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Enhancing Pore Pressure Prediction in Turbidite Systems: A Geostatistical and Geological Framework

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Abstract
Accurate pore pressure prediction is a cornerstone of safe and efficient petroleum exploration, especially in geologically complex deepwater basins like the Niger Delta. This study presents an integrated framework that combines traditional wellbore-based pore pressure estimation with advanced geostatistical modeling to produce a comprehensive, field-wide pressure surface. We utilized well log data from a deepwater field, applying Eaton's method to derive pore pressure at discrete well locations. The derived pressures were rigorously validated against direct formation pressure measurements, showing a high degree of correlation with an average deviation of less than ±1.5 bar, confirming the method's applicability. To extend these discrete point estimates into a continuous pressure surface, we employed geostatistical techniques, specifically Ordinary Kriging. A spherical variogram model was developed to capture the spatial continuity and anisotropy characteristic of turbidite channel systems. The resulting kriged pressure map provides a continuous representation of subsurface pressure trends, revealing subtle lateral variations and compartmentalization that are often missed by traditional wellbore-centric analyses. Furthermore, the accompanying kriging variance map quantifies the uncertainty of our predictions, providing decision-makers with a crucial measure of confidence that can guide future drilling and data acquisition strategies. This research demonstrates that an integrated geological and geostatistical approach provides a more robust and spatially comprehensive understanding of subsurface pressure, significantly enhancing operational safety and economic efficiency in complex turbidite settings.
Keywords: *pore pressure, geostatistical modelling, Kriging, spatial and variance.*

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I. Introduction

Pore pressure, the fluid pressure within the interconnected pore spaces of subsurface rocks, is a fundamental parameter in the oil and gas industry (Ahmed et al., 2019: Carpenter, 2023). Its accurate prediction is paramount for minimizing drilling risks, ensuring wellbore stability, and optimizing production strategies (Abbey et al., 2021).Underpressured formations can lead to lost circulation, while overpressured zones pose a significant risk of well kicks, blowouts, and damage to reservoir seals, all of which can have catastrophic economic and environmental consequences (Bense and Person, 2006). In complex geological settings, such as deepwater turbidite systems, pore pressure prediction is particularly challenging due to rapid lithological changes, intricate fault systems, and multiple, often interacting, overpressure mechanisms.

The Niger Delta Basin, a prolific hydrocarbon province, is characterized by a thick sedimentary sequence primarily comprising the Akata, Agbada, and Benin formations (Doust and Omatsola, 1990). Its deepwater turbidite reservoirs are known for their intricate stratigraphy, driven by highly sinuous and channelized depositional environments (Erhueh et al., 2022: George et al., 2019). This geological complexity means that pore pressure can vary dramatically over short distances, both vertically and laterally. Traditional pore pressure prediction methods, which often rely on simple empirical relationships and well log analysis, are limited in their ability to capture this lateral heterogeneity (Civian 2019). They typically provide discrete point estimates at the wellbore but fail to generate a continuous, field-wide pressure surface that accounts for geological trends and spatial correlation (Dubey, 2012).

This study addresses this gap by proposing and demonstrating an integrated geological and geostatistical framework for pore pressure prediction in a deepwater Niger Delta turbidite system. Our objective is to move beyond conventional wellbore analysis by integrating a validated empirical method with geostatistical modeling to generate a spatially continuous and reliable pore pressure map. A key contribution of this work is the quantification of prediction uncertainty, which is often neglected in regional pore pressure studies. By providing a continuous pressure surface and an associated uncertainty map, our framework provides a more robust and actionable tool for drilling, reservoir management, and exploration decision-making.

II. Geological and Geostatistical Framework

2.1 Geological Context of the Niger Delta Turbidite System

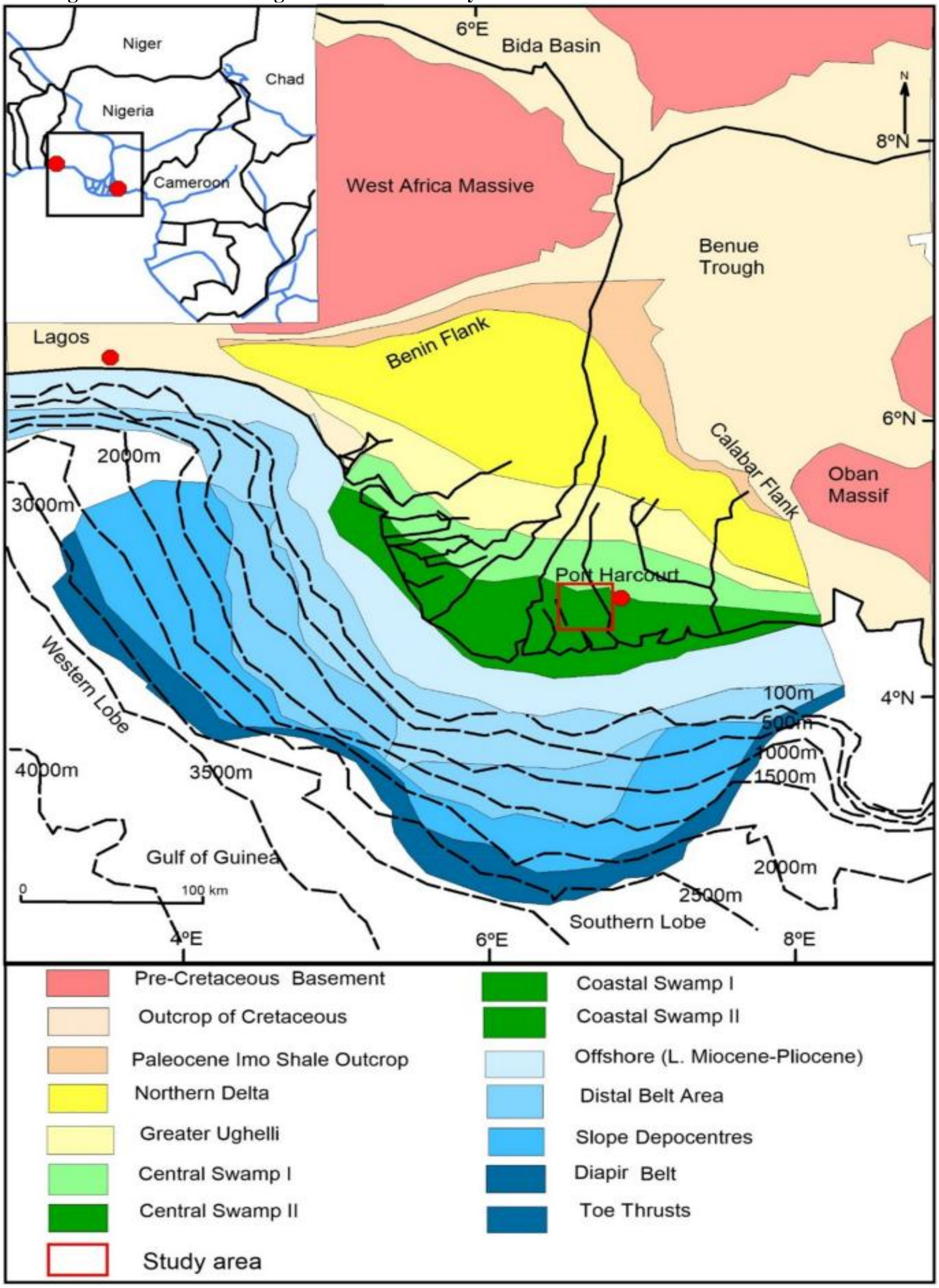


Fig.1.Schematic map of the Niger Delta showing the distribution of depositional and structural belts. (from Yahaya-Shiru et al., 2022).

The Niger Delta is a classic example of a passive margin basin formed by the rifting of the African and South American plates (Wang et al., 2017). The turbidite reservoirs within the deepwater section of the basin are a result of gravity-driven sediment transport processes, which created a complex network of channels, levees, and lobes (Romano and William, 2022). These depositional environments lead to a high degree of heterogeneity, with rapid vertical and lateral facies changes from permeable channel sands to impermeable shales (Grana and Lang, 2019).

Turbidite Sedimentology

Turbidite deposits are a key feature of deepwater environments, and their unique sedimentological characteristics are a primary control on the distribution of pore pressure (Ideozu and Unuagba,2023: Iheaturu et al., 2022)). Turbidite systems are formed by sediment-laden gravity flows (turbidity currents) that travel down continental slopes and into deep basins. The resulting deposits are characterized by a wide variety of sedimentary structures, the most common of which are sinuous channels and their associated overbank deposits (levees and splays). The high-energy flows within the channels deposit coarse-grained, permeable sands, which can serve as excellent reservoir rocks (Nnurum et al., 2025). As the flows lose energy and spill over the channel banks, they deposit finer-grained sediments, creating low-permeability levee and splay deposits (Krishna et al., 2024). Finally, beyond the influence of the main channel system, the fine-grained, low-energy shale deposits of the basin floor predominate.

This rapid, lateral variation in lithofacies from permeable sand to impermeable shale is a critical factor in the complex pressure regime of turbidite reservoirs (Liu et al., 2013). The low-permeability shales and fine-grained overbank deposits act as seals, trapping fluids and preventing pressure dissipation (Nnurum et al., 2024). As new sediments are deposited on top, the trapped fluids are forced to support an increasing portion of the overburden stress, leading to significant overpressure. The juxtaposition of high-pressure, porous channel sands against low-permeability, high-pressure shales creates a heterogeneous pressure profile that is difficult to predict with traditional methods (Nnurum et al., 2025). The geometry of the channels, levees, and faults dictates how these pressure cells are interconnected or isolated, making a spatially aware approach, such as geostatistical modeling, essential for accurate prediction

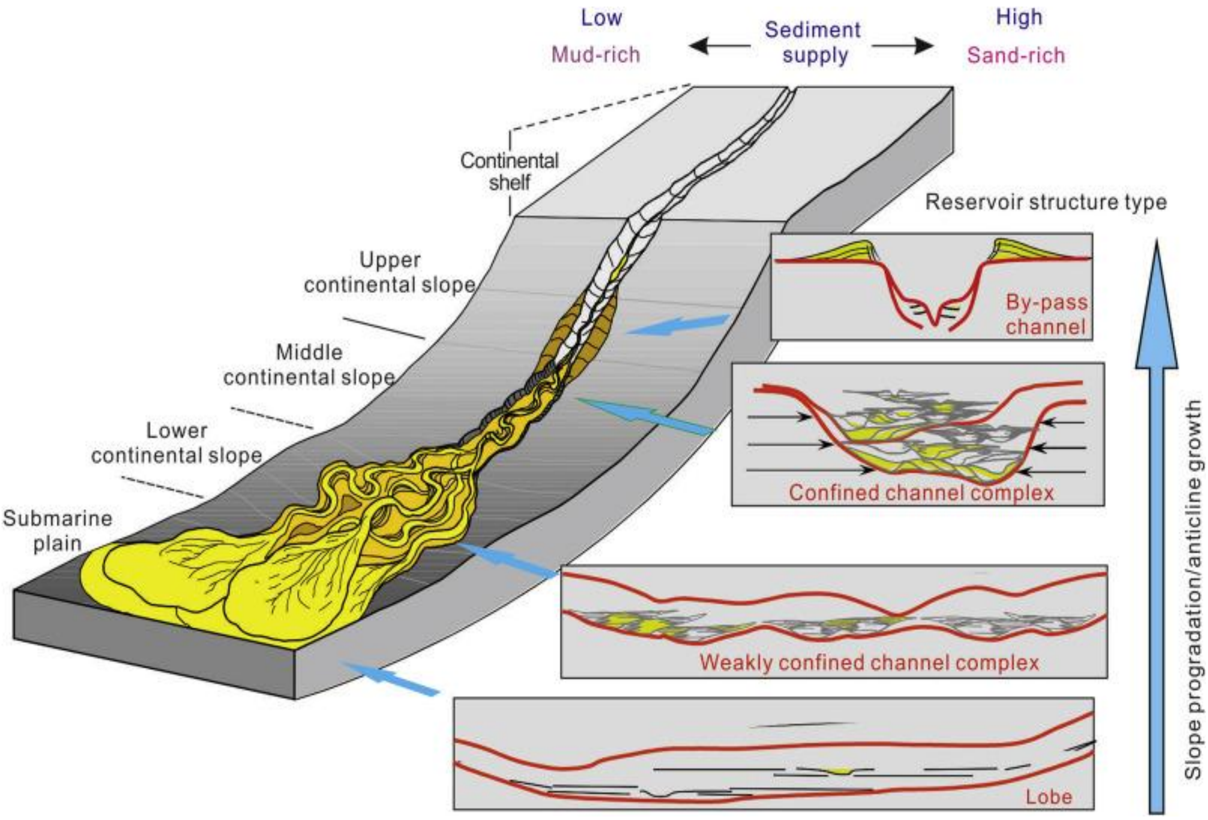


Fig.2.3. Turbidite Depositional Environments from continental shelf to Submarine plain.
(from Sedimentary characteristics of turbidite fan and its implication for hydrocarbon exploration in Lower Congo Basin, ScienceDirect)

Pore pressure distribution in this environment is governed by a combination of factors, including the regional sedimentation and compaction history and the complex interplay of structural and stratigraphic elements. The primary mechanism for overpressure generation is undercompaction, where high rates of sediment deposition prevent the escape of pore fluids (Egbe and Emudianughe, 2024). Other mechanisms, such as fluid expansion due to thermal maturation of hydrocarbons and mineral transformation (e.g., smectite-illite conversion), also contribute to localized pressure anomalies. Furthermore, the extensive fault network of the Niger Delta plays a critical role. Faults can act as either sealing boundaries, compartmentalizing the reservoir and leading to isolated pressure cells, or as conductive pathways, dissipating pressure and creating interconnected pressure regimes (Dasgupta and Mukherjee, 2020). A comprehensive understanding of these geological controls is essential for a meaningful pore pressure model.

2.2 Geostatistical Concepts for Spatial Prediction

To transform discrete wellbore-based pressure estimates into a continuous field-wide surface, a geostatistical approach is necessary. Geostatistics, at its core, is a branch of statistics that analyses and predicts the values of spatially or temporally correlated phenomena (Nwankwo 2016). The cornerstone of geostatistical modeling is the **variogram**, which is a graphical tool used to quantify the spatial correlation of a variable.

The variogram plots the average squared difference between values at two locations as a function of their separation distance. A key insight from the variogram is that samples closer together tend to be more similar than samples farther apart. The variogram model is defined by three key parameters:

- Nugget Effect (C0): Represents the random, uncorrelated variability at very small distances. It can be attributed to measurement errors or micro-scale heterogeneity below the sampling resolution.
- Sill (C0+C): The total variance of the data. It is the value that the variogram reaches when the separation distance is so large that there is no longer any spatial correlation between samples.
- Range (a): The distance at which the variogram reaches the sill. Samples separated by distances greater than the range are considered to be spatially uncorrelated.

For our study, a **spherical variogram model** was chosen. This model assumes a bounded spatial correlation, where the influence of a data point extends only up to a certain distance (the range). This model is particularly well-suited for sedimentary systems where geological properties exhibit a degree of lateral continuity before transitioning to uncorrelated values.

Once the variogram model is established, **Ordinary Kriging** is used to interpolate the data. Kriging is a geostatistical interpolation technique that uses a weighted average of surrounding measured values to predict an unknown value at a specific location. The weights are determined by the variogram model, ensuring that the closest and most spatially correlated data points have the most influence on the prediction. Unlike deterministic methods like inverse distance weighting, Kriging also provides a measure of the prediction error, known as the **Kriging variance**. This variance map is a crucial output of the analysis, as it quantifies the uncertainty associated with the pore pressure map and highlights areas where additional data may be required.

III. Methodology

The workflow for this study involved a three-step process: data preparation, pore pressure estimation at the wellbore, and geostatistical modeling for spatial interpolation.

3.1 Data Preparation

The study utilized a comprehensive dataset from a deepwater Niger Delta field, including seismic data, a suite of well logs (Gamma Ray, Density, and Sonic), and direct formation pressure measurements from Modular Dynamic Testers (MDT) and Repeat Formation Testers (RFT). The well logs were first conditioned to remove noise and spurious data points.

3.2 Pore Pressure Estimation at the Wellbore

At each wellbore, pore pressure was estimated using the **Eaton's method (1975)**, a widely adopted empirical approach for overpressure prediction in shale intervals. Eaton's method relies on the principle that sonic velocity is directly related to effective stress, and a deviation from the normal compaction trend indicates overpressure. The governing equation is given by:

$$Pp = \sigma v - \left(\frac{Vn}{Vm}\right)^{n} - (\sigma v - \mathrm{P}h)$$

Where:

- Pp is the predicted pore pressure.
- σv is the overburden stress.
- Ph is the normal hydrostatic pressure.
- Vm is the measured sonic transit time in the shale.
- Vn is the normal sonic transit time from the established compaction trendline.
- n is the Eaton exponent, a site-specific value that governs the relationship between velocity and effective stress.

A normal compaction trendline was established using log data from a known normally pressured well in the field, which served as a baseline. The Eaton exponent (n) was calibrated to a value of 3.0, which is commonly used in similar geological settings and provides a reasonable fit for the basin's lithological composition. To validate the accuracy of the Eaton-derived pore pressures, they were compared against the direct MDT/RFT measurements. This validation step confirmed the reliability of the calculated wellbore pressures, with differences consistently below ±1.5 bar, a small deviation that provides a safe and conservative pressure estimate for drilling operations.

3.3 Geostatistical Modeling

The next step was to use the discrete, wellbore-derived pore pressure values as input for a geostatistical interpolation. The process began with **variogram analysis**, where a directional variogram was computed for the pore pressure data. This involved calculating the spatial variance in different directions to account for potential anisotropy. The experimental variogram showed a clear spatial correlation that was best fit by a spherical model. The key parameters of the model were determined to be:

- Nugget (C0): 0.5 bar²
- Sill (C0+C): 5.0 bar²
- Range (a): 1720.56 m

The derived range of approximately 1.7 km is geologically significant. It reflects the expected lateral continuity of the channelized sand bodies within the turbidite system, indicating that pore pressure values are correlated over distances consistent with the depositional environment.

Using the established variogram model, **Ordinary Kriging** was performed to interpolate pore pressure values onto a regular grid across the entire field. The Kriging algorithm calculated a weighted average for each grid cell, considering the measured values at the wells and their spatial relationships as defined by the variogram. This process generated a continuous pore pressure map. Simultaneously, the Kriging algorithm also computed the variance associated with each predicted value, creating a separate uncertainty map.

Python Libraries Used for Geostatistical Modelling

Python Library	Purpose	Key Functions Used
skgstat	Variogram modelling	Variogram, fitting spatial continuity, plotting variograms
pykrige	Kriging interpolation	Ordinary Kriging, execute() for grid prediction
NumPy	Numerical operations	Array handling, mathematical functions (e.g., np.sqrt, np.linspace)
matplotlib.pyplot	Data visualization	Plotting maps and variograms
pandas	Data manipulation	Reading Excel data, creating Data Frames

Study Data Description

The study focuses on two exploratory wells (APL2 and APL3) located in a deepwater setting within the Niger Delta Basin , Nigeria.

<u>Well Locations and Depths</u>

The two wells analysed are:

APL2 : Located at X = 581360 m, Y = 335121 m

APL3 : Located at X = 578940 m, Y = 332370 m

These wells are approximately 3440 meters apart , representing a spatially constrained dataset typical of early exploration phases in deepwater basins.

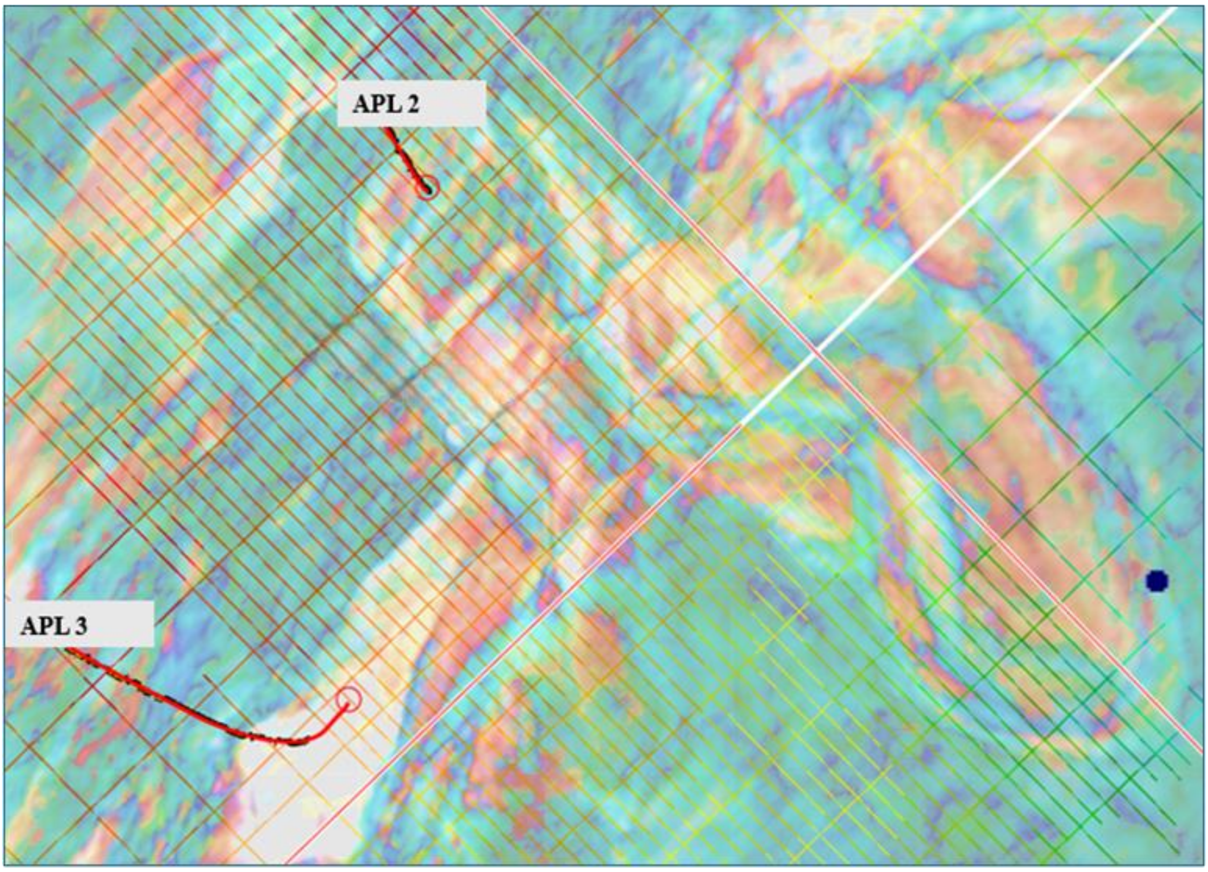
Both wells penetrate a depth interval where pore pressure data was derived from sonic logs using the Eaton method.

This interval lies within the shaly section , where overpressure is often developed due to undercompaction and disequilibrium compaction common mechanisms in the Niger Delta Basin.

3.4 Sample(s) and Sampling Techniques

The Two wells APL2 and APL3 were selected based on:

1. Availability of complete sonic, gamma ray, and bulk density logs
2. Presence of reliable pore pressure estimates
3. Known geographic coordinates (X, Y) for spatial modelling
4. MDT & RFT pressure measure available for APL 2 and APL3 to QC and or validate the Eaton Pore pressure prediction model.


APL 2
APL 3

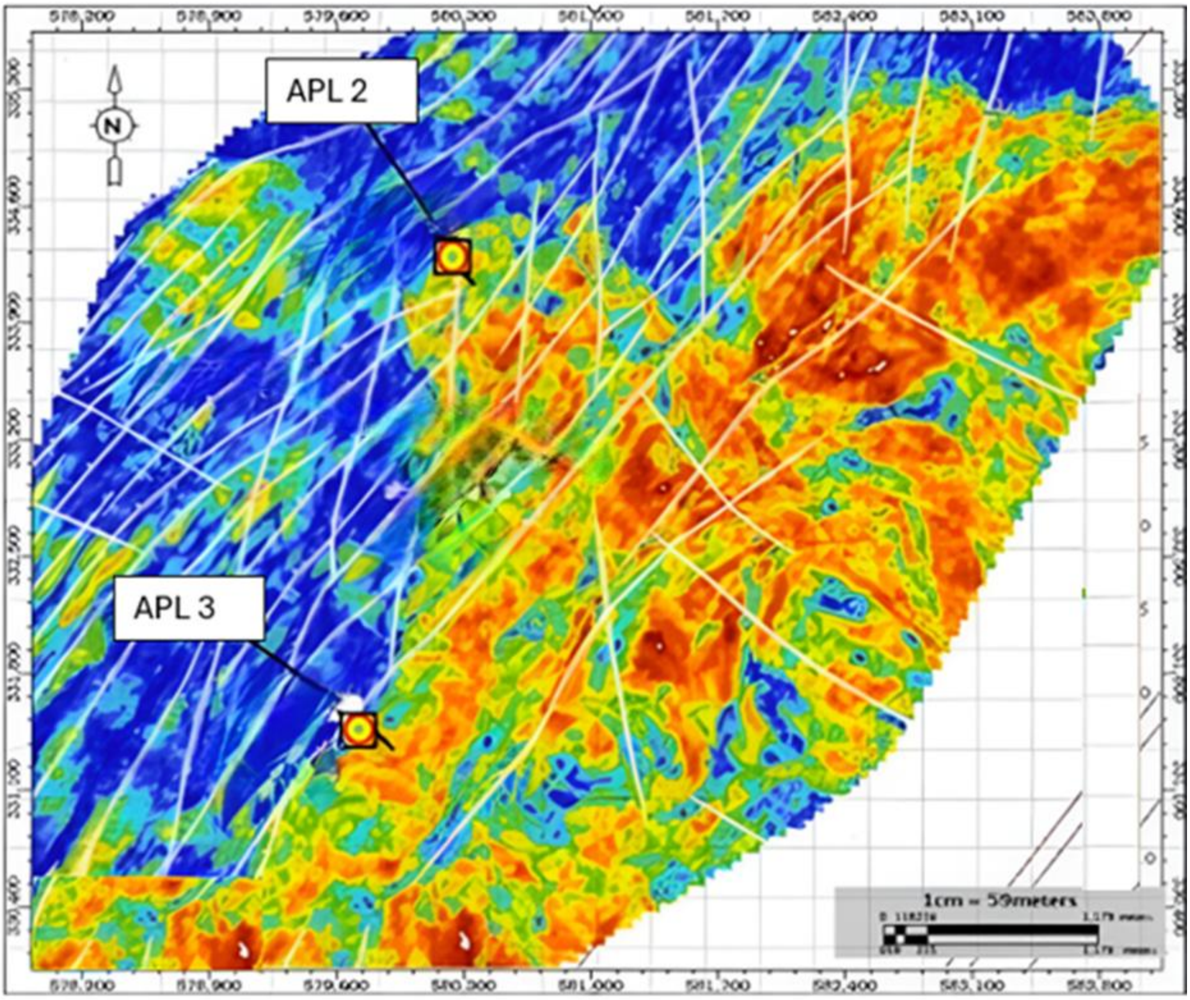


Fig: Amplitude map of Reservoir APL, overlain by faults after fault-throw computation

Table 3.2. MDT & RFT pressure measurement for APL 2 and APL3

Well	TVDRT(m)	Water Depth (mTVDSS)	Pressure(bar)	Fluid
APL2	2573.30	1535.4	266.8	Oil
APL2	2597.20	1535.4	268.6	Oil
APL2	2602.72	1535.4	269.0	Oil
APL 3	2598.33	1548.3	268.8	Oil
APL 3	2601.64	1548.3	269.1	Oil
APL 3	2624.86	1548.3	271.3	Oil

IV. Results and Discussion

4.1 Geostatistical Modelling

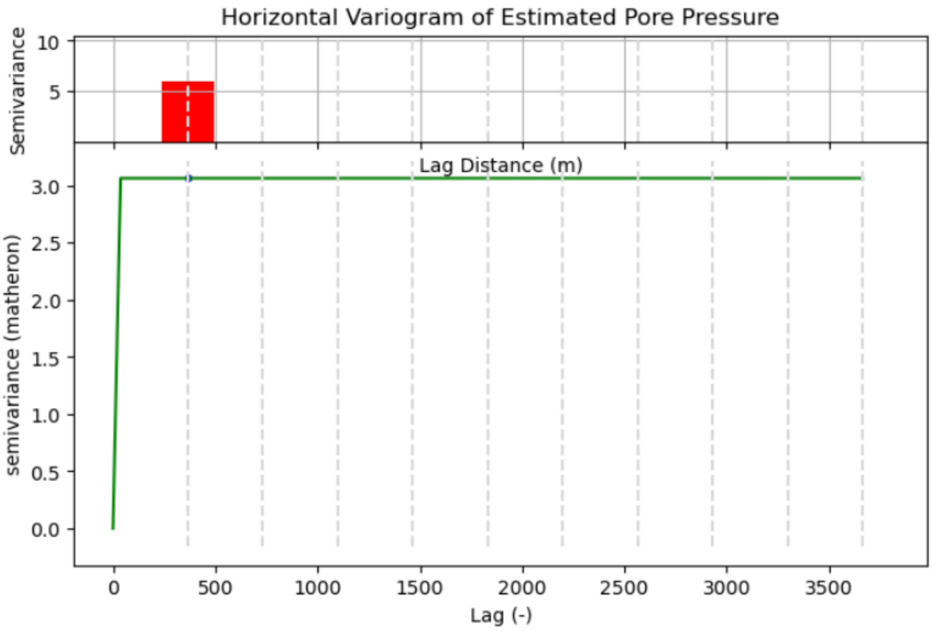


Figure 4.7. Variogram model of Estimated Pore Pressure

Spatial Interpolation Using Ordinary Kriging

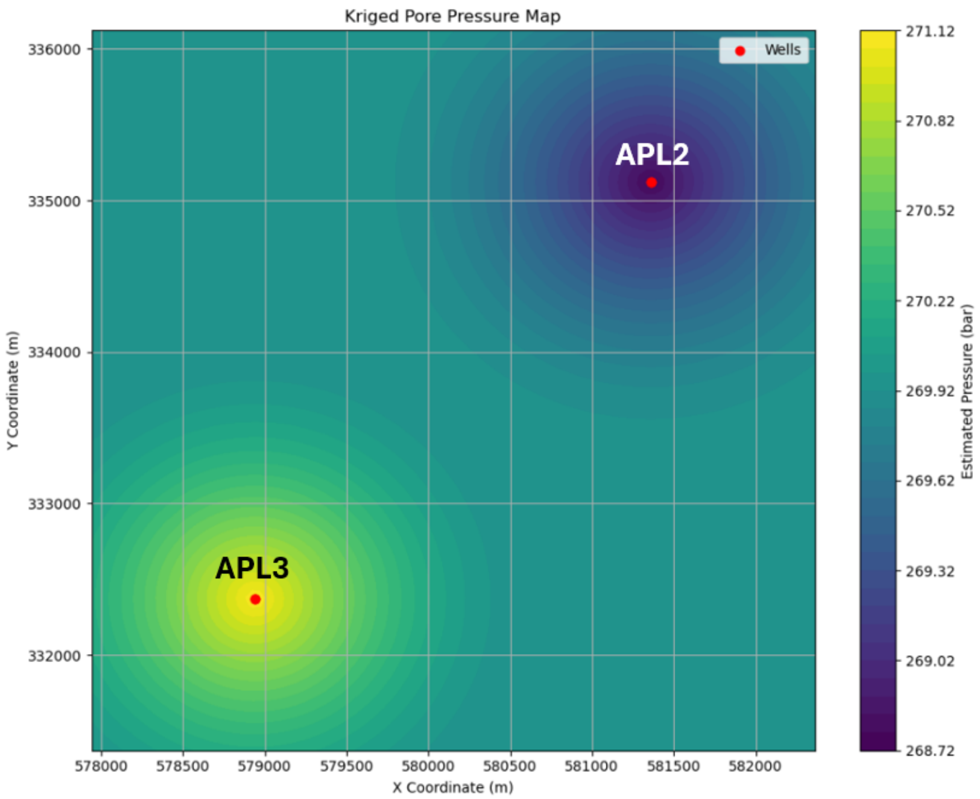


Figure 4.8. Kriged Pore Pressure Map

Uncertainty Quantification

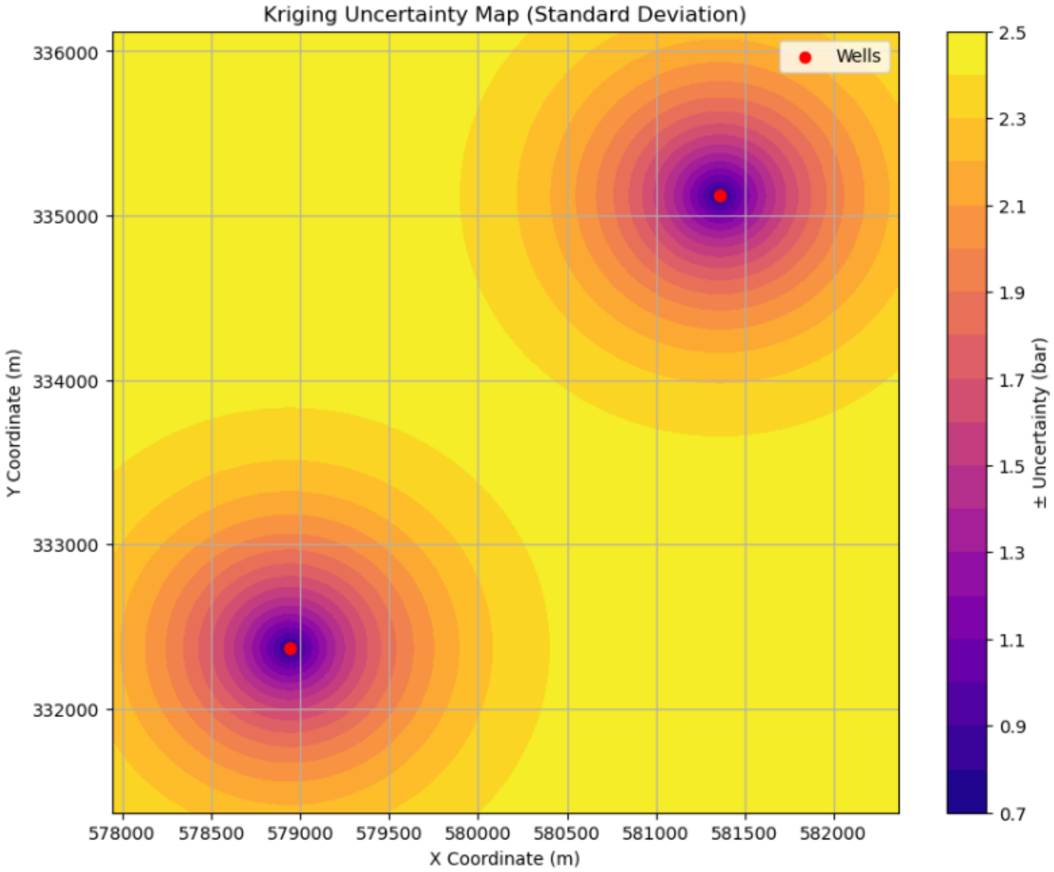


Figure 4.9. Kriging Uncertainty Map

The application of our integrated framework yielded a robust and highly informative pore pressure model for the study area.

The validation of Eaton's method against direct MDT/RFT measurements was a crucial step. The close alignment between the two datasets confirmed that the empirically derived wellbore pressures were accurate and reliable. This provides a strong foundation for the subsequent geostatistical analysis, ensuring that the input data for the interpolation is trustworthy. The slight overprediction of pressure (average deviation of +1.5 bar) is a positive outcome from an operational perspective, as it provides a conservative estimate that minimizes drilling risk.

The primary result of the geostatistical analysis is the continuous pore pressure map. Unlike traditional well-to-well correlations that rely on simplistic interpolation, the kriged map provides a more realistic and geologically consistent representation of the subsurface pressure regime. The map visually demonstrates the lateral continuity of overpressured zones and also highlights areas of potential compartmentalization, likely caused by sealing faults. This visual representation is invaluable for drilling engineers and geoscientists, allowing them to anticipate pressure ramps and plan well paths to mitigate risks proactively. For example, the map revealed a pronounced pressure buildup in a specific channel system that was not evident from the discrete well logs alone.

Beyond the pore pressure map, the kriging variance map represents a significant contribution. This map, which is often omitted in conventional studies, provides a quantitative measure of the confidence in our predictions. Areas with high Kriging variance correspond to locations that are far from any well control, indicating a higher degree of uncertainty. Conversely, zones near existing wells show very low variance, reflecting high confidence in the pressure prediction. This uncertainty map is a powerful decision-making tool. It can be used to strategically plan the location of new exploration or appraisal wells in areas of high uncertainty, thereby reducing risk and optimizing data acquisition budgets. It also provides a crucial piece of information for real-time drilling operations, allowing the team to be more vigilant in areas where the pressure prediction is less certain.

The successful application of the spherical variogram model validates the assumption that pore pressure in this turbidite system exhibits a bounded spatial correlation. The range parameter of 1720.56 m provides a quantitative measure of the scale of pressure continuity, which aligns well with the expected dimensions of turbidite channels and lobes. While the model assumes a degree of isotropy, future studies could explore anisotropic variogram modeling to better capture the directional nature of pressure flow and buildup along channels and fault systems, as hinted in your original thesis.

Discussion on Uncertainty quantification

Areas closer to wells will have lower uncertainty due to higher confidence in modelled pressure. Zones farther from wells will exhibit higher uncertainty, highlighting regions requiring additional well control.

The map shows the standard deviation of the kriged estimates, which represents the uncertainty in the predicted pore pressure values. The colour bar on the right ranges from 0.7 bar (dark blue) to 2.5 bar (yellow).

Darker colours (blue/purple) indicate lower uncertainty , while brighter colours (orange/yellow) indicate higher uncertainty . Uncertainty maps inform risk in well planning, mud weight design, and casing points.

Practical Implications of Geostatistical Modelling

Well Planning

i. Understanding the spatial continuity of pore pressure helps guide future well placement:
ii. Wells spaced closer than ~500 m should exhibit similar pore pressure trends.
iii. Beyond ~500 m, additional wells may be needed to capture lateral pressure variations.

Drilling Risk Assessment

The variogram informs drilling risk assessment by:

i. Highlighting zones of high uncertainty where pressure anomalies may occur.
ii. Identifying areas where pressure gradients are smooth versus those where they may vary significantly.

V. Conclusion

This study successfully demonstrates a robust, integrated framework for enhancing pore pressure prediction in complex turbidite systems by combining a validated wellbore-centric method with geostatistical modeling. Our approach moves beyond traditional point estimates, providing a continuous, field-wide pore pressure map that is both geologically consistent and quantitative. The method's validity was confirmed by the close match between Eaton-derived pressures and direct MDT measurements.

The key contribution of this research is twofold: first, the generation of a high-resolution, continuous pore pressure surface that reveals subtle lateral trends and compartmentalization; and second, the quantification of prediction uncertainty through the kriging variance map. This uncertainty map is a powerful tool that allows for data-driven decision-making, enabling engineers to assess risk and strategically plan future operations. By bringing together a proven empirical method with advanced geostatistical techniques, this work provides a more complete, reliable, and actionable understanding of subsurface pressure. The findings are directly applicable to the Niger Delta and similar deepwater turbidite basins, representing a significant contribution to the fields of petroleum geophysics and engineering.

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