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Rock Physics Uncertainty Analysis For Fluid Discrimination In The Paleocene Heimdal Formation Reservoir, Northern North Sea

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Abstract
Reservoir fluid discrimination from seismic data is inherently uncertain because of the overlap in elastic properties between lithologies and pore-fluid types. This study evaluates the capability of statistical rock physics to characterize fluid-related changes within the Paleocene Heimdal Formation turbidite reservoir in the northern North Sea. Five exploration wells, 2D common-depth-point (CDP) gathers, 3D migrated partial-stack seismic volumes, and petrophysical logs provided the initial input to investigate uncertainties in inferring reservoir parameters. Statistical rock physics analysis was performed using probability density functions (PDFs) and Monte Carlo simulations to quantify uncertainties associated with key elastic parameters. The results reveal considerable overlap between brine- and oil-saturated distributions of P-wave velocity and Vp/Vs ratio, particularly within unconsolidated sands, indicating that these parameters alone provide limited discriminatory power for reliable fluid identification. Cemented sands exhibit comparatively lower uncertainty owing to their narrower elastic-property distributions.

Keywords: *Heimdal Formation; Rock physics; Monte Carlo simulation; Probability density function; Reservoir uncertainty; Fluid discrimination; Northern North Sea.*

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I. Introduction

Accurate prediction of subsurface reservoir properties remains one of the most challenging aspects of petroleum exploration and reservoir characterization. Seismic data provide indirect information about the Earth's subsurface, while well logs and core analyses offer direct but spatially limited observations. Rock physics provides the essential framework that links measurable geophysical responses to the intrinsic physical properties of rocks, including porosity, mineral composition, fluid saturation, permeability, and elastic properties (Dvorkin et al., 2009; Mavko, 2020).

Conventional rock physics models are generally deterministic, assuming fixed relationships between elastic properties and reservoir parameters. However, natural geological formations exhibit significant heterogeneity arising from variations in mineralogy, pore geometry, diagenesis, compaction history, and fluid distribution. These uncertainties often result in substantial errors when deterministic models are applied to complex reservoirs (Grana, 2014).

Statistical rock physics has emerged as an advanced approach for addressing these uncertainties by incorporating probabilistic and stochastic descriptions of rock properties (Dvorkin *et al.,* 2009; Mavko, 2020). Rather than assigning a single deterministic value to reservoir parameters, statistical rock physics characterizes them as probability distributions, allowing uncertainties to be quantified and propagated throughout reservoir prediction workflows (Takahashi, 2000).

For heterogeneous reservoirs such as the Heimdall Formation in the Northern North Sea, uncertainty quantification is particularly important because depositional variability and complex diagenetic processes produce highly variable reservoir properties (Cayley, 1987) There is therefore a need for statistical methodologies capable of integrating multiple sources of uncertainty while providing probabilistic estimates of reservoir properties.

II. Geological Setting

Paleocene strata are widely distributed and provide one of the most important hydrocarbon accumulations throughout the North Sea Basin (Figure 1). The preserved Paleocene strata in the North Sea Basin comprise siliciclastic sediments with minor amounts of volcanoclastic rocks, tuff, coal, marls and reworked carbonate sediments (Ahmadi *et al.,* 2003). The great volumes of the siliciclastic sediments were primarily sourced from the Scotland-Shetland hinterland (Jordt *et al*., 1993). An important reservoir in the Paleocene strata which this project focuses on is the Heimdal Formation sandstone. The Heimdal sandstone is a late Paleocene turbidite sands characterised by complex thin sands distribution embedded in relatively pure shales (Avseth *et al*., 2005).

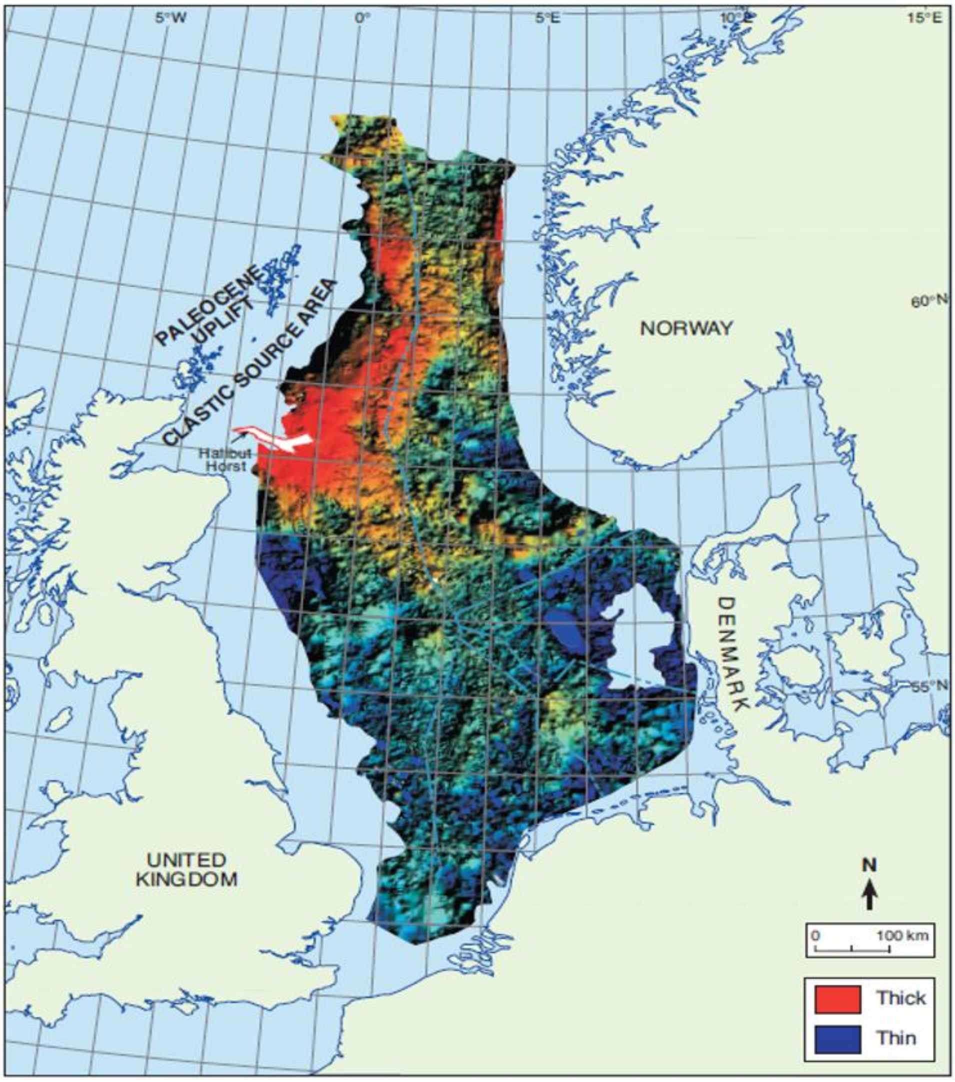


Figure 1. Paleocene distribution in the North Sea. The map shows the thickness of Paleocene strata throughout the North Sea Basin. The thickness data are presented as colour shaded-relief image. The areas of maximum thickness are adjacent to the Shetland platform and the Norwegian landmass. The Halibut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

Stratigraphy

The Paleocene and earliest Eocene strata in the North Sea record a second order regression and transgression (Haq *et al*., 1988). Cycles of regressive/transgressive, regardless of order, are characterised by the input of sand into various parts of the basin during the regressions and the confinement of sands deposition along basin margins during transgressions (Figure 2). Individual cycles can exhibit a spectrum of depositional environments that range from shore zone or coastal-deltaic to deep water (Neal, 1996).

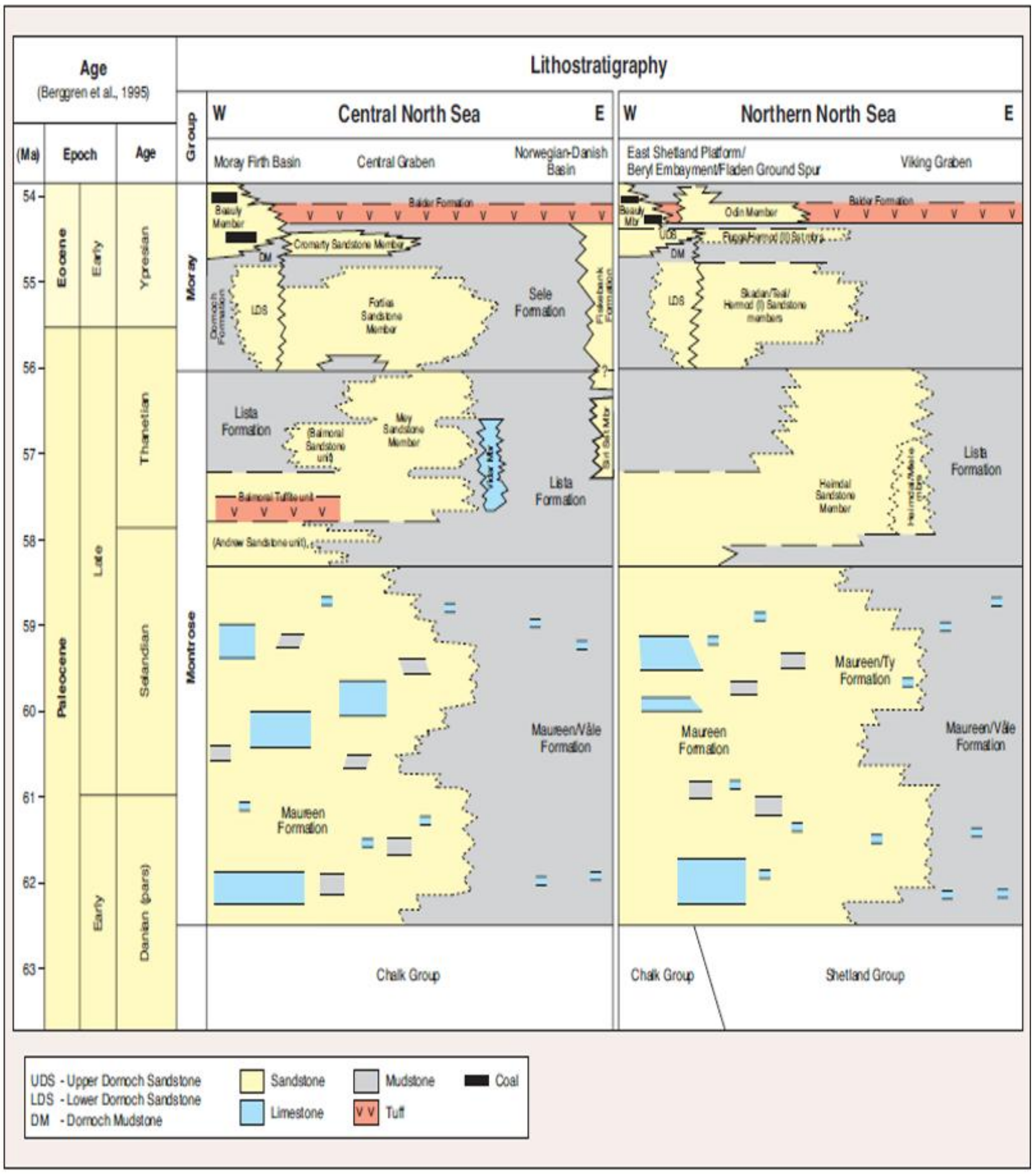


Figure 2. Lithostratigraphy of the North Sea Paleocene. (After Knox and Holloway, 1992)

The top of the Paleocene interval is marked by the ash fall deposits of Balder Formation (Figure 2), which are recognised across most of the central and northern North Sea (Ahmadi et al., 2003). They form an excellent seismic reflector and a reliable time-marker horizon, and are used in oil industry to informally define the top of the Paleocene strata. The base of the Paleocene strata has been taken as the top of the Ekofisk Formation of mid-late Danian age, this is also characterised by good seismic marker that reflects fundamental changes in sedimentation (Zeigler, 1990). Paleocene sediments in the central and northern North Sea range in depth from the sea bed to in excess of 3000m, and reach a maximum thickness of approximately 1000m in the outer Moray Firth Basin (Whyatt et al., 1992).

Heimdal Sandstones

The Heimdal sandstone is a late Paleocene turbidite sands characterised by complex thin sands distribution embedded in relatively pure shales (Mukerji *et al*., 2001). Core and thin section report indicates the Heimdal Formation as a whole has up to six different lithofacies, these facies are: pure shale, silty shale, clean sand, silty-sand1, silty-sand2 and cemented sand (Avseth, et al., 2001a). The main zone of interest in this research is at a measured depth of 2153-2183 m, it consists of four sand bodies interbedded with shale (Avseth, et al., 2000). Individual sand/shale bodies range in thickness from 10 to 30 m. Paleocene reservoir sands represented by Heimdal Formation formed oil fields of economic interest.

Hydrocarbon source and reservoir

The Paleocene strata with proven reservoir potential are present over large part of the central and northern North Sea, making them the most widespread play in the area. The source rock for Paleocene hydrocarbon occurrence is the Upper Jurassic Kimmeridge Clay Formation that is mature for oil and gas generation over much of the North Sea Basin (Cayley, 1987). Paleocene sandstone do not come into close juxtaposition with the underlying source rock anywhere within the basin and are commonly separated by hundreds or even thousands of meters of Cretaceous shales and carbonates. The exact mechanism of vertical migration remains unclear.

The major reservoirs of the North Sea Paleocene oilfields are deep-water fan sandstones. Channelling within the deep-water Paleocene turbidite is widespread; Paleocene sandstones typically form excellent reservoirs, and have good regional connectivity. The fields have average porosity ranging from 17 to 33% and permeability in the 16 milliDarcies to 10 Darcies range (Whyatt *et al*., 1992).

Although the intra-Paleocene shales appear unreliable seal for trapping light oil and gas, laterally extensive, thin bed shale can form significant barriers to fluid flow within fields (O'Connor and walker, 1993, Batzle and Wang, 1992). The most successfully proven trapping styles in the Paleocene of the North Sea are generally low-relief, four-way, dip-closed anticlinal traps. Stratigraphic traps associated with lateral reservoir pinchout have also proven to be successful (O'Connor and Walker, 1993).

Therefore, the expected geological setting of the turbidite sand would likely be sedimentary units consisting of: laminated shales with tuffs and occasional thin limestone interbedded with local sandstone that may be massive. overlying fissile and commonly laminated mudstones and sandstones (Knox and Holloway, 1992). The laminated mudstones are underlain by complex thin sands distribution embedded in relatively pure shales (Avseth *et al*., 2000); underneath the interbedded shale-sandstones lay laminated silty shales which are further underlain by pure shales (Whyatt and Rhodes, 1991). The geological setting depicts a complex turbidite sand distribution where assessment of the Paleocene sands based on conventional seismic and well log stratigraphic analysis may be very uncertain in these depositional settings. Therefore, a need to employ and/or integrate other techniques is of paramount importance so that proper decisions can be made.

Previous geophysical work

Relatively few studies have applied comprehensive statistical rock physics workflows to the Heimdall Formation in the Northern North Sea. Most existing studies focus on deterministic fluid substitution and seismic interpretation without fully quantifying uncertainty. Therefore, integrating Monte Carlo simulation, and probabilistic rock physics provides an opportunity to improve prediction reliability for porosity, lithology, and fluid saturation in the Heimdall reservoir. The following are selected research works on reservoir characterisation, carried out on Heimdal Formation and related settings:

Eissa *et al*. (2009) presented a detailed study of thin, porous, gas- saturated sandstone packages in the onshore Guajira Basin of northern Columbia. The sandstone packages are similar to the Heimdal sandstone in terms of complexity and geometry. The study includes acoustic impedance inversion, fluid substitution, and AVO modelling/analysis. The study successfully predicts the thin sandstone reservoirs as heterogeneous in terms of thickness, rock properties and areal distribution and suggested that better imaging of the thin sandstones can be best achieved either by acquiring new seismic data using new technology with better frequency content or by reprocessing existing seismic data for frequency enhancement.

A study by Avseth *et al*., (2009) utilises the application of contact cement model concept to study two clean sandstone intervals, both representing the Palaeocene age Heimdal Formation in the North Sea. Both intervals are oil-filled reservoir sands of commercial interest. The rocks were diagnosed using well log measurements and rock physics theory. It was assumed that if in the velocity-porosity plane of a data point falls close to a theoretical line, the internal structure of the rock would be similar to the idealized structure used in the model. It was found from such diagnostic approach that one interval is composed of unconsolidated sand, while the other interval is composed of cemented high-porosity sand. By studying the seismic signatures of these two different types of clean sands log-based diagnostic was upscale to seismic scale.

Seirra *et al.,* (2009) conducted a study to evaluate the possibility for seismic to discriminate lithology and fluids through attributes derived by elastic inversion in a new prospect down dip and south of Main Saldado Field, Trinidad and Tobago. The Formation studied is also similar to Heimdal Formation in terms of lithology and geometry. The results were integrated with amplitude maps, well information, and structural stratigraphy. They concluded that integrated interpretation of the 3-D seismic volume and well log data delineated several thin discrete stratigraphic features of Miocene age which are potential reservoirs; all techniques applied in the study-including acoustic impedance and elastic impedance, rock physics, and spectral decomposition-show the feasibility that the sands could have acoustic and elastic impedances contrast although the seismic data do not have good resolution. In spite of this the, it was possible to recognise the main geobodies.

To understand how the type of sand (unconsolidated versus cemented) affects the seismic response, Avseth *et al*., (1998) analysed CDP gathers at different well locations where horizons were picked at the top of the Heimdal formation; by using a 30 Hz zero-phase Ricker wavelet synthetic CDP gathers for different wells were produced and a reflectivity series were derived. Both the real and synthetic gathers show reflectivity increasingly negative with increasing offset at the picked horizon. For one well, the reflectivity was plotted versus offset (angle), together with the theoretical Zoeppritz line. The synthetic response appears to be very close to the real data which means that it can be relied on well-log-based rock diagnostic to predict seismic response. This offset-dependent reflectivity analysis shows that clean sands of the same formation, similar porosity, and with comparable oil saturation produce drastically different seismic response depending on whether they are truly unconsolidated or have initial quartz cementation.

III. Materials And Methods

Data

The study utilized an integrated geophysical and petrophysical dataset comprising: Five wells penetrating the Heimdal Formation reservoir; Two-dimensional Common Depth Point (CDP) seismic gathers; Three-dimensional migrated partial-stack seismic volumes; Wireline well logs, including compressional velocity (Vp), shear velocity (Vs), density, gamma ray, neutron porosity, and resistivity logs; Petrophysical interpretations of lithology, porosity, and fluid saturation. The dataset was obtained via Open Repository (Avseth *et al*., 2005). These datasets provided the basis for rock physics modelling, statistical reservoir characterization, and uncertainty assessment. Note that a secondary data derived from this data described above served as an input to the uncertainty analysis.

Well Log Analysis

The well logs were subjected to quality control before interpretation. Spurious measurements were removed, missing intervals corrected, and depth matching performed to ensure consistency between logs. Reservoir intervals corresponding to the Heimdal Formation were identified using gamma-ray and resistivity logs, while elastic properties such as P-wave velocity (Vp), S-wave velocity (Vs), density, acoustic impedance (AI), and Vp/Vs ratio were computed (Bello et al., 2026). These properties formed the input parameters for subsequent statistical and rock physics analyses.

Rock Physics Modelling

Rock physics analysis was undertaken to establish quantitative relationships between reservoir properties and seismic responses. Acoustic impedance, shear impedance, density, and Vp/Vs ratio were calculated from the well-log data. Fluid substitution modelling was performed using Gassmann's equations to predict changes in elastic properties associated with replacing brine by oil within the reservoir sands. The modelling assumed isotropic porous media and homogeneous mineral composition while preserving porosity and rock framework properties during fluid substitution. The resulting elastic properties were used to evaluate fluid sensitivity and quantify uncertainties associated with seismic reservoir prediction (Bello et al., 2026).

Statistical Rock Physics Analysis

Statistical analysis was performed to quantify the variability of reservoir properties and evaluate uncertainties in lithology and fluid discrimination. Kernel-based Probability Density Functions (PDFs) and Cumulative Distribution Functions (CDFs) were generated for acoustic impedance, Vp/Vs ratio, porosity, density, and P-wave velocity using MATLAB routines developed by Avseth et al. (2005). The probability distributions provided quantitative measures of overlap between lithofacies and fluid classes, thereby indicating the reliability of seismic attributes for reservoir characterization.

Monte Carlo Simulation

Monte Carlo simulation was employed to extend the available well-log dataset and estimate the statistical distributions of elastic properties under different fluid saturation conditions. One thousand realizations of reservoir properties were generated from non-parametric cumulative distribution functions derived from the measured well-log data. Correlations among Vp, Vs, and density were preserved through least-squares linear regression relationships.

The simulated datasets were subsequently propagated through Gassmann's fluid substitution model to obtain equivalent elastic properties for oil-saturated reservoir conditions. Comparing histograms and scatter plots with the original well-log data validated the simulated distributions.

Uncertainty Assessment

Uncertainty analysis focused on evaluating the capability of seismic attributes to discriminate between oil- and brine-saturated sands. Probability density functions of P-wave velocity and Vp/Vs ratio were compared for the different fluid scenarios. The degree of overlap between the distributions was used as a quantitative measure of uncertainty (Takahashi, 2000). Greater overlap indicated poorer discrimination capability and higher uncertainty in fluid prediction. The uncertainty assessment enabled identification of the seismic attributes that provide the most reliable indicators of reservoir fluids within the Heimdal Formation.

IV. Results And Discussion

Statistical Rock Physics Analysis

Statistical rock physics analysis was carried out to evaluate the variability of the seismic and elastic properties of the Paleocene Heimdal Formation reservoir sands and to quantify uncertainties associated with lithology and pore-fluid discrimination. The analysis focused on seismic attributes that have direct physical re-lationships with reservoir properties, including P-wave velocity (Vp), S-wave velocity (Vs), acoustic impedance (AI), density, porosity, and the Vp/Vs ratio. These attributes were derived from well-log measurements and subsequently analysed using MATLAB routines based on the methodology of Avseth et al. (2005). Probability Density Functions (PDFs) and Cumulative Distribution Functions (CDFs) were generated to characterize the statistical distributions of the reservoir properties and to evaluate the degree of overlap among the identified lithofacies (Takahashi, 2000). Understanding these overlaps is important because uncertainty in seismic re-sponses directly influences reservoir characterization and fluid prediction.

Probability Density Function Analysis

Kernel-estimated PDFs of Acoustic Impedance (AI) and Vp/Vs ratio were generated for the principal lithofacies encountered within the Heimdal Formation (Figures 3 and 4).

The AI distributions reveal varying degrees of overlap among shale, silty sand, unconsolidated sand, and cemented sand facies. Shale exhibits relatively high probability density owing to its homogeneous elastic properties. Likewise, the silty-sand facies displays a narrow and distinct distribution characterized by relatively high acoustic impedance, suggesting good sorting and minor cementation.

Conversely, the unconsolidated sand facies shows a broad distribution with significant overlap with neighbouring lithologies. This behaviour reflects increased heterogeneity resulting from variable porosity, grain sorting, and cementation. Such variability introduces considerable uncertainty into seismic interpretation when acoustic impedance is used as the primary discriminating attribute.

The Vp/Vs ratio exhibits a similar pattern of overlap; however, the separation between lithofacies is generally more pronounced than that observed for acoustic impedance. Consequently, the Vp/Vs ratio appears to provide greater lithological discrimination within the Heimdal reservoir interval.

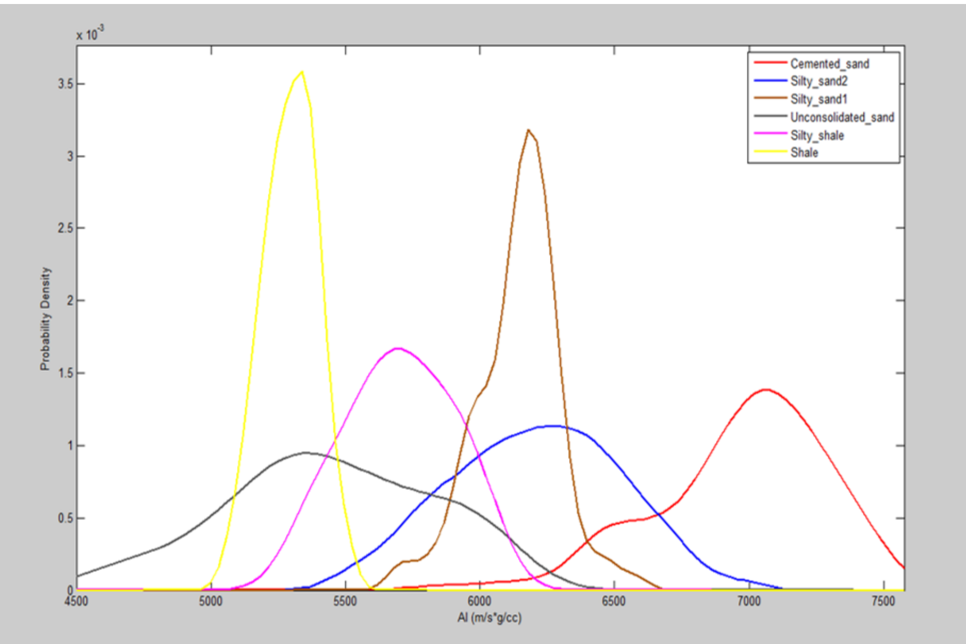


Figure 3. Kernel estimates for pdf of acoustic impedance (AI) from well 2 data. Each colour line is representing a facie listed in a legend above the plot.

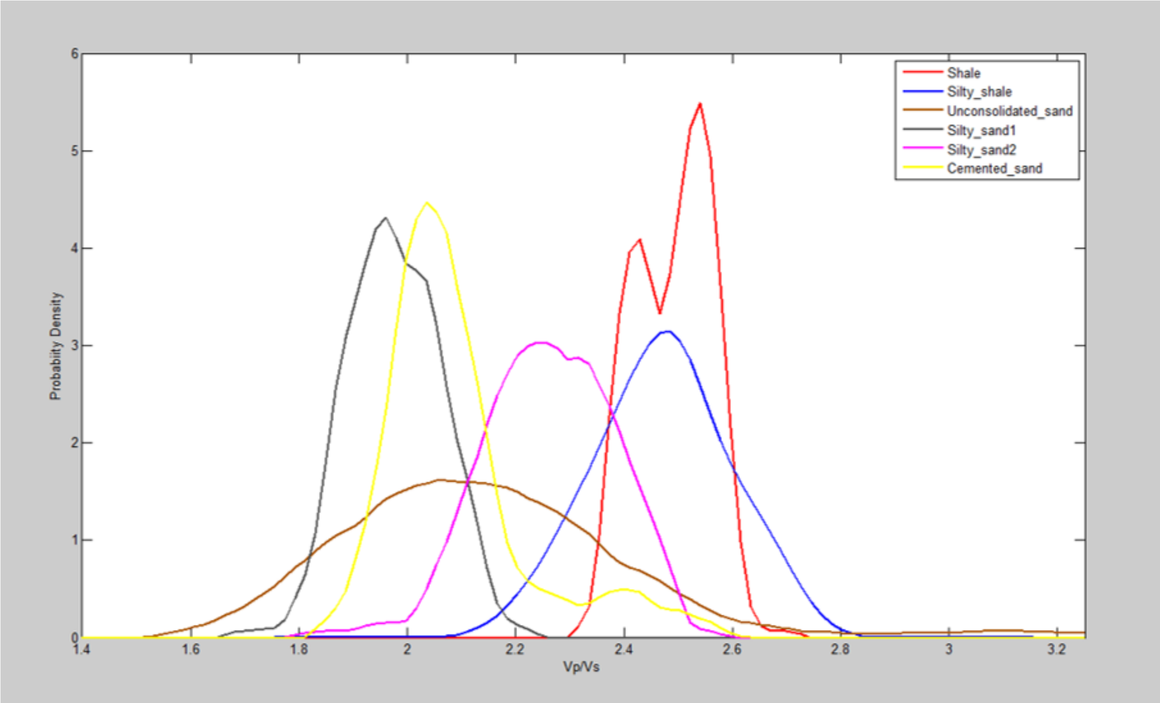


Figure 4. Kernel estimates for pdf of Vp/Vs from well 2 data. Each colour line is representing a facie listed in a legend above the plot.

Porosity Distribution

The probability density distribution of porosity for the identified lithofacies is presented in Figure 5. The results indicate considerable overlap in porosity among the different facies, demonstrating that porosity alone cannot reliably distinguish reservoir lithologies. Nevertheless, important trends are evident. The silty-sand facies exhibits a relatively narrow porosity distribution associated with high probability density, indicating well-sorted reservoir sands with comparatively uniform pore geometry.

The unconsolidated sand possesses a much broader porosity range accompanied by lower probability density. This behaviour reflects substantial heterogeneity and greater uncertainty in reservoir quality. Such variability is expected to influence elastic properties and consequently reduce the reliability of seismic fluid prediction.

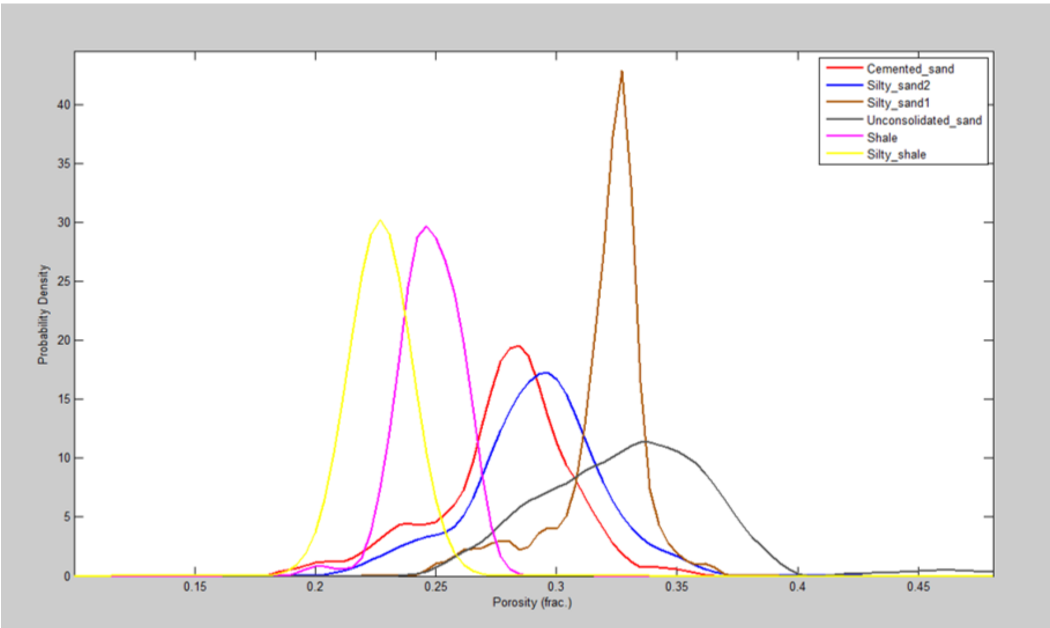


Figure 5. Kernel estimates for pdf of derived density-porosity for different lithofacies of the Heimdal Formation sands from well 2 data. Each colour line is representing a facie listed in a legend above the plot.

Monte Carlo Simulation

Monte Carlo simulation was employed to extend the available training dataset beyond the observed well-log measurements. Since the reference well was assumed to contain brine-saturated sands (Avseth et al., 2001a), fluid substitution based on Gassmann's equations was used to generate synthetic oil-saturated elastic properties. A total of 1,000 realizations were generated for each reservoir property using non-parametric cumulative distribution functions. Correlations among P-wave velocity, S-wave velocity, and density were preserved through linear regression relationships derived from the measured well-log data.

The generated realizations successfully reproduced the statistical behaviour of the original measurements, indicating that the simulation accurately captured the variability of the reservoir properties. Histogram and scatter plot comparisons demonstrate excellent agreement between the observed and simulated datasets, confirming the robustness of the Monte Carlo workflow.

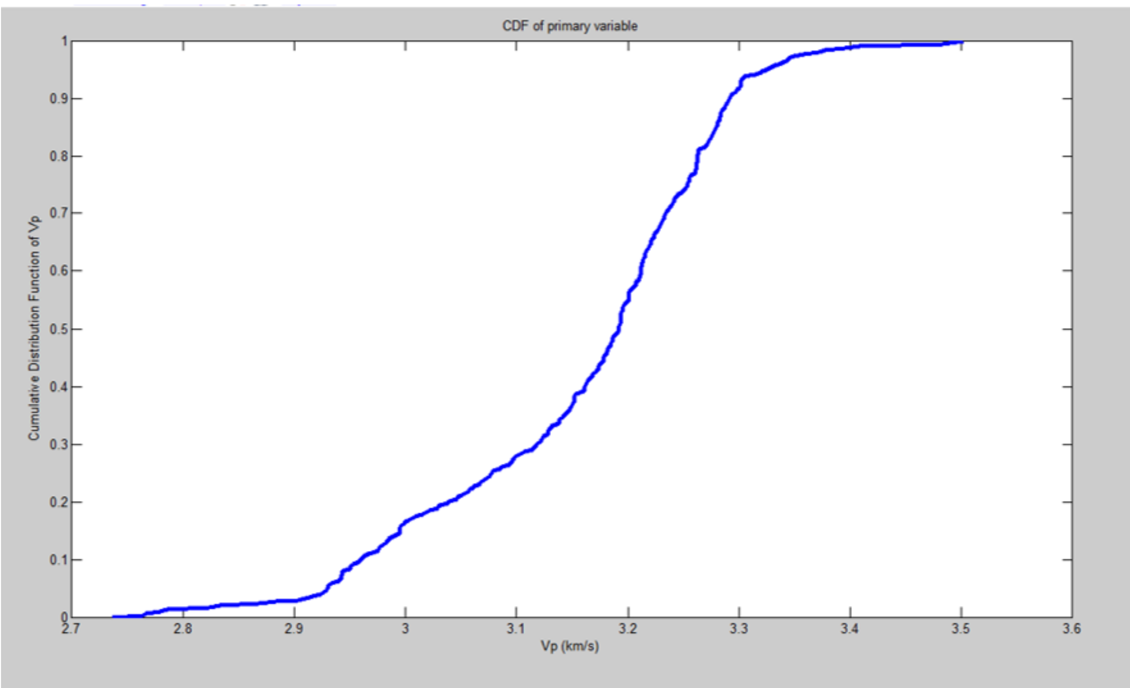
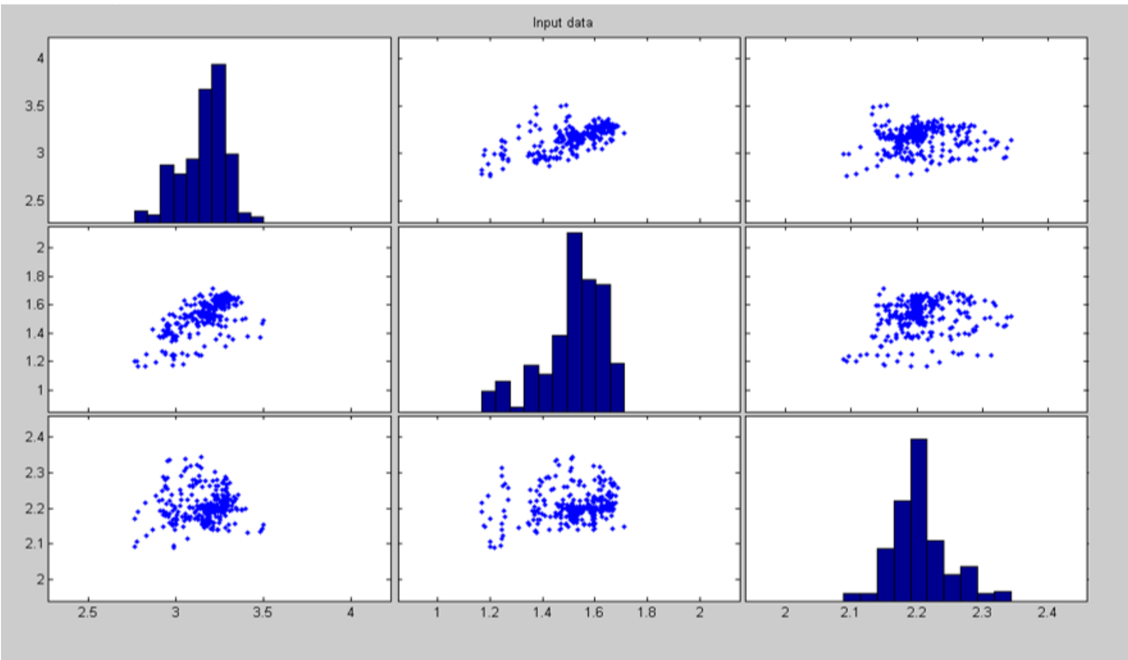
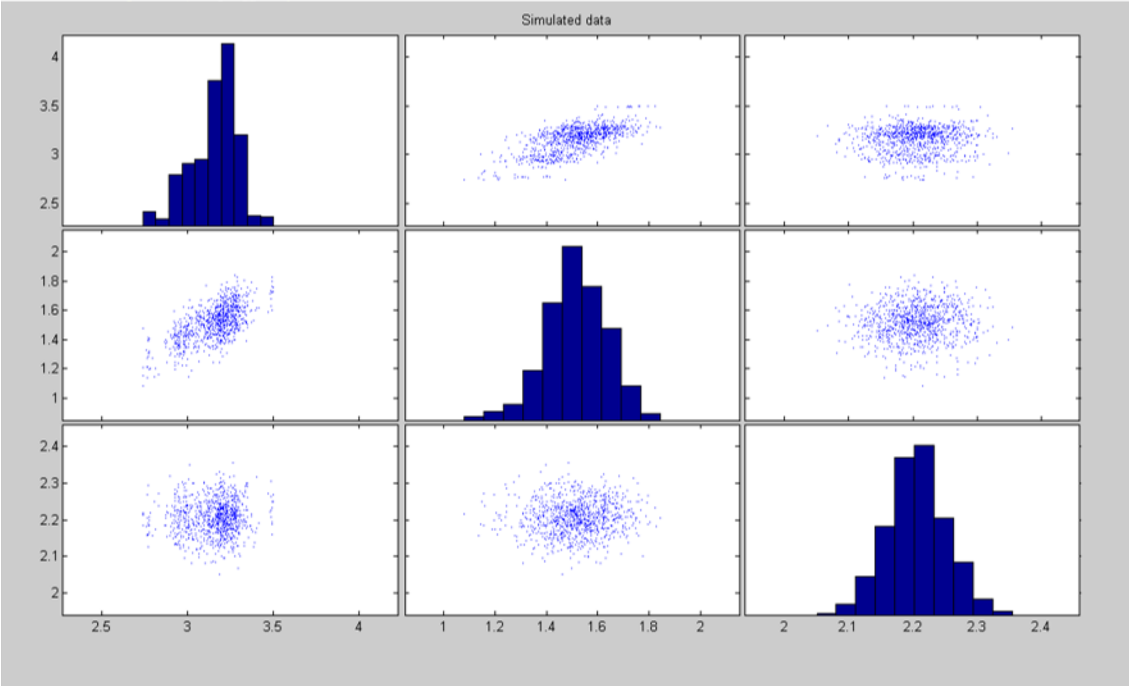


Figure 6. Non parametric univariate cdf for the primary variable (Vp) for the unconsolidated sand facie.



(a)



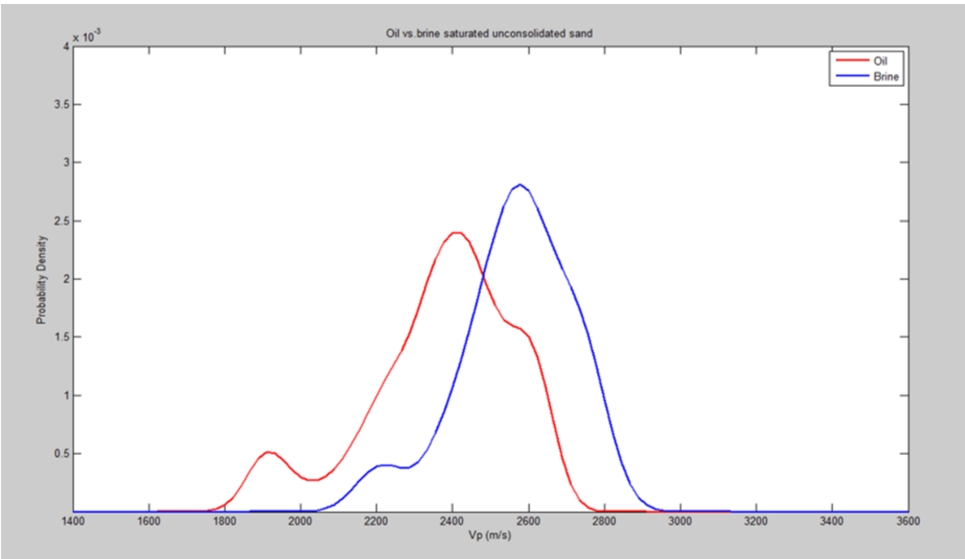
(b)

Figure 7. Plots of histogram and scatter plot of input (a) and simulated (b) data. The plots compare the similarity of the input and simulated data for unconsolidated sand facie.

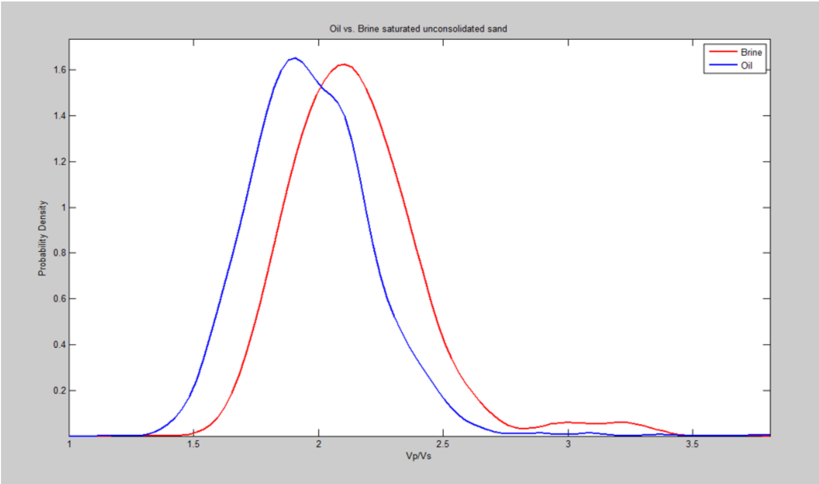
Uncertainty in Fluid Identification

The simulated elastic properties were subsequently used to evaluate uncertainty associated with distinguishing oil- and brine-saturated reservoir sands. Probability density functions of P-wave velocity and Vp/Vs ratio were generated for both unconsolidated and cemented sands following Gassmann fluid substitution. For unconsolidated sands, substantial overlap exists between the distributions corresponding to oil and brine saturation. This overlap indicates that both P-wave velocity and Vp/Vs ratio possess limited capability for reliable fluid discrimination within heterogeneous reservoir intervals. The broad distributions primarily reflect the influence of porosity variability and reservoir heterogeneity.

In contrast, cemented sands exhibit relatively narrower distributions with reduced overlap between fluid states. Consequently, fluid prediction is expected to be more reliable within well-cemented reservoir intervals. Although measurable shifts occur in both P-wave velocity and Vp/Vs ratio following fluid substitution, the magnitude of statistical overlap remains sufficiently large to limit the effectiveness of these individual seismic attributes as standalone fluid indicators.

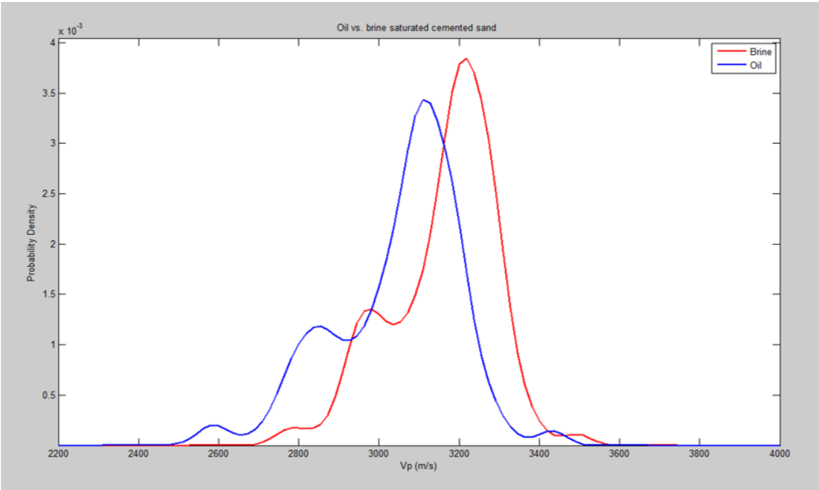


(a)

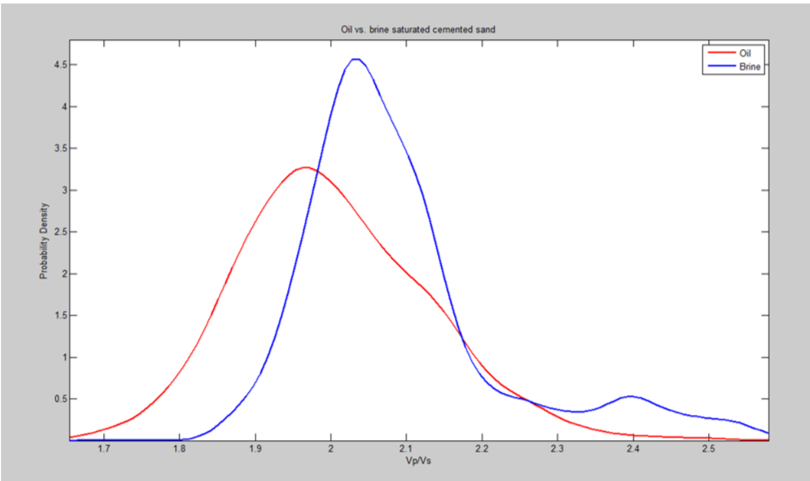


(b)

Figure 8. Kernel estimates for pdf of (a) P-wave velocity and (b) Vp/Vs for unconsolidated sands facie from well 2 data.



(a)



(b)

Figure 9. Kernel estimates for pdf of (a) P-wave velocity and (b) Vp/Vs for cemented sand facie from well 2 data.

V. Conclusions

The statistical analyses demonstrate that uncertainty in reservoir characterization is strongly controlled by the intrinsic heterogeneity of the Heimdal Formation. Reservoir properties exhibit considerable variability arising from differences in porosity, grain sorting, cementation, and shale content.

The Monte Carlo simulations confirm that uncertainty propagates from petrophysical properties into seismic attributes, thereby reducing confidence in fluid identification based solely on conventional elastic parameters. Among the investigated attributes, the Vp/Vs ratio provides slightly better lithological discrimination than acoustic impedance; however, neither attribute alone can reliably distinguish oil- from brine-saturated sands because of the substantial overlap in their probability distributions.

These findings emphasize the necessity of integrating multiple seismic attributes with rock physics modelling, AVO analysis, and probabilistic interpretation techniques. Such integrated workflows reduce uncertainty and improve the reliability of reservoir characterization and time-lapse seismic monitoring within the Heimdal Formation reservoir.

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