3D MODEL-BASED INVERSION FOR ONSHORE CO_2 STORAGE IN THE OSAGEAN AND MERAMECIAN STRATA OF STACK PLAY, ANADARKO BASIN

By

VICTOR OLUWASEUN FAKEYE

Bachelor of Technology in Applied Geology

Federal University of Technology Akure

Akure, Ondo State

2019

Submitted to the Faculty of the
Graduate College of the
Oklahoma State University
in partial fulfillment of
the requirements for
the Degree of
MASTER OF SCIENCE
December, 2022

3D MODEL-BASED INVERSION FOR ONSHORE

CO_2 STORAGE IN THE OSAGEAN AND

MERAMECIAN STRATA OF STACK PLAY,

ANADARKO BASIN

Thesis Approved:

Dr. Camelia C. Knapp

Thesis Adviser

Dr. James H. Knapp

Dr. Jack C. Pashin

ACKNOWLEDGEMENTS

This thesis will not be complete without me acknowledging first, my heavenly Father, for by him I have run over troops and leaped over walls. I thank my parents, Pastor and Deaconess E.A. Fakeye, and my sisters: Deborah, Opeyemi, and Marvellous, for their ever-present support, encouragement, and prayers. Special thanks to my best friend, Alice Okpafi. Thank you for always being there.

I also appreciate my advisor, Dr. Camelia Knapp, for her guidance and support, and for providing me with the necessary resources for the completion of this degree. Special thanks to my committee members: Dr. James Knapp and Dr. Jack Pashin for their constructive reviews, feedback, and comments. I appreciate my lab mates for always helping me whenever I get stuck at any point. Thank you so much.

Worthy of mention are the U.S. DOE, Southern States Energy Board, SECARB-USA, and Devon Energy. Thanks for funding this project and providing the necessary dataset to carry out the project.

Name: VICTOR OLUWASEUN FAKEYE

Date of Degree: DECEMBER, 2022

Title of Study: 3D MODEL-BASED INVERSION FOR ONSHORE CO_2 STORAGE IN THE OSAGEAN AND MERAMECIAN STRATA OF STACK PLAY, ANADARKO BASIN

Major Field: GEOLOGY

Abstract: Depleted hydrocarbon reservoirs can store some amount of supercritical CO_2 depending on their reservoir properties. An understanding of these properties is therefore imperative for an assessment of the CO_2 storage potential of these reservoirs. The seismic reflection survey method, with its extensive use over the years, has gained prominence over other geophysical methods in providing an image of the subsurface to depths extending thousands to hundreds of thousands of feet. However, seismic reflection data are sometimes ambiguous and non-unique, hence the need for seismic inversion. Unlike the conventional seismic section which provides data based on the properties of the interface, seismic inversion provides information based on the properties of the rock. The seismic inversion methods incorporate the use of well logs - particularly sonic and density logs, and seismic data, from which lithology can be delineated and porosity extracted. Porosity and permeability are physical properties of rocks that determine how well a reservoir performs, and how much fluid can be stored in a rock formation.

The Osagean and Meramecian strata, informally known as the “Mississippi Lime”, constitute part of the STACK play in the Anadarko Basin. These formations were assessed for their CO_2 storage capacities by carrying out a post-stack, model-based inversion on available seismic data. The inverted seismic volume was transformed to predict porosity distribution by applying an empirical relationship derived from crossplotting the acoustic impedance model and porosity measurements taken from the wells. Porosity-permeability relationship was established to assess the spatial distribution of permeability across the study area. Taking other parameters into consideration, storage capacities of 79.81 Mt and 7.3 Mt were estimated for the Meramecian and Osagean formations respectively.

TABLE OF CONTENTS

Chapter	Page

LIST OF TABLES

LIST OF FIGURES

CHAPTER I

INTRODUCTION

1.1 Motivation

With recent developments in geological characterization methods and technological advancements in drilling techniques such as horizontal drilling, production from unconventional hydrocarbon reservoirs with low porosity and low permeability is increasing (Hoffman, 2019). However, because these wells usually have low recovery factors, it becomes important to develop methods to boost recovery. One of such methods is the injection of carbon dioxide (CO_2) for Enhanced Oil Recovery (EOR) purposes. CO_2-EOR is a method for permanently sequestering CO_2 since a substantial fraction of the injected CO_2 stays in situ (Dai *et al.*, 2014).

The behavior of fluids stored in pore spaces in rocks is subject to rock properties such as porosity and permeability, as well as other petrophysical properties. An understanding of these properties is critical for assessing the possibility of a long-term CO_2-EOR and storage. Estimating the storage capacity requires taking into consideration a number of parameters including the efficiency factor of the reservoir, which is often higher in conventional reservoirs when compared to unconventional reservoirs (DOE-NETL, 2008). A detailed evaluation of the pore space efficiency is therefore critical in assessing potential sites for CO_2 storage and enhanced oil recovery.

The mission of the United States Office of Fossil Energy and Carbon Management is to mitigate the impact of the emissions caused by fossil fuel combustion and to help advance the United States towards a clean energy future. The Southeast Regional CO_2 Utilization and Storage Acceleration Partnership (SECARB-USA) project support this mission. As part of this project, the Osagean and Meramecian strata of the STACK (Sooner Trend in Anadarko [Basin] in Canadian and Kingfisher counties) play will be assessed for their CO_2 storage capacities, and recommendations for EOR opportunities will be given. A model-based seismic inversion will be performed on available 3D seismic data, which will help to delineate lithology and determine porosity. Seismic inversion is a procedure that provides more detailed information and image of the geology of the subsurface. The fundamental goal of seismic inversion is to gain a better understanding of reservoir properties by converting seismic reflection data into quantitative rock properties (Ogagarue, 2016; Maurya & Singh, 2019). The process employs an integration of seismic and well log data to derive the physical properties of rocks. Some of the most important physical properties of interest are impedance, velocity, density, and porosity (Maurya & Singh, 2019). The interpretation of the seismic data is significantly improved by the high-resolution images of the subsurface and seismic attributes produced by the seismic inversion (Chen & Sidney, 1997; Hampson *et al.*, 2001; Pendrel, 2006; Haris *et al.*, 2017).

1.2 Research Hypothesis & Objectives

The STACK play is a major oil and gas play with good reservoir performance. I hypothesize that the Meramecian and Osagean formations can store significant amounts of CO_2 (tens of megatons), which can be used for enhanced oil recovery purposes.

The objectives of this research are to: (1) carry out a model-based post-stack seismic inversion on 3D seismic data, which provides a quantitative prediction on reservoir properties, (2) estimate porosity from seismic and well log data by converting the inverted volume into a porosity volume, (3) evaluate reservoir quality from seismic inversion results, (4) infer porosity-permeability relationships from core analysis reports, and (5) examine the petrophysical properties of rocks and their impacts on storage capacity.

CHAPTER II

GEOLOGIC BACKGROUND

The unconventional Mississippian reservoirs in the Anadarko basin show a high level of heterogeneity in their petrophysical properties as a result of various geologic processes such as uplift, and changes in sea level (Miller *et al.*, 2021). Several studies have been carried out in an attempt to aid an understanding of the depositional environment and the reservoir properties of the Mississippian lime. The properties of these reservoirs are directly influenced by natural fractures, calcite cement, mineral composition, and rock fabric (Brito *et al.*, 2021).

Miller *et al.* (2021) found that reservoir lithologies from the analysis of cores from the STACK play are in close relation to the lithologies inferred from porosity-permeability relationships. The authors deduced that calcareous-rich lithologies have lower porosities and permeabilities, and higher water saturation, and that argillaceous-rich lithologies have higher porosities and permeabilities and lower water saturation.

Neely *et al.* (2020) characterized reservoir heterogeneity within the Meramecian formation of the STACK Play using a 3D seismic volume and well logs. They generated porosity volumes which helped to delineate porous and non-porous intervals within the Meramecian formation in the study area.

Wang (2019) analyzed the sequence stratigraphy and characterized the fractures of the STACK Play from core samples. All core samples show naturally mineralized fractures, with the silty limestone-rich intervals having the highest average fracture intensity. These studies contribute significantly to the existing literature about the STACK play, upon which future work can be carried out.

The Anadarko basin is a structural, hydrocarbon-producing basin with a depth of about 40,000 ft and spanning an area of approximately 50,000 square miles. An estimated 5 billion barrels of liquids and 135 trillion cubic feet of gas have been produced, making it one of the largest producers of natural gas in the United States (Hugman & Vidas, 1987; Johnson, 1988; Ball *et al.*,1991). Nemaha uplift bounds the basin on the east, the Ardmore basin and Arbuckle Mountains on the southeast, the Amarillo uplift and Wichita Mountains on the south (Figure 1) (Ball *et al.*, 1991). At a basement depth of less than 5000 ft in the subsurface, there is a shoaling of the basin into a broader shelf (Ball *et al.,* 1991).

The STACK Play, discovered in 1942, is one of the giant fields in the Anadarko Basin, and one of the most significant unconventional hydrocarbon-producing reservoirs in the United States with a large amount of potential oil and gas reserves that have drawn attention over the past couple of years (Brito *et al.*, 2021; Ball *et al.*, 1991). The play was named so for two major reasons: its geographical location and geological setting, and the presence of multiple producible stacked reservoirs (Brito *et al.*, 2021). The two primary reservoirs are the Meramecian and Osagean formations, both Mississippian in age, and containing a mixture of carbonates and siliciclastic units (Droege & Vick, 2018; Price *et al.*, 2020; Miller *et al.*, 2021). The Devonian-Mississippian Woodford shale serves as the source rock for the petroleum system and the Mississippian Chester shale is the top seal (Figure 2) (Brito *et al.*, 2021).

Structurally, the STACK play is a fractured reservoir and from core analysis, Wang (2019) identified four natural fracture types sealed with calcite cement. The amount of calcite cement present largely influences reservoir quality (Price *et al.*, 2020).

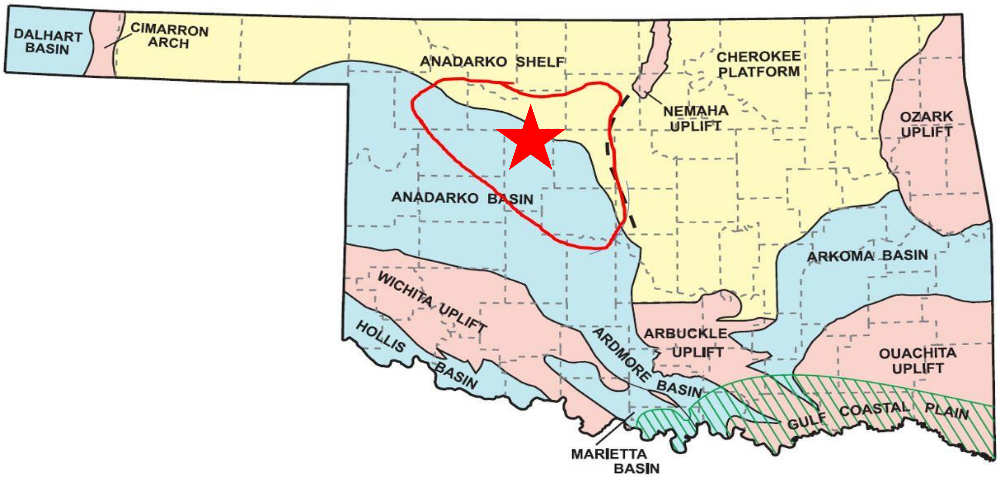


Figure 1: Geologic map of Oklahoma with the STACK play highlighted within the Anadarko Basin (modified after Johnson, 1988).

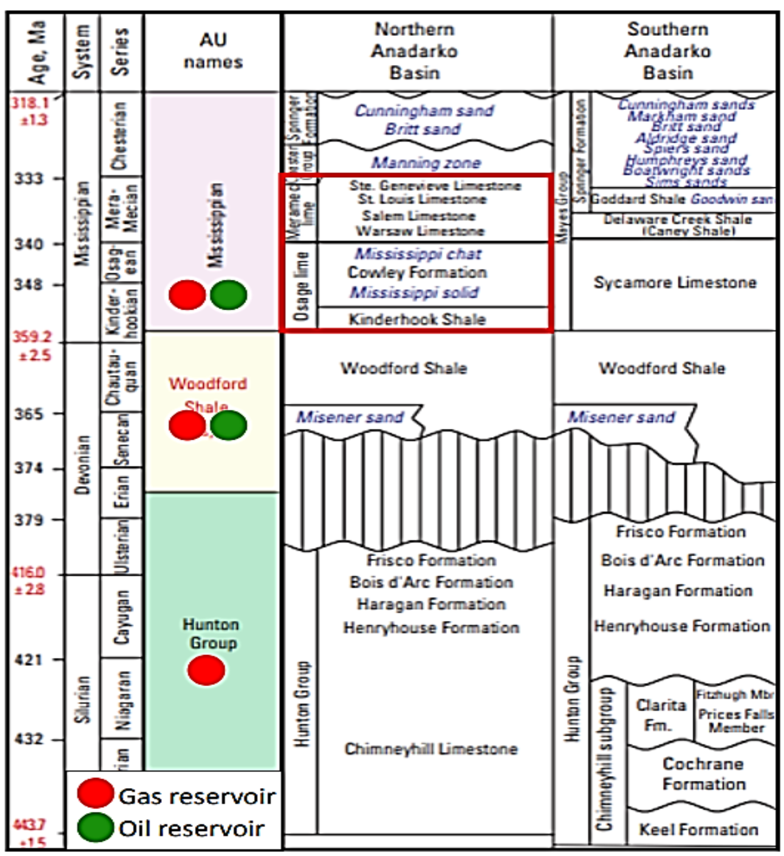


Figure 2: Stratigraphy of Anadarko Basin highlighting the Osagean and Meramecian formations (Droege & Vick, 2008).

2.1 Meramecian

The Meramecian mostly consists of silty limestones, argillaceous-calcareous siltstones, and mudstones (Droege & Vick, 2018; Price *et al.*, 2020; Miller *et al.*, 2021). Chert may be present in some sections across the Anadarko basin (Jordan and Rowland, 1959; Ball *et al.*, 1991). The deposition of the Meramecian unit was on a continental shelf covered by a shallow, warm sea, and there is a strong transition in the style of deposition, causing a change from carbonates in the north to siliciclastics. The different styles and environments of deposition, and variations in the energy environment resulted in lateral facies change (Perry, 1989). Prograding clinoforms in the northeast-southwest orientation have been used to identify the parasequences formed from clay-rich flooding surfaces across the Meramecian formation (Hickman, 2018; Drummond, 2018; Price *et al.*, 2020; Brito *et al.*, 2021; Miller *et al.*, 2021). Miller *et al.* (2021) identified that the Meramecian is made up of seven stratigraphic units that are each topped by a marine flooding surface and described as strike-elongate, shoaling-upward parasequences. The Mississippian carbonates are often prone to diagenetic alterations, which make the porosity values vary widely and difficult to correlate in the subsurface (Shelley *et al.*, 2017).

2.2 Osagean

The Osagean is predominantly formed of chert-rich grainstones and packstones, as seen on log and core data from the STACK play (Droege & Vick, 2018). Chert was formed in some intervals when deposited sponge and spicules in the elevated silica marine waters were exposed to air. The low clay content, aggradational and progradational stacking patterns make Osagean intervals easily identifiable, while Meramecian shows a coarsening-upward sequence with high clay content. Generally, the Meramecian formation has higher porosity values than the Osagean (Shelley *et al.*, 2017).

2.3 Study Area

Figure 3 shows the study area for this research, covering approximately 180 square miles within the STACK play of the Anadarko Basin.

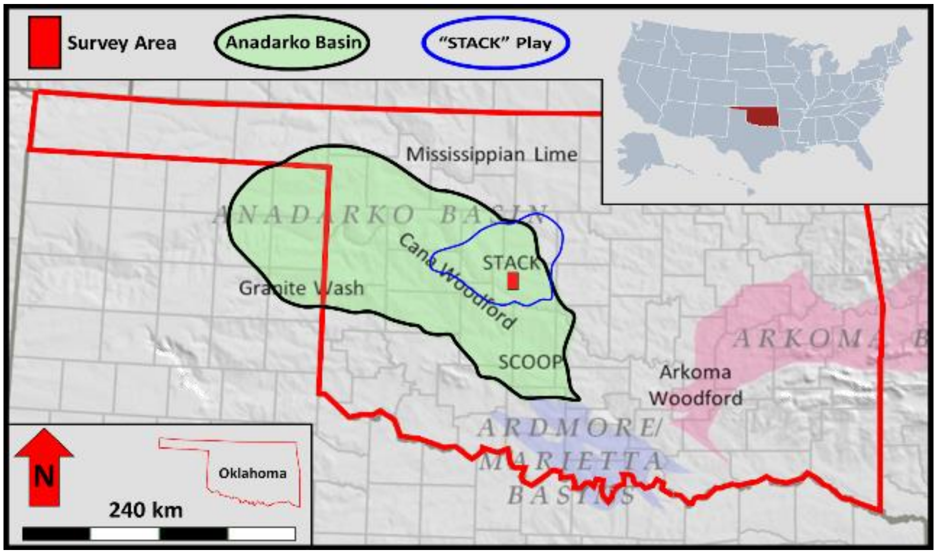


Figure 3: A base map of the study area within the STACK play showing the 3D survey area in the red rectangle.

CHAPTER III

DATA AND METHODS

Reservoir characterization depends on the availability and quality of seismic data and well logs. Well logs provide a better vertical resolution and can be used to obtain petrophysical properties such as porosity, volume of shale, reservoir thickness, and water saturation (Darling 2005, Soleimani *et al.*, 2020). They, however, have a lower spatial resolution. Seismic data have a higher spatial resolution and can cover a larger area, hence a combination of the two types of data will provide information about reservoir properties such as porosity and saturation and enhance a better characterization of the subsurface (Oliveira *et al.*, 2005; Hampson *et al.*, 2001; Soleimani *et al.*, 2020).

The dataset used for this research consists of 3D seismic reflection survey data, covering an area of approximately 180 square miles, and well log suites provided by Devon Energy. 4 wells with gamma-ray logs, neutron-porosity logs, sonic logs, and density logs were used for the study. The location of the wells in the study area and the properties of the wells are shown in Figure 4 and Table 1 respectively. Data from the core analysis were also provided for permeability measurements. CGG's Hampson-Russell software was used for carrying out most of the processes in the workflow, such as the seismic interpretation and well log correlation, acoustic impedance inversion, and cross-plotting porosity against acoustic impedance. This study follows a seismic inversion workflow used by Almutairi *et al.*, 2022 (Figure 5) to estimate porosity from available seismic and well log data.

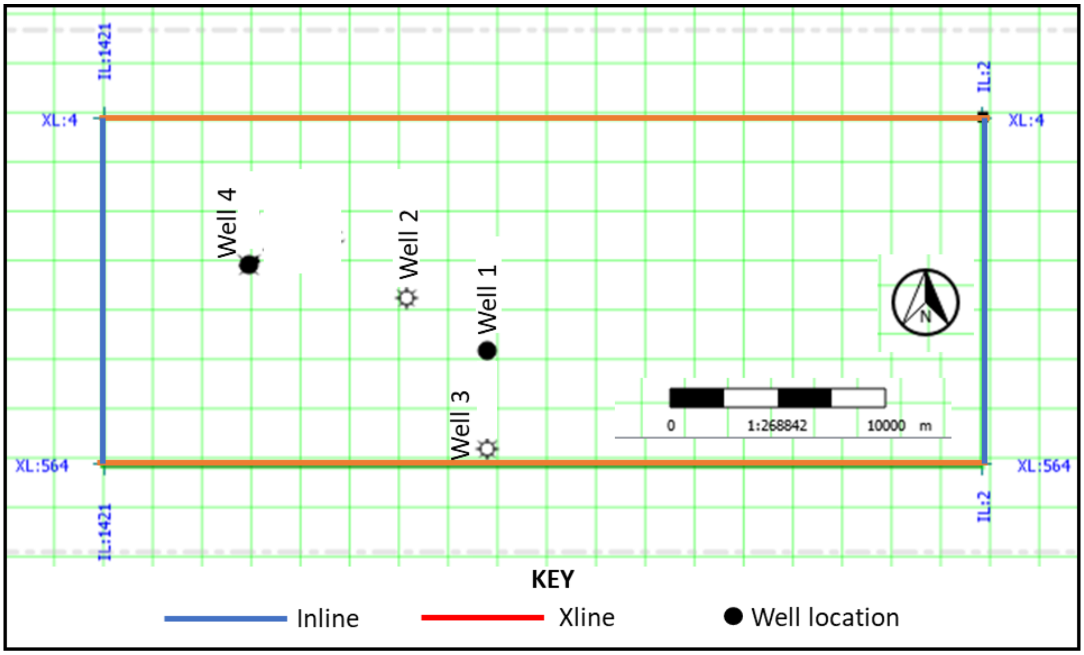


Figure 4: Location of wells within the study area. A total of 1420 inlines and 561 crosslines are present in the study area.

Table 1: Description of wells in the study area.

Well Name	Units	X Location	Y Location	Inline	Xline	KB Elev.	Surface Elev.	Elev. Units
1	ft	1974981.00	206172.00	801	378	1395.00	1370.00	ft
2	ft	1981975.00	216743.80	929	293	1362.00	1337.00	ft
3	ft	1961815.00	206172.00	801	537	1440.00	1415.00	ft
4	ft	1986322.00	237873.70	1186	240	1346.00	1326.00	ft

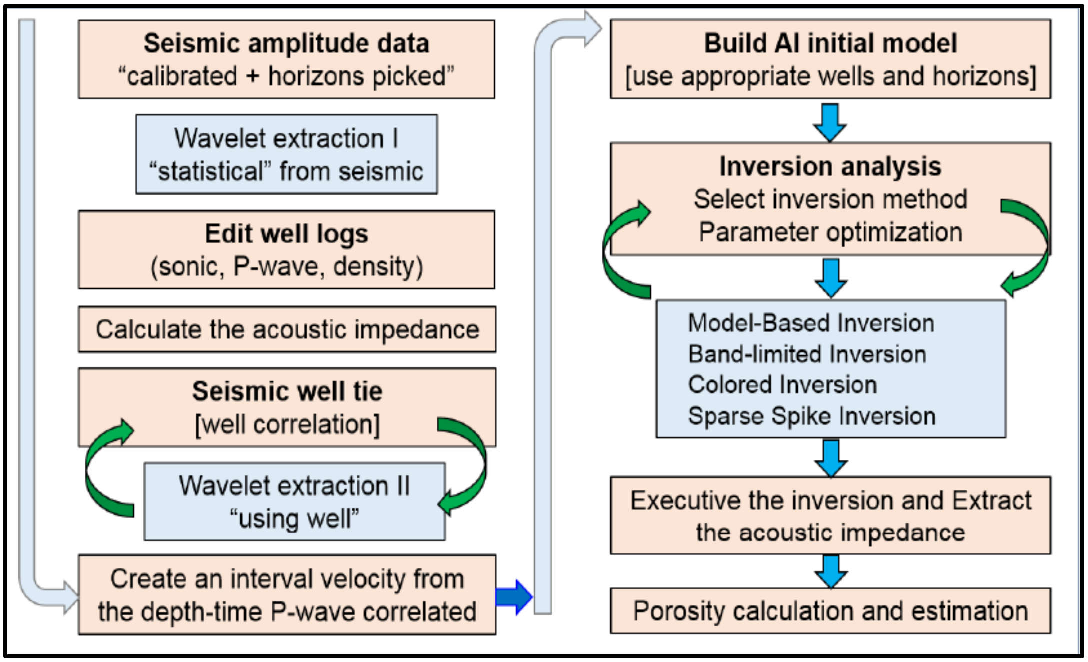


Figure 5: Seismic Inversion workflow (Almutairi *et al.*, 2022).

3.1 Seismic Interpretation

The goal of seismic interpretation is to develop a geological framework, which involves identifying, mapping and correlating significant fault planes, stratigraphic surfaces and horizon-fault intersections. By matching events on wells to the seismic data, the horizons of interest were picked across the entire seismic volume. Figure 6 shows a section of the seismic data with the picked horizons of interest. Time structure maps were generated for the Osagean and Meramecian formations, which are the major formations of interest, and plotted in Figure 7.

3.2 Well Log Interpretation

Well logs are useful in delineating stratigraphic and lithologic tops, among many other functions. For this study, gamma ray, sonic, density, and porosity logs were provided. Gamma-ray logs measure the radioactive materials in formations. Lithologies such as sandstones and carbonates generally contain low quantities of radioactive materials, hence giving off low gamma ray values (Asquith *et al.*, 2004).

The top of the upper Meramecian formation is marked by low gamma-ray values, and in some wells, the gamma-ray response shows a funnel shape, which is a characteristic of prograding, coarsening upward sequence, indicating a change from clastic to carbonates. The Osagean is marked by a much lower gamma-ray value, followed by a sharp increase in gamma-ray reading indicating a change in lithology to Woodford shale.

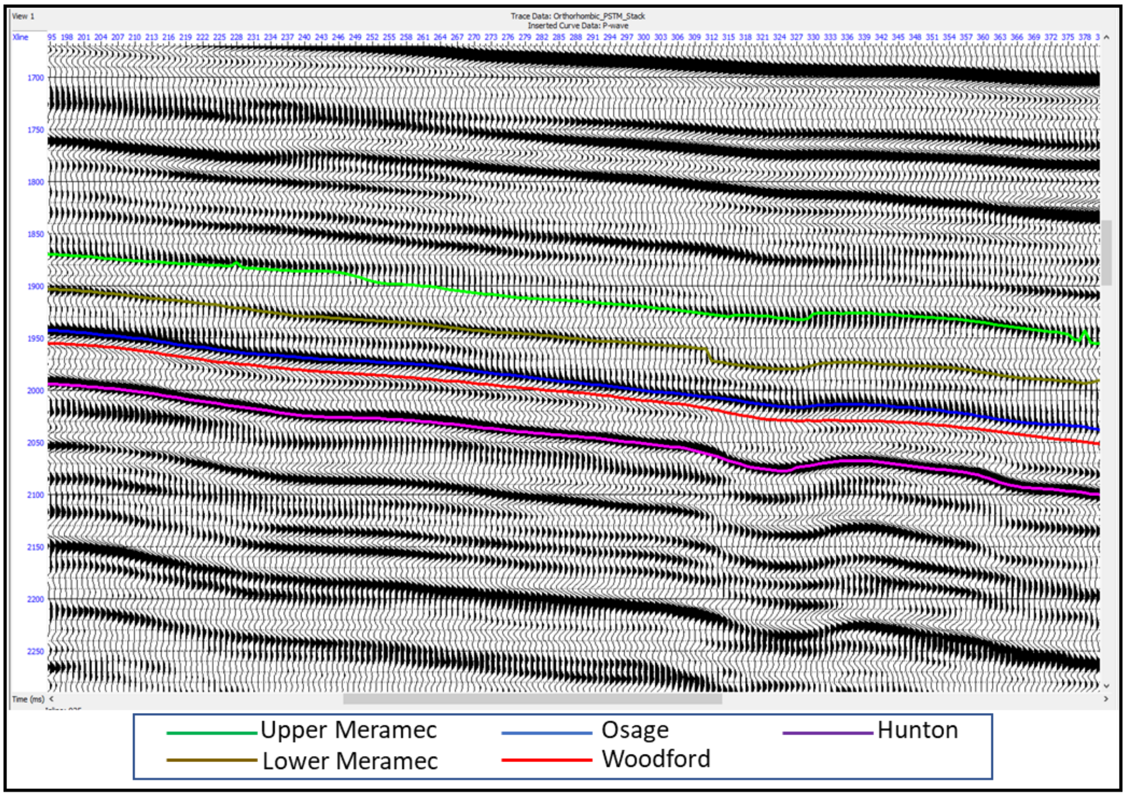


Figure 6: Seismic section along inline 925 showing picked horizons.

(a) (b)

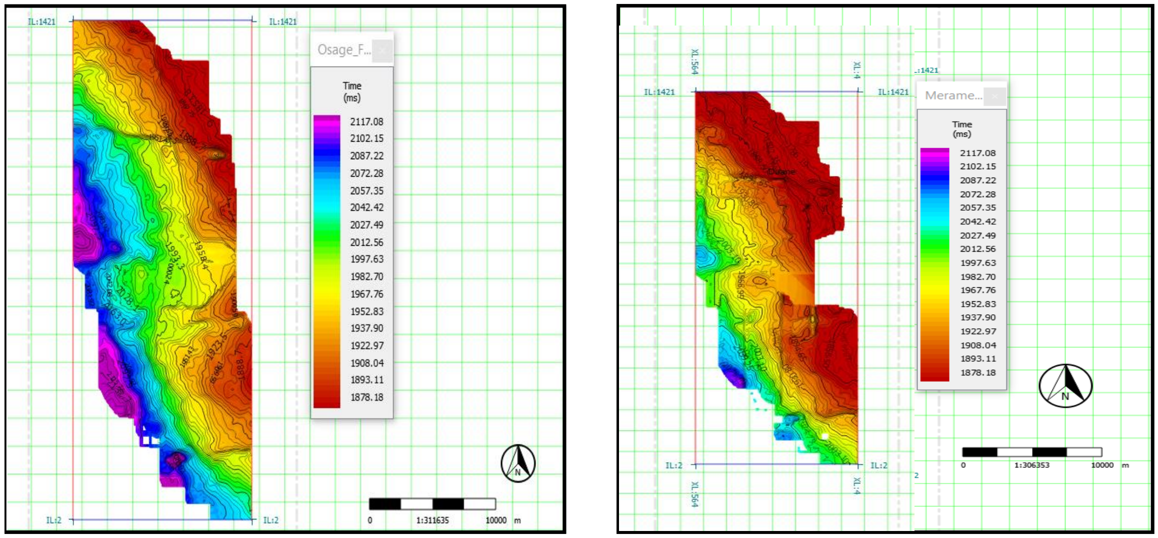


Figure 7: (a) Time structure map for Osage. (b) Time structure map for Meramec.

3.3 Wavelet Extraction and Synthetic Seismogram

To ensure that the formation tops on the wells match the corresponding horizons on seismic data, a synthetic seismogram was generated to tie the well logs to the seismic data. The process of generating the synthetic seismogram involves extracting a statistical wavelet from the seismic data (Figure 8) and convolving the reflectivity derived from digitized acoustic and density logs (Figure 9). The extracted wavelet is a zero-phase wavelet with a length of 100 ms. The synthetic seismogram generated and the well-to-seismic correlation are also shown in Figure 9. The cross-correlation coefficient for all 4 wells (Figure 10) shows a high value which indicates a good correlation. Upon successful correlation of the wells, a deterministic wavelet was extracted from the wells (Figure 11), which will be used for the seismic inversion.

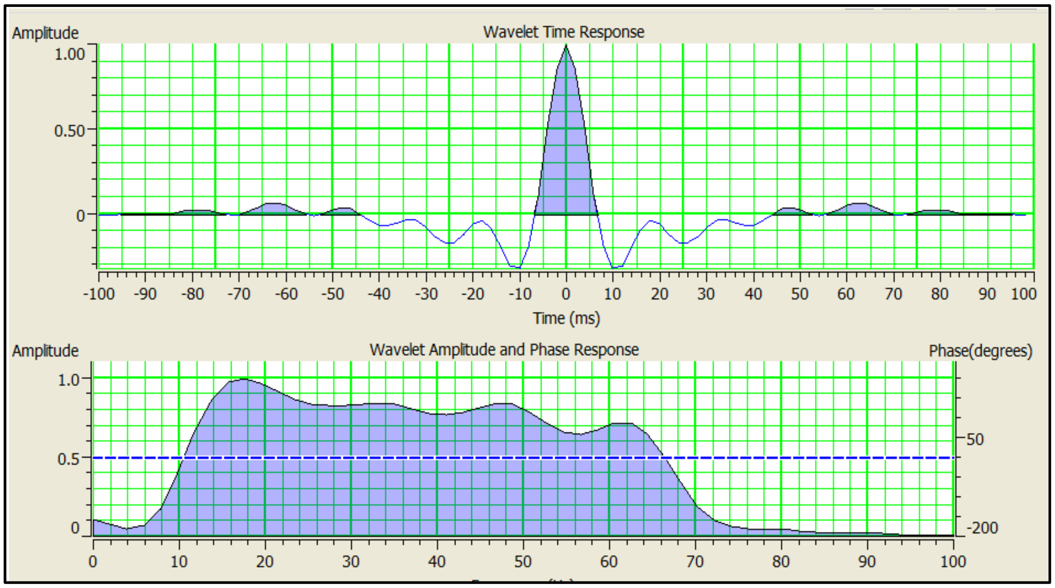


Figure 8: Statistical wavelet extracted from seismic data.

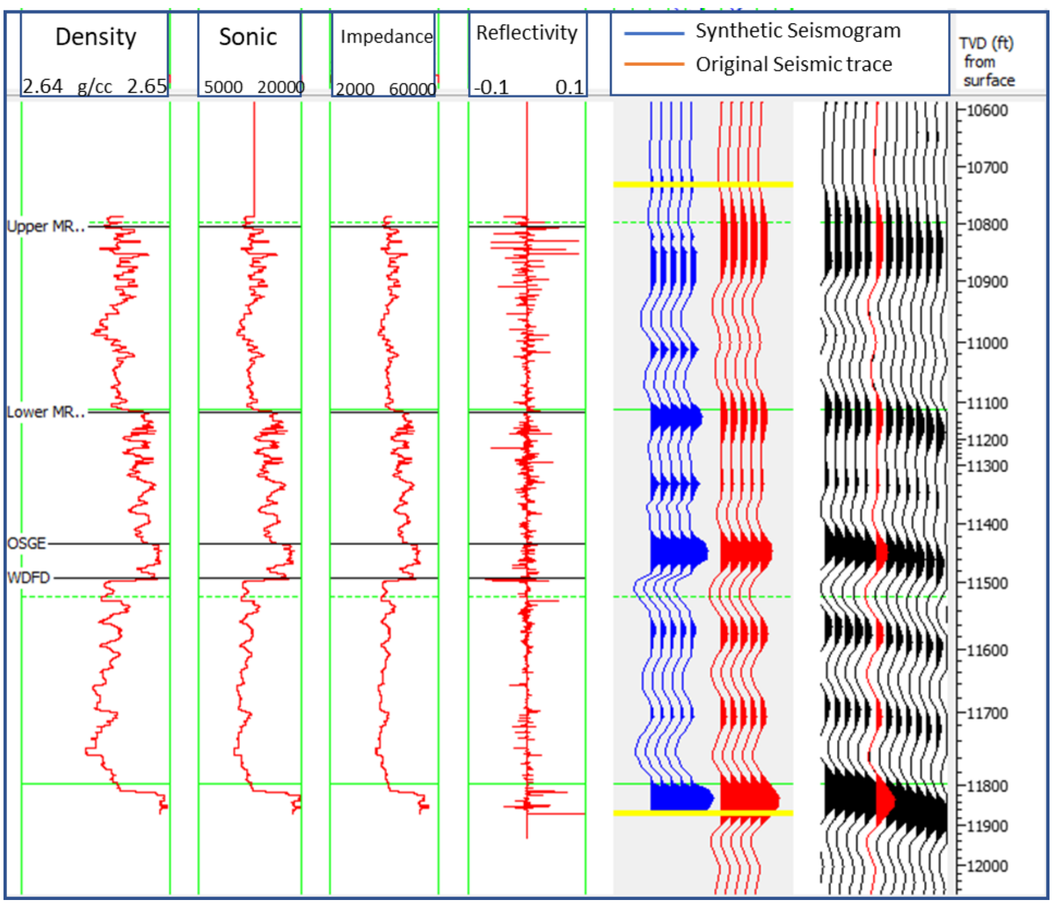


Figure 9: Well to seismic correlation for well 1.

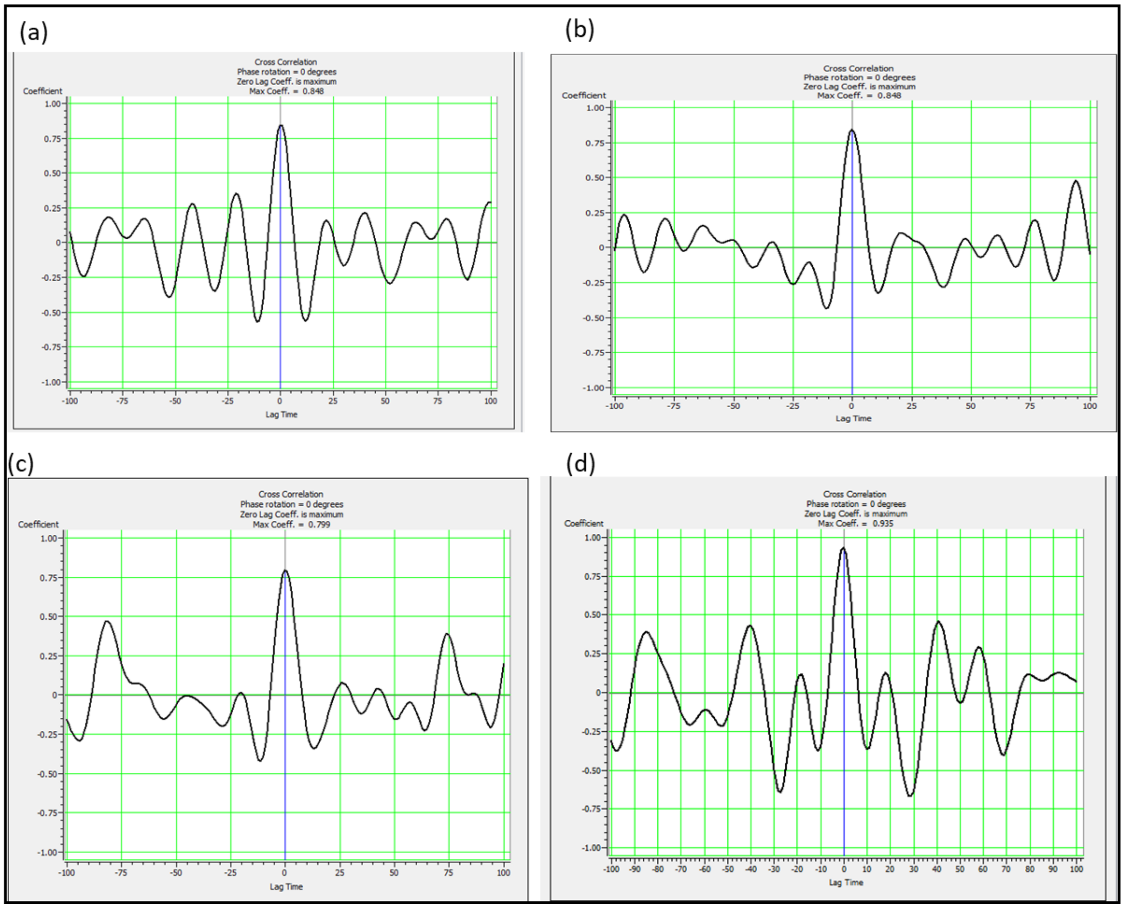


Figure 10: Cross correlation window (a) for well 1 with a coefficient of 84.8%, (b) for well 2 with a coefficient of 84.8%, (c) for well 3 with a coefficient of 79.9% and (d) for well 4 with a coefficient of 93.5%.

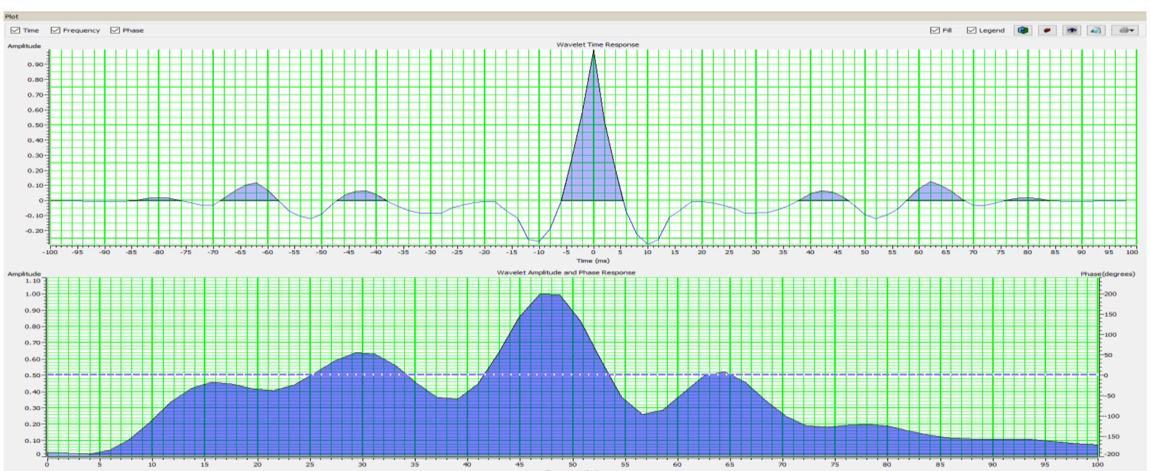


Figure 11: Deterministic wavelet averaged from all 4 wells.

3.4 Well to seismic tie

Seismic reflection data is recorded in two-way traveltime, while well log data is in depth. It is important to match events on well logs to events on seismic data, and the process is called "well-to-seismic tie". A time-depth relationship is typically computed by integrating the slowness function measured at a wellbore. This process is an integral part of the entire seismic inversion which could potentially compromise the inversion results if not accurately done. Figure 12 shows a section of the seismic data where well 1 and 3 are correlated and tied to the seismic volume.

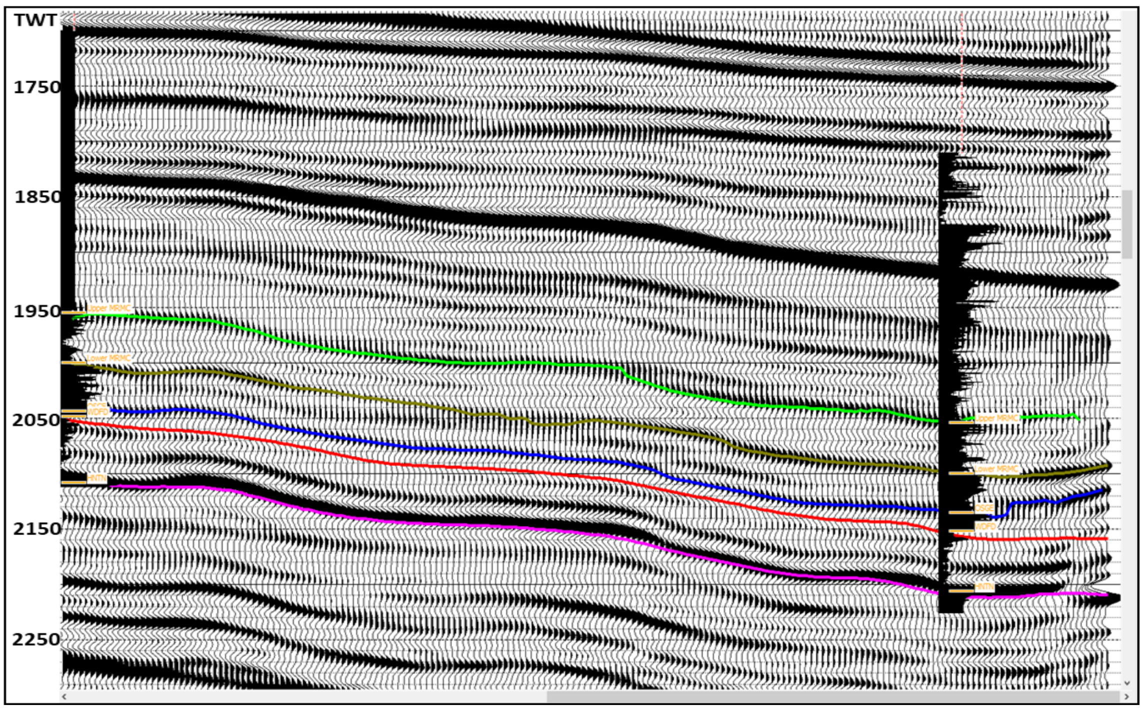


Figure 12: Well to seismic tie for well 1 (left) and well 3 (right).

3.5 Initial Model

An initial acoustic impedance model was built using appropriate wells and horizons (Figure 13). The model utilizes low frequency information from surrounding wells and helps to delineate rock lithology by the variations in acoustic impedance of layers, which is a function of the density and p-wave velocity.

The model also gives an insight into the porosity of formations as an inverse proportionality relationship exists between acoustic impedance and porosity; the higher the acoustic impedance, the lower the porosity, and vice-versa. This model was used to run the inversion analysis.

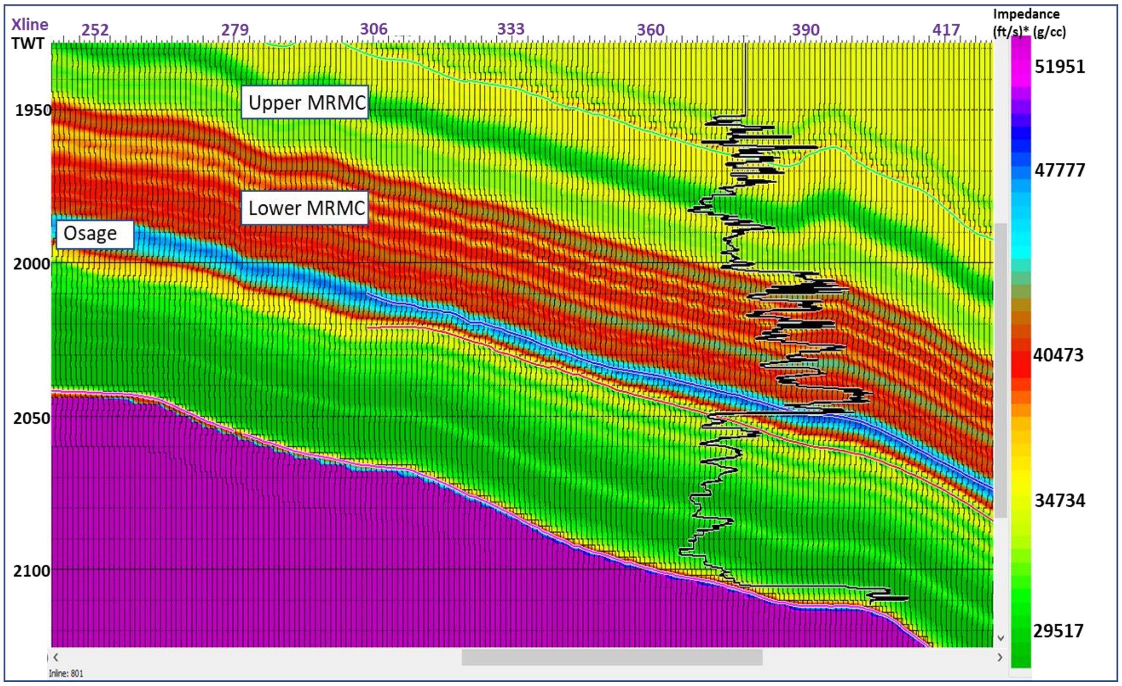


Figure 13: Initial acoustic impedance model with sonic log overlain on well 1.

3.6 Model-Based Inversion

Seismic inversion converts the seismic data from an interface/boundary property into a layer property. While there are different types of seismic inversion techniques, the ultimate goal is to produce a more interpretative image of the subsurface. The model-based inversion is based on the forward model, also commonly known as the convolutional model, in which the reflection coefficient from an acoustic impedance model (product of density and p-wave velocity) are convolved with a source wavelet, in addition to noise, to generate a synthetic seismic data. The accuracy of the model-based inversion hinges on the disparity between the original seismic trace and the derived synthetic trace. When the difference is at its barest minimum, the inverted model can then be applied to the seismic volume. Using the deterministic wavelet extracted from the wells and the existing initial model, the inversion analysis was run for all 4 wells (Figure 14) and applied to the seismic volume (Figure 15).

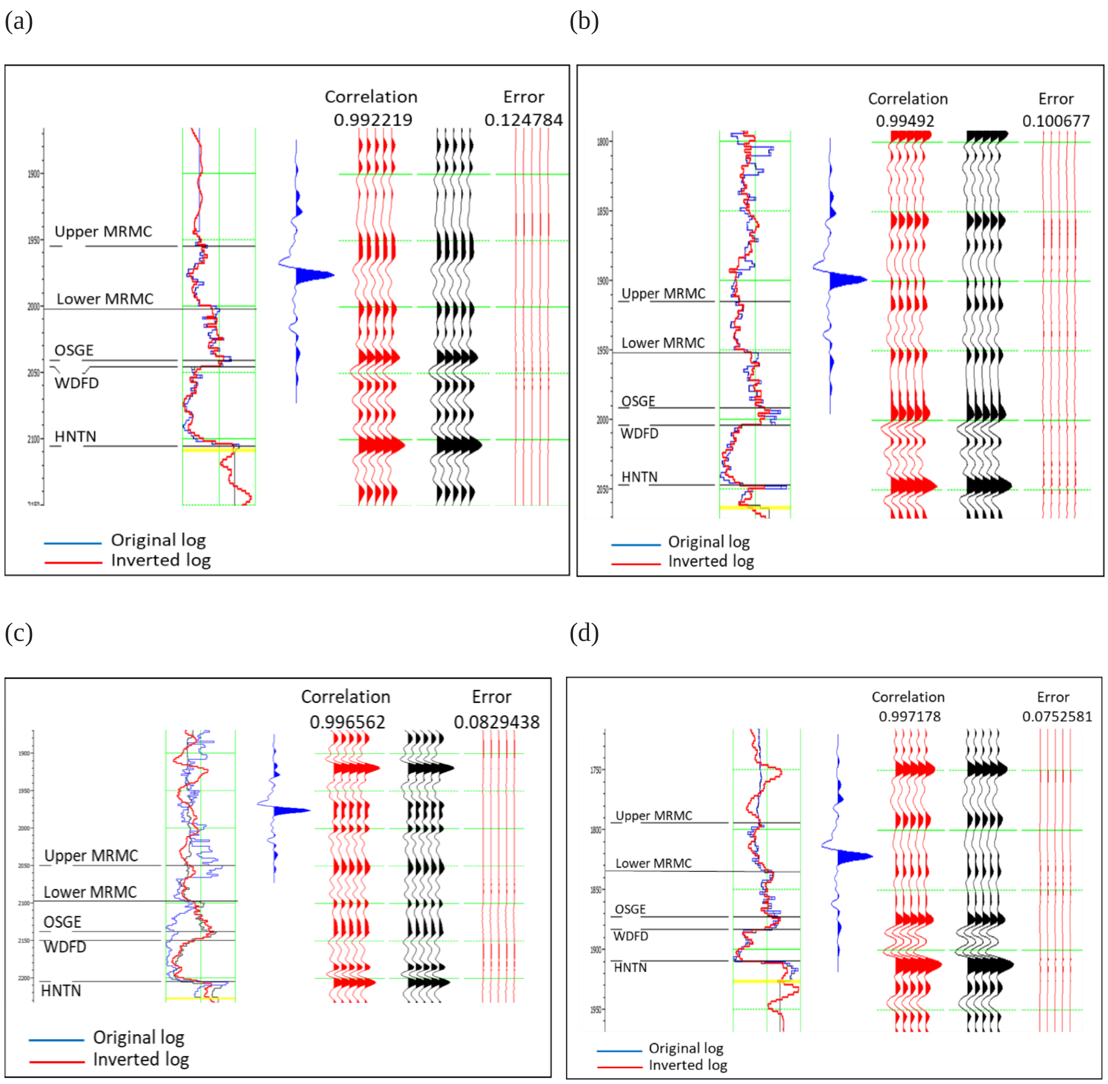


Figure 14: Inversion analysis for (a) well 1 (b) well 2 (c) well 3 and (d) well 4

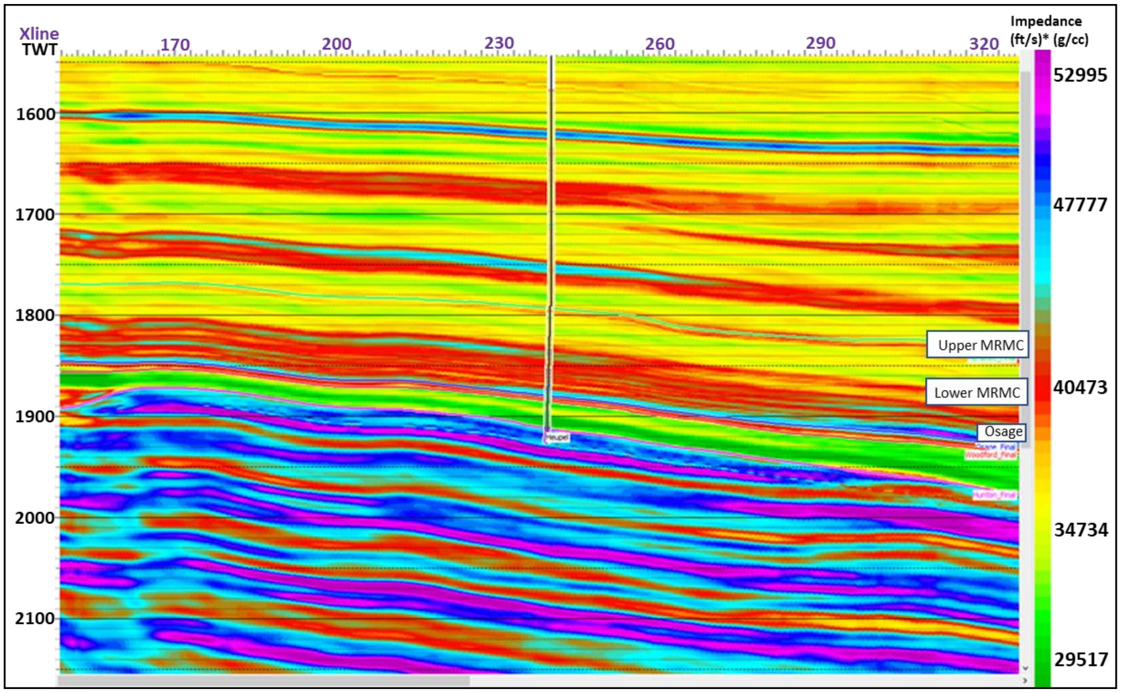


Figure 15: Post Stack Acoustic Impedance Inversion.

3.7 Porosity Analysis

Porosity and permeability are essential properties a body of rock must have to be called a reservoir. These two properties play an important role in determining reservoir quality and performance. They are also fundamental properties for CO_2 storage and EOR purposes. Different logging tools estimate the amount of pore space in a rock, but do not directly measure porosity. Porosity is best estimated when two or more of these logs are used together (Asquith *et al.,* 2004). The combination of the neutron and density logs is arguably the most used log combination for porosity estimation. Neutron logs measure the concentration of hydrogen in a formation, and density logs measure the bulk density and matrix density of a formation (Asquith *et al.*, 2004). Neutron-Density porosity (ND_{Φ}) was calculated for well 1 (Figure 16a), using available neutron porosity and density porosity logs. The density porosity was derived from the bulk density log using equation 1 (Eq. 1).

$$\Phi = \frac{\rho_{\mathrm{ma}} - \rho_{\mathrm{b}}}{\rho_{\mathrm{ma}} - \rho_{\mathrm{f}}}$$

Eq. 1. (Serra, 1984)

where:

Φ = porosity, ρ_{ma} = matrix density (estimated as 2.65g/cc for sandstone and 2.71 g/cc for limestone), ρ_b = formation bulk density, ρ_f = fluid density (usually 1.0 for freshwater and 1.1 for saltwater mud).

ND_Φ was calculated using equation 2 (Eq. 2)

$$f = \sqrt{\frac{f_D^{\,2} + f_N^{\,2}}{2}} \qquad \text{Eq. 2.} \qquad \text{(Gaymard \& Pourpon, 1968)}$$

where:

Φ = porosity, Φ_D = density porosity, Φ_N = neutron porosity

At well 3, a total porosity log (PHIT) was provided (Figure 16b).

(a) (b)

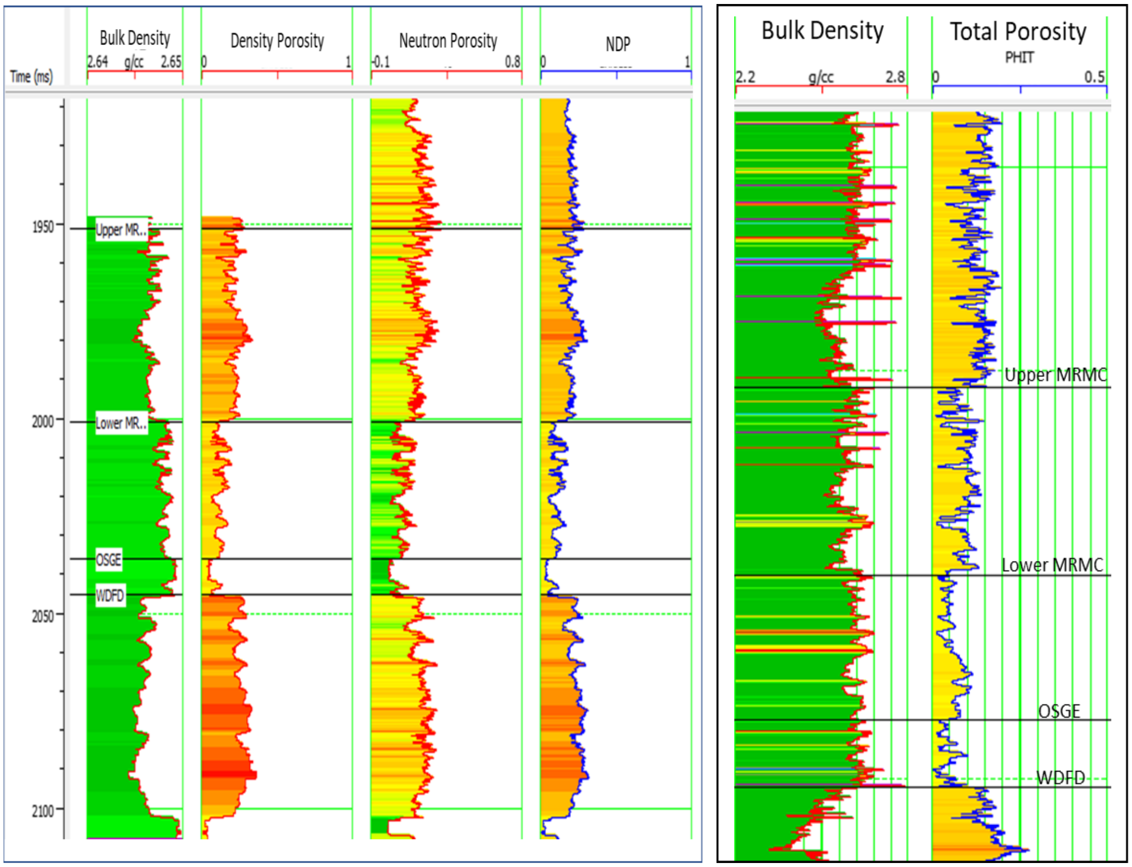
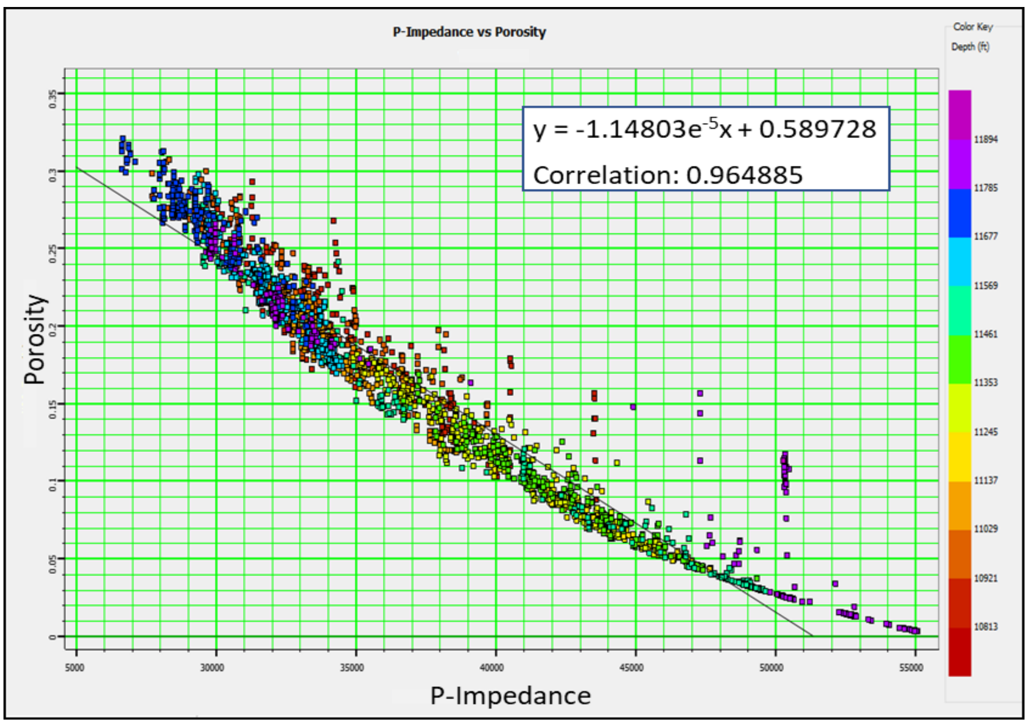


Figure 16: (a) Neutron-Density Porosity (NDP) log calculated from Neutron and Density porosity logs for well 1. Porosity values are in the form of fraction. (b) Bulk density and PHIT log provided for well 3.

3.8 Crossplots

Crossplots are a graphical way to show how two or more properties are related. The relationship between these properties may be linear or logarithmic. Acoustic impedance generally has a strong relationship with rock properties such as porosity and fluid saturation (Eze *et al.*, 2019). Acoustic impedance was cross-plotted linearly against porosity for wells 1 and 3 (Figure 17) and a regression equation that relates acoustic impedance to porosity was derived for each well.

(a)



(b)

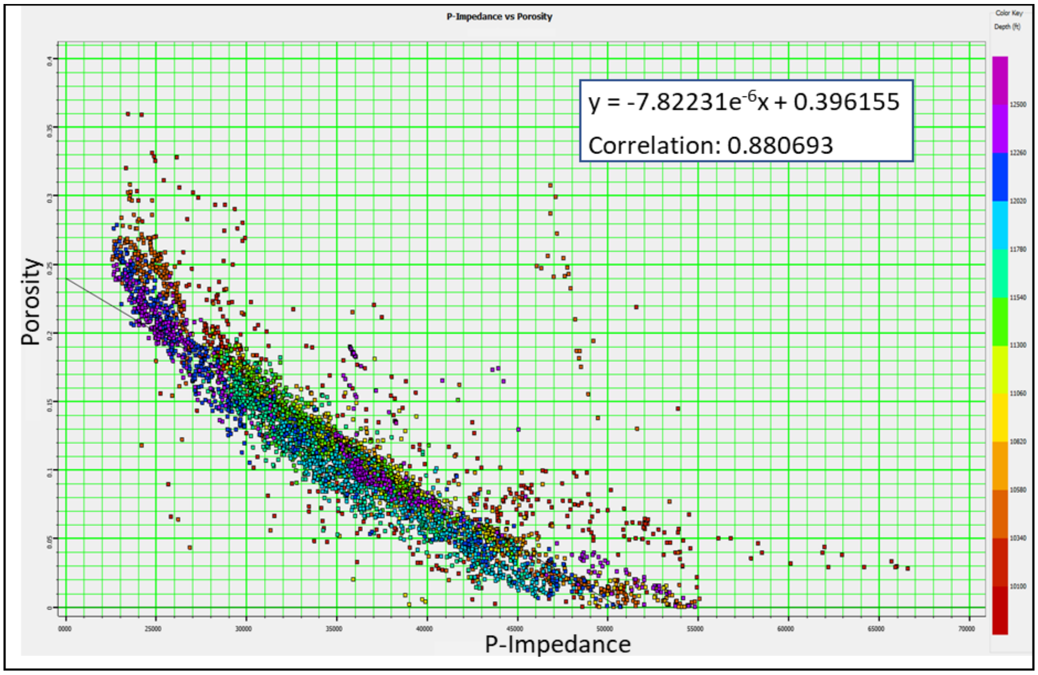
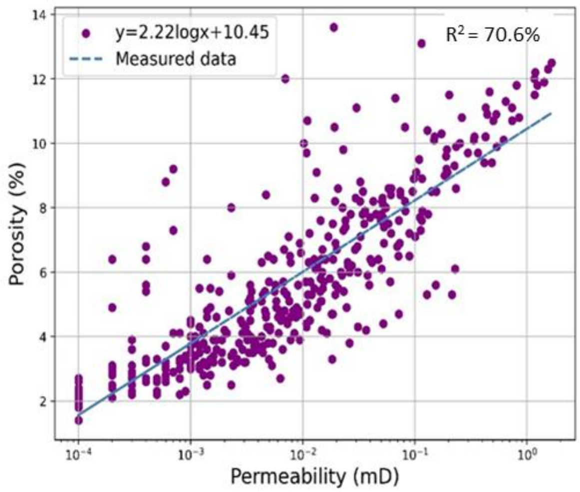


Figure 17: Crossplot of AI and porosity at (a) well 1, (b) well 3, showing the linear regression equation between the two properties and their correlation coefficients.

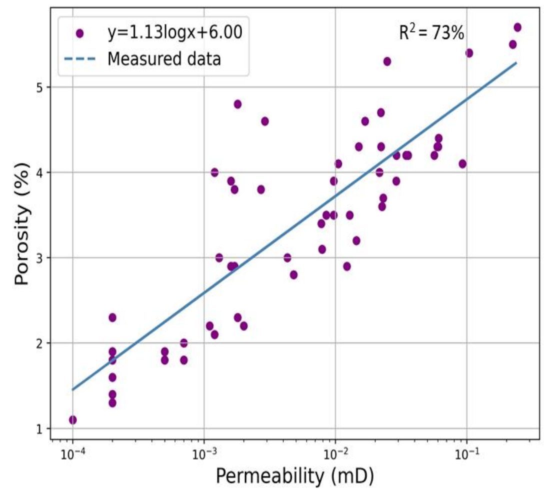
3.9 Permeability Analysis

Permeability is a petrophysical property that describes the ease of fluids through rock and has a direct relationship with effective porosity. It is a fundamental reservoir property for CO_2-EOR purposes. Permeability measurements are usually taken from core samples with values ranging from less than 0.001 mD to 1 Darcy (Lucia 2007; Bohnsack *et al.*, 2020). Porosity-permeability relationship from cores can be inferred by crossplotting porosity against permeability and observing the trend. In many cases, porosity is plotted on a linear scale and permeability is plotted on a logarithmic scale. The regression equation from the cross plot can then be applied to the porosity volume to obtain information about permeability across the seismic volume. Core analysis reports from all 4 wells contained effective porosity and permeability measurements for each formation, which were crossplotted to establish an empirical formula (Figure 18). Permeability values for Meramecian range between 0.0001 and 1.66 mD, with an average value of about 0.1mD. The permeability values for Osagean range between 0.0001 and 0.6 mD, with an average value of 0.03 mD.

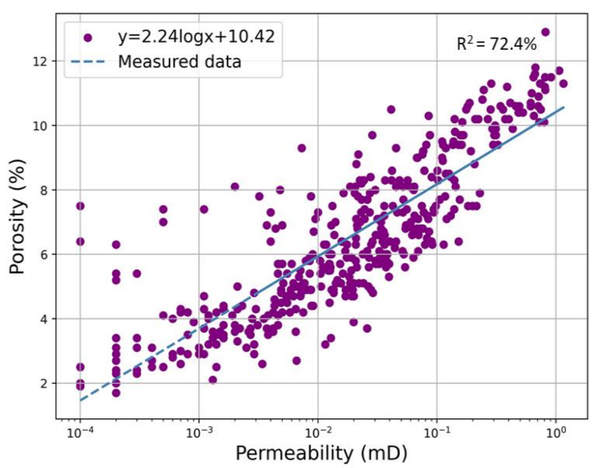
(a)



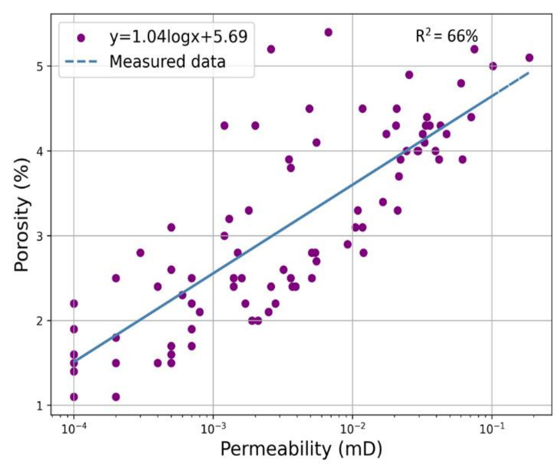
(b)



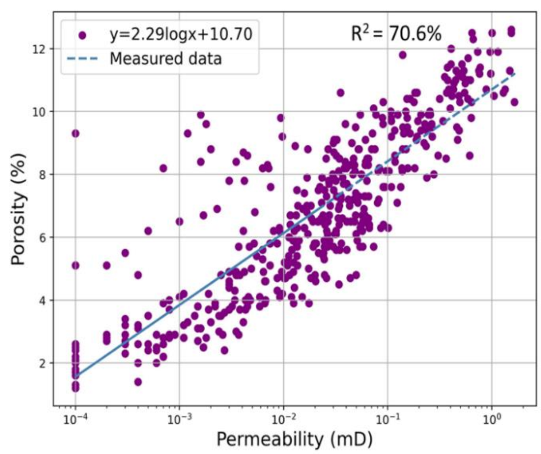
(c)



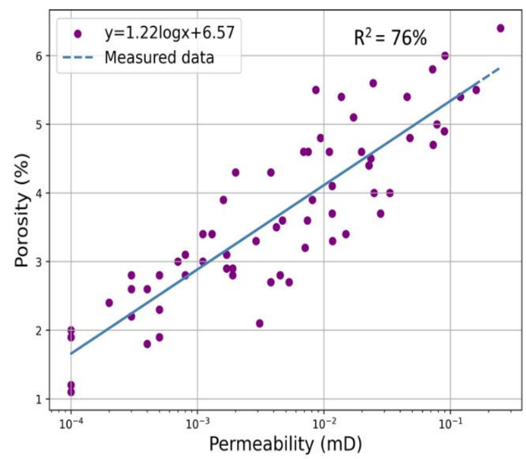
(d)



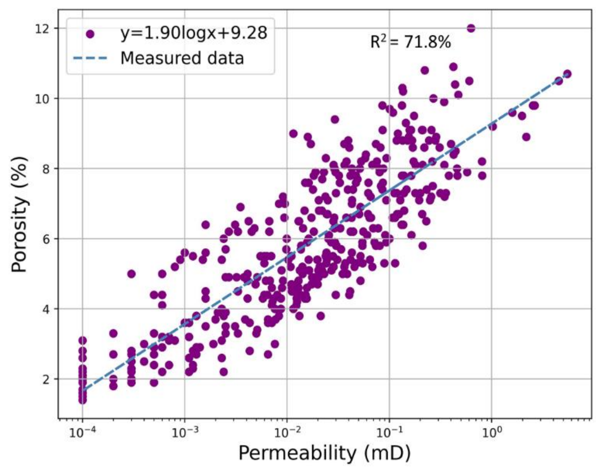
(e)



(f)



(g)



(h)

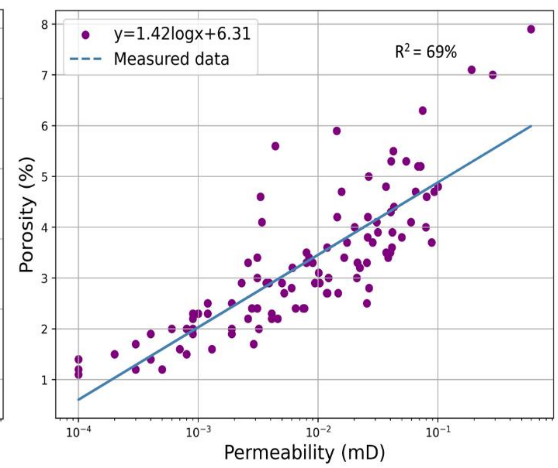


Figure 18: Porosity-Permeability crossplot for (a) Meramecian formation at well 1, (b) Osagean formation at well 1, (c) Meramecian formation at well 2, (d) Osagean formation at well 2, (e) Meramecian formation at well 3, (f) Osagean formation at well 3, (g) Meramecian formation at well 4, and (h) Osagean formation at well 4. Permeability (x-axis) is logarithmic.

CHAPTER IV

DISCUSSION

Reservoir porosity can be estimated from a variety of methods. An integration of well log and seismic data helps to provide a reliable porosity distribution in the study area. Porosity and permeability measurements taken from core samples provide a more accurate description of local porosity and can be used to calibrate the porosity derived from well log and seismic data to give a regional description of the spatial distribution of porosity.

4.1 Acoustic Impedance – Porosity Relationship

Seismic inversion helps to convert the seismic trace into an impedance trace. Variations in density and velocity at each trace can be better indicators of lateral changes in rock properties such as porosity. A strong correlation exists between AI and porosity at wells 1 and 3 with a correlation coefficient of 96.48 % and 88 % respectively. This indicates a reliable function that can be applied to the inverted seismic volume. Well 1 shows the highest correlation coefficient and its regression equation in equation 3 (Eq. 3) was applied to the inverted seismic volume for conversion into a porosity volume (Figure 19).

$$y = -1.14803e^{-5}x + 0.589728 \quad \text{(Eq. 3)}$$

Amplitude slices were generated for the horizons of interest to show the porosity distribution across the formation and the degree of heterogeneity in the reservoir (Figure 20). The Meramecian formation shows a high level of reservoir heterogeneity with varying porosity values. Porosity values range between 10 % and 14 %, with an average of 12 %. The lower MRMC has higher acoustic impedance values and lower porosity values ranging between 5 % and 9 %, with an average porosity value of 7%. Neely *et al.*, (2019) suggest that this is due to increased calcite cementation, causing the velocity and density of the rock to increase. Hence, larger porous zones in the Meramecian are found at the upper section of the reservoir. The Osagean, made up of chert-rich grainstones and packstones, has porosity values ranging between 4 % and 8 %, with an average value of 6 %. The amplitude slice of the porosity distribution shows a significant spatial variation in porosity values of the Osagean formation across the study area. The northern section appears to have lower values, compared to other parts of the section.

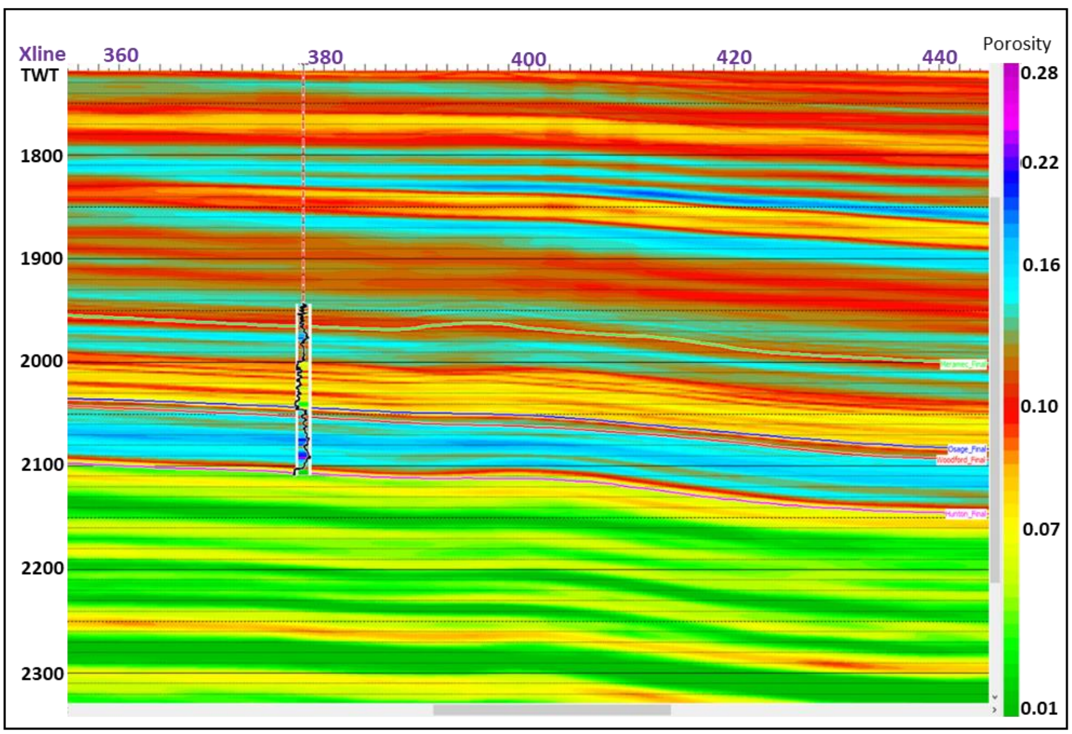


Figure 19: Porosity volume overlain with gamma ray log at well 1.

(a) (b)

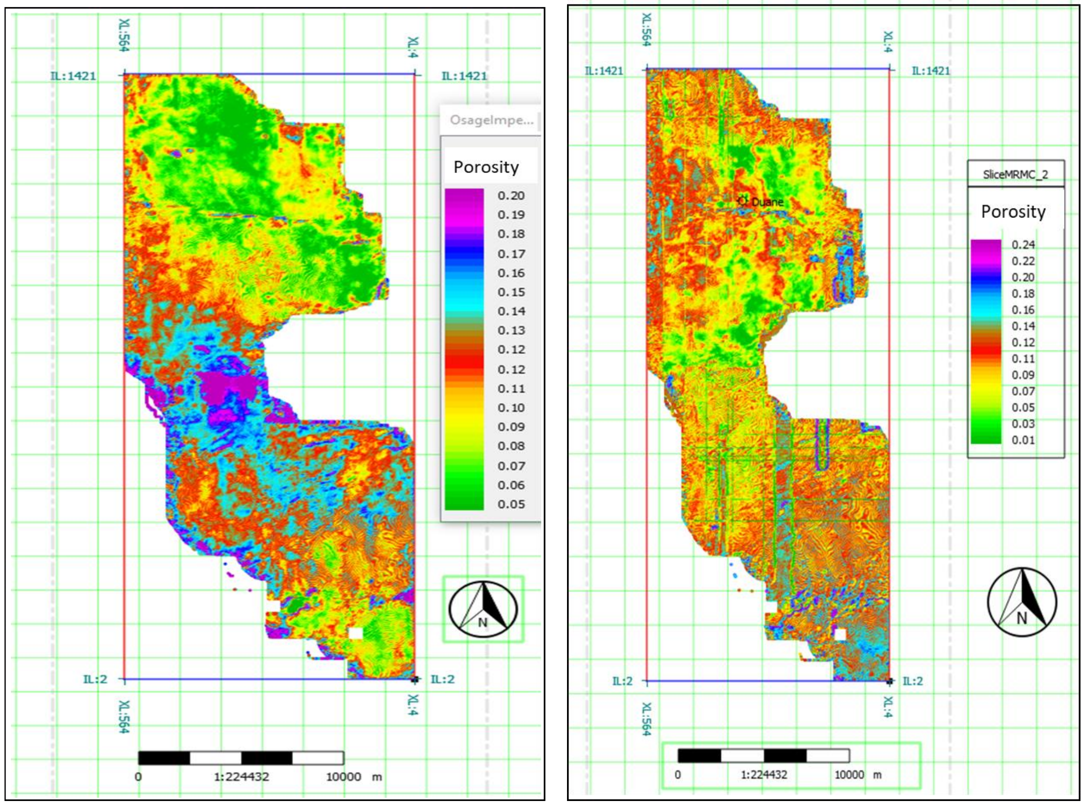


Figure 20: Porosity amplitude slices for (a) Osagean formation (b) Meramecian formation.

4.2 Porosity-Permeability Relationship

Porosity has a significant control on permeability. The connectivity of the pores creates a pathway for the flow of fluid. Permeability also depends on other factors, such as the presence of fractures, which could significantly enhance permeability, especially in unconventional reservoirs. The relationship between porosity and permeability could be described in cases where: (i) the matrix porosity with pore spaces is generally small and therefore permeability is low, and (ii) fracture, fissure, and joint porosity with large pore size and consequently permeability is high (Adekanle & Enikanselu, 2013). From the porosity-permeability crossplots, the correlation coefficients for the Meramecian formation at wells 1, 2, 3, and 4 are 70.6 %, 72.4 %, 70.6 % and 71.8 % respectively.

The correlation coefficients for the Osagean formation are 73 %, 66 %, 76 % ,and 69 % at wells 1, 2, 3, 4 respectively. These values show a good relationship between porosity and permeability.

4.3 CO_2 Storage Assessment

For a reservoir to be considered fit as a potential geologic CO_2 storage site, certain criteria have to be met, which include capacity, injectivity and containment (Ajayi *et al.*, 2019). The potential storage site needs to be porous to sequester a significant amount of CO_2 and permeable to allow for injection at a steady rate. Cap rocks with reliable sealing abilities are necessary to prevent the escape of CO_2 to the surface or leakage into groundwater, thereby contaminating it. CO_2 is best stored in geologic formations as a supercritical fluid. At supercritical conditions, CO_2 is compressed to temperature (about 89°F) and pressure conditions (about 7.4 MPa) where it behaves as both a liquid and gas (NETL, 2015; Ajayi *et al.*, 2019; Almutairi *et al.*, 2022). At a minimum burial depth of 800 m (about 2500 ft), supercritical conditions can be attained (Levine *et al.*, 2016). Storing CO_2 in this phase occupies less storage space and allows for more volume to be stored, compared to when storing at standard room conditions (NETL, 2015; Almutairi *et al.*, 2022).

The Osagean and Meramecian strata of the STACK play satisfy these criteria. An assessment of the porosity and permeability distribution shows that CO_2 can be injected into the pore spaces. In most wells, the formations were found at depths greater than 9000 ft. The Mississippian Chester shale overlying the Meramecian formation has a reliable sealing ability to prevent the leakage of injected CO_2.

4.4 Volumetric Calculation

CO_2 storage capacity was estimated for the upper Meramecian, lower Meramecian and Osagean formations following a US-DOE methodology which is based on the equation:

$G_{CO2} = A \times h \times \phi \times \rho \times E_f$ (U.S. DOE, 2008) where: G_{CO2} = CO_2 storage capacity, A = total area covered by reservoir, h = reservoir thickness, ϕ = reservoir porosity, ρ = density of supercritical CO_2, E_f = CO_2 storage efficiency factor (Goodman *et al.*, 2011)

The formations of interest cover a total geographic area of 3.352E+08 m^2. The average reservoir thickness for the upper Meramecian is 290 ft (~88.4 m), 300 ft (~91.44 m) for the lower Meramecian and 85 ft (~25.9 m) for the Osagean strata. The reservoir thicknesses were averaged out from the wells. Average porosity in the upper and lower Meramecian is 12 % and 7%, respectively. The Osagean has an average porosity value of 6 %. The density of supercritical CO_2 used for the estimation was 700 kg/m^3 (NETL, 2015), and an efficiency factor of 2.0 %, corresponding to the P_{50} percent probability using the Monte Carlo method (Goodman *et al.*, 2011) was also used in the analysis. The CO_2 storage efficiency factor represents a fraction of the total pore volume that will be occupied with CO_2. The Monte Carlo method sets the efficiency factor between 1.2 % and 4.1 % over the 10th and 90th percentile (P_{10} and P_{90}) probability range (Goodman *et al.*, 2011). Using these parameters, the storage capacity was estimated for each formation (Table 2).

Table 2: Estimated CO_2 storage capacity.

	Upper MRMC	**Lower MRMC**	**Osagean**
Area (m)	3.35E+08	3.35E+08	3.35E+08
Thickness(m)	88.4	91.44	25.9
Avg. Porosity	0.12	0.07	0.06
ρ	700	700	700
E_f (P_{50})	0.02	0.02	0.02
Est. Storage (Mt)	**49.78**	**30.03**	**7.3**

Using other efficiency factors corresponding to P_{10} (1.3%) and P_{90} (2.8%) (Goodman *et al.*, 2011), storage capacity was estimated (Table 3).

Table 3: Estimated CO_2 storage capacity using P_{10} and P_{90} efficiency factor

	Upper MRMC	**Lower MRMC**	**Osagean**
E_f (P_{10})	0.013	0.013	0.013
Est. Storage (Mt)	**32.36**	**19.52**	**4.74**
E_f (P_{90})	0.028	0.028	0.028
Est. Storage (Mt)	**69.7**	**42.05**	**10.21**

CHAPTER V

CONCLUSIONS

A detailed reservoir characterization and a profound understanding of the subsurface is crucial to the success of a CO_2 storage project. An integration of all available datasets (seismic, well logs, core samples) is therefore expedient in achieving this purpose. Seismic inversion converts the seismic volume from boundary properties into layer properties, thus aiding a better interpretation of subsurface features. Hydrocarbons have been produced and are still being produced in large amounts from unconventional reservoirs in the United States. Depending on some factors, some of these reservoirs can serve as a geologic sink for CO_2 storage upon depletion of hydrocarbon and can benefit from existing infrastructure created for producing hydrocarbon. Injecting CO_2 into an active hydrocarbon reservoir, such as the Mississippian lime of the STACK play in the Anadarko basin, can enhance oil/gas recovery. Porosity, permeability, seal properties, subsurface pressure, and depth of burial, are among the important considerations for storing CO_2 in geologic formations. Using a model-based seismic inversion technique and from core analysis reports, this study has looked into the spatial distribution of porosity and permeability across the Meramecian and Osagean formations in the study area and has estimated the amount of CO_2 that each formation can hold. An average porosity of 12 % exists in the upper Meramecian, 8 % in the lower Meramecian, and 7 % in the Osagean formation. Being a fractured reservoir, the permeability can be considered good. Using an efficiency factor of 2 %, an estimated total storage capacity of 79.81 Mt and 7.3 Mt is available in the Meramecian and Osagean, respectively. Future studies can look into the numeric modeling of flow through the reservoir, and reservoir simulation models can be built for CO_2 injection.

REFERENCES

Adekanle, A., & Enikanselu, P. A., (2013). Porosity prediction from seismic inversion properties over ‘XLD’ Field, Niger Delta. American Journal of Scientific and Industrial Research, 4(1), 31-35.

Ajayi, T., Gomes J.S., & Bera, A., (2019). A review of CO_2 storage in geological formations emphasizing modeling, monitoring and capacity estimation approaches. Petroleum Science 16.5: 1028-1063.

Almutairi, K.F., Knapp, C.C., Knapp, J.H., & Terry, D.A., (2022). Assessment of Upper Cretaceous Strata for Offshore CO_2 Storage, Southeastern United States. Modern Environmental Science and Engineering, v. 03, no. 08, p. 532.

Asquith, G. B., Krygowski, D., & Gibson, C. R., (2004). Basic Well Log Analysis: Tulsa: American Association of Petroleum Geologists (AAPG)/ v. 16.

Ball, M., Henry, M., & Frezon, S., (1991). Petroleum Geology of the Anadarko Basin Region, Province (115), Kansas, Oklahoma, and Texas. USGS Open File report 88- 450W.

Bohnsack, D., Potten, M., Pfrang, D., Wolpert, P., & Zosseder, K., (2020). Porosity-permeability relationship derived from Upper Jurassic carbonate rock cores to assess the regional hydraulic matrix properties of the Malm reservoir in the South German Molasse Basin. Geotherm Energy 8:12

Brito, R., Davogustto, O., Djordjevic, O., Miceli, A., Quintero, J., & Sinclair J., (2021). Introduction to special section: The STACK play in Oklahoma. *Interpretation*; 9 (2): SEi-SEii.

Chen, Q., & Sidney, S., (1997). Seismic attribute technology for reservoir forecasting and monitoring. The Leading Edge, 16(5), 445-448.

Dai, Z., Viswanathan, H., Fessenden-Rahn, J., Middleton, R., Pan, F., Jia, W., Lee, S., McPherson, B., Ampomah, W., & Grigg, R., (2014). Uncertainty Quantification for CO2 Sequestration and Enhanced Oil Recovery. Energy Procedia, Volume 63, p. 7685-7693, ISSN 1876-6102.

Darling, T., (2005). Well Logging and Formation Evaluation, Gulf Professional Publishing, Elsevier, p. 326

DOE-NETL (U.S. Department of Energy – National Energy Technology Laboratory – Office of Fossil Energy), 2008. Carbon Sequestration Atlas of the United States and Canada, 2nd ed., http://www.netl.doe.gov/technologies/carbon seq/refshelf/atlas/

Droege, L. & Vick, H., (2018). Redefining the STACK Play from Subsurface to Commercialization: Identifying Stacked Pay Sweet Spots in the Northern Anadarko Basin. Search and Discovery 11104.

Drummond, K., (2018). Regional stratigraphy and proximal to distal variation of lithology and porosity within a mixed carbonate-siliciclastic system, Meramec and Osage series (Mississippian), central Oklahoma: M.S. thesis, University of Oklahoma, 165.

Eze, S., Orji, O. M., Nnorom, S. L., & Ubogun, K., (2019). Model Based Inversion of Acoustic Impedance from Seismic Trace for Lithofacies Differentiation: An Application in Xy Field Offshore Niger Delta. Journal of Applied Sciences and Environmental Management, 23(9), 1677-1684.

Gaymard, R., & Poupon, A., (1968). Response of neutron and formation density logs in hydrocarbon bearing formations: The Log Analyst, v.9, p. 3–12.

Goodman, A., Hakala A., Bromhal G., Deel D., Rodosta, T., Frailey, T., Small, M., Allen, D., Romanova, V., Fazio, J., Huerta, N., McIntyre, D., Kutchko, D., Guthrie, G., (2011). U.S. DOE methodology for the development of geologic storage potential for carbon dioxide at the national and regional scale, International Journal of Greenhouse Gas Control, 5 (2011), pp. 952-965.

Hampson, D.P., Schuelke J.S., Quirein J.A., (2001). Use of multiattribute transforms to predict log properties from seismic data. Geophysics 66(1):220–236. https://doi.org/10.1190/1.1444899

Haris, A., Novriyani, M., Suparno, S., Hidayat, R., & Riyanto, A., (2017). Integrated seismic stochastic inversion and multi–attributes to delineate reservoir distribution: Case study MZ fields, Central Sumatra Basin. In AIP Conference Proceedings, AIP Publishing, v.1862(1), p. 030180.

Herzog H., Drake E., Tester J., & Rosenthal R., (1993). A Research Needs Assessment for the Capture, Utilization, and Disposal of Carbon Dioxide from Fossil Fuel-Fired Power Plants, DOE/ER-30194, US Department of Energy, Washington, DC.

Herzog H., Drake E., & Adams E., (1997). CO_2 Capture, Reuse, and Storage Technologies for Mitigating Global Climate Change. A White Paper Final Report, DOE Order No. DE-AF22-96PC01257, Energy Laboratory, Massachusetts Institute of Technology.

Hickman, G., (2018). Parasequence-scale stratigraphic variability of lithology and porosity of Mississippian Meramec reservoirs and the relationships to production characteristics, STACK trend, Oklahoma: M.S. thesis, University of Oklahoma, 105.

Hoffman, B.T., (2019). Enhanced Oil Recovery in Unconventional Reservoirs. 81st EAGE Conference & Exhibition 2019, 3-6 June 2019, London, UK.

Hugman, R.H., & Vidas, F.H., (1987). Oil and gas resources of the Mid-continent region: Energy and Environmental Analysis, Incorporated, Arlington, VA, p. 140.

Johnson, K.S., (1988). Geologic evolution of the Anadarko Basin; In Anadarko Basin Symposium, 1988; Johnson, K.S., ed.: Oklahoma Geological Survey Circular 90, p. 3-12.

Jordan, L., & Rowland, T.L., (1959). Mississippian Rocks in Northern Oklahoma: Symposium of the Mississippian of Oklahoma and Kansas: Tulsa Geological Digest, 1959, v. 27, part III, p. 124-136.

Levine, J. S., Fukai, I., Soeder, D. J., Bromhal, G., Dilmore, R. M., Guthrie, G. D., Rodosta, T., Sanguinito, S., Frailey, S., Gorecki, C., Peck, W., & Goodman, A. L., (2016). US DOE NETL methodology for estimating the prospective CO_2 storage resource of shales at the national and regional scale. International Journal of Greenhouse Gas Control, 51, 81-94.

Lucia F.J., (2007). Carbonate reservoir characterization: an integrated approach. Berlin: Springer

Maurya, S. P., & Singh, K. H., (2019). Predicting porosity by multivariate regression and probabilistic neural network using model-based and coloured inversion as external attributes: a quantitative comparison. Journal of the Geological Society of India, 93(2), 207-212.

Miller, M.J., Pranter, M.J., Gupta, I., Devegowda, D., Marfurt, K.J., Sondergeld, C., Rai, C., McLain, C.T., Packwood, J. & Larese, R.E., (2021). Mississippian Meramec lithologies and petrophysical property variability, STACK trend, Anadarko Basin, Oklahoma. *Interpretation*, *9*(2), pp.SE1-SE21.

Neely, W., Ismail, A., Ibrahim, M., & Puckette, J., (2020). Seismic-based characterization of reservoir heterogeneity within the Meramec interval of the STACK play, Central Oklahoma. Interpretation 9(1): 1-46.

NETL (2015) Carbon Storage Atlas, 5th Edition, National Energy Technology Laboratory.

Oliveira, M.R., Ribeiro, N., Johann, P.R., Camarao, L.F., Steagall, D.E., Kerber, P., & Carvalho, M.J., (2005). Using seismic attributes to estimate porosity thickness in “pinch-out” areas. In: SPE Latin American and Caribbean petroleum engineering conference, 20–23 June, Rio de Janeiro, Brazil. https://doi.org/10.2118/94913-MS

Ogagarue, D. O., (2016). A Comparative Study of Acoustic and Elastic Impedance Seismic Models for Rock Property Prediction: An Example from XYZ Field, Nigeria. International Journal of Sciences: Basic and Applied Research (IJSBAR), 26(3), 24-34.

Pendrel, J., (2006). Seismic inversion–a critical tool in reservoir characterization. Scandinavian oil–gas magazine, v.5(6), pp.19–22.

Perry, W. J. Jr., (1989). Tectonic evolution of the Anadarko basin region, Oklahoma. In: U.S. Geological Survey bulletin 1866-A, A multidisciplinary approach to research studies of sedimentary rocks and their constituents and the evolution of sedimentary basins, both ancient and modern.

Price, B., Haustveit, K., & Lamb, A., (2017). Influence of stratigraphy on barriers to fracture growth and completion optimization in the Meramec Stack Play, Anadarko Basin, Oklahoma. In Unconventional Resources Technology Conference, Austin, Texas, 24-26 July 2017 (pp. 3453-3460). Society of Exploration Geophysicists, American Association of Petroleum Geologists, Society of Petroleum Engineers.

Price, B. J., Pollack, A. C., Lamb, A. P., Peryman, T. C., & Anderson, J. R., (2020). Depositional interpretation and sequence stratigraphic control on reservoir quality and distribution in the Meramecian Sooner trend Anadarko Basin, Canadian and Kingfisher Counties (STACK) play, Anadarko Basin, Oklahoma, United States: AAPG Bulletin, 104, 357–386, doi: 10.1306/04301917411.

Serra, O., (1984). Fundamentals of Well-Log Interpretation (Vol. 1): The Acquisition of Logging Data: Dev. Pet. Sci., 15A: Amsterdam (Elsevier).

Shelley, S., Grammer, G. M., & Pranter, M. J., (2017). Reservoir Characterization and Modeling of a Subsurface Meramec Analog from a Quarry in Northeastern Oklahoma. Oklahoma City Geological Society – The Shale Shaker, September-October 2017, p. 224-243.

Soleimani, F., Hosseini, E., & Hajivand, F., (2020). Estimation of reservoir porosity using analysis of seismic attributes in an Iranian oil field. Journal of Petroleum Exploration and Production Technology. 10. 1-28. 10.1007/s13202-020-00833-4.

United States Department of Energy (U.S. DOE), (2008). Carbon Sequestration Atlas of the United States and Canada, Pittsburg, PA, National Energy and Technology Laboratory (NETL) -, 2015, Carbon Storage Atlas, National Energy Technology Laboratory (NETL), Office of Fossil Energy, v. 5

Wang, Y., (2019). Sequence Stratigraphy, Fracture Characterization, and Rebound Hardness Analysis of the Unconventional "Mississippian Limestone"/Stack Play, North-central Oklahoma, USA (Doctoral dissertation, Oklahoma State University).

Watson, R.T., Zinyowera, M.C., & Moss R.H., (1996). Climate Change 1995 - Impacts, Adaptations and Mitigation of Climate Change: Scientific-Technical Analyses, Contribution of Working Group II to the Second Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press.

VITA

Victor Oluwaseun Fakeye

Candidate for the Degree of

Master of Science

Thesis: 3D MODEL-BASED INVERSION FOR ONSHORE CO_2 STORAGE IN THE OSAGEAN AND MERAMECIAN STRATA OF STACK PLAY, ANADARKO BASIN

Major Field: Geology

Biographical:

Education:

Completed the requirements for the Master of Science in Geology at Oklahoma State University, Stillwater, Oklahoma in December, 2022.

Completed the requirements for the Bachelor of Technology in Applied Geology at the Federal University of Technology Akure, Ondo State, Nigeria in 2019.

Experience:
Graduate Research and Teaching Assistant, Boone Pickens School of Geology, Oklahoma State University, Stillwater OK (Jan. 2021 – Dec. 2022)
Graduate Summer Intern, Lawrence Livermore National Laboratory, California (May 2022 – August 2022)
Graduate Research Assistant, Department of Geology, Akwa Ibom State University, Nigeria (April 2020 – Dec. 2020)

Professional Memberships:
Society of Exploration Geophysicists (SEG)
Geological Society of America (GSA)
National Association of Black Geoscientists (NABG)
American Association of Petroleum Geologists (AAPG)
American Institute of Professional Geologists (AIPG)