

Seismic Inversion and Unsupervised Neural Network for Volumetric Uncertainty Reduction

Introduction

Vermilion Energy Netherlands B.V. (Vermilion), a subsidiary of the Canadian Vermilion Energy Inc., has been operating in the Netherlands since 2004. The company is engaged in the exploration and production of natural gas for use by Dutch households and industries. In recent years, seismic inversion and Amplitude Versus Offset (AVO) technique have helped the company make two Permian Rotliegend gas discoveries onshore in the Netherlands. Building on this success, Vermilion is expanding the application of these technologies across a broader Rotliegend exploration portfolio.

A new exploration prospect has been identified targeting the A Sand interval, located in the uppermost part of the Rotliegend Formation, with an estimated reservoir thickness of only a few meters. Although preliminary volumetric estimates and economic evaluations are encouraging, significant uncertainties remain regarding reservoir presence, thickness variability, reservoir properties, and their impact on resource estimates. Forward modeling studies indicate that increases in A Sand thickness from 0 to 5 m result in measurable amplitude enhancements at the Top Rotliegend reflector, while further increases from 5 to 20 m led to additional amplitude strengthening associated with changes in reservoir thickness. These observations suggest that seismic amplitude variations may contain predictive information related to reservoir thickness and facies distribution; however, quantitative calibration is required through seismic inversion and advanced attribute analysis.

To address these uncertainties, a post-stack seismic inversion study was initiated to validate the concept and demonstrate its practical value. Inversion-derived acoustic impedance, together with other seismic attributes, were integrated using an unsupervised neural network workflow to improve facies discrimination and reservoir thickness prediction. The objective was to generate a geologically consistent A Sand distribution model that could support volumetric updates, field development planning, and economic reassessment. The results of the study proved valuable in reducing volumetric uncertainty and improving the quantification of subsurface exploration risk.

Method and/or Theory

A post-stack seismic inversion workflow was applied to derive acoustic impedance (AI). Well log conditioning, wavelet extraction, and low-frequency model building were performed to ensure consistency between seismic and well domains. The inversion results were calibrated against available well control within the Area of Interest (AOI).

The inversion results indicate that increases in A Sand thickness correlate with lower acoustic impedance at the Top Rotliegend reflector. However, thickness-related impedance effects are non-linear and may be influenced by tuning and lateral facies variability. Consequently, acoustic impedance alone cannot be used as a direct volumetric trend across the full AOI.

In addition to inversion-derived attributes, a suite of conventional seismic attributes was computed. These attributes capture complementary information related to lithology, fluid effects, and stratigraphic continuity.

To integrate the multi-attribute dataset objectively, an unsupervised neural network (self-organizing approach) was implemented. The workflow includes:

- Normalization and/or conditioning of inversion and conventional seismic attributes.
- Dimensionality reduction and feature clustering.
- Generation of facies probability volumes.

The unsupervised approach avoids bias introduced by limited well control and enables identification of natural clusters within the seismic attribute space. These clusters are interpreted in terms of reservoir vs. non-reservoir facies after calibration with well data. The resulting probability distribution map of A Sand presence shows promising spatial patterns. However, because the neural network training was performed over a limited portion of the study AOI, the derived probability distribution cannot be directly extrapolated as a deterministic trend across the full area.

To overcome this limitation, the neural-network-derived probability map was combined with well data to construct a geostatistical model. Experimental variograms were computed from well facies indicators and calibrated against the attribute-derived probability trends.

The calibrated variogram model was then applied to generate stochastic realizations of A Sand facies distribution across the entire AOI. This approach ensures:

- Honor all available well data,
- Spatial continuity consistent with geological understanding,
- Integration of seismic-driven trends,
- Quantification of uncertainty through multiple realizations.

The resulting facies models form the basis for updated volumetric calculations and economic re-evaluation.

Forward Modelling

Figure 1 illustrates the relationship between “A” Sand thickness increase and corresponding amplitude response at the Top Rotliegend reflector. The progressive amplitude strengthening for 0–5 m and 5–20 m thickness increments highlight the sensitivity of seismic response to reservoir development. This behavior supports the integration of inversion attributes within a probabilistic modelling framework rather than reliance on single-attribute interpretation.

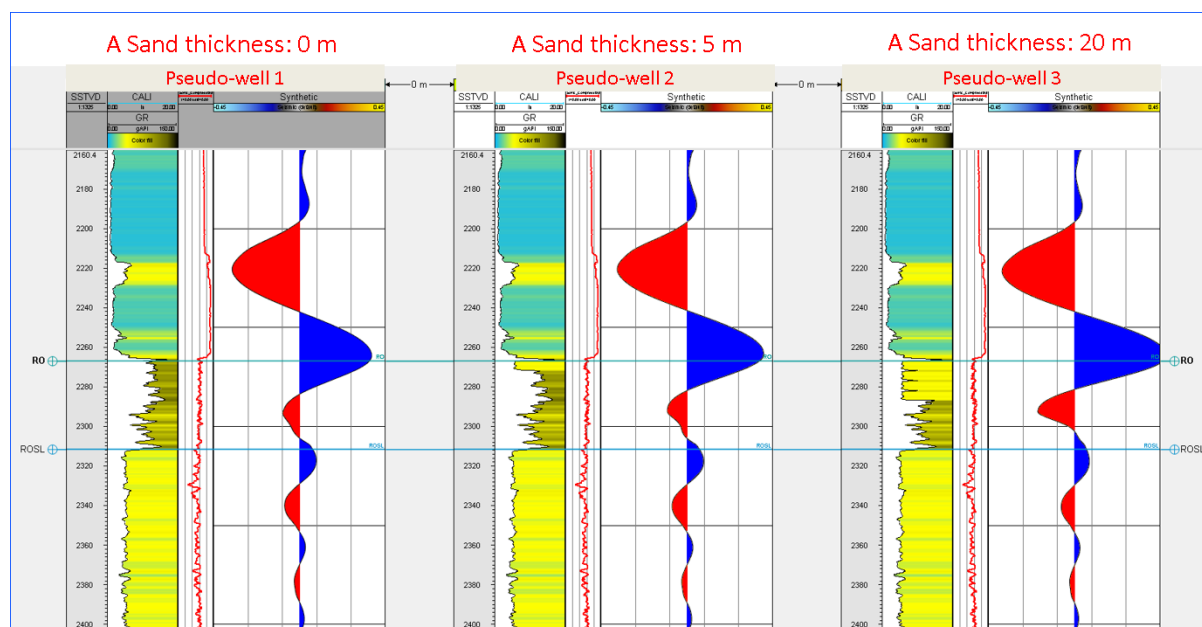


Figure 1 Modelled relationship between “A” Sand (Uppermost part of Rotliegend Fm) thickness increase and Top Rotliegend reflector amplitude response. Amplitude strengthening is observed for incremental thickness increases due to reservoir effects.

Well Calibration and Blind Test

Figure 2 illustrates predictive power of inversion results. Well 1 is the calibration well that was utilized as input for inversion model building, while well 2 is the blind testing well, which is ca. 300m away. P-Wave impedance shows low-impedance anomalies around well 1, which has ca. 5m of “A” sand, while the anomalies pinched out towards well 2, in which the well has less than 1m of “A” sand.

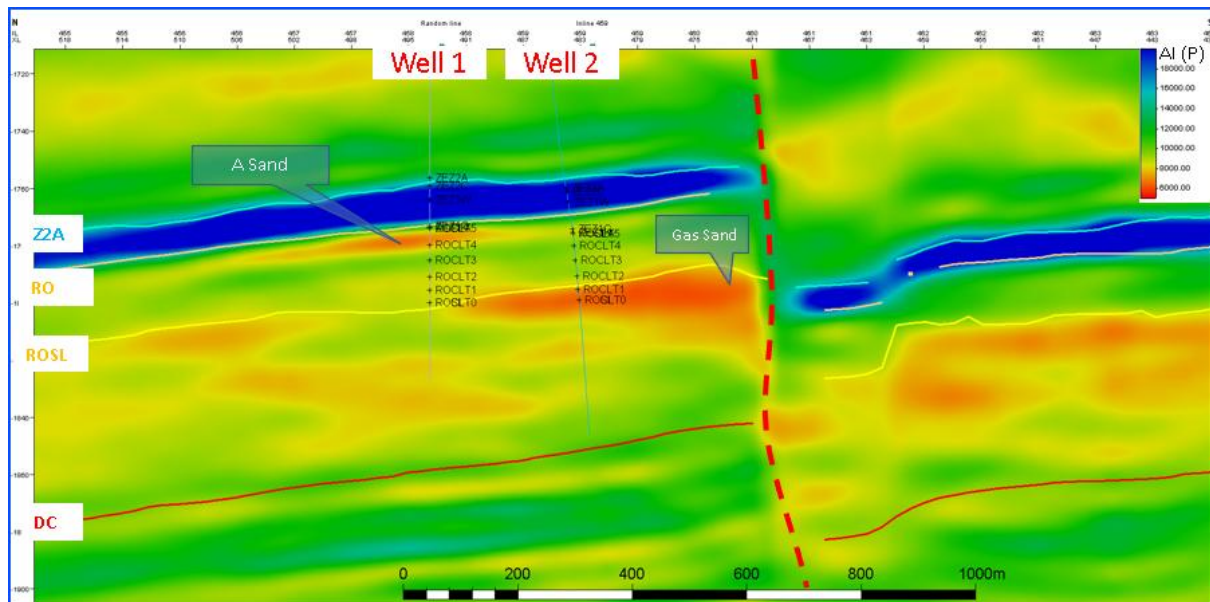


Figure 2 Inversion result from P-impedance with calibration well 1 and blind test well 2.

Integration

Figure 3 illustrates the methods of utilizing unsupervised neural network to combine various attributes including inversion attributes together for facies classification. Note some attributes were removed from inputs after principal component analysis (PCA) and correlation tests to reduce redundancy.

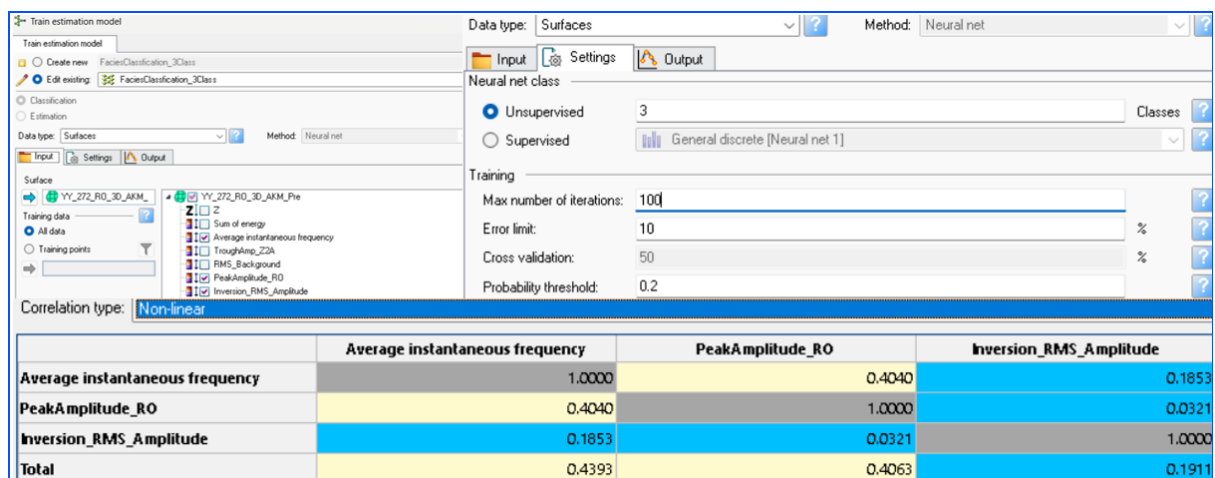


Figure 3 Neural network methodology for facies classification

Conclusions

A workflow integrating seismic inversion, unsupervised neural network and geostatistical modeling was developed to reduce volumetric uncertainty in an exploration prospect where the A Sand constitutes the primary reservoir target.

Key conclusions are:

- Top Rotliegend amplitude response is demonstrably sensitive to A Sand thickness variation, supporting reservoir-driven amplitude interpretation.
- Post-stack inversion success provides good foundation for the pre-stack inversion investigation.
- Integration of inversion and conventional seismic attributes using an unsupervised neural network enhances facies discrimination beyond single-attribute analysis.
- Variogram-based facies modelling provides a spatially consistent A Sand distribution model and enables improved uncertainty quantification.
- The updated reservoir distribution model provided valuable inputs for volumetric refinement, subsurface risk quantification, well trajectory optimization, and economic evaluation.

Overall, this integrated workflow reduces geological uncertainty, supports more robust decision-making for the development concept, and provides a foundation for initiating a pre-stack inversion project to further enhance subsurface understanding.