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Technical Risk Assessment Of 4D Seismic Monitoring Feasibility For The Heimdal Formation Reservoir, Northern North Sea

M. Bello, G. Mohammed, M. A. Yusuf, Y. Abdulmumin And A. Salihu
Department Of Physics, Abubakar Tafawa Balewa University, Bauchi – Nigeria
Department Of Geology, Abubakar Tafawa Balewa University, Bauchi – Nigeria

Abstract
This study presents an integrated workflow for evaluating the feasibility of 4D seismic monitoring of the Paleocene Heimdal Formation reservoir in the Northern North Sea. Five exploration wells, well-log data, petrophysical measurements, pre-stack CDP gathers, 3D migrated partial-stack seismic volumes serve as input for rock physics modelling, amplitude variation with offset (AVO) analysis, acoustic impedance inversion, fluid substitution modelling and uncertainty analysis to provide guidance for future reservoir monitoring strategies in the Northern North Sea. The technical feasibility of 4D seismic monitoring was assessed using the risk-based methodology proposed by Lumley et al. (1997), in which key reservoir and seismic variables were quantitatively evaluated. Rock physics and fluid substitution analyses demonstrate that P-wave velocity is the most sensitive elastic parameter to pore-fluid variations, whereas Monte Carlo uncertainty analysis reveals significant overlap in the elastic properties of brine- and oil-saturated sands, reducing confidence in seismic fluid discrimination. The results indicate that the Heimdal reservoir possesses moderate reservoir quality, achieving a reservoir score of 16/25, largely due to favorable porosity and dry-rock elastic properties. However, the seismic score was only 4/20 because of limited seismic resolution, poor repeatability, and the absence of mappable seismic fluid contacts. Consequently, the combined technical risk assessment suggests that the reservoir is presently an unfavourable candidate for successful 4D seismic monitoring.

Keywords: *4D seismic monitoring; Heimdal Formation; Rock physics; Time-lapse seismic; Technical risk assessment; Northern North Sea.*

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I. Introduction

Background

Time-lapse (4D) seismic technology has become one of the most effective geophysical techniques for monitoring dynamic changes in hydrocarbon reservoirs during production. By comparing repeated three-dimensional (3D) seismic surveys acquired over the same field at different production stages, subtle variations in seismic amplitudes, travel times, and elastic properties resulting from changes in pore pressure, fluid saturation, and reservoir compaction can be detected (Lumley et al., 1997). These observations provide valuable information for reservoir management, including identifying bypassed hydrocarbons, monitoring fluid fronts, evaluating sweep efficiency, optimizing infill drilling, and improving history matching of reservoir simulation models (Wang, 1997; Whyatt et al., 1991).

Despite its widespread application, the success of a 4D seismic monitoring programme depends strongly on both reservoir characteristics and seismic acquisition conditions (Lumley et al., 1997). Reservoirs exhibiting high porosity, significant fluid substitution, appreciable elastic-property contrasts, and favourable rock compressibility generally produce measurable seismic responses during production. Conversely, reservoirs with weak elastic contrasts, limited fluid movement, poor seismic resolution, or low survey repeatability often fail to generate detectable time-lapse seismic anomalies (Whyatt et al., 1991). Consequently, a rigorous technical feasibility assessment should precede any investment in a 4D seismic programme.

The Heimdal Formation of the Northern North Sea represents an important Paleocene deep-water turbidite reservoir that has been extensively investigated using rock physics and seismic inversion techniques (Avseth et al., 2001a; Mukherji et al., 2001; Bello et al., 2026). The reservoir consists of vertically and laterally heterogeneous sandstone and shale successions deposited within submarine fan systems (Cayley et al., 1987; Neil, 1996). Diagenesis, cementation, and lithological variability significantly influence its elastic properties and fluid sensitivity, making the reservoir an ideal case study for evaluating the applicability of time-lapse seismic monitoring.

Rock physics provides the quantitative framework required to understand the relationship between geological properties and seismic responses (Mavko et al., 2003). Combined with fluid substitution modelling, amplitude variation with offset (AVO) analysis, acoustic impedance inversion, and uncertainty analysis, rock physics enables prediction of production-induced changes in seismic properties before repeated seismic surveys are acquired. Integrating these techniques provides a comprehensive assessment of whether reservoir changes are likely to be detectable by 4D seismic methods.

Among the available screening methodologies, the technical risk assessment proposed by Lumley et al. (1997) remains one of the most widely adopted approaches. The method evaluates key reservoir variables—including dry-rock bulk modulus, porosity, fluid compressibility contrast, fluid saturation change, and impedance variation—alongside seismic factors such as image quality, repeatability, resolution, and fluid-contact visibility. The combined score provides an objective indication of the likelihood that a time-lapse seismic programme will successfully monitor reservoir changes.

This study applies an integrated workflow incorporating results from rock physics analysis, fluid substitution, AVO interpretation, acoustic impedance inversion, statistical uncertainty analysis (Bello et al., 2026a 2026b & 2026c), and the Lumley technical risk assessment framework to evaluate the feasibility of implementing 4D seismic monitoring in the Heimdal Formation reservoir (Lumley et al., 1997). The approach provides a systematic evaluation of both geological and geophysical factors controlling the detectability of production-related seismic changes.

II. Literature Review

Fundamentals of 4D Seismic Reservoir Monitoring

Time-lapse (4D) seismic refers to the repeated acquisition of three-dimensional seismic surveys over the same reservoir at different stages of production (Wang, 1997). The objective is to detect changes in seismic response resulting from variations in pore pressure, fluid saturation, temperature, or stress conditions. Unlike conventional 3D seismic, which provides a static image of the subsurface, 4D seismic captures the temporal evolution of reservoir properties.

Production-induced changes modify elastic parameters such as P-wave velocity, S-wave velocity, density, acoustic impedance, and reflectivity (Yilmaz, 2001). These changes may manifest as amplitude differences, travel-time shifts, or variations in AVO behaviour. Interpretation of these anomalies enables mapping of fluid fronts, identification of bypassed hydrocarbons, monitoring of injected fluids, and calibration of reservoir simulation models. Numerous field applications have demonstrated that 4D seismic can significantly improve reservoir management by reducing drilling uncertainty and increasing hydrocarbon recovery (Whyatt et al., 1991). However, not all reservoirs are suitable candidates because detectable seismic changes depend on both reservoir sensitivity and seismic data quality (Yilmaz, 2001).

Geological Setting of the Heimdal Formation

The Heimdal Formation forms part of the Paleocene succession within the Northern North Sea and consists predominantly of submarine fan and mass-flow turbidite sandstones interbedded with shale (Ahmadi et al., 2003). The formation constitutes an important hydrocarbon reservoir owing to its favourable porosity and permeability (Avseth et al., 2001a).

Deposition occurred in deep-marine environments where gravity-driven sediment transport produced complex channel-levee and fan-lobe architectures (Fig. 1) Consequently, reservoir quality varies considerably both vertically and laterally due to differences in depositional facies, diagenesis, cementation, and shale content (O'Connor and Walker, 1993). These geological heterogeneities strongly influence elastic properties and therefore the seismic response observed during production. Because of these complexities, integrated rock physics and seismic interpretation are required to characterize reservoir behaviour and predict the effectiveness of time-lapse seismic monitoring (Lumley et al., 1997).

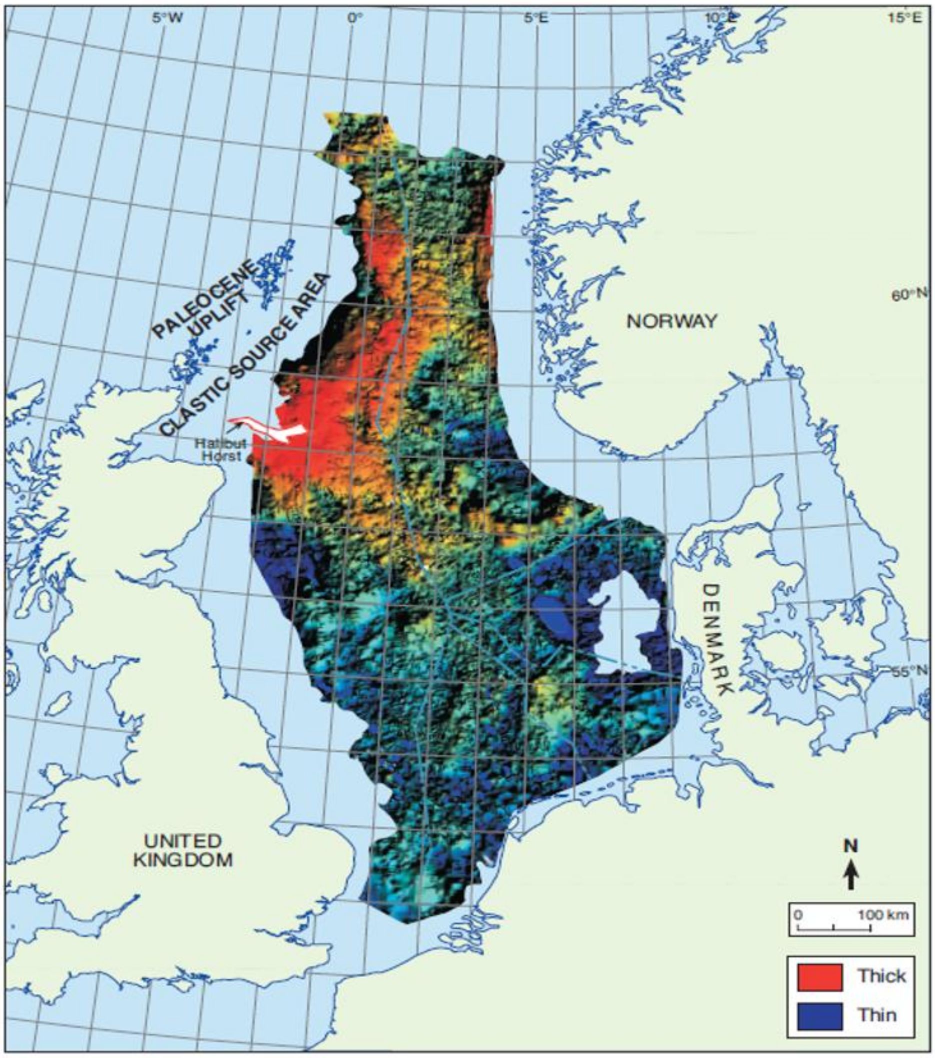

Fig. 1. Paleocene distribution in the North Sea. The map shows the thickness of Paleocene strata throughout the North Sea Basin. The thickness data are presented as colour shaded-relief image. The areas of maximum thickness are adjacent to the Shetland platform and the Norwegian landmass. The Halibut Horst was a prominent high throughout the Paleocene times. Precise limits of the Paleocene are not shown (Ahmadi et al., 2003).

Rock Physics in Reservoir Characterization

Rock physics establishes quantitative relationships between geological properties and measurable seismic parameters. It provides the theoretical basis for interpreting seismic responses in terms of lithology, porosity, mineral composition, pore geometry, fluid type, and effective stress (Dvorkin and Nur, 1996). Elastic properties are controlled by both the mineral framework and pore-filling fluids. Variations in porosity generally reduce seismic velocity and acoustic impedance, whereas increased cementation produces higher velocities and greater rock stiffness (Mavko et al., 2003). Clay content also influences elastic behaviour by reducing shear rigidity and increasing the Vp/Vs ratio (Dvorkin and Nur, 1996). Rock physics models therefore provide a means of predicting how production-induced changes will modify seismic properties and whether these changes will be detectable in repeated seismic surveys (Mavko et al., 2003).

Fluid Substitution Modelling

Fluid substitution analysis predicts changes in elastic properties resulting from replacement of one pore fluid by another while maintaining the same rock framework (Bello et al., 2026b). The method is commonly based on Gassmann's fluid substitution theory (Gassmann, 1951), which relates saturated-rock bulk modulus to mineral properties, dry-rock elasticity, porosity, and fluid bulk modulus.

The technique enables prediction of changes in P-wave velocity, S-wave velocity, density, acoustic impedance, and reflectivity associated with production. In most reservoirs, P-wave velocity exhibits greater sensitivity to fluid changes than S-wave velocity because shear waves are largely unaffected by pore fluids (Avseth et al., 2001b). Fluid substitution has become an essential component of feasibility studies for 4D seismic monitoring because it provides quantitative estimates of expected seismic changes before production data become available.

Amplitude Variation with Offset (AVO)

AVO analysis investigates variations in seismic reflection amplitude as a function of source-receiver offset or incidence angle (Shuey, 1985). These variations arise from contrasts in elastic properties across geological interfaces and provide valuable information on lithology and pore-fluid distribution. The integration of AVO analysis with rock physics enables discrimination between shale, brine-saturated sandstone, oil-bearing sandstone, and gas-bearing sandstone (Avseth et al., 2003). When combined with fluid substitution modelling, AVO responses can also be used to predict production-induced changes expected during time-lapse seismic monitoring. Because AVO directly reflects elastic property variations, it forms an important component of integrated reservoir characterization workflows.

Acoustic Impedance Inversion

Acoustic impedance inversion transforms seismic reflection data into quantitative estimates of acoustic impedance. Unlike conventional seismic amplitudes, impedance provides a direct physical property that can be related to lithology, porosity, and fluid saturation (Avseth et al., 2009). Model-based inversion constrained by well logs has become one of the most widely used techniques for reservoir characterization. Acoustic impedance volumes facilitate mapping of reservoir continuity, identification of lateral heterogeneity, and estimation of petrophysical properties (Mavko et al., 2003). Although inversion reduces interpretation ambiguity, solutions remain non-unique and depend strongly on the quality of the input seismic data and the low-frequency model (Mavko et al., 2003). Proper calibration with well information is therefore essential.

Uncertainty Analysis in Reservoir Characterization

Subsurface characterization is inherently uncertain because of limited data coverage, measurement errors, geological complexity, and modelling assumptions. Quantifying these uncertainties improves confidence in reservoir predictions and supports risk-based decision making (Bello et al 2026d). Statistical rock physics methods, including Monte-Carlo simulation, generate multiple realizations of reservoir properties by incorporating uncertainties in porosity, mineral composition, fluid properties, and elastic parameters (Avseth et al., 2001a; Bello et al., 2026d). The resulting probability density functions describe the likelihood of different elastic responses and reveal overlaps between lithologies or fluid types. In the context of 4D seismic monitoring, uncertainty analysis is particularly important because it determines whether predicted production-induced changes exceed natural variability and measurement noise.

Technical Risk Assessment for 4D Seismic Monitoring

Technical screening is essential before implementing expensive time-lapse seismic programmes. One of the most widely accepted screening methods is the workflow proposed by Lumley et al. (1997), which evaluates the probability of successful 4D seismic monitoring using key reservoir and seismic variables. The reservoir assessment considers dry-rock bulk modulus, porosity, fluid compressibility contrast, fluid saturation change, and predicted impedance or travel-time change. Seismic assessment evaluates image quality, repeatability, resolution, and visibility of seismic fluid contacts.

Each variable is assigned a numerical score, and the combined total provides an objective estimate of the technical feasibility of a 4D seismic programme. Reservoirs that satisfy both reservoir and seismic thresholds are considered suitable candidates, whereas failure to meet either threshold indicates a low probability of successful monitoring. The Lumley methodology remains widely adopted because it integrates geological understanding with practical seismic acquisition considerations within a simple and reproducible framework.

III. Materials And Methods

The datasets used in this study were obtained from the benchmark North Sea reservoir dataset developed by Avseth et al. 2005 and include well logs, petrophysical information, seismic data, and rock physics modelling tools.

Well Log Data

Five exploration wells penetrating the Heimdal Formation were available for analysis. The available wireline logs include compressional-wave velocity (Vp), shear-wave velocity (Vs), bulk density, gamma-ray, and neutron porosity logs. Shear-wave measurements were available for two wells, while gamma-ray and neutron porosity logs were available for four wells. The well logs were quality controlled prior to interpretation to remove erroneous measurements and ensure consistency between elastic and petrophysical properties (Bello et al., 2026b). The corrected logs served as input for rock physics modelling, fluid substitution, AVO modelling, and acoustic impedance inversion.

Petrophysical Data

Reservoir petrophysical information included effective stress, reservoir temperature, mineral elastic constants, fluid densities, fluid bulk moduli, porosity, and hydrocarbon properties. These parameters were required for rock physics analysis and fluid substitution modelling.

Quartz and clay mineral elastic properties were used to estimate the effective elastic behaviour of the rock matrix, while brine and oil properties were incorporated into fluid substitution calculations to predict production-related changes in seismic velocities and acoustic impedance.

Seismic Data

The seismic dataset consisted of: Two-dimensional pre-stack common-depth-point (CDP) gathers; Three-dimensional migrated near-offset partial-stack seismic volume; Three dimensional migrated far-offset partial-stack seismic volume. The seismic data were processed for true-amplitude preservation to facilitate quantitative interpretation. The near- and far-stack volumes were used for AVO interpretation and acoustic impedance inversion (Bello et al., 2026c).

Rock Physics Analysis

Rock physics analysis was performed to establish quantitative relationships between elastic properties and reservoir parameters including porosity, shale volume, cementation, and fluid saturation. Cross-plots involving P-wave velocity, S-wave velocity, density, acoustic impedance, Vp/Vs ratio, porosity, and shale volume were generated to identify lithological trends and evaluate the sensitivity of elastic properties to changes in reservoir conditions. The analysis also provided estimates of dry-rock elastic properties required for subsequent fluid substitution modelling and technical risk assessment.

Fluid Substitution Modelling

Fluid substitution modelling was carried out using Gassmann's fluid substitution theory to simulate the effects of replacing brine with hydrocarbons within the reservoir pore space while maintaining constant rock-frame properties (Gassmann, 1951). The workflow involved: Estimation of dry-rock elastic moduli; Calculation of saturated-rock bulk modulus after fluid replacement; Prediction of P-wave velocity, S-wave velocity, density, acoustic impedance, and Vp/Vs ratio following fluid substitution. The resulting elastic-property variations were analysed to determine the seismic parameters most sensitive to production-induced fluid changes.

Amplitude Variation with Offset (AVO) Analysis

AVO analysis was performed using the pre-stack CDP gathers to investigate variations in ref lection amplitude with incidence angle. The objectives of the AVO analysis were to: identify lithological contrasts across reservoir interfaces; discriminate fluid effects within the Heimdal Formation; evaluate the expected amplitude response associated with production-induced fluid substitution (Bello et al., 2026c). The AVO interpretation complemented the rock physics analysis by providing additional evidence of fluid sensitivity within the reservoir.

Acoustic Impedance Inversion

Model-based acoustic impedance inversion was applied to the migrated partial-stack seismic data. The inversion workflow consisted of: Well-to-seismic calibration; Wavelet estimation; Construction of the low-frequency impedance model; Iterative inversion of seismic amplitudes; Validation using measured well-log impedance. The inverted impedance volume was interpreted to evaluate lateral variations in reservoir properties and identify spatial changes in lithology and porosity.

Technical Assessment of 4D Seismic Feasibility

The feasibility of time-lapse seismic monitoring was evaluated using the technical risk assessment methodology developed by Lumley et al. (1997). The assessment considered five reservoir variables: dry-rock bulk modulus; fluid compressibility contrast; fluid saturation change; porosity; predicted acoustic impedance change (Table 1). Each parameter was assigned a score between 0 and 5 according to published screening criteria (Lumley et al., 1997). Four seismic variables were also evaluated: seismic image quality; seismic resolution; seismic repeatability; visibility of seismic fluid contacts (Table 2). Individual reservoir and seismic scores were summed to obtain overall technical scores. Reservoir feasibility was considered satisfactory when the reservoir score exceeded 15/25, while seismic acquisition conditions were considered acceptable when the seismic score exceeded 12/20. Reservoirs satisfying both conditions were regarded as favourable candidates for successful 4D seismic monitoring.

Table 1. Reservoir scorecard used to assign scores on a 0-5 scale to the key reservoir variables.

	Reservoir scorecard						
Score		5	4	3	2	1	0
	Unit						
Dry rock Bulk modulus	GPa	<3	3-5	5-10	10-20	20-30	30+
Fluid Compresssibility contrast	% change	250+	150-250	100-150	50-100	25-50	0-25
Fluid saturation change	% change	50+	40-50	30-40	20-30	10-20	0-10
Porosity	%	35+	25-35	15-25	10-15	5-10	0-5
Impedance Change	% change	12+	8-12	4-8	2-4	1-2	0
Travel time change	# samples	10+	6-10	4-6	2-4	1-2	0

Table 2. 4-D technical risk spreadsheet for assessing 4-D seismic project on a given reservoir.

	4-D Technical Risk Spreadsheet		
	Ideal	Reservoir X	Reservoir Y
Reservoir	5	-	-
Dry rock bulk modulus	5	-	-
Fluid compress. Contrast	5	-	-
Fluid saturation change	5	-	-
Porosity	5	-	-
Predicted impedance change	5	-	-
Reservoir total	25	-	-
Seismic			
image quality	5	-	-
Resolution	5	-	-
fluids contacts	5	-	-
Repeatability	5	-	-
Seismic total	20	-	-
Total Score	45	-	-

IV. Results And Discussion

Results

The Heimdal Formation comprises heterogeneous Paleocene turbidite sandstones interbedded with shale. Well-log interpretation and rock physics analysis reveal considerable vertical and lateral variability in reservoir properties, reflecting changes in depositional environment, grain sorting, shale content, and diagenetic cementation (Fig. 2). The elastic properties show systematic relationships with petrophysical parameters. Compressional-wave velocity (Vp), shear-wave velocity (Vs), and bulk density increase with increasing cementation and decreasing porosity, indicating progressive compaction of the reservoir. Conversely, cleaner sandstone intervals exhibit lower Vp/Vs ratios than shale-rich intervals, demonstrating the influence of clay content on elastic behaviour. These observations indicate that lithological heterogeneity exerts a first-order control on the seismic response of the Heimdal Formation.

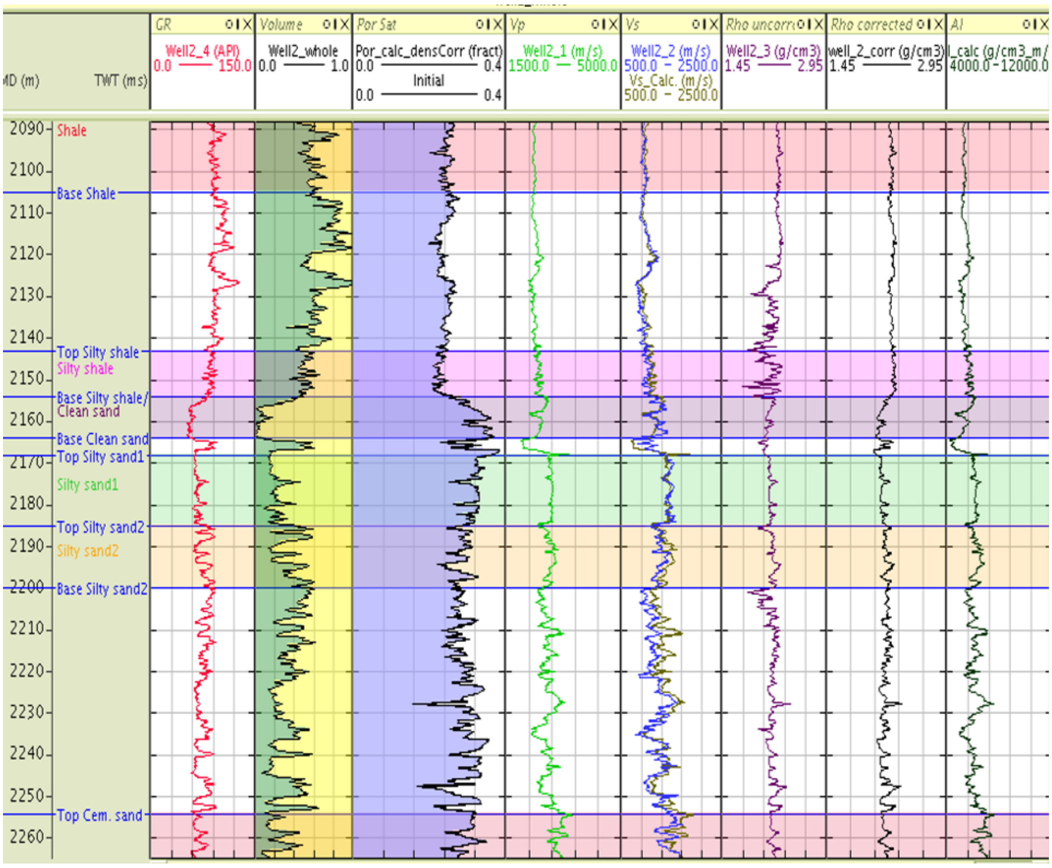

Fig. 2. Well-log data from well 2 showing part of the target Heimdal sandstone units (2100-2300m) measured depth. Acoustic impedance (AI) shown in track 9, shear velocity (Vs) in track 6, Porosity log in track 3, and Vshale in track 3 are calculated.

Fluid Substitution Results

Fluid substitution modelling was performed to evaluate the effect of replacing brine with hydrocarbons within the reservoir pore system. The results demonstrate that fluid replacement produces measurable changes in compressional-wave velocity and acoustic impedance, whereas shear-wave velocity remains essentially unchanged because primarily the rock framework controls shear-wave propagation (Table 3). Replacement of brine with oil resulted in a reduction of P-wave velocity from approximately 2.58 km/s to 2.30 km/s, while S-wave velocity remained close to 1.20 km/s. This behaviour agrees with Gassmann fluid substitution theory (Gassmann, 1951) and confirms that P-wave velocity is the most sensitive elastic parameter for detecting production-induced fluid changes in the Heimdal reservoir. Although measurable elastic-property variations occur following fluid substitution, the predicted impedance changes remain relatively modest. Consequently, only moderate time-lapse seismic anomalies are expected under the assumed production scenario.

Table 3. Calculated changes in rock elastic moduli after fluid substitution from brine to oil and from brine to gas. KD represents dry bulk modulus, Mu represents shear modulus and RhoD represents dry density.

Fluid Substitution for the upper 50m of the Heimdal Formation Sand					
Brine to Oil					
Dry values		Poisson ratio	KD	Mu	RhoD
		0.235	4.544GPa	2.926GPa	1.947g/cm3
Wet values			Vp(Km/s)	Vs(Km/s)	Rho(g/cm3)
	Porosity(frac)	*0.27*	2.3	1.2	2.16
	Por. Pert(frac).	*0.32*	2.2	1.1	2.09
Brine to Gas					
Dry values		Poisson ratio	KD	Mu	RhoD
		0.235	4.544GPa	2.926GPa	1.947g/cm3
Wet values			Vp(Km/s)	Vs(Km/s)	Rho(g/cm3)
	Porosity(frac)	*0.27*	2.1	1.2	1.99
	Por. Pert.(frac)	*0.32*	2.0	1.2	1.85

AVO Interpretation

The AVO analysis demonstrates that reflection amplitudes vary systematically with incidence angle across the reservoir interval, indicating changes in elastic impedance associated with lithology and pore-fluid distribution. The integrated interpretation of AVO attributes and rock physics trends suggests that hydrocarbon-bearing sandstone intervals can be distinguished from shale-dominated units. However, the magnitude of the AVO response is moderated by the heterogeneous nature of the reservoir, where interbedded sand and shale layers reduce the overall elastic contrast across stratigraphic boundaries (Bello et al., 2026c). These findings indicate that although AVO provides valuable lithological and fluid information, its effectiveness for predicting dynamic production changes is constrained by reservoir complexity.

Acoustic Impedance Inversion

Model-based acoustic impedance inversion successfully reproduced the major impedance variations observed in the well logs and provided continuous spatial imaging of reservoir properties. The inverted impedance sections reveal pronounced lateral variability within the Heimdal Formation. Lower acoustic impedance values correspond to cleaner and relatively porous sandstone intervals, whereas higher impedance values are associated with cemented sandstones and shale-rich facies. The inversion results also demonstrate that impedance distribution is strongly influenced by depositional architecture and post-depositional diagenesis. While inversion effectively maps reservoir heterogeneity, the solution remains non-unique and depends on the quality of the low-frequency model and well constraints (Bello et al., 2026a).

Reservoir Characterization

The interpretation starts by characterizing the seismic properties of the Heimdal Formation sands, followed by assessment of 4D seismic properties of the sands. The interpretation was carried out as highlighted below:

i. A quick look at the Heimdal formation sands scenario assuming heterogeneous layers of interbedded sands and shales. The scenario was briefly analysed. This is to give a picture of the expected seismic and reservoir properties as well as the geology and likely influence on the Heimdal Formation sands properties.

ii. Interpretation of the rock physics and fluid substitution results to characterise the seismic properties of the Heimdal sands and their associated uncertainties.

iii. Interpretation of the blocky model and 2-D line AVO response to have a picture of the interface derived elastic properties, fluid types and their associated prediction uncertainties.

iv. The well acoustic impedance and the sections will be analysed to ascertain the basis for the impedance at the zone of interest and across the seismic volume in order to have a picture of the variation in the Heimdal sands' properties away from the well location.

v. Assessment of 4-D seismic properties of the sands using the reservoir properties and the seismic variable derived above.

i. Heimdal formation sand scenario model

The Heimdal sands scenario model shown in Fig. 3 represents a complex turbidite sand distribution in which the lithology vary vertically and laterally. The sands (unconsolidated and cemented) are expected to have higher P-wave velocity and density than the overlying undifferentiated silty-shale and ambiguous (presumably shaly) layer respectively; hence appreciable seismic properties contrast is expected. This is tied to the assumption that there is no tuning effect. However, the presence of hydrocarbon may alter the expected seismic properties in these sands (e.g. lower the acoustic impedance). The geology is also put into perspective in the interpretation so that a picture of the effect of various geological events on seismic and reservoir properties of the Heimdal Formation sands can be seen.

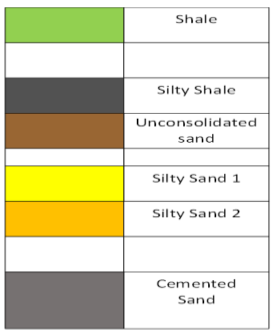

Fig. 3. Heimdal sands scenario model in well 2. Each layer is labelled with the lithology give on the suite of logs. The unlabelled layers are layers between lithofacies of interest. The figure is not drawn to scale.

ii. Interpretation of the rock physics and fluid substitution results

The characteristics of seismic properties given by results of the rock physics analysis (Section 4) is summarised below:

❖Increase in cementation and decrease in porosity with increasing seismic properties (Vp, Vs and density).
❖Variation in porosity is controlled by diagenesis as well as sedimentation.
❖Higher Vp/Vs for high shale content lithofacies and lower Vp/Vs for cleaner sands
❖Volume of shale decreases with decreasing Vp, Vs and density.
❖Increase in cementation from top to the base of the sand units of the Heimdal Formation.

The fluid substitution analysis shows that P-wave velocity decreases from denser brine 2.58 km/s to less dense oil 2.30 km/s, while the S-wave velocity remain relatively constant 1.19 km/s to 1.20 km/s. This result shows that the most sensitive seismic attribute to fluid changes is the P-wave velocity.

iii. Assessment of 4-D seismic properties of the Heimdal sands

Below is the analysis of the reservoir variables carried out before assigning scores in the reservoir scorecard using Lumley et al., (1997) described in section 3.

- Dry bulk modulus: From the analysis of fluid substitution, the dry bulk modulus of the Heimdal sands was found to be in the order of 4.54GPa.
- Fluid compressibility contrast: this is the change in bulk modulus from fluid 1 to fluid 2:

$$\frac{(\mathrm{Kf2}-\mathrm{Kf1})}{\mathrm{Kf1}} * 100 \quad 1$$

Where fluid 1 is the initial fluid in pore space (say, brine) and fluid 2 is the replacement fluid (say, oil). The fluid compressibility contrast is expressed as percentage. The fluids bulk moduli of the Heimdal reservoir are calculated using RokDoc^{TM} as shown in Table 3 the necessary input values are given by the petrophysical data, where: Brine bulk modulus is 2.8 GPa and Oil bulk modulus is 1.71 GPa. The initial fluid in the Heimdal Formation sands is assumed to be brine and the final fluid is oil. Therefore, the fluid compressibility contrast:

$$\frac{(2.80 - 1.712)}{1.712} * 100 = 63\%$$

Fluid saturation change: Due to the limitation of available data, this study assumed static reservoir scenario. What if analysis was carried out in which three cases of different values of fluid saturation change were assumed, these are: 10 %, 30 % and 50 %

- Porosity: From the analysis of fluid substitution, the porosity of the upper 50 m of the Heimdal sands was found to be in the order of 32 %. Porosity predicted from fluids substitution is believed to be relatively more accurate than one predicted from rock physics analysis and statistical rock physics because it takes into consideration the properties of fluid within the pore spaces.
- Impedance change: Due to the static nature of this study, three cases of different values of impedance change were assumed, these are: 2 %, 5 % and 10 %. Assuming fluid saturation and impedance change of 30 % and 5 % respectively, the appropriate scores in the reservoir scorecard for the Heimdal Formation sands will be (Table 4):

Table 4. Reservoir scorecard used to assign scores on a 0-5 scale to the key Heimdal Formation sands reservoir variables.

Reservoir variable	Score
Dry rock bulk modulus	4
Fluid compression contrast	2
Fluid saturation change	3
Porosity	4
Impedance change	3

The above appropriate scores are then entered into the top half of the 4-D technical risk spreadsheet (Table 5) and the seismic-related scores at the bottom of the Table.

Table 5. 4-D technical risk spreadsheet for assessing the 4-D seismic project on the Heimdal Formation sands.

4-D Technical Risk Spreadsheet		
	Ideal	Heimdal Formation sand
Reservoir		
Dry rock bulk modulus	5	4
Fluid compress. Contrast	5	2

Fluid Saturation change	5	3
Porosity	5	4
Predicted impedance change	5	3
Reservoir total	25	16
Seismic		
image quality	5	2
Resolution	5	0
fluids contacts	5	0
Repeatability	5	2
Seismic total	20	4
Total Score	45	20

Discussion

Form the analysis above; the reservoir sands barely meet the reservoir threshold. The Heimdal sands did not pass the seismic score of 12/20. In general, the total of reservoir and seismic score show that it will be highly unlikely for a 4-D seismic project to succeed for Heimdal reservoir sands. If fluid saturation and impedance change of 50 % and 10 % respectively were assumed. The total reservoir score will be 18/25 while the seismic score will remain 4/20 giving a total score of 22. It can be seen that due to very low seismic score, the Heimdal Formation sands would hardly produce the minimum passing total score to warrant 4-D seismic project, because the seismic score must pass the 60 % threshold.

However, since the major contributing factor to the low total score appears to be solely technical, improvement in technology leading to better acquisition and processing techniques improve the chances of conducting a meaningful 4-D seismic on the Heimdal Formation sands.

V. Conclusions

The integrated reservoir characterization demonstrates that the Heimdal Formation exhibits considerable lateral and vertical heterogeneity resulting from variations in depositional facies, shale content, cementation, and diagenetic alteration. These geological factors exert significant control on the elastic properties of the reservoir and consequently influence the detectability of production-induced seismic changes.

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