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Digital Rock Physics Assessment of Reservoir Quality from Ditch Cuttings Using SEM-Derived Porosity Analysis of D1 Sandstones in the *Inneh* Field, Niger Delta, Nigeria

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Abstract

Conventional core analysis remains the most reliable basis for calibrating reservoir properties, yet full-core acquisition is commonly restricted by cost, operational risk and limited interval coverage, particularly in offshore fields. This study restructures and advances a Digital Rock Physics approach for evaluating reservoir quality from ditch cuttings obtained from the D1 reservoir interval of the "Inneh" Field, offshore southeastern Niger Delta, Nigeria. The work applies scanning electron microscopy, 2D image segmentation, and pore-area-based porosity estimation to representative ditch cutting samples from "Inneh"-1, "Inneh"-7 and "Inneh"-10. The central objective is to test whether ditch cuttings, when processed through a controlled SEM-based workflow, can provide reservoir-quality information consistent with conventional log-derived porosity. The analyzed samples show quartz-rich sandstone fabrics with partially fractured grains, open intergranular pores, secondary pore features and locally infilled pore spaces. Image analysis yielded SEM-derived porosity values of 34.8%, 34.9% and 37.5% for "Inneh"-1, "Inneh"-7 and "Inneh"-10, respectively, compared with log-derived porosity values of 32.0%, 37.0% and 36.0%. The absolute differences range from 1.5 to 2.8 percentage points, with a mean absolute error of 2.13 percentage points, a root mean square error of 2.20 percentage points and a mean absolute percentage error of 6.20%. Although the small sample size limits statistical correlation, the close absolute agreement supports the use of SEM-derived porosity as a screening and validation tool where conventional cores are unavailable. The study demonstrates that ditch cuttings retain meaningful pore-scale information and can supplement formation evaluation workflows in clastic reservoirs. The applied workflow provides a practical, cost-conscious route for integrating readily available drilling materials into preliminary reservoir characterization, while recognizing the need for larger sample populations, core calibration, and three-dimensional imaging before pore connectivity or field-scale reservoir behavior can be evaluated for full field-scale validation.

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1.0 Introduction

Accurate reservoir characterization is fundamental to hydrocarbon exploration, reserve evaluation, field development and production optimization. The commercial behavior of a reservoir is controlled not only by the presence of hydrocarbons but also by the geometry, continuity and connectivity of the pore system that stores and transmits fluids. In conventional reservoir studies, core analysis remains the most direct method for evaluating porosity, permeability, capillary behavior, mineralogy, wettability and pore architecture. Core plugs provide physical measurements that can be used to calibrate well logs and reservoir models (Harry et al., 2022a; 2022b). However, conventional core acquisition is expensive, time consuming and typically restricted to selected intervals, while many exploration and development wells are drilled without adequate core recovery. This limitation is particularly important in offshore fields, where coring decisions are strongly influenced by rig time, operational risk and economics.

The growing need for cost-effective and higher-resolution reservoir characterization has driven the development of Digital Rock Physics. Digital Rock Physics integrates imaging, image processing, numerical analysis and petrophysical interpretation to estimate rock properties from digital representations of pore systems. The method has expanded from early micro-computed tomography applications to workflows that include scanning electron microscopy, focused ion beam SEM, thin-section scanning, pore-network modeling and increasingly machine-learning-assisted segmentation. The value of this approach lies in its ability to link pore-scale features to macroscopic properties such as porosity, permeability and flow behavior. Digital representations of rock fabrics can provide insight into pore shape, pore size, pore distribution, and cementation patterns that are not fully captured by routine well logs. However, quantitative assessment of tortuosity and connectivity requires three-dimensional imaging or pore-network extraction, which is beyond the scope of the present 2D SEM-based study.

Ditch cuttings represent one of the most widely available but historically underused materials in petroleum geology. They are generated continuously during drilling, transported to the surface by drilling fluids and routinely collected for lithological description. Unlike conventional cores, which are collected only from selected intervals, ditch cuttings can provide geological material across much of the drilled section. Their availability makes them attractive for reservoir screening, especially in data-limited fields. Nevertheless, their quantitative use has long been viewed with caution because cuttings may be contaminated by drilling mud, mixed with cavings from shallower depths, mechanically altered during drilling and affected by depth uncertainty during transport. These concerns have generally confined ditch cuttings to qualitative descriptions rather than quantitative petrophysical interpretation.

Recent advances in imaging and image analysis provide a route for reassessing the role of ditch cuttings in reservoir characterization. Scanning electron microscopy (SEM) can reveal the microstructure of small rock fragments at magnifications that permit direct observation of pore spaces, grain contacts, microfractures, clay coatings and cementation. When SEM imaging is combined with image segmentation, pore area can be separated from mineral framework and quantified. The resulting image-derived porosity can then be compared with independent measurements from well logs or core analysis. This comparison is essential because the practical value of any ditch-cuttings workflow depends on whether the measured microstructural properties correspond meaningfully to reservoir-scale petrophysical behavior (Harry et al, 2017a; 2017b).

The “Inneh” Field in the southeastern offshore Niger Delta provides a useful case for testing such a workflow. The D1 reservoir interval is a sandstone-rich section of the upper Agbada

Formation that has already been evaluated petrophysically using wireline logs. Samples from “Inneh”-1, “Inneh”-7 and “Inneh”-10 allow a direct comparison between SEM-derived porosity and log-derived porosity from the same reservoir interval. This study therefore addresses a specific methodological question: can SEM-based Digital Rock Physics applied to ditch cuttings produce porosity estimates that are consistent enough with conventional formation evaluation results to support reservoir-quality assessment?

The research gap is clear. Digital Rock Physics studies commonly rely on conventional core plugs, micro-CT volumes or carefully prepared laboratory specimens, whereas fewer studies have tested the quantitative reliability of ditch cuttings in offshore deltaic sandstone reservoirs. Similarly, SEM imaging is often used descriptively to document pores and mineral textures, but fewer studies use SEM-derived porosity as a quantitative dataset validated against log-derived petrophysical values. The contribution of this study is best regarded as an incremental, field-specific application of SEM-derived porosity estimation from ditch cuttings rather than the development of a new Digital Rock Physics method. Previous studies have demonstrated the broader potential of digital rock imaging, SEM-based pore observation, and drill-cuttings analysis for reservoir characterization. Building on this existing work, the present study applies a SEM-based image-analysis workflow to ditch-cutting samples from the D1 sandstone reservoir of the INNEH Field, southeastern offshore Niger Delta. The study quantifies two-dimensional image-derived pore area from segmented SEM images and compares the resulting porosity estimates with log-derived porosity values from corresponding reservoir intervals. Its main value lies in testing whether readily available ditch cuttings from the INNEH Field can provide supplementary pore-scale information for reservoir-quality assessment where conventional core data are limited or unavailable.

The aim of the study is to evaluate the effectiveness of SEM - based Digital Rock Physics for reservoir-quality assessment using ditch cuttings from the D1 reservoir interval of the “Inneh” Field. The paper specifically documents SEM-based pore-space features and sandstone microfabric, estimates 2D image-derived porosity, compares SEM-derived porosity with log-derived porosity, evaluates the reliability and limitations of the workflow, and discusses how ditch cuttings may be incorporated as supplementary materials in future reservoir appraisal programs where conventional core data are limited.

2.0 Scientific Background and Literature Context

Digital Rock Physics developed as a response to the need for non-destructive and computationally efficient methods of evaluating rock properties. Karimpouli and Tahmasebi (2016) described Digital Rock Physics as a workflow that integrates imaging and numerical simulation to infer rock properties from digital models of pore space. Subsequent studies have demonstrated that digital workflows can estimate porosity and permeability when adequately calibrated and when image resolution captures the representative pore system (Mehmani et al, 2020). Al-Marzouqi (2018) emphasized the increasing use of CT scans and digital rock models for computing rock properties, while Dhar et al. (2019) presented digital core analysis as a tool for enhanced petrophysical evaluation and reservoir characterization. More recent studies have advanced segmentation, multiscale imaging and pore-network extraction, demonstrating that digital models can provide insight into flow properties that are difficult to measure continuously at reservoir scale (Harry & Akata, 2019; Harry et al., 2018)). Scanning electron microscopy remains one of the most powerful imaging methods for reservoir microstructural analysis. SEM imaging can identify intergranular pores, dissolution pores, microfractures, grain boundaries, clay coatings, quartz overgrowths and cement distribution. In sandstone reservoirs, these features are critical because porosity and permeability are shaped by the combined effects of depositional texture and diagenesis. Devarapalli et al. (2017) showed how SEM and related imaging techniques can be used to characterize pore systems at multiple scales, while Hathon et al. (2017) demonstrated the value of multimodal SEM imaging for reservoir microstructure. SEM is particularly useful where sample volume is limited, as in the case of ditch cuttings, because small fragments can still reveal diagnostic pore-scale features.

Image analysis has transformed SEM from a predominantly qualitative tool into a quantitative component of reservoir characterization. In a typical workflow, SEM images are imported into software such as ImageJ, contrast is enhanced, noise is reduced, grayscale thresholds are selected and pore spaces are segmented from the mineral matrix. The segmented pore-space image can then be used to calculate pore area, pore-size descriptors, pore-shape parameters, and two-dimensional image-derived porosity. Alyafei et al. (2020) highlighted the educational and technical value of image processing in understanding petrophysical properties, while studies involving true pore-network modelling, such as Saraji and Piri (2014) illustrate how connected pore models can be used to analyze flow pathways when appropriate three-dimensional datasets or network-extraction methods are available. In contrast, the present study is limited to 2D SEM-based pore-space observation and pore-area estimation.

Although segmentation provides quantitative data, it also introduces interpretive uncertainty because calculated porosity is sensitive to threshold choice, image contrast, magnification and representativeness of the selected field of view. Ditch cuttings offer a practical but imperfect material for Digital Rock Physics. Ortega and Aguilera (2013) and Chen et al. (2021) noted both the promise and the limitations of cuttings-based petrophysical analysis. The advantages are clear: cuttings are readily available, inexpensive and collected over wide depth intervals. The limitations are equally important: cuttings may be contaminated, broken, mixed or depth-shifted. These limitations mean that cuttings should not be presented as direct replacements for conventional cores in all circumstances. Instead, they should be viewed as supplementary materials that can provide first-order reservoir-quality estimates, identify microstructural trends and guide intervals for more detailed analysis. Kadyrov et al. (2022) provided important support for this direction by demonstrating the use of Digital Rock Physics to define reservoir properties from drill cuttings, thereby showing that the material class can have quantitative value when handled carefully.

Validation is the key requirement for moving cuttings-based Digital Rock Physics from a descriptive method to a useful reservoir-evaluation tool. Validation may be performed against core porosity, core permeability, mercury injection data, nuclear magnetic resonance results or log-derived petrophysical measurements. In many fields, well logs provide the most available independent dataset. However, log-derived porosity and SEM-derived porosity do not represent identical measurement scales. Logs sample a much larger rock volume than SEM images, whereas SEM captures a small two-dimensional field. Agreement between these methods therefore should not be interpreted as exact equivalence. Instead, close absolute agreement can indicate that the selected SEM images capture representative pore-scale features of the reservoir interval. This study adopts that practical validation philosophy.

3.0 Geological Setting

The “Inneh” Field is located in the southeastern offshore Niger Delta, one of the most prolific hydrocarbon provinces in Africa. The Niger Delta Basin developed along the Gulf of Guinea following the opening of the South Atlantic and the establishment of a large regressive deltaic system supplied by the Niger-Benue drainage network (Evamy et al., 1978). The basin contains a thick Tertiary sedimentary succession exceeding several kilometers in the depocenter and is characterized by rapid sediment loading, gravity-driven deformation, growth faulting, rollover anticlines and shale movement. These structural and stratigraphic features strongly influence reservoir distribution, hydrocarbon migration and trap development.

The stratigraphy of the Niger Delta is classically divided into the Akata, Agbada and Benin Formations (Tuttle et al, 1999) (Figure 1). Figure 2 and Figure 3 show the map of the studied locations and depobelts within the Niger Delta, respectively. The Akata Formation consists mainly of marine shale and is widely regarded as the principal source-rock interval (Reijers, 2011). The Agbada Formation overlies the Akata and contains alternating sandstone and shale deposited in delta-front, distributary-channel, shoreface and shallow marine environments. It forms the main petroleum-bearing unit of the basin. The Benin Formation is the uppermost continental sand-dominated unit and is more important regionally for groundwater than hydrocarbon accumulation. The D1 sandstone interval investigated in this study belongs to the upper Agbada Formation and reflects the sand-rich components of the deltaic to shallow marine depositional system.

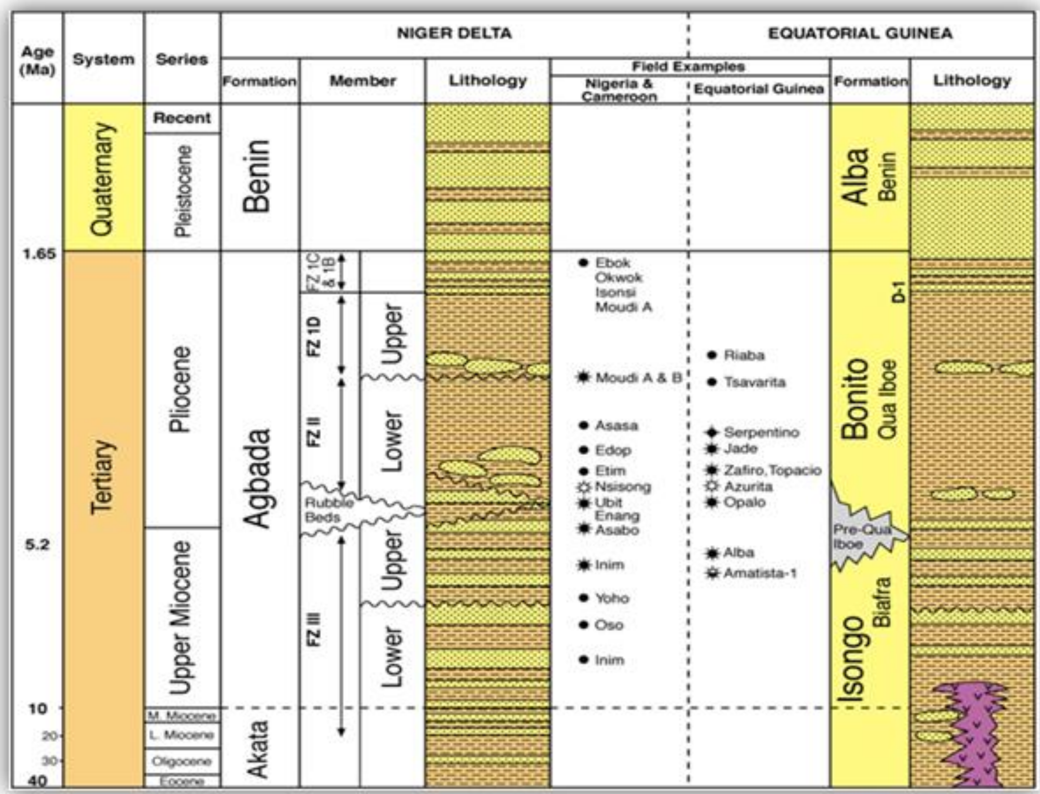


Figure 1: Stratigraphic framework of the Niger Delta Basin

The "Inneh" Field occurs within OML 67 and contains multiple sandstone reservoir packages at shallow offshore depths. The D1 interval occurs at approximately 3000 to 3400 ft subsea and has been identified as a reservoir-quality sandstone unit with high net-to-gross ratio, effective porosity exceeding 30% in the studied wells and permeability values exceeding 1800 mD in previous log-based evaluation. These favorable properties make the interval suitable for testing SEM-based Digital Rock Physics, because the reservoir contains sufficient pore development for image-based porosity extraction and enough petrophysical data for comparison with log-derived values.

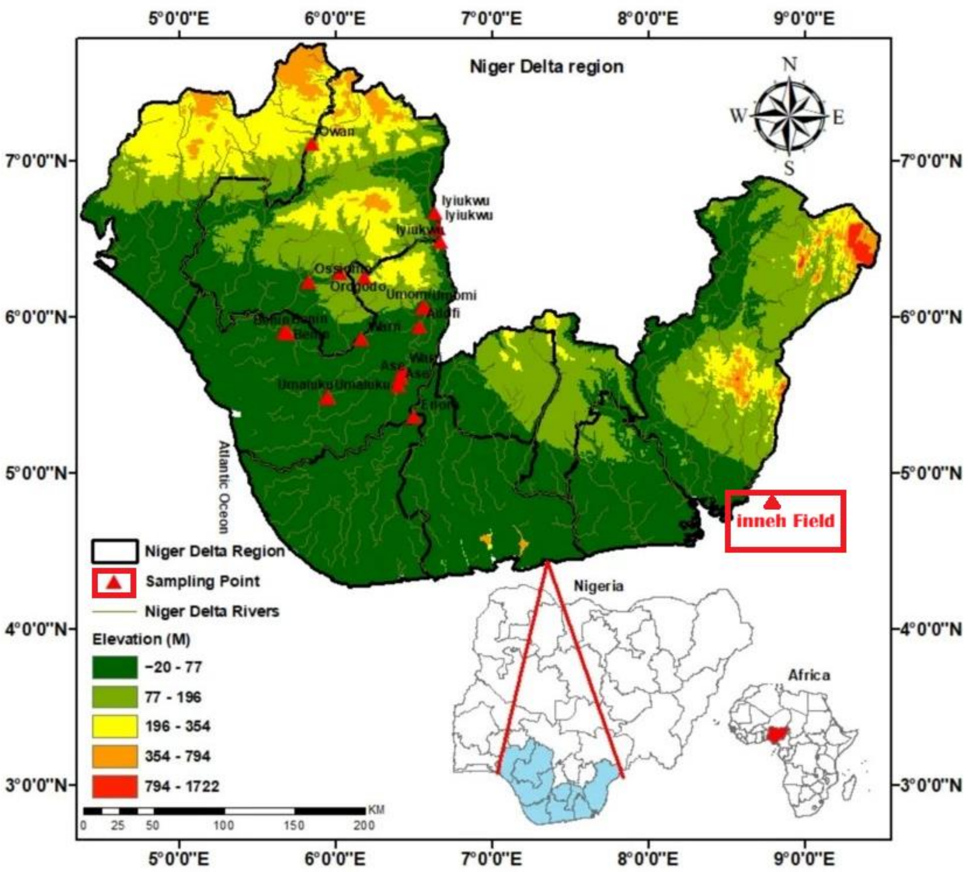


Figure 2: Location Map of “Inneh” field, Niger Delta Basin

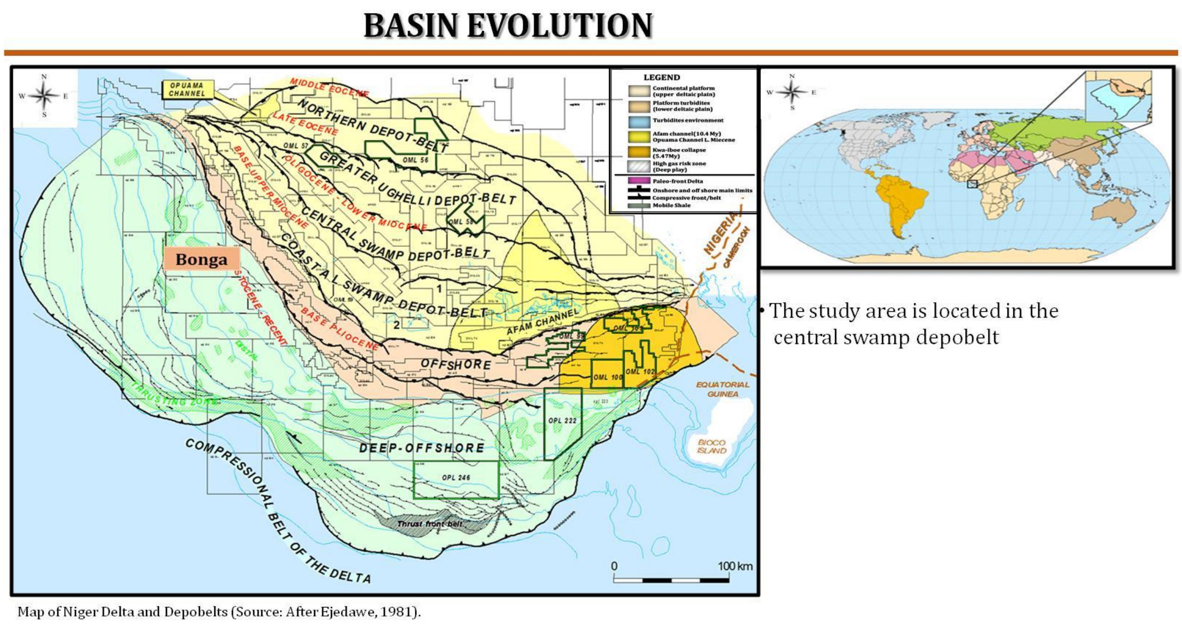


Figure 3: Depobelts within the Niger Delta Basin

4.0 Materials and Methods

Scanning Electron Microscopy (SEM) Imaging was carried out at the Cardiff University Laboratory, UK, using a ZEISS scanning electron microscope equipped with an Oxford Instruments AZtec EDS system. The instrument was used to document pore morphology, grain textures, clay occurrence, cementation, and microfractures in the selected ditch-cutting samples from the D1 reservoir interval. The SEM was operated at an accelerating voltage of 3–5 kV with a working distance of 8–10 mm and at magnifications of 2,000× for pore-area segmentation. The SEM images were acquired at a resolution of 1024 × 768 pixels with a calibrated pixel size of 0.10 µm/pixel, corresponding to a field of view of 102.4 × 76.8 µm and an analyzed area of approximately 7,864 $µm^2$ per image.

Imaging was performed using the secondary electron (SE) detector. Representative sandstone fragments were selected to minimize contamination, avoid obvious caving or drilling-mud residue, and preserve clear pore visibility for segmentation. The SEM scale bar was calibrated using the instrument settings and verified against the acquisition metadata before image analysis. These images were then used for 2D image segmentation and pore-area estimation rather than true 3D pore-network reconstruction.

The study used representative ditch cutting samples from the D1 reservoir interval of three wells: “Inneh”-1, “Inneh”-7 and “Inneh”-10. The selected depth intervals were 3040-3060 ft for “Inneh”-1, 3180-3200 ft for “Inneh”-7 and 3250-3260 ft for “Inneh”-10. These intervals correspond to reservoir-quality sandstone sections identified in the formation-evaluation dataset. The choice of these samples was guided by the need to compare pore-scale image-derived properties with log-derived porosity from the same reservoir interval.

Table 1: Ditch cutting samples used for SEM-based Digital Rock Physics analysis

Well	Sample interval (ft)	Analytical purpose
“Inneh”-1	3040-3060	SEM imaging, pore segmentation and porosity validation
“Inneh”-7	3180-3200	SEM imaging, pore segmentation and porosity validation
“Inneh”-10	3250-3260	SEM imaging, pore segmentation and porosity validation

Before SEM imaging, the ditch cuttings were cleaned to reduce the influence of drilling mud and loose contaminants that could obscure pore structures. The samples were dried carefully to remove moisture and then mounted on aluminum stubs using conductive carbon tape. A thin conductive coating was applied to minimize charging during SEM imaging. The preparation procedure was designed to preserve microstructural detail while providing sufficient conductivity for high-resolution imaging. Although ditch cuttings are inherently more disturbed than core plugs, careful cleaning and imaging can still reveal pore geometry, grain fabric and mineral textures relevant to reservoir quality.

Scanning electron microscopy was carried out at multiple magnifications in order to capture both grain-scale and pore-scale features. Lower magnifications were used to assess grain framework, fracture occurrence and general fabric, while higher magnifications were used to observe pore boundaries, clay occurrence, microfractures and pore-throat relationships. The imaging process emphasized the identification of clean pores, infilled pores, partially fractured quartz grains, secondary pore features and connected pore clusters. These observations provided the qualitative basis for interpreting reservoir microfabric and the quantitative basis for image segmentation.

The SEM images were processed using an image-analysis workflow consistent with Digital Rock Physics practice. The workflow began with image importation, followed by contrast enhancement and noise reduction. Thresholding was then applied to distinguish pore spaces from solid mineral grains. After thresholding, the images were converted to binary form, enabling pore area to be measured directly relative to total image area. The SEM-derived porosity was calculated as the ratio of segmented pore area to total analyzed image area, expressed as a percentage. This two-dimensional area-based porosity is treated as an image-derived estimate of pore abundance rather than a direct replacement for laboratory volumetric porosity. Its value lies in comparison with independent petrophysical measurements and in the interpretation of pore morphology and connectivity.

The validation dataset consisted of SEM-derived porosity values and log-derived porosity values for the same wells. "Inneh"-1 had log-derived porosity of 32.0% and SEM-derived porosity of 34.8%. "Inneh"-7 had log-derived porosity of 37.0% and SEM-derived porosity of 34.9%. "Inneh"-10 had log-derived porosity of 36.0% and SEM-derived porosity of 37.5%. To evaluate agreement, the absolute difference, mean absolute error, root mean square error, mean bias and mean absolute percentage error were calculated. However, in this work the emphasis is placed on absolute agreement and geological consistency rather than formal statistical generalization.

5.0 Results

The SEM images reveal that the D1 reservoir sandstones contain well-developed pore systems hosted within a quartz-rich framework. The observed grains include partially fractured quartz grains and subordinate mineral fragments. Pore spaces occur as both open cavities and pores partly filled by rock fragments or fine-grained material. The open pores represent the most effective storage and potential flow spaces, whereas the infilled pores contribute less to effective flow despite being visible in the rock fabric. The coexistence of clean and dirty pores indicates that the reservoir has experienced both pore preservation and pore modification during burial and diagenesis Samples were collected from the D1 section of "Inneh" field for SEM, EDS and Image analysis as part of the Digital Rock Physics studies. Table 6 shows the well samples and respective intervals within the D1 section that was studied.

5.1 Scanning Electron Microscopy (SEM)

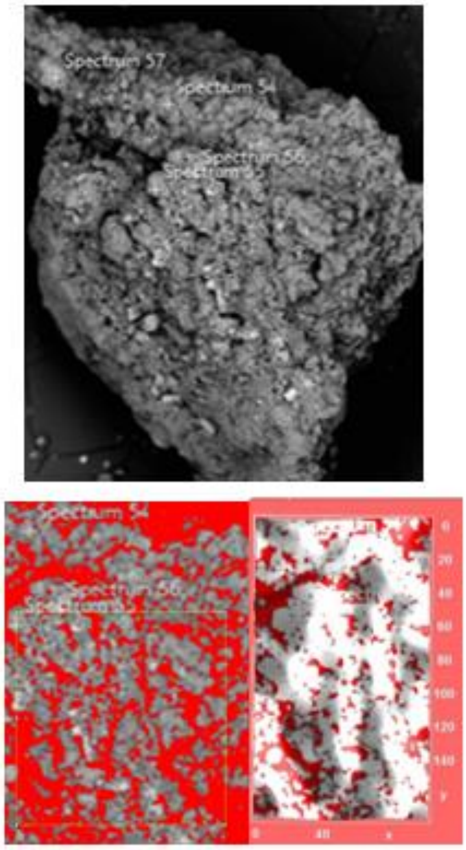
SEM investigation of the "Inneh" sandstone revealed partially fractured quartz grains ranging in size from 10 to 100 µm. The SEM images also revealed two types of pore spaces; on the one hand, it was observed that open holes in the sandstone corresponded to free pore spaces. On the other hand, pore spaces filled with rock fragments such as Quartzites or debris might be found. The bulk of these components are derived from the host substance. In this context, pore spaces are classified as clean (open cavities) or dirty (filled with rock fragments).

It is crucial to note that bicarbonate solutions from mudstone deposits flowed into "Inneh" sandstone. This migration may have an impact on the sandstone's petrophysical properties as well as its potential for oil and gas production. The sandstones "Inneh" 1 (34.8%) and "Inneh" 7 (34.9%), while the "Inneh" 10 (35.5%) sandstone had the highest estimated porosity. These values represent the percentage of void spaces or pores within the material. By measuring and comparing the porosity in different samples, we can gain a deeper understanding of their structural properties.

The workflow for achieving these results involved several steps using ImageJ software. Firstly, the SEM images of the samples were imported into ImageJ. Then, the images were pre-processed to enhance contrast and remove noise. Next, a thresholding technique was applied to segment the pores from the background. This allowed for the accurate identification and measurement of the pores. Finally, the porosity was calculated by dividing the total area of the pores by the total area of the sample. the SEM image analysis and segmented pore-space representations generated using ImageJ software. These figures illustrate 2D pore-area estimation and should not be interpreted as true three-dimensional pore-network reconstructions.

The significance of this study lies in its contribution to the understanding of the porosity characteristics of the "Inneh" samples. Porosity plays a crucial role in determining the physical and mechanical properties of materials, such as their strength, permeability, and thermal conductivity. By quantifying the porosity, we can assess the suitability of these samples for various applications, such as in construction, geology, or materials science. The existence of both clean and unclean pores, as well as the migration of bicarbonate solutions from mudstone layers, indicate that the sandstone has had a varied history of deformation, modification, and fluid migration.

This study holds good potential for determination of Porosity from ditch cuttings, especially as a validation tool though there is still need for triangulation using the numbers from core analysis which is a better 'ground truth'. Figures 4 to 6 show the image analysis and pore connectivity network using ImageJ software.



Slice		Count	Total Area	Average Size	%Area	Mean
Inneh 01	image-2.jpg	116	4135	35.647	34.806	84.036

Figure 4: SEM image analysis of the D1 sandstone ditch-cutting sample from "Inneh"-1 at 3040–3060 ft. The figure shows the original SEM image and processed 2D segmented pore-space representation used to estimate pore-area coverage. Segmented pore regions are shown in [Grey], while the mineral framework/background is shown in [Red]. SEM-derived porosity was calculated as: segmented pore area divided by total analyzed image area × 100. The resulting SEM-derived porosity for "Inneh"-1 is 34.8%, compared with log-derived porosity of 32.0%. This figure supports the interpretation that visible pore spaces are preserved in the sampled D1 sandstone, although the result represents 2D image-derived pore area rather than 3D pore connectivity. Magnification: [x2000]. Software: ImageJ

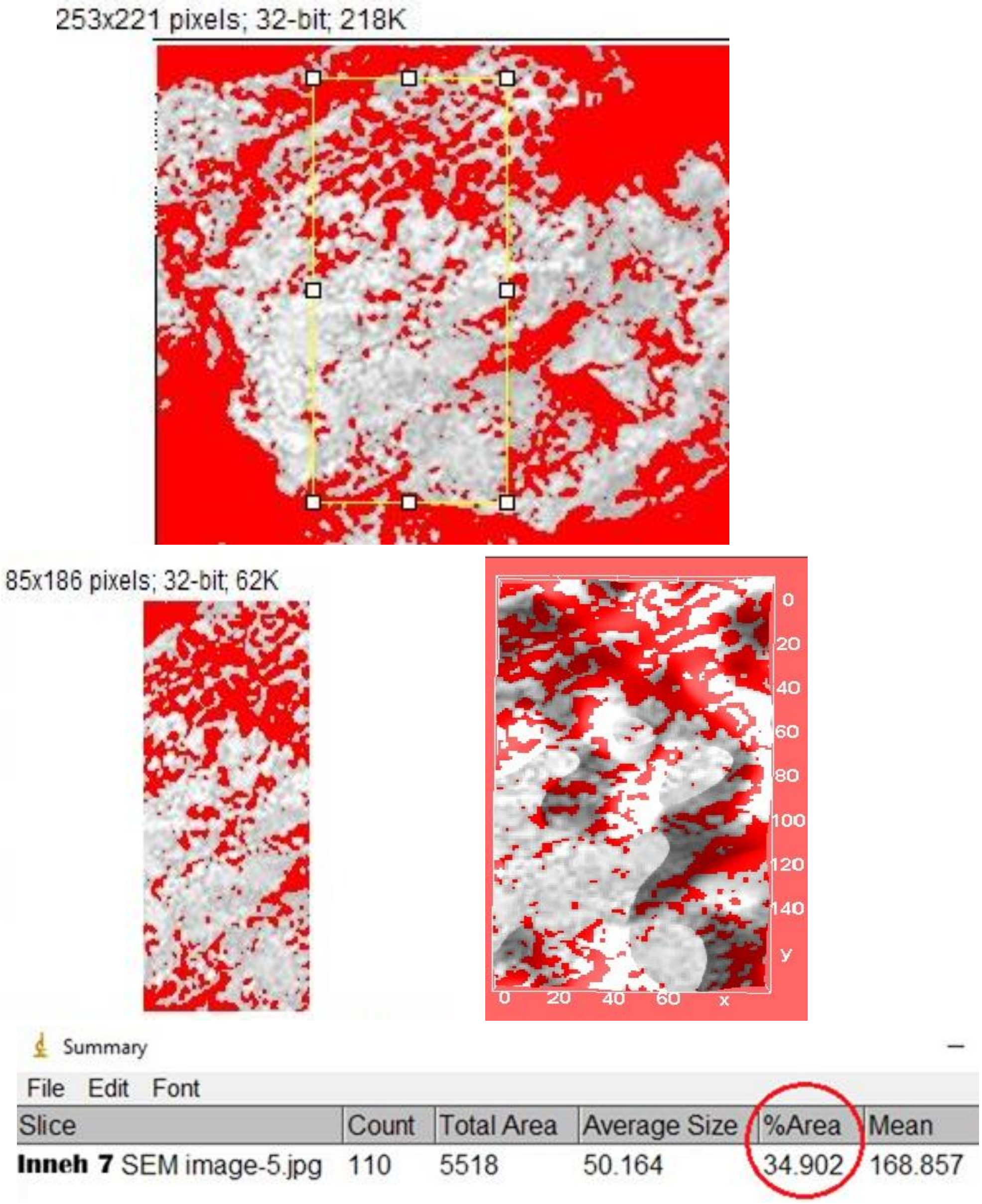


Figure 5: SEM image analysis of the D1 sandstone ditch-cutting sample from "Inneh"-7 at 3180–3200 ft. The figure shows the 2D segmentation of visible pore spaces from the SEM image. Segmented pores are shown in [Grey-bottom right], and non-pore mineral framework or background is shown in [Red/White]. Pore-area percentage was calculated by dividing the number/area of segmented pore pixels by the total analyzed image pixels/area. The SEM-derived porosity for "Inneh"-7 is 34.9%, compared with log-derived porosity of 37.0%. The slight underestimation relative to the log value may reflect pore infill, local heterogeneity, thresholding uncertainty, or the limited field of view of the SEM image. Magnification: [x2000]. Software: ImageJ.

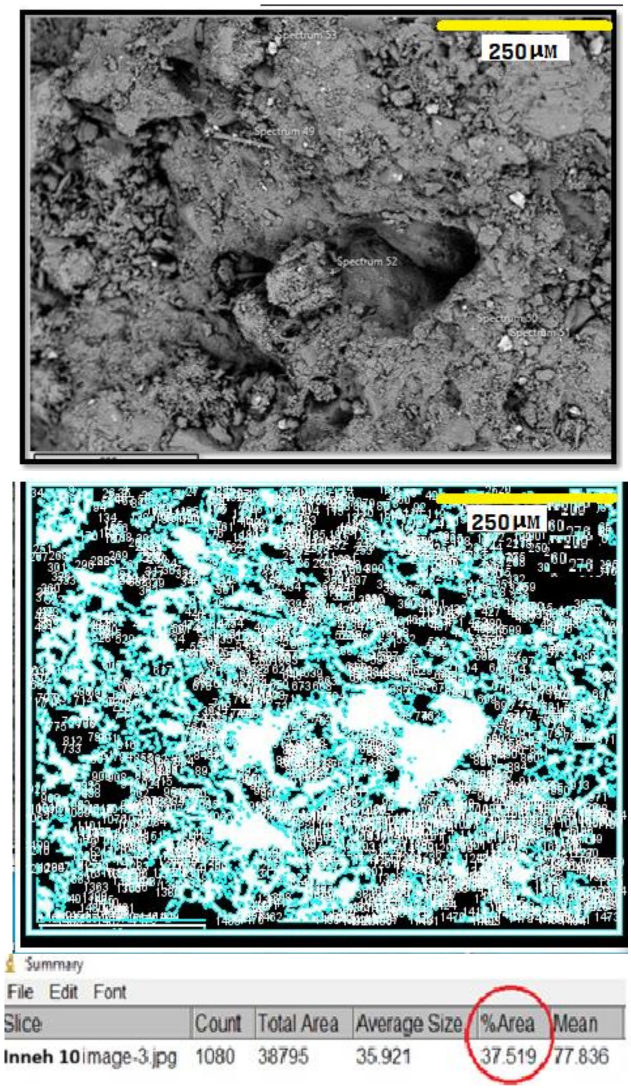


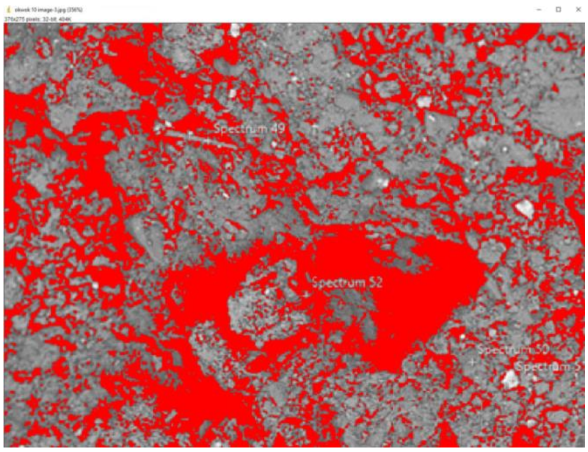
Figure 6. SEM image analysis of the D1 sandstone ditch-cutting sample from "Inneh"-10 at 3250–3260 ft. The figure shows segmented pore-area coverage derived from the SEM image and used for 2D image-based porosity estimation. Pore regions are represented by [Grey], whereas mineral grains, cement, and background are represented by [Cyan/White]. SEM-derived porosity was calculated as segmented pore area divided by total analyzed image area × 100. The SEM-derived porosity for "Inneh"-10 is 37.5%, compared with log-derived porosity of 36.0%, giving the closest agreement among the three analyzed samples. This suggests that the selected SEM field may be more representative of the log-scale pore abundance at this interval, although 3D connectivity and permeability cannot be inferred from this image alone. Magnification: [x2000]. Software: ImageJ.

"Inneh"-1 displays a pore fabric characterized by open intergranular pores and partially fractured grains. The SEM-derived porosity of 34.8% is slightly higher than the log-derived porosity of 32.0%, producing an absolute difference of 2.8 percentage points. This difference may reflect local selection of pore-rich image fields, scale effects between microscopic images and log measurements or the presence of visible secondary pores not fully expressed in the log-derived effective porosity. Nevertheless, the values are sufficiently close to support the interpretation that the SEM images capture representative reservoir-quality features within the sampled interval.

"Inneh" 7 has SEM-derived porosity of 34.9%, compared with log-derived porosity of 37.0%. In contrast to "Inneh"-1, the SEM value is lower than the log value by 2.1 percentage points. The difference may indicate that the imaged cuttings contain slightly more pore-filling material or less representative pore-rich zones than the larger volume sampled by the logs. The result is important because it demonstrates that the SEM method does not systematically overestimate porosity. Instead, differences vary by sample, suggesting that the method is sensitive to local pore architecture and image representativeness.

“Inneh”-10 shows the highest SEM-derived porosity at 37.5%, compared with a log-derived value of 36.0% (Table 2). The absolute difference is 1.5 percentage points, the smallest in the dataset. The SEM images indicate relatively good pore connectivity and open pore development as seen in Figure 7, consistent with the reservoir quality suggested by log-based petrophysical evaluation. The agreement between methods in “Inneh”-10 is particularly encouraging because this well has been interpreted as one of the more prospective D1 reservoir intervals in the broader reservoir characterization dataset. Table 3, shows the Statistical validation of SEM-derived porosity against log-derived porosity.

The validation metrics shown in Table 3 show close absolute agreement between SEM-derived and log-derived porosity values. The mean absolute error is 2.13 percentage points and the root mean square error is 2.20 percentage points. The mean absolute percentage error is 6.20%, indicating that SEM-derived porosity values deviate from log-derived values by a relatively modest amount. The mean bias is +0.73 percentage points, suggesting a slight overall tendency for the SEM workflow to produce higher porosity values in this small dataset. The pore morphology observed in the SEM images includes rounded to irregular intergranular pores, elongate pore spaces along grain boundaries and locally developed secondary pore features.



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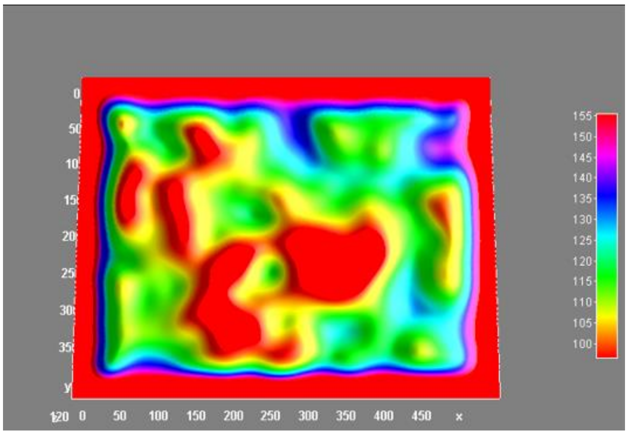

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Figure 7: Segmented pore-space representation of the D1 sandstone ditch-cutting sample from “Inneh”-10. The image displays the apparent 2D distribution of segmented pore spaces obtained from SEM image processing. This figure illustrates the spatial arrangement of visible pore areas used in SEM-derived porosity estimation, but it does not independently quantify tortuosity, pore-throat size, coordination number, or permeability. Magnification: [x2000]. Software: ImageJ.

Table 2: Comparison between log-derived and SEM-derived porosity

Well	Log-derived porosity (%)	SEM-derived porosity (%)	SEM - log difference (percentage points)
“Inneh”-1	32.0	34.8	+2.8
“Inneh”-7	37.0	34.9	-2.1
“Inneh”-10	36.0	37.5	+1.5

Table 3: Statistical validation of SEM-derived porosity against log-derived porosity

Metric	Value	Interpretation
Mean absolute error	2.13 percentage points	Average absolute deviation between SEM and log porosity.
Root mean square error	2.20 percentage points	Overall magnitude of porosity mismatch.
Mean bias	+0.73 percentage points	Average tendency of SEM values relative to log values.
Mean absolute percentage error	6.20%	Relative error normalized by log-derived porosity.

These pore types imply a reservoir system influenced by both primary depositional fabric and post-depositional modification. The presence of clean pore spaces is favorable for hydrocarbon storage, while connected pore clusters suggest that the reservoir may support fluid movement. Infilled pores and rock fragments within some voids indicate that not all visible porosity contributes equally to effective permeability. This distinction reinforces the importance of combining image-derived porosity with pore-connectivity interpretation rather than relying solely on total pore area.

6.0 Discussion

The SEM-derived porosity values show that the three D1 sandstone samples retain measurable pore space, but the comparison with log-derived porosity must be interpreted in the context of scale, representativeness, and segmentation uncertainty. The differences between the two datasets are small in absolute terms, ranging from 1.5 to 2.8 percentage points, which suggests that the selected SEM fields captured pore fabrics broadly consistent with the reservoir-scale response. At the same time, SEM porosity is derived from a small two-dimensional image area, whereas wireline logs integrate a much larger rock volume. The apparent agreement therefore reflects broad consistency rather than direct equivalence. This is an important distinction because the study is not measuring a full pore network, tortuosity, or pore-throat connectivity, but rather the visible pore-area fraction in selected SEM images. The manuscript already notes that the sample size is very small and that segmentation introduces uncertainty, and these limitations remain central to the interpretation.

Among the three samples, Inneh-10 shows the closest agreement between SEM-derived and log-derived porosity, with values of 37.5% and 36.0%, respectively. This better agreement likely reflects a combination of factors rather than a single cause. First, the imaged fragment may have been more representative of the overall pore fabric in the reservoir interval, so the SEM field of view happened to match the log-scale average more closely. Second, the sandstone at that interval may have preserved a more open intergranular fabric, with less pore occlusion by clay, cement, or drilling-related fine debris. Third, the imaged fragment may have suffered less mechanical disturbance during drilling and sample handling, reducing the chance that artificial microfractures or broken grain edges biased the pore estimate. In contrast, Inneh-1 slightly overestimates log porosity, while Inneh-7 slightly underestimates it, which is consistent with local microfacies variability and the limited representativeness of single SEM fields.

The pore-space patterns observed in the SEM images also point to geological controls on porosity preservation. The D1 sandstone is quartz-rich, and quartz-dominated sands commonly preserve framework stability better than less mature sands, but porosity is still strongly modified by burial processes. Open intergranular pores suggest that parts of the original depositional fabric remain intact, whereas partly infilled pores indicate pore reduction by cementation, clay occurrence, or fine-grained debris. Local microfractures may increase the visible pore area, but they should not automatically be treated as effective storage or flow pathways because some fractures may be drilling-induced rather than geological. The observed mix of open pores, partly filled pores, and fractured grains therefore implies that reservoir quality in the D1 interval is controlled by an interplay of depositional sorting, compaction, cementation, dissolution, and post-depositional damage. This heterogeneity is exactly what one would expect in a deltaic sandstone reservoir, where pore preservation can vary substantially over short distances.

These microstructural observations also have diagenetic implications. Where intergranular pores remain open, compaction and cementation have not completely destroyed the primary pore system. Where pores are partly occluded, diagenetic reduction of pore volume has likely occurred through quartz overgrowths, clay coatings, or other fine-grained infill. Dissolution may locally improve apparent porosity by generating secondary pores, but secondary porosity can be patchy and highly localized. This helps explain why SEM-derived porosity may differ from the log-derived estimate even when both values are broadly similar. Logs average a larger volume and therefore smooth out such local heterogeneity, whereas SEM images are sensitive to the exact fragment and field of view selected for analysis. The current study therefore supports the view that ditch cuttings can preserve meaningful pore-scale information, but the information is spatially limited and must be interpreted cautiously.

Grain fracturing is another factor that deserves careful interpretation. In the SEM images, fractured quartz grains may reflect either natural brittle deformation or mechanical breakage during drilling and cuttings transport. If the fractures are natural, they may represent an additional contribution to pore volume and potentially improve connectivity at the microscale. If they are drilling-induced, they may artificially inflate the apparent pore area and produce a porosity estimate that is slightly higher than the reservoir's true in-situ fabric. This ambiguity is one reason why SEM-derived porosity from ditch cuttings should be treated as a supplementary measure rather than a replacement for core-based porosity. The method is useful for observing the presence of pores and the style of pore preservation, but it cannot by itself distinguish perfectly between in-situ microfracturing and mechanically induced damage.

The results also have implications for reservoir heterogeneity. The fact that the three samples show similar but not identical porosity values indicates that the D1 sandstone is not perfectly uniform at the scale of the sampled fragments. Instead, it contains local variations in pore preservation and mineral fill that probably reflect changes in depositional texture and diagenetic history. This heterogeneity is important because reservoir quality is determined not only by total pore abundance, but also by how pores are distributed, whether they are isolated or clustered, and how much of the original pore system has been preserved. The present study cannot quantify pore connectivity in a true three-dimensional sense, but it does show that the D1 interval contains visible microstructural variability that is relevant to reservoir appraisal.

In relation to published digital rock physics studies, the present results are consistent with the broader literature in showing that image-based porosity estimates can approximate independent petrophysical measurements when the imaged material is representative and the segmentation workflow is carefully controlled. At the same time, the study also reflects the common limitations reported in digital rock applications: sensitivity to threshold choice, dependence on image resolution, and the risk of overinterpreting small datasets. The agreement seen here is encouraging, but it is still preliminary because the workflow is applied to only three ditch-cutting samples and only 2D SEM images. Published DRP studies are generally more robust when they use larger sample numbers, multiple images per sample, and independent calibration from core or micro-CT data. The present work therefore fits best as a field-specific demonstration of feasibility rather than a definitive validation of cuttings-based digital rock physics.

Overall, the discussion supports a cautious but positive interpretation. The SEM images show that ditch cuttings from the D1 reservoir retain enough pore-scale information to produce porosity estimates that are broadly comparable with log-derived values. The closer agreement in Inneh-10 may reflect better pore preservation, lower local heterogeneity, or a more representative imaged fragment, but this cannot be confirmed from the present dataset alone. The main scientific contribution of the study is therefore not the introduction of a new method, but the demonstration that carefully selected and analyzed ditch cuttings can provide useful supplementary evidence on reservoir quality in a data-limited offshore sandstone system.

7.0 Conclusions

This study provides a preliminary assessment of SEM-derived porosity analysis from ditch cuttings as a supplementary reservoir-characterization approach for the D1 sandstone interval of the "Inneh" Field, southeastern offshore Niger Delta. SEM observations show quartz-rich sandstone fabrics with visible intergranular pores, partly fractured grains, secondary pore features, and locally infilled pore spaces. These microstructural features indicate that ditch cuttings can retain useful pore-scale information relevant to reservoir-quality assessment.

The SEM-derived porosity values of 34.8%, 34.9%, and 37.5% for "Inneh"-1, "Inneh"-7, and "Inneh"-10, respectively, are broadly comparable with log-derived porosity values of 32.0%, 37.0%, and 36.0%. The absolute differences range from 1.5 to 2.8 percentage points, with a mean absolute error of 2.13 percentage points. This agreement suggests that SEM-based pore-area estimation from carefully selected ditch cuttings may provide useful supplementary information where conventional core data are unavailable. However, the results should be interpreted cautiously. The dataset is limited to three samples, and the porosity estimates are based on 2D SEM image segmentation rather than volumetric or three-dimensional pore-network analysis. The method does not directly quantify pore connectivity, tortuosity, pore-throat distribution, or permeability. In addition, ditch cuttings may be affected by drilling-induced breakage, mud contamination, cavings, depth uncertainty, and limited representativeness.

Therefore, SEM-derived porosity from ditch cuttings should not be presented as a replacement for conventional core analysis. Instead, it should be regarded as a supplementary screening and interpretive tool that can support reservoir characterization when integrated with well logs, petrographic observations, EDS/mineralogical data, and core measurements where available. Broader validation using larger sample populations, multiple SEM images per sample, routine core analysis, permeability measurements, and three-dimensional imaging is required before this approach can be applied confidently at field scale.

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