. The results are presented in Table 7.

Table 7 Determination of Maximum Injection Rates for 1 Injector Wells in for Various Aquifer Dimensions

Boundary Condition No flow			***100 km² Grid***			***200 km² Grid***			***300 km² Grid***		
Simulation Scenario	**Target Injection Rate (MT/Year)**	**# of Wells**	**Max BHP (bar)**	**Storage Capacity (MT)**	**Injection Rate (MT) / Year**	**Max BHP (bar)**	**Storage Capacity (MT)**	**Injection Rate (MT)/ Year**	**Max BHP (bar)**	**Storage Capacity (MT)**	**Injection Rate (MT)/ Year**
Case 1	2	1	270	34	0.7	270	57.5	1.15	270	83.5	1.67

The maximum injection rate in a small aquifer (100 km^2) cannot exceed more than 0.7 MT/year. Another simulation showed that a 200 km^2 aquifer could support a flowrate of 1.15 MT/year which represent a 64% increase in storage capacity each year compared to a small aquifer. Then, a larger confined aquifer showed the capability to store up to 1.67 MT/year, or a 31% increase from the storage capacity of a medium size aquifer.

The dimensions and geometry of a potential geological target play a crucial part in determining the storage capacity of a confined saline aquifer. However, for all the tested cases, it appears that a single vertical injector well provides the best injectivity under the given conditions used for these simulations. Due to the fast diffusion of pressure over long distances in the aquifer, additional wells appear to be unnecessary as the injection in one well at the maximum injection rate estimated above (Table 7) lead to a higher injectivity than 2 or more combined wells.

2.2.5 Storage Capacity Sensitivity to Sandstone Compressibility

Lastly, sandstone reservoir total compressibility represents one of the main unknown parameters and can vary greatly depending on the composition of the formation. A sensitivity analysis of this parameter was conducted on all cases described in Table 4. Compressibility values were adjusted by one order of magnitude with a minimum sandstone compressibility of $9x10^{-11}$ Pa^{-1} and a maximum value of $2x10^{-9}$ Pa^{-1} to assess the impact of this parameter on the storage capacity (Zimmerman, 1990).

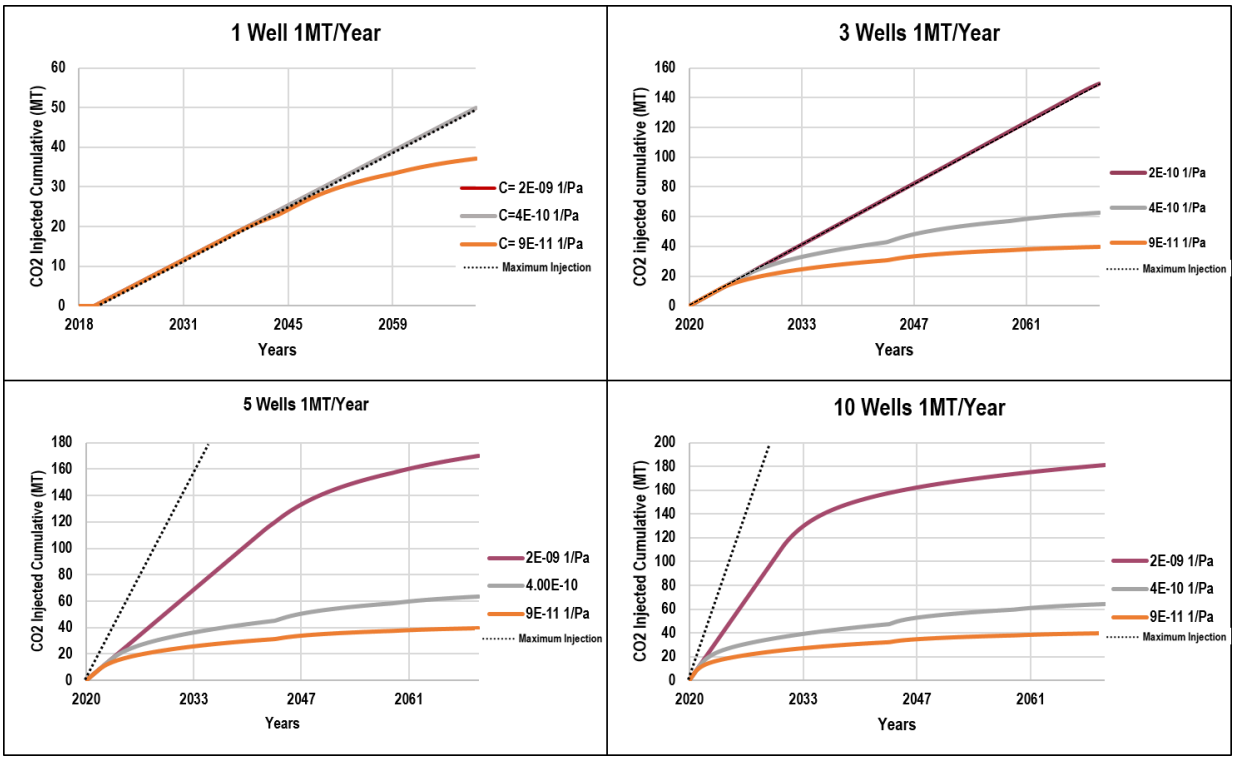

Figure 4 Effect of Rock Compressibility on the Storage Capacity of a Confined Aquifer

The results of these simulation presented in Figure 4, show a high impact of the rock compressibility on the storage capacity of a 200 km^2 confined homogeneous aquifer especially on multi-wells runs. The dotted line represents the slope of the storage capacity if the injection rate was maintained at 1 MT/year for 50 years. Every multi-wells simulation showed an adjustment of the CO_2 flowrate after a short period of time for every compressibility tested.

However, higher compressibility value can drastically increase the storage capacity of this aquifer from 130% for 3 wells runs and 180% for 10 wells runs. Whereas, a lower value can reduce this capacity by 40% on average. These results can be explained by a variable change in available pore volume due to formation and brine compressibility and increased fluid pressure during the injection. The rock compressibility directly impacts the pore volume multiplier and therefore the variation of reservoir pore volume under increased pressure conditions observed during CO_2 injection. For higher rock total compressibility values, when the fluid pressure increases, the bulk and fluid in place adjust their state to accommodate the increased fluid volume providing more available pore space. This increase in pore space limits the pressure build-up in the aquifer and allows a higher injectivity of CO_2. Inversely, lower compressibility values lead to a limited injectivity in all scenarios due to less pore space available at higher-pressure conditions.

Storage capacity predictions for a homogeneous confined aquifer widely depend on the knowledge of the aquifer. These scenarios ran in this section showed the sensitivity of the storage capacity to two main parameters: reservoir dimensions and rock compressibility. However, other should be mentioned such as the estimated fracture pressure, which depends on the geological specificity of the injection site. The sensitivity to this parameter was not investigated for this publication.

3. CASE STUDY OF HETEROGENEOUS RESERVOIR

To understand the effect of heterogeneity of reservoir parameters in the same type of aquifer on the storage capacity, a range of reservoir parameters was randomly distributed in the geomodel. Ranges for permeability (IJK), porosity and Net-Reservoir for the three lithologies

present in the geomodel were extracted from publications and publicly available data (P. M. Brown et al., 1972; Spangler, 1950; Swain, 1947). Identical injection scenarios were run on the heterogeneous model; however, perforations depth was adjusted to fit in sandstone's high permeability and high porosity zones.

3.1 Model and Simulation Set-up

To obtain a realistic range of reservoir properties that could potentially apply to the study area, core data from wells located on the coastal plain of North Carolina were analyzed to extract reservoir properties for the 3 lithologies present in the geomodel (Table 8). This range was calculated to take into account zone with lower reservoir quality as well as zone with above average reservoir quality.

Table 8 Range of Reservoir Properties for Sandstone, Carbonates and Shale

Upper Cretaceous Formation	Sandstone	Shale	Carbonate
Porosity Range	0.1-0.4	0.2-0.3	0.1-0.2
Permeability (mD) Range	1-500	0.01-0.1	0.01-0.1
Net-to-Gross Range	0.6-0.9	0.1-0.3	0.1-0.3

Figure 5 displays the distribution of these parameters in one of the sandstone reservoirs (Injection Zone 1). The well's locations remained unchanged from the previous simulation in the homogeneous aquifer. Only the perforation's depth was adjusted to zone with better reservoir quality (higher permeability and porosity zones) to provide the highest storage capacity.

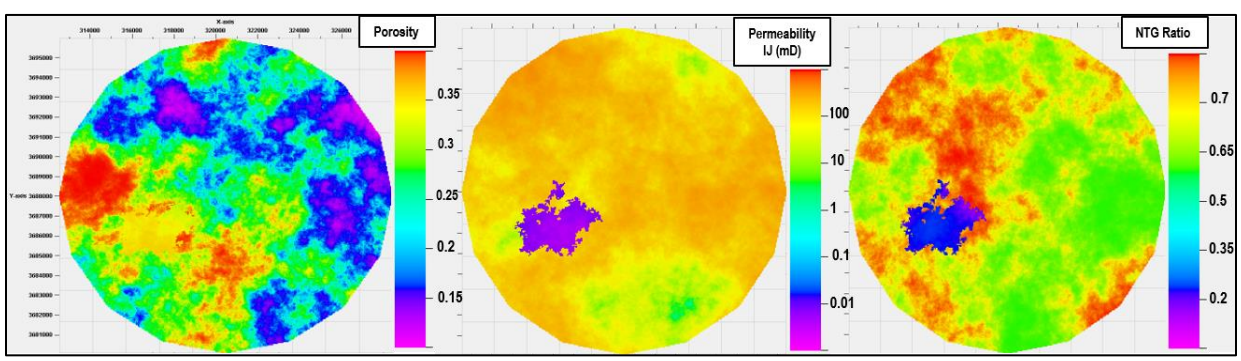

Figure 5 Reservoir Property Distribution at 1,270 meters in a 200 km² Aquifer

A net-to-gross (NTG) ratio was added to take into account the presence of non-reservoir rocks within each sandstone reservoir. Including this ratio to the storage capacity calculation prevents overestimation of the storage capacity and can provide a more conservative estimation of the storage potential of an area.

3.2 Confined Aquifer Results

3.2.1 Storage Capacity Estimation in Heterogeneous Aquifer

The results presented in Table 9 showed that in a heterogeneous 200 km^2 aquifer, a single vertical injector well still remain the best option as simulation showed that one well can successfully inject 100% of the target injection rate of 1MT/year for 50 years. Multi-wells run highlighted the difficulty for this type of aquifer to support more than one well as the addition of other well limits the injection rate from 1 to 0.7MT/year/well for Case 2, 0.5 Mt/year/well for Case 3 and 0.38 MT/year/well for Case 4. The injection of 1 MT of CO_2/year, in the 3-stacked aquifers allows the diffusion of pressure from the borehole to the aquifer at a sufficient rate to limit the BHP increase and maintain the flowrate to its initial target. However, for the multi-wells cases, the diffusion of pressure in the aquifer impacts the injectivity of additional wells after a short injection time. The pressure build-up can be observed in all the confined aquifer and therefore CO_2 flowrate are adjusted for the BHP to remain below the fracture pressure limiting the storage capacity of this aquifer. These observations are similar to the one observed in a homogeneous aquifer.

Table 9 Storage Capacity Estimations in a Heterogeneous 200 km² Aquifer

Boundary Condition No flow			*200 km² Grid*		
Simulation Scenario	**Injection Rate (MT/Year)**	**# of Wells**	**Max BHP (bar)**	**Storage Capacity (MT)**	**Injection Rate (MT/ Year**
Case 1	1	1	246	50	1
Case 2	1	2	270	71.5	1.42
Case 3	1	3	270	75	1.5
Case 4	1	5	270	76	1.52

3.2.2 Comparison Between Storage Capacity of Homogeneous and Heterogeneous Aquifers

Heterogeneous aquifers showed an increased storage capacity compared to the homogeneous aquifer for multi-wells run (Figure 6). This increase in injectivity can be attributed to the presence of higher permeability zones in the aquifer. Higher permeability areas, in proximity to the wellbore, increase the diffusion of pressure, allowing the injection of CO_2 at a higher flowrate over time.

Compared to the homogeneous aquifer, a 200 km^2 heterogeneous aquifer can store 17% more CO_2 for a 2 wells injection strategy, 19% more for 3 wells and 20% more for 5 wells run. Including heterogeneity for storage capacity calculation greatly impacts the obtained results for multi wells simulation. However, the storage capacity remains the same for Case 1 as in both homogeneous and heterogeneous cases, the injection rate remain unchanged at 1MT/year.

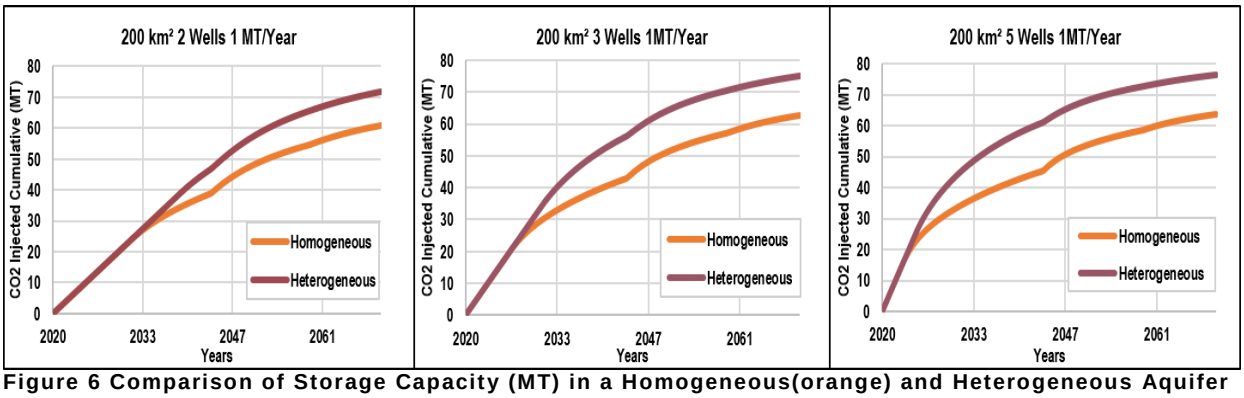

Figure 6 Comparison of Storage Capacity (MT) in a Homogeneous(orange) and Heterogeneous Aquifer (maroon).

3.2.3 Sensitivity to Aquifer Dimensions

A similar sensitivity test to aquifer dimension was conducted on a heterogeneous aquifer. The trend observed is equivalent to the one observed in a homogeneous aquifer.

A smaller aquifer (100 km^2) will store between 25 and 51% less CO_2, than a 200 km^2 aquifer. However, Case 1 injection rate increased from 0.67 MT/year in a homogeneous aquifer to 0.75 MT/year in a heterogeneous aquifer, which represent a 15% increase of storage capacity in 100 km^2. Case 1 remains the most adequate injection strategy in a heterogeneous aquifer with an area of 100 km^2. Multi-wells simulations are constrained by the BHP pressure limit and therefore limit the total storage capacity (Table 10) also observed in a homogeneous aquifer.

Table 10 Storage Capacity Estimations in a Heterogeneous 100 km² Aquifer

Boundary Condition No flow			*100 km² Grid*			
Simulation Scenario	Injection Rate (MT/Year)	# of Wells	Max BHP (bar)	Storage Capacity (MT)	Injection Rate(MT) / Year	% Variation from 200 km²
Case 1	1	1	270	37.3	0.75	**-25.4%**
Case 2	1	2	270	37.9	0.756	**-47%**
Case 3	1	3	270	38.1	0.76	**-49.2%**
Case 4	1	5	270	38.3	0.77	**-51.4%**

In a 300 km^2 aquifer, similar results are observed in both homogeneous and heterogeneous reservoirs (Table 11). In both cases, Case 1 showed no injection rate adjustment which allowed the storage of 50MT of CO_2 after 50 years of injection. For multi-wells cases, increasing the aquifer sizes, also increase the storage capacity by 23 to 40% depending on the number of wells in each run. However, compared to an identical size homogeneous aquifer, the storage capacity in a heterogeneous aquifer only increased by 1.6 to 6%. In a larger aquifer, the effect of heterogeneity is less important than in smaller size aquifers. This result can be explained by a decrease in pressure build-up and therefore a BHP below the limit for longer periods, allowing a higher flowrate of CO_2 in both types of aquifer. The limited increase in storage can be attributed to higher permeability zones, which provide a better diffusion of pressure close to the wellbore.

Table 11 Storage Capacity Estimations in a Heterogeneous 300 km² Aquifer

Boundary Condition No flow			*300 km² Grid*			
Simulation Scenario	Injection Rate (MT/Year)	# of Wells	Max BHP (bar)	Storage Capacity (MT)	Injection Rate (MT)/ Year	% Variation from 200 km²
Case 1	1	1	221	50	1	**0%**
Case 2	1	2	270	88.4	1.77	**+23%**
Case 3	1	3	270	98.5	1.9	**+31%**
Case 4	1	5	270	107	2.15	**+40%**

In a heterogeneous aquifer, the storage capacity appears to be greater than a homogeneous aquifer. However, the aquifer dimensions and the distance to lateral boundaries still plays a crucial part in determining the storage capacity of an aquifer.

3.2.4 Determination of Maximum Injection Rate in 100 km², 200 km² and 300 km² Heterogeneous Aquifers

The injection scenario presenting the most successful injectivity remains Case 1 in a heterogeneous aquifer. Only in a smaller aquifer (100 km^2), the flowrate is lowered to 0.75 MT/year on average to maintain the BHP below 270 bars (Table 10). When the target injection rate is raised to 2MT/year, as predicted in a 100 km^2, the injection rate remains unchanged at 0.75 MT/year. However, on a 200 km^2 and 300 km^2, the injection rate average respectively 1.4 and 1.7 MT/year. These injection rates represent the maximum flowrate a single injector can support while remaining below the estimated fracture pressure (Table 12). The effect of heterogeneity is especially observed on a 200 km^2 aquifer, where the maximum injection rate increase by 22% compared to the one estimated on a homogeneous aquifer. This injection rate rise from 1.15 MT/year to 1.4 MT/year. In this type of aquifer, the higher permeability zones compensate the pressure build-up, allowing the injection of CO_2 at higher flowrate than on a homogeneous aquifer.

Table 12 Maximum Injection Rate for a Single Injector Strategy

Boundary Condition No flow			*100 km² Grid*			*200 km² Grid*			*300 km² Grid*		
Simulation Scenario	Injection Rate (MT/Year)	# of Wells	Max BHP (bar)	Storage Capacity (MT)	Injection Rate (MT)/ Year	Max BHP (bar)	Storage Capacity (MT)	Injection Rate (MT)/ Year	Max BHP (bar)	Storage Capacity (MT)	Injection Rate (MT) / Year
Case 1	2	1	270	**37.7**	0.75	270	69.7	1.4	270	85	1.7

To estimate the storage capacity of a large area such as the ones presented above, the heterogeneity present in sandstone reservoirs plays a major role. This simulation highlighted the impact of heterogeneity on the storage capacity in multiple injection scenarios and with variable aquifer dimensions. The heterogeneous distribution of permeability provides high permeability zones capable of enhancing the diffusion of fluids in the reservoir and therefore diffuse the pressure away from the injection well, increasing the flowrate of CO_2 and therefore the total storage capacity.

However, to include a heterogeneous distribution of reservoir parameters in the calculation of storage capacity, a higher degree of knowledge of the aquifer is needed to prevent any overestimation or underestimations compared to a homogeneous distribution. Average values carry less uncertainty at this stage of exploration as those values are based on observed data at specific locations. In this case, core data were obtained from onshore wells located on the coastal plain of North Carolina, 15 km away from the considered aquifers. Extrapolating averaged reservoir parameters over these distances carries high uncertainty, but also provide a more conservative approach than a heterogeneous distribution of reservoir parameters.

4. COMPARISON OF STORAGE CAPACITY BETWEEN STATIC AND DYNAMIC APPROACH

The continental shelf of North Carolina represents a total area of 46,600 km^2. However, to store CO_2 under supercritical state, any potential reservoirs should be buried below the 800 m

limit. Preserving seal integrity is also a crucial part of long-term geological storage of CO_2. Based on density logs from 2 offshore wells located on the continental shelf of New-Jersey, COST B-2 and COST B-3 (Amato & Simonis, 1979; Smith et al., 1976), shales become less ductile and more brittle below 1,600 m, which consequently can reduce their seal integrity. This two boundary conditions described in more depth in (Mullendore, Parent, et al., 2018), reduce the study area to a 12,400 km^2 zone (Figure 7). A small polygon of this area was removed from the volumetric calculations due to its too close proximity to the shore and its limited width (grey area on Figure 7).

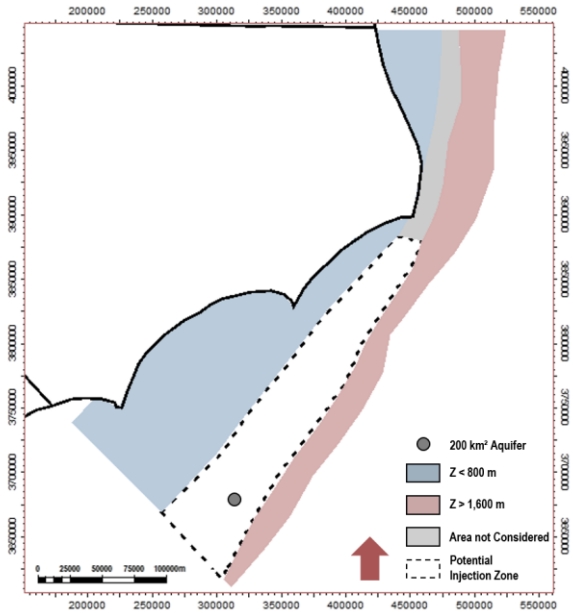

Figure 7 Potential Injection Zone Defined on the Continental Shelf of North Carolina

To estimate the storage capacity of the identified injection zone, two approach can be applied: static and dynamic. Dynamic volumetric calculations are based on reservoir numerical modelling and simulations. The storage capacity estimated in this publication are the results of the dynamic approach applied to small portions (100, 200 and 300 km^2) of the potential injection

zone (Figure 7). However, During the early stages of exploration, volumetric calculation can be conducted by following a static approach.

4.1 Static Volumetric Calculation

DOE-NETL developed a static method to estimate the storage capacity of saline aquifer while incorporating an efficiency factor proper to clastic reservoirs (Equation 1). This efficiency factor was calculated by following a Monte Carlo approach based on data acquired from various clastic reservoirs and ranges between 0.5, 2.0 and 5.4 % (10th, 50th and 90th percentile) (Goodman et al., 2016). Other static approaches have been developed by other authors and have been summarized in (Goodman et al., 2016). To estimate the storage capacity of a saline clastic aquifer, a straight forward equation can be used (Equation 1).

$$G(CO2) = A * h * \emptyset * \mathrm{NS} * \mathrm{NTG} * \rho * E \qquad (1)$$

With:

G (CO_2): calculated storage capacity of CO_2 in GT
A: total area of the reservoir (12,400 km^2)
h: stratigraphic thickness of sandstone reservoir interval(s) (Figure 1)
Ø: average estimated porosity of the formation (Table 2)
NS: Net sandstone in the reservoir interval (Table 1)
NTG: Net to gross ratio (Table 2)
ρ: density of CO_2 at supercritical state (700 kg/m^3)
E: estimated CO_2 storage efficiency factor in clastic saline aquifer (Goodman et al., 2016)

Table 13 Storage Capacity Estimation Calculated with Static Approach (DOE-NETL)

							Storage Coefficient			Storage Potential (Gt)		
Formation	**Volume (m3)**	**Area (m2)**	**Net Sand**	**Net to Gross**	**Density (kg/m3)**	**Porosity**	P10	P50	P90	P10	P50	P90
Injection Zone 1	7.94E+11	1.24E+10	0.90	0.8	700	0.2	0.005	0.02	0.054	**0.40**	**1.60**	**4.32**
Injection Zone 2	4.34E+11	1.24E+10	0.90	0.8	700	0.2	0.005	0.02	0.054	**0.22**	**0.87**	**2.36**
Injection Zone 3	3.72E+11	1.24E+10	0.90	0.8	700	0.2	0.005	0.02	0.054	**0.19**	**0.75**	**2.02**
										0.81	**3.22**	**8.71**

The results of this approach show that for all 3 intervals combined, the storage potential ranges between 0.81 and 8.71 GT of CO_2.

4.2 Dynamic Volumetric Calculations

The reservoir simulations conducted in the section above only estimated the storage capacity of limited area of the total injection zone identified on Figure 7 (100, 200 and 300 km^2). For all three aquifer dimensions, reservoir simulations identified a maximum injection rate for a scenario with a single injection well (Table 12). To extend the storage capacity to the total injection zone, the number of aquifers of each dimension that could cover the entire injection zone was calculated. The results showed that 62 aquifers with an area of 200 km^2 could be considered for CO_2 storage, 41 aquifers for 300 km^2 and 124 for 100 km^2 to cover the entire injection zone shown on Figure 7. Based on the results displayed in previous section (confined heterogeneous aquifer), the total storage capacity was estimated for the total injection zone for all three aquifer sizes.

Table 14 Maximum Storage Capacity in the Total Injection Zones for 3 Aquifer Dimensions

Aquifer Dimensions	Storage Capacity in 1 Aquifer (MT)	# of Potential Aquifers in Total Injection Zone	Total Storage Capacity (GT)
100	37.7	124	4.67
200	69.7	62	4.32
300	85	41	3.48

The storage capacity estimations obtained by using a dynamic approach are consistent with the results obtain with the static methodology and approach the storage capacity estimated by using the P50 value of the efficiency factor. The efficiency factor for each aquifer was calculated individually by following the methodology described in Figure 8. The total rock compressibility provided a pore volume multiplier as a function of pressure. The efficiency factor was calculated for all three aquifers sizes and for three different rock compressibility used in 2.2.5 (Table 15).

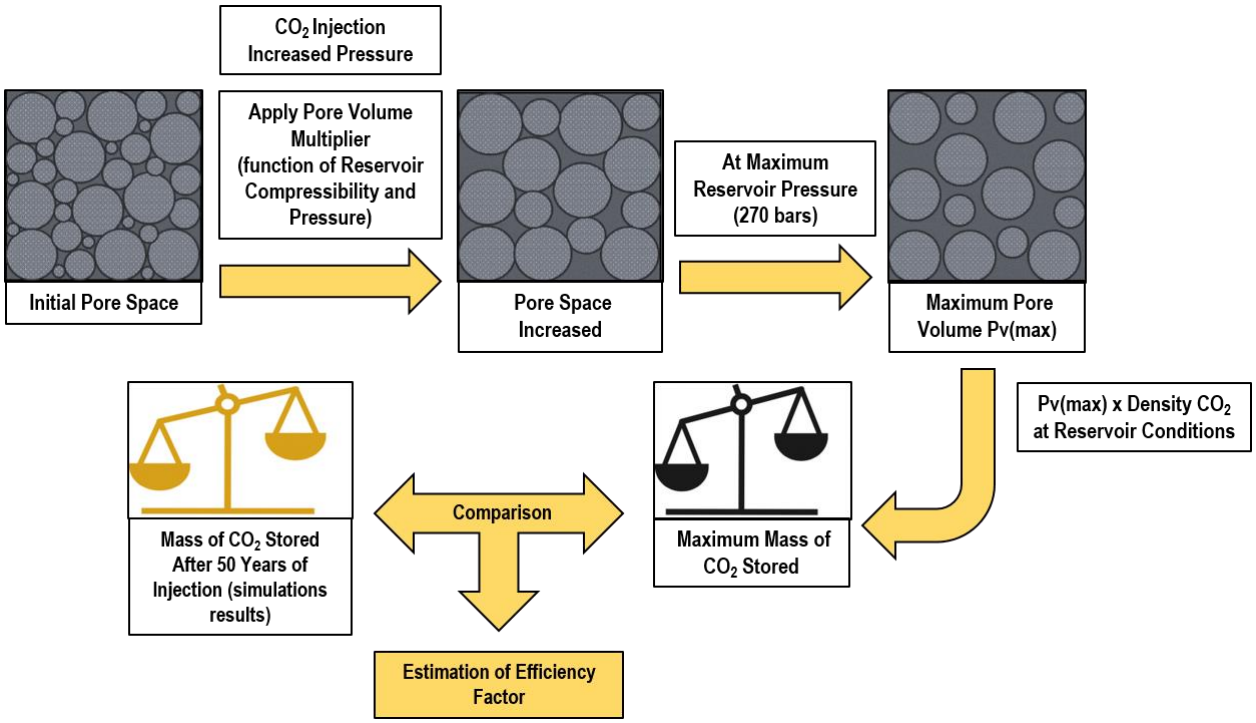

Figure 8 Methodology Used to Estimate the Storage Capacity of Each Aquifer

The efficiency factor estimated by the dynamic approach (reservoir simulation), took into account a pressure gradient in the reservoir and also the variation in density of CO_2 under different pressure conditions. Including these parameters, provides an accurate estimation of the maximum mass of CO_2 that could be stored in the 3 sandstone intervals. When compared to the actual mass of CO_2 injected after 50 years of continuous injection estimated by reservoir simulations, an efficiency factor proper to this type of formation and reservoir conditions can be calculated (Table 15).

Table 15 Efficiency Factor (%) for all Aquifer Dimensions and all Compressibility

Compressibility	Aquifer Dimension	Mass of CO2 Stored After 50 Years of Injection (GT)	Maximum Mass of CO2 Stored (GT)	Efficiency %
4E-10 bars-1 (medium)	100 km2	1.28	0.03	2.34
	200 km2	2.45	0.06	2.44
	300 km2	3.84	0.08	2.08
2E-09 bars-1 (high)	100 km2	1.31	0.09	6.89
	200 km2	2.52	0.10	3.96
	300 km2	3.95	0.10	2.53
9E-11 bars-1 (low)	100 km2	1.27	0.02	1.63
	200 km2	2.44	0.04	1.69
	300 km2	3.82	0.05	1.39

Reservoir conditions with higher rock compressibility values present a higher efficiency corresponding to value between the P50 and P90 percentile of the efficiency factor value calculated by Goodman et al. (2016). A lower compressibility decreases the efficiency factor to a value ranging between the P10 and P50 percentile of the value estimated in the same publication. Results also showed that for median and low compressibility, the 200 km^2 aquifer presents the higher efficiency factor.

Comparing the storage capacity obtained by static volumetric calculation to the storage capacity estimated by reservoir simulation is a way for engineers to validate geomodel and initial reservoir parameters. In this case, the results obtained by reservoir simulation are consistent with the one obtained by using the DOE-NETL methodology. In most cases, the efficiency factor estimated varied within the range provided in Goodman et al. (2016) for clastic aquifers.

To refine this analysis, additional data could be used to update the geomodel and initial reservoir conditions. The uncertainty associated with sandstone intervals' thicknesses and the associated reservoir parameters could be reduced by collecting additional high-resolution 3D seismic surveys and by drilling stratigraphic tests.

5. CASE STUDY OF OPEN AQUIFER SYSTEM

The lateral boundaries of the confined aquifers mentioned above were not observed on seismic data. The hypothesis of their presence was based on the poor resolution of the 2D seismic reflection data interpreted. The lateral boundaries such as stratigraphic or structural traps were believed to be below the resolution of the seismic and therefore not observable and mappable. However, in the case of absent trapping mechanisms or at too far distances, simulations were conducted in an open aquifer system. For this type of aquifer, challenges shift from pressure management to plume migration management. The overall objective of the simulation was to optimize the storage capacity while maintaining the CO_2 plume to a small area. The concerns associated with CO_2 storage in an open aquifer are various and range between unwanted migration of CO_2 and freshwater contamination but also infiltration of brine in fresh water aquifer in the coastal plain. On the East coast of the U.S, and especially in the coastal plain of North Carolina, saltwater intrusion has already been identified as problematic for freshwater aquifers. This issue is mostly attributed to over-pumping of drinking water in this area, which promotes lateral and upward migration of brine into freshwater aquifers (US-Geological-Survey, 2000). Injecting CO_2 in the subsurface on the continental shelf could enhance this issue by increasing the flow of brine away from the injection zone and towards the continental shelf. Injection strategies developed in this section are focused on limiting the CO_2 plume and therefore limit the diffusion of brine away from the injection zone.

5.1 Storage capacity in a Heterogeneous Open Aquifer System

To model a heterogeneous open aquifer system, a constant pressure boundary condition was added to the simulation to allow the evacuation of fluids outside the grid. All simulation

cases tested previously on a confined aquifer, were tested on a 200 km^2 to show the storage potential of this type of aquifer. The results are presented in Table 13.

Results showed the large storage potential of this type of aquifer as all cases reached 100% injectivity for 50 years of continuous injection.

Table 16 Storage Capacity of a 200 km^2 Heterogeneous Open Aquifer

Boundary Condition Constant Pressure			*200 km^2 Grid*		
Simulation Scenario	**Injection Rate (MT/Year)**	**# of Wells**	**Max BHP**	**Storage Capacity**	**Injection Rate / Year**
Case 1	1	1	163	50	1
Case 2	1	2	178	100	2
Case 3	1	3	200	150	3
Case 4	1	5	213	250	5

The large storage potential of this type of aquifer is due to the limited pressure build-up in the aquifer and to the diffusion of brine outside the grid. From the initial reservoir pressure set as 140 bars, the maximum increase in reservoir pressure is observed in Case 4 when 5 wells are injecting CO_2 simultaneously for 50 years (213 bars). In all cases the pressure remains below the fracture pressure (270 bars) and therefore does not affect the injectivity of the active wells. However, as mentioned above, injecting large amount of CO_2 carries the risk of displacing large amount of brine towards to coastal plain and increase the risk of saltwater intrusion in freshwater aquifers. Any additional wells should be placed in the N-S plane from Injector 1 to increase the storage potential and limit the displacement of brine.

5.2 CO_2 Migration (Plume) In an Open Aquifer System

For the reasons mentioned above and with the objective of performing long-term monitoring of the injection zone, it is important to contain the CO_2 plume to a controlled area. Typically, 3D and 4D seismic surveys are used to monitor injector zones and can cover limited area. The plume was analyzed and quantified for a single well injection strategy with a flowrate

of 2 MT/year, to understand the migration of CO_2 in a heterogeneous open aquifer. The total storage capacity of this well after 50 years of injection successfully reached 100 MT. The distribution of reservoir parameters remained unchanged from the one used in a confined aquifer and are shown on Figure 5.

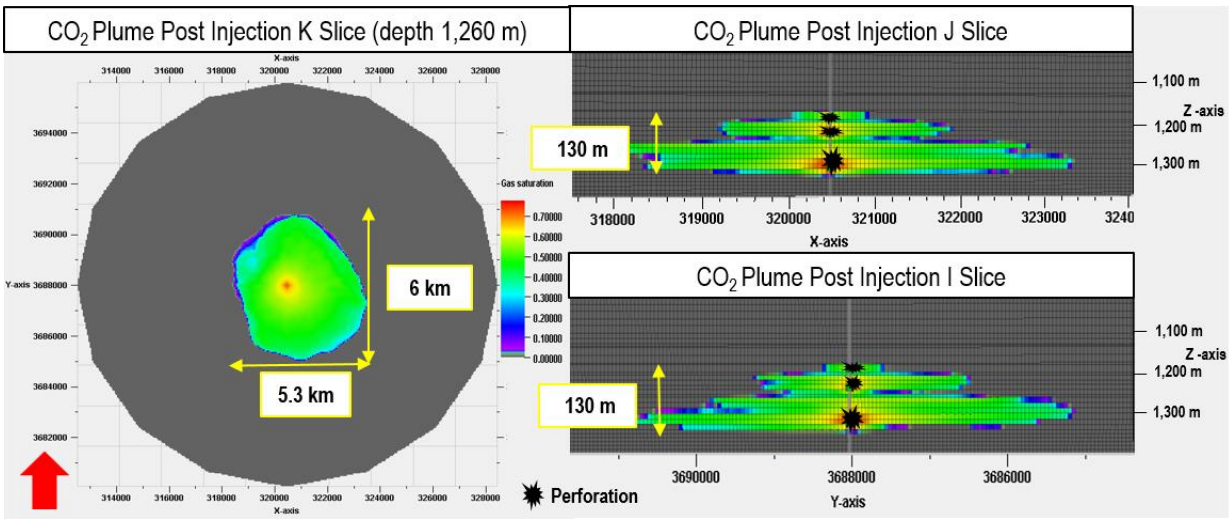

Figure 9 CO_2 Plume After 50 Years of Continuous Injection at a Rate of 2 MT/year

Figure 7 shows that after 50 years of injection, the plume extension reaches approximately 5 km diameter in the N-S and E-W directions. The longer injection period in Injection zone 1 lead to a larger plume in the deepest reservoir. The upward migration of CO_2 is contained by Confining Unit 1. The thin carbonate formations present in the model act as short-term seal as they slow down the upward migration of CO_2 and encourage the lateral extension of the plume in between each injection zone. After 50 years, Confining Unit 1 remain unperturbed by the injection and appear to maintain its sealing integrity.

Despite the CO_2 plume being contained to a limited area, the “pressure plume” affects the entire grid and extend further than the grid boundaries located at an 8 km radius from the injection well. Figure 8 displays the “pressure plume” after 50 years of continuous injection. On

the left, the pressure is represented at 1,260 meters below sea floor (Injection Zone 1) and shows the pressure affects the entire reservoir. On the right, a lateral view of the geomodel shows the diffusion of pressure upward and laterally. In Injection Zone 1, the pressure only increased by 40 bars from the initial pressure at the end of the injection due to the absence of lateral confinement and to the mobility of the water outside the grid.

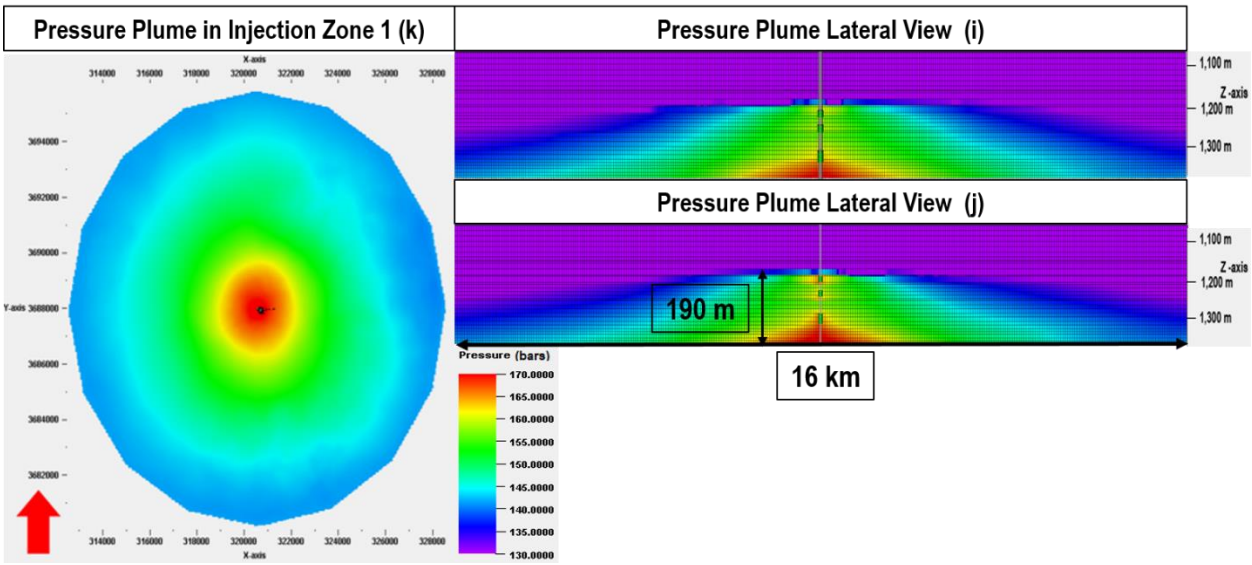

Figure 10 Pressure Plume Extension in a 200 km² Open Aquifer After 50 Years of Continuous Injection

5.2.1 Sensitivity to Net-Reservoir Ratio

The reservoir parameters used in these simulations represents a large part of the uncertainty of this study. The extrapolation of well data from onshore wells over long distances carries large uncertainty. One of the main unknowns of this study remains the presence and thickness of sandstone reservoirs. Due to the resolution of the interpreted seismic data, seismic facies analysis are difficult and therefore the interpretation relied heavily on sequence stratigraphy to predict sand deposit in this formation. The prediction obtained with this method were then combined to well data to approximate the thickness of the reservoirs and confining units to obtain the facies distribution presented in Figure 1. However, to account for this

uncertainty, a sensitivity analysis was conducted to quantify the effect of a Net-to-Gross ratio or Net-Reservoir on the plume extension in an open aquifer system. A factor of ± 30% was applied to the NTG already used in the previous simulations. The results are presented in Figure 9.

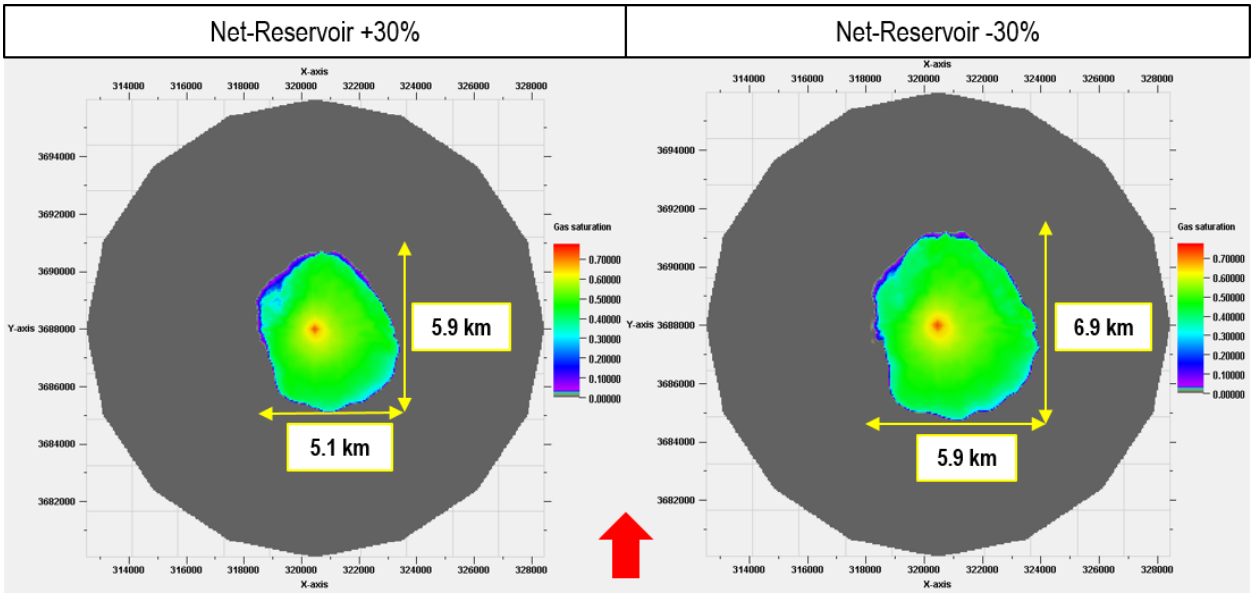

Figure 11 Plume Extension on a 200 km² Open Aquifer with a Factor ± 30% Applied on the NTG Ratio

The plume is not impacted much by an increase in the NTG ratio, however it increased the gas saturation in the plume as more reservoir is available in proximity to the wellbore. A decrease in the NTG ratio expands the plume by 15% in the N-S direction and 11% in the E-W direction. This observation confirms the impact of the knowledge of the aquifer to predict plume extension as much as it did on the storage capacity of a confined aquifer.

5.2.2 Sensitivity to Reservoir Parameters: Porosity and Permeability

A similar sensitivity analysis was then conducted to observe the effect of variable porosity and permeability in the aquifer. A factor of ± 30% was added to these properties and an identical injection strategy was tested to compare the plume extension when reservoir parameters are altered.

Figure 10 shows that a decrease in permeability, allows a limited increase in the lateral diffusion of CO_2 and therefore an extension of the plume in all directions (5% in the N-S direction and 2% in the E-W direction). Inversely, an increase in permeability slightly decreases the plume size. This analysis showed that the variation in the range of permeability has a limited impact on the plume extension.

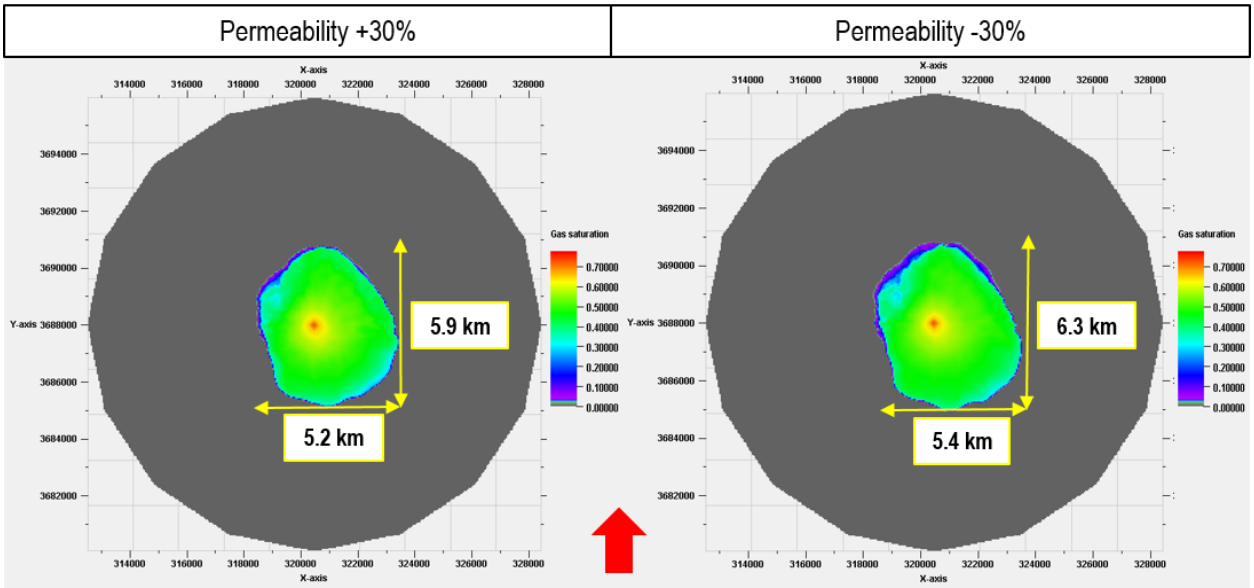

Figure 12 Plume Extension on a 200 km² Open Aquifer with a Factor ± 30% Applied on the Permeability

The last parameter tested for this sensitivity analysis is the porosity of the reservoir. A factor of ± 30 % was applied on this property and the results showed in Figure 11, highlight the important impact of this property on the plume extension in this type of aquifer.

An increased overall porosity can reduce the plume extension by 10% in the N-S direction and 11% in the E-W direction. Similarly, decreasing the porosity can enhance the plume extension by 13% in all directions. These results can be easily explained by the variation in available pore space occupied by CO_2. Increasing the porosity, increase the storage capacity in proximity to the wellbore, limiting the lateral expansion of the CO_2 plume.

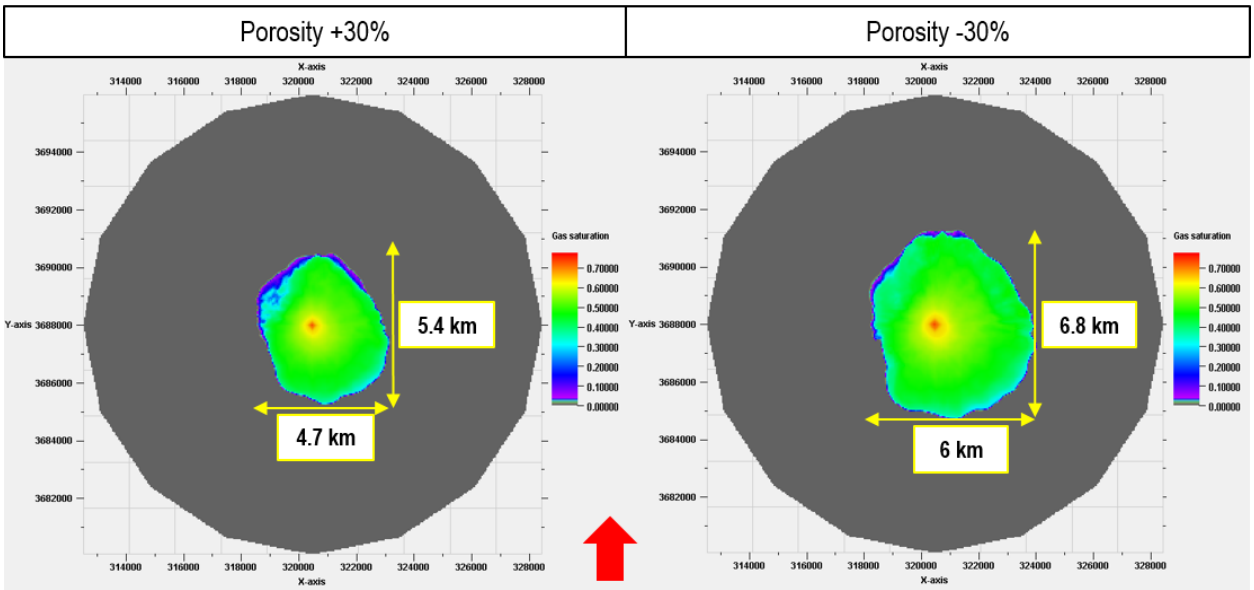

Figure 13 Plume Extension on a 200 km² Open Aquifer with a Factor ± 30% Applied on the Porosity

This sensitivity analysis was necessary to understand the impact of each parameter on the plume extension. The NTG ratio as well as the porosity values estimated in this paper have a large impact on the plume migration. Predicting the plume migration is as crucial as predicting the storage capacity prior any field development. These predictions can influence the development of injection strategies that should be implemented in this type of aquifer. In this case, these simulations confirmed that any additional wells should be located in the N-S plane to prevent an increase in diffusion of brine and CO_2 towards the coastal plain. This analysis also highlighted the importance of gathering as much data as possible, as any variation in the reservoir properties impacts the plume extension and therefore the positioning of additional wells.

DISCUSSION

This analysis provided the basis to understand the potential of the continental shelf of North Carolina for the geological storage of CO_2. For both types of aquifers (confined and open),

the storage capacity estimations as well as the plume extension depend greatly on the density and quality of the data gathered for this assessment. At this stage of exploration, it is common to rely any resource assessment on limited dataset. However, it is important to understand that these assessments carry large uncertainties due to the lack of data. Pursuing the exploration of a study area by collecting additional data, can refine the storage capacity estimations and the prediction of plume extension.

At this stage, the main uncertainties associated with the results presented in this paper are for the most part related to the presence, extent and quality of the sandstone reservoirs. The geomodel presented in this paper is based on extrapolation of onshore or distant wells information and on sparse, low-resolution 2D seismic data analyzed and interpreted in previous publication (Mullendore, Parent, et al., 2018; Mullendore, Schlosser, et al., 2018).

Another major uncertainty lies with the estimation of the fracture pressure. The fracture pressure refers to the tensile failure pressure (J. Zhang & Yin, 2017) in an impermeable case, in this case the wellbore. In the eventually of the BHP rising above the fracture pressure, the wellbore could be submitted to tensile failure and therefore lose its integrity. This parameter is important for CO_2 storage as leakage from the lack of well integrity is considered a major issue. This publication highlighted the importance of this parameters as it determines the BHP pressure limit used to calibrate the flowrate of CO_2. In a confined system, this BHP pressure limit was set to maintain borehole stability and prevent leakage from the borehole itself and from the formation. The results showed a strong influence of this limit on the maximum flowrate for each cases tested and therefore on the storage capacity. The estimation of this fracture pressure was based on geomechanical studies conducted on borehole stability. To estimate the “formation breakdown pressure”, Haimson and Fairhurst (1967) proposed the model presented in equation 2.

$$P_{Max} = 3\sigma_h - \sigma_H + T \qquad (2)$$

With:

P_{Max}: the formation breakdown pressure or fracture pressure
σ_h: minimum horizontal stress
σ_H: maximum horizontal stress
T: tensile strength

Both horizontal stresses (maximum and minimum) were assumed equals in this case due to the limited data. The tensile strength was assumed to be null. Estimating the vertical stress can be deduced from the stratigraphic column and the estimated thickness and depth of each strata. The horizontal stress can be estimated by using the ratio k between vertical stress and horizontal stress described by Sheorey's model.

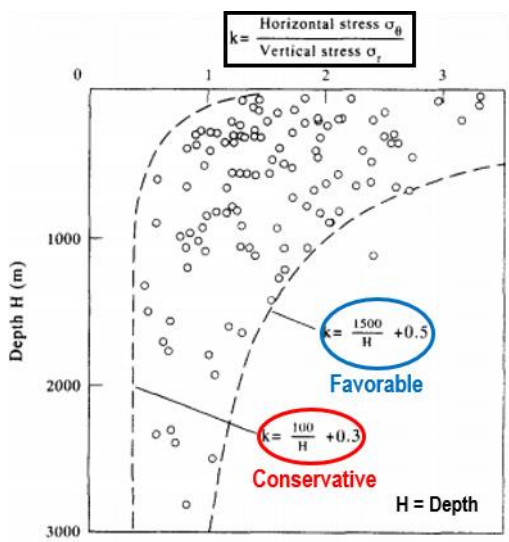

Figure 14 Ratio Between Vertical and Horizontal Stress vs Burial Depth modified from Sheorey (1994) Based on Measurements by Hoek and Brown (1980)

These two ratios (conservative and favorable) are then used to estimate the horizontal stress and deduce a conservative and favorable minimum fracture opening pressure also referred as fracture pressure (Equation 3).

$$P_{Max} = 2\sigma_V k \quad (3)$$

With:

σ_V: vertical stress
k: ratio obtained by Sheorey's model

An average value between the conservative and favorable fracture pressure (P_{max}) calculated was chosen to determine the fracture pressure to be used in the reservoir simulations. The BHP pressure limit (270 bars) represents 90% of the estimate fracture pressure.

Many assumptions were made to obtain the estimated fracture pressure which impact the storage capacity calculated by reservoir simulations. A sensitivity analysis to this specific parameter should be conducted to quantify its effect on a storage resource assessment. Additional data could also contribute in refining the estimation of the fracture pressure by determining the stress regime on the continental shelf of North Carolina and provide a more accurate estimation of the vertical stress.

CONCLUSION

The U.S DOE has for objective to identify geological targets which could store up to 30 MT of CO_2 each year. This type of project would lead to an impactful mitigations of CO_2 emissions in the state of North Carolina. This audacious objective could be reached in this location due to the potential large pore volume available in the UCF. With an efficiency factor around 2%, our results showed that this formation could store between 70 and 90 MT each year.

However, to provide an accurate estimation of the CO_2 storage potential of the continental shelf of North Carolina, a large amount of data is required. Additional dataset should be collected prior any deployment to reduce the large uncertainties identified throughout this study. The next step of exploration should be focused on identifying specific sandstone deposits and

defining the geometry and boundaries of each identified aquifer. To do so, high-resolution 3D seismic surveys should be considered as they could identify lateral boundaries necessary to determine the type of aquifer (confined or closed) and the boundary conditions associated with it.

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CONCLUSION

To help mitigate the emissions of anthropogenic CO_2 in the atmosphere, CCS projects are currently being developed to demonstrate the capture of CO_2 from industrial sources and permanent storage in geological formations. Onshore storage in various types of formations (primarily sandstone and coalbeds) have been accomplished in recent years; however, onshore storage provides limited storage capacity. To improve storage capacity, the suitability of offshore geological storage is being investigated for an expansive storage project.

The overall objective of this research is to provide a preliminary estimation of the CO_2 storage resource potential of the Mid-Atlantic, specifically the outer continental shelf of North Carolina, and to provide recommendations for future work. The workflow followed that of the early stages of oil and gas exploration. The development of large-scale CO_2 geological storage in offshore settings requires a robust characterization of the subsurface to assess the storage potential, evaluate the potential risks, and consequently determine the feasibility of such a project.

A literature review of CO_2 geological storage highlighted the necessary requirements that need to be met to ensure the safe and permanent storage of CO_2 in an offshore environment. This chapter showed that previous studies have identified geological formations suitable for carbon storage as well as the type of trapping mechanisms necessary to confine the injected CO_2 over a long period of time. Sandstone saline aquifers were designated as adequate for carbon storage due to their high porosity and high permeability compared to other formations. Shale deposits typically exhibit a low permeability, which could provide confinement to an injection zone, otherwise known as stratigraphic trapping. Other trapping mechanisms such as dissolution and

mineralization were mentioned, as they could play a role in long-term storage processes. Gathering background geological information of the subsurface of the continental shelf of North Carolina was also crucial in providing a regional geological framework of this study area. The literature confirmed the presence of large sandstone and shale deposits at a regional scale in adjacent locations, such as the Baltimore Canyon Trough and the Carolina Trough. This research concluded that the knowledge of the subsurface of the Mid-Atlantic seaboard remains uncertain, as information was limited when these studies were published.

Additional geological and geophysical data collected during past oil and gas exploration campaigns have since been released to the public, and new studies can be conducted to improve the understanding of the subsurface in the Mid-Atlantic. The Bureau of Ocean Energy Management (BOEM), in collaboration with the U.S. Geological Survey (USGS), has contributed to purchasing and gathering a geological and geophysical dataset to be made available to the public. The release time after acquisition of this data follows a memorandum specific to each dataset. Geological data can be released after 10 years, whereas process geophysical data such as seg-y_s and well logs can be released after 25 years. Regarding unprocessed data (raw), the delay reaches 50 years after their collection.

In the Mid-Atlantic, a sizable amount of data was made available by BOEM and USGS over the years. The collection and analysis of these datasets was described in Chapter 2. The objective of this study was to select the most pertinent datasets that would be interpreted to identify potential targets for CO_2 storage, as well as confining units. The other objective of the study was to determine the limitations of these datasets in regard to their application for reservoir exploration. Over 1,000 2D seismic reflection profiles were collected, but only 300 were selected in the final dataset. The selection was based on the data coverage (location and density) and

quality. Parameters such as the signal-to-noise ratio (S/N) and vertical resolution were estimated to assess the limitation of the data regarding the detectability and separability of reservoirs and confining units within large geological formations. This chapter concluded that the publicly available data coverage and quality varies from one location to another on the continental shelf. The proximal part of the shelf shows sparse coverage of low-resolution data. Interpreting these data could only provide a regional geological framework of the subsurface. On the more distal part of the shelf, the data coverage appears denser and of higher quality, thus more applicable to conduct reservoir exploration. The absence of wells in this location was also noted, and additional wells located outside the study area (onshore and offshore) had to be added to the data selection to provide information about lithologies and reservoir properties. The final selection represents a trade-off between coverage, location and quality to encompass the maximum information in all areas of the shelf, which can be used to identify specific geological targets for CO_2 storage.

The dataset selected was then interpreted with the objective to identify and characterize adequate reservoirs (sandstone saline aquifers) and confining units (shales). The results were discussed in Chapter 3. The Upper Cretaceous Formation and the upper part of the Lower Cretaceous Formation were identified as likely hosts for CO_2 storage. Seismic stratigraphy and onshore well correlations predicted the probable presence of multiple thick sandstone intervals confined by large shale intervals within these two formations. The geomodel was converted from two-way-time (TWT) to depth by using stacking velocities provided by BOEM. Petrophysical properties were extrapolated from onshore well core analyses obtained in the literature and applied to the geomodel. A CO_2 storage resource assessment was then conducted, following a static approach, to determine the storage capacity of each main interval in the study area. This

chapter showed that the Upper Cretaceous Formation could store between 0.9 and 10 gigatons (GT) of CO_2, whereas the Lower Cretaceous Formation has the potential to store between 1.4 and 15 GT of CO_2. If stacked, all these intervals could store up to 26 GT of CO_2. However, this chapter concluded that large uncertainties are associated with this storage resource assessment. The identification of potential sandstone saline aquifers and seals are based on the interpretation of limited and low-resolution data, unable to provide the adequate resolution to accurately predict the presence and geometry of any reservoirs. The extrapolation of lithofacies and reservoir properties from distant onshore wells provided some information. However, this carried a lot of uncertainty, as lateral variations of lithologies and reservoir properties cannot be taken into account. Despite the high levels of uncertainty associated with this study, these storage resource estimations represent a preliminary assessment of the potential of this area for CO_2 storage.

To understand these uncertainties and their potential impact on a storage capacity assessment, dynamic volumetric calculations were conducted and discussed in Chapter 4. A dynamic approach was taken, consisting of running various reservoir simulations to understand the effect of each parameter with the estimated highest amount of uncertainty on the storage capacity. This method is typically referred to as a storage capacity assessment, whereas the static approach is referred to as a storage resource assessment. Due to the low resolution of the data, lateral boundaries in the form of structural or stratigraphic traps were not identified on seismic profiles, and therefore two geomodels had to be defined. The first model prescribed no-flow boundary conditions at the edge of the geomodel, coinciding with a closed or confined aquifer. The second model prescribed constant pressure boundary conditions at the edge of the geomodel, coinciding with an open aquifer without lateral boundaries. The objectives of this chapter were to

quantify the effect of uncertain parameters on the storage capacity and plume extension and compare both static and dynamic approaches on the volumetric calculations. The results presented in this chapter showed the tremendous impact of uncertainty of some parameters, such as the reservoir dimensions and the rock compressibility, on the storage capacity of a confined aquifer. In an open aquifer, the petrophysical properties of the aquifer can greatly impact the extent of the CO_2 plume after a long period of injection. This study highlighted the need to improve the knowledge of the subsurface by collecting additional data, to obtain more accurate prediction of the storage capacity and plume migration. The efficiency factor estimated by the dynamic approach was within the range of efficiency calculated with the methodology developed by the U.S. Department of Energy, as discussed in Chapters 3 and 4. This successful comparison contributed to validate the geomodel and reservoir simulations conducted in Chapter 4, and any additional data collected in the near future could contribute to reduce the error margins and provide higher quality storage capacity estimations.

To pursue the exploration of the Mid-Atlantic, Chapters 3 and 4 highlighted the need for additional datasets. The determination of the locations and type of data that should be acquired to explore the Mid-Atlantic subsurface depends on the objectives set by future exploration teams. The data collection and analysis described in Chapter 2 guided this study towards the exploration of the continental shelf of the Mid-Atlantic, as most of the data collected during past oil and gas exploration campaigns focused on this area. To identify suitable reservoirs with the sole objective of storing CO_2, the recommendation would be to collect 3D surveys of the potential injection zone displayed in Figure 7 of Chapter 4. The goal would be to identify and characterize the specific dimensions of targets within this area. The identification of extensive sand bodies, which could provide a large storage capacity, would lead then towards the drilling of exploration

boreholes to obtain reservoir properties within the identified target. These next steps would improve the storage capacity estimations and allow economic factors to be considered in determining the deployment feasibility of this type of project.

However, a ban on exploration in the Atlantic Ocean is still in effect at the time of writing. In the event that this ban is lifted by the current administration, permits approved by BOEM would have oil and gas exploration as their main objective. In this case, the exploration should be guided by the need to add data in places of complex geometries on the shelf in order to image potential salt deposits and carbonate reefs in the Carolina Trough or in the basin, which was left vastly unexplored during past campaigns. The presence of oil and gas in the Mid-Atlantic could be coupled with CO_2 storage, in the form of CO_2 flooding for enhanced oil recovery (EOR), and still contribute to the mitigation of CO_2 emissions via carbon capture utilization and storage (CCUS).

The storage capacity assessment presented in this dissertation contributes to improving the knowledge of the subsurface of the Mid-Atlantic seaboard. Additional geological and geophysical datasets released in the recent years were collected and interpreted to construct the most recent geomodel of the subsurface of the outer continental shelf of North Carolina. This geomodel provided a first estimation of the carbon storage potential of this area. This works also contributed to highlighting the limitations associated with the data and their usefulness and the need for additional data to continue updating the geomodel and the associated carbon storage potential.