# Full-azimuth differential seismic facies analysis for predicting oil-saturated fractured reservoirs

Alexander Inozemtsev[1*], Zvi Koren[1], Alexander Galkin[2] and Igor Stepanov[3] present a novel technology for azimuth-dependent facies analysis (facies analysis versus azimuth – FACIVAZ) to improve the prediction of hydrocarbon-saturated permeable fractures in terrigenous carbonate reservoirs.


## Summary

This work presents a novel technology for azimuth-dependent facies analysis (Facies Analysis versus Azimuth – FACIVAZ) to improve the prediction of hydrocarbon-saturated permeable fractures in terrigenous carbonate reservoirs. The analysis is performed in the depth domain along high-resolution, full-azimuth, angle domain common image gathers created by the EarthStudy 360™ Local Angle Domain (LAD) imaging system. The amplitude and phase preservation of the seismic reflectivities obtained by this imaging system is crucial to the proposed analysis. Prior to the facies analysis, the general orientation and intensity of the target fracture systems are analysed and characterized by azimuth-dependent velocity and amplitude analyses (VVAZ and AVAZ) performed along these LAD gathers. The remaining effects of the azimuth-dependent (and frequency-dependent) absorption and dispersion on the LAD gather events are then detected and further connected to the rate of the existing oil-saturated fractures within the reservoirs. The examples presented in this article show the effectiveness of the proposed FACIVAZ technology in accurately predicting the distribution of seismic facies in target production areas associated with oil-saturated fractured reservoirs in Western Siberia and Middle Volga. The results strongly agree with the corresponding facies characteristics measured in the boreholes along the reservoir area, and therefore serve as valuable information for the drilling decisions of new wells.


## Introduction

Seismic facies classification is an important tool in the structural/stratigraphic and qualitative interpretation of fine seismic reflection image data. It is routinely used to identify depositional settings, the internal and external configuration/geometry of target reservoirs, lateral continuity of the elastic properties, and variations in seismic amplitudes and phase or frequency in these areas. Moreover, seismic facies classification can help in the study of porosity distribution, and permeability of the various deposition units. It is hence an important stage in exploration, prospecting, reservoir characterization, and field development, providing an extremely valuable indication of the potential of the target reservoirs (e.g., oil-saturated zones).

The traditional methods for analysing seismic facies within production reservoirs are based on conventional post- and pre-stack migrated images/gathers. However, these types of seismic migrated data provide limited information with low reliability when used for predicting oil-saturated zones. This is mainly due to their low-resolution nature caused by the averaging process performed in conventional seismic migrations where the angle/azimuth-dependent reflected seismic events are stacked, resulting in a single (average) reflectivity image volume. It is well known, however, that the amplitudes of reflecting seismic events are highly sensitive to the orientation of the aligned fracture systems within the reservoirs (e.g., the effect of azimuthal seismic anisotropy and different types of edge/tip diffractions). Moreover, in cases where the fracture systems are filled with permeable oil, the amplitude and phase of the reflecting events are further affected by absorption and dispersion, which are highly sensitive to the orientation (e.g., azimuth) and intensity of the fracture systems.

In order to successfully analyse these effects (azimuthally dependent absorption/dispersion), it is essential to first accurately map the recorded seismic data from the acquisition surface(s) into the reservoir grid points, and bin the image events with respect to their actual (true) reflecting/diffracting angles and azimuths. The Local Angle Domain (LAD) seismic imaging method presented by Koren and Ravve (2011) provides the required high-resolution, amplitude/phase preserved, full-azimuth angle domain reflection gathers, which are the optimal data for the proposed analysis. VVAZ (e.g., Ravve and Koren, 2016) and AVAZ analyses (e.g., Canning and Malkin, 2009) are first performed to obtain general information about the orientation and intensity of the fracture systems within the reservoirs. The remaining effect on the azimuth-dependent amplitude and phase is associated with the absorption and dispersion caused by the oil-saturated rate at the detected fractures. In a recent work, Inozemtsev et al. (2019) demonstrated the azimuth-dependent sensitivity of the low-frequency components of the migrated reflecting signals along the LAD gathers to the oil saturation. This paper can be considered a continuation of the previous one, with the additional involvement of machine learning for detailing the fracture (small faults) system disturbances within the reservoirs.


[1] Emerson | [2] JSC GSD-POLE | [2] JSC SINTEZ PETROLEUM

[*] Corresponding author, E-mail: Alexander.Inozemtsev@emerson.com


DOI: 10.3997/1365-2397.fb2021067

## Method and technology

This paper presents a new approach and technology for azimuth-dependent facies analysis (referred to as facies analysis versus azimuth – FACIVAZ) to improve the accuracy of the qualitative prediction of hydrocarbon-saturated permeable fractures in terrigenous and carbonate reservoirs, as well as detailing the system of faults that from the tectonic framework of the oil field.

It has been shown by, for example, Novikov, Lisitsa and Kozyev (2018) that when compressional seismic waves pass through a fractured and fluid-saturated medium, there are changes in the amplitude, phase velocity and frequency of the reflected signals. In particular, in fluid-saturated reservoirs with dual permeable porosity (fractures plus matrix porosity or cavities), absorption of low-frequency signal components can occur. Some examples of these effects from Western Siberia are presented in the monograph by Kozlov (2007).

The sensitivity of the absorption rate of the low- and high-frequency components of the reflected waves to the relative directions between the propagating waves and the fracture orientations, has also been shown by Inozemtsev et al. (2019). In this paper we demonstrate that the low-frequency components of the reflected waves are subject to greater absorption across cracks, whereas the high-frequency components are considerably attenuated along cracks. Although the absorption rate (for both directions) can reach one octave (Figures 1, 2), it is higher for high-frequency components. Our study is performed over a reservoir located at a Paleozoic basement in West Siberia. The general direction (azimuth) of the aligned fracture systems is about 130 degrees with respect to the north (northwest to southeast; two parallel blue lines below the images in Figure 1), where the normal direction (across the fractures, indicated by a red line) is about 40 degrees with respect to the north. Note that the normal direction also represents the symmetry axis direction of the considered anisotropic media (transverse isotropy with horizontal symmetry axis – HTI). Figure 1A shows a full-azimuth 0-360° stack image, where the blue rectangle indicates the target reservoir area. Figures 1B and 1C show two images at the same place created by stacking traces with certain azimuth ranges (sectors), 115°-145° (green rectangle along the fractures) and 25°-55° (red rectangle across the fractures), respectively. The corresponding amplitude spectra for the data within the blue, green and red rectangles are plotted in Figure 1D.

It can be clearly seen that the seismic image within the green rectangle (Figure 1B – along the fractures) and its corresponding amplitude spectrum (green curve in Figure 2) are quite different from the seismic image within the red rectangle (Figure 1C – across the fractures) and its corresponding amplitude spectrum (red curve in Figure 2). In the direction across the fractures (red, 14 to 33 Hz) the amplitudes of the low-frequency components are mainly attenuated (absorbed), whereas along the fracturs, the high frequencies are mainly attenuated. It is interesting to note that only the low-frequency components of the full-azimuth stack image (Figure 1A and the corresponding blue curve in Figure1D) are mainly affected (attenuated). These characteristic results agree with the observable characteristics of azimuth-dependent reflections from oil-saturated fracture reservoirs in other regions. In this work, we use the ability to differentiate between these azimuthal and frequency dependent characteristics of the signal shapes to detect seismic facies (FACIVAZ analysis) in order to obtain a more accurate qualitative prediction of hydrocarbon-saturated fractures in terrigenous and carbonate reservoirs. A comparison between the results obtained from the FACIVAZ analysis and information from actual production wells shows substantial agreement. The proposed FACIVAZ significantly increases the lateral resolution of the seismic facies within the production reservoirs. The FACIVAZ method also increases the reliability of separating between oil-saturated and dry fractures,

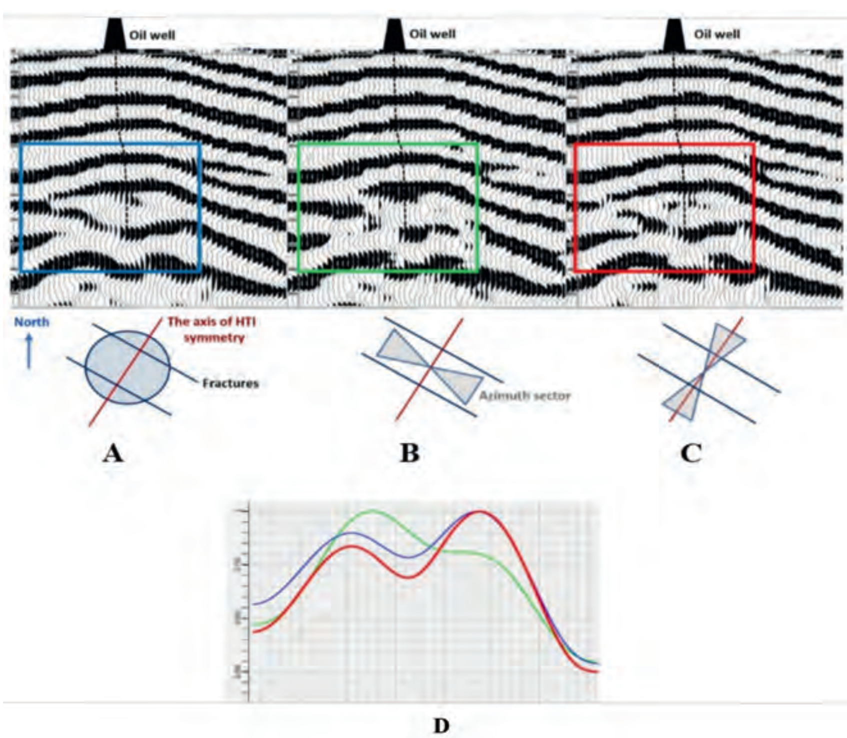


**Figure 1** Changes in the trace shape depending on the azimuth direction of the seismic sector analysis in the oil-saturated reservoir interval. (A) full azimuth stack: 0-360°; (B) azimuthal sector stack: 115-145°; (C) azimuthal sector stack: 25-55°. Paleozoic basement / West Siberia. (D) – Amplitude-frequency spectra of the three images. Paleozoic basement in West Siberia.

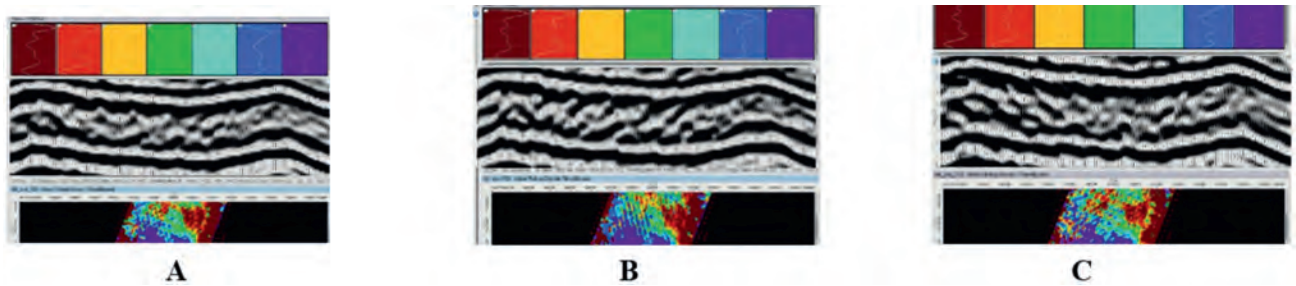


**Figure 2** Changing the shape of the traces and the classes depending on azimuth. Lower Chalk (K1). Neokom. Western Siberia. (A) Full Azimuth 0-360 °, (B) Sector 135º-180º, (C) Sector 45º-90º.

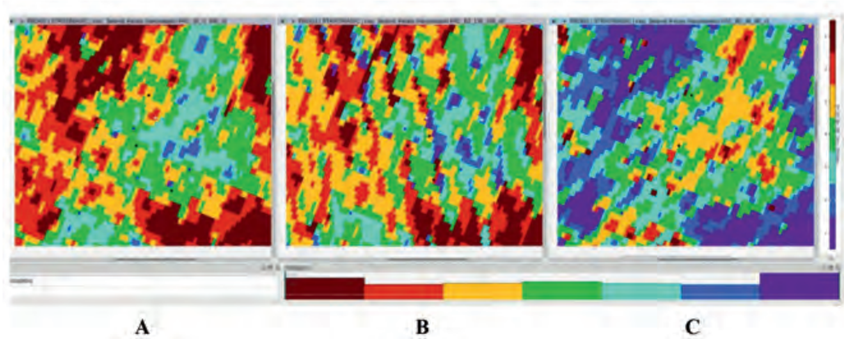


**Figure 3** Maps of seismic facies in the interval of oil-saturated reservoirs for different azimuth sectors: (A) Full azimuth 0-360°, (B) 135º-180º, (C) 45º-90º. Pinch-out zones, Lower Cretaceous (K1), Neokom. Western Siberia.

which is extremely valuable information when planning new wells in the production area.

In addition, this paper proposes a machine learning approach for improving fault system detection using principal component analysis (PCA). This methodology can be efficiently and accurately applied to automatically classify different seismic facies and identify faults at the map levels.

## Results and example predictions

Figure 2 shows the process and results of comparing machine learning using the principal component method in the seismic facies analysis of full-azimuth data for different azimuthal sectors as well as a full-azimuth stack.

In the machine learning stage, seven track shapes (classes) were selected for each azimuth sector. Automatic transformation operators were applied for all three variants, resulting in three seismic facies maps.

Figure 2 shows the classes and seismic facies map from different azimuthal stacking options: the full azimuthal stack (left), the sector stack along the HTI axis (centre), and the sector stack orthogonal to the HTI axis (right).

Note the main features of the results. The maximum trace reshaping effect corresponds to the sector along the HTI axis (B). It is in this sector that the wedge-shaped forms of terrigenous layers are best distinguished.

Figure 3 shows the results of FACIVAZ analysis at the level of final maps in the interval of the oil-saturated terrigenous reservoirs (Age K1, Neocomian, oil field in Western Siberia). The seismic facies maps obtained from different azimuthal sectored and full-azimuthal stacks are fundamentally different in the lateral distribution of seismic facies.

An analysis of the seismic facies maps shows, depending on the azimuth, the structure of the seismic facies distribution changes. The seismic facies associated with the wedge formation are identified as regular systems (Figure 3B). In Figure 3B (azimuthal sector stack along the HTI symmetry axis) the correlation between the well productivity information and the distribution of the same seismic facies is 88%. In Figure 3A (full-azimuth stack), the correlation between the well information and the similar seismic facies is 63%. In Figure 3C (azimuthal sector stack perpendicular to the axis of symmetry HTI), the correlation is 52%.

The statistics for assessing the correlation between productive dry and water-saturated wells, and the same type of facies zone information, used information from 14 wells. Note the fundamental feature of the azimuthal analysis of seismic facies – the full-azimuthal sum (the traditional approach to analysing seismic facies) gives a highly smoothed version of the seismic facies distribution, masking many important geological details.

Figure 4 shows the results of FACIVAZ analysis in the interval of an oil-saturated fractured carbonate reservoir in another oil field, in the Middle Volga region in the CIS. Carbonate reservoirs are D-3 age and represent a total thickness of carbonate strata of up to 800-1000 m. Oil traps are associated with barrier reefs that spread in the carbonate strata at different depths and are localized laterally.

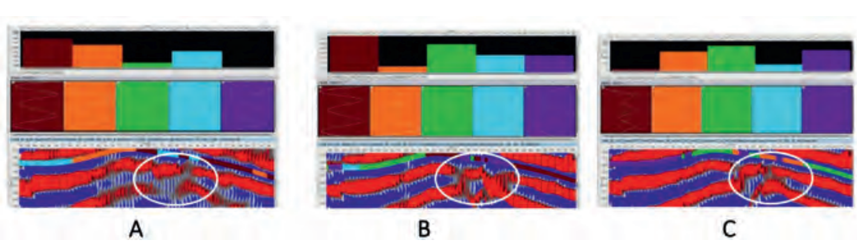


**Figure 4** Selection of templates (classes) for sectored azimuth analysis of seismic facies: (A) = 60º-90º, (B) = 140º-170º, (C) = 0º-360º. Below are the stacks for the different azimuthal sectors. The zones of the oil-bearing part of the reservoir are marked with ovals.

In this example, five classes (templates) are selected for the machine learning stage. The classes have a significant difference in this oil field, depending on the azimuthal directionality of the sector data. Similarly, the form of recording changes quite sharply, depending on the azimuthal direction. As in the previous examples, the full-azimuth stack gives the averaged version of the classes for machine learning.

Figure 5 shows the final seismic facies maps for predicting promising areas in the interval of oil-saturated carbonate reservoirs.

The results of interpretation of the seismic facies maps for the target carbonate interval show a similar tendency – the most promising azimuthal direction of analysis and prediction coincides with the direction of the HTI anisotropy symmetry axis (across fractures). In Figure 5A, all three productive wells are located within the same seismic facies. In Figures 5B and 5C, productive wells are distributed according to different seismic facies.

Below are the results of the FACIVAZ forecast for one of the oil fields in the terrigenous deposits of the Jurassic (J2) in West Siberia.

Figure 6 shows the results (maps) of the seismic facies prediction at the target reservoir area, performed using a traditional seismic facies analysis (Figure 6A) and the proposed FACIVAZ technology, using the azimuthal sector stacks along the fractures (Figure 6B) and across the fractures (Figure 6C). The figures also provide information about the location of the production wells. The target reservoirs are mainly composed of sandstones and clays from the terrigenous sediments of the Jurassic period.

The results of Figure 6 show that the new technology enables a more accurate prediction of the productive zones in the fractured sandstone reservoirs. Brown-yellow colours indicate the seismic facies that correspond to the area of sandstone fractured-porous reservoirs. Green and light/dark blue colours indicate the seismic facies associated with clays and clayed terrigenous strata. The seismic facies map generated from the azimuth sector stack across the fractures (Figure 6C) shows that three productive wells fall into the seismic facies distribution zone associated with fractured-porous oil reservoirs, and a non-productive well is in the seismic facies distribution zone associated with the clayed formations. The facies maps generated by the traditional method (Figure 6A) and by the azimuth sector stack along the fractures (Figure 6B) are fundamentally different and do not agree with the existing production wells. An unproductive well falls into the zone related to the productive facies; on the other hand, some of the production wells fall into the zone related to the facies of clayed sediments.

Finally, we present the results of a new approach to applying machine learning to more accurately detail fault systems at the map level. The method is based on principal component analysis (PCA) applied to the stack volume after a diffraction filter is applied to the directional gathers.

Figure 7 shows the process of creating classes and obtaining results in the form of maps of disturbance fault systems, the details of which carry additional important information.

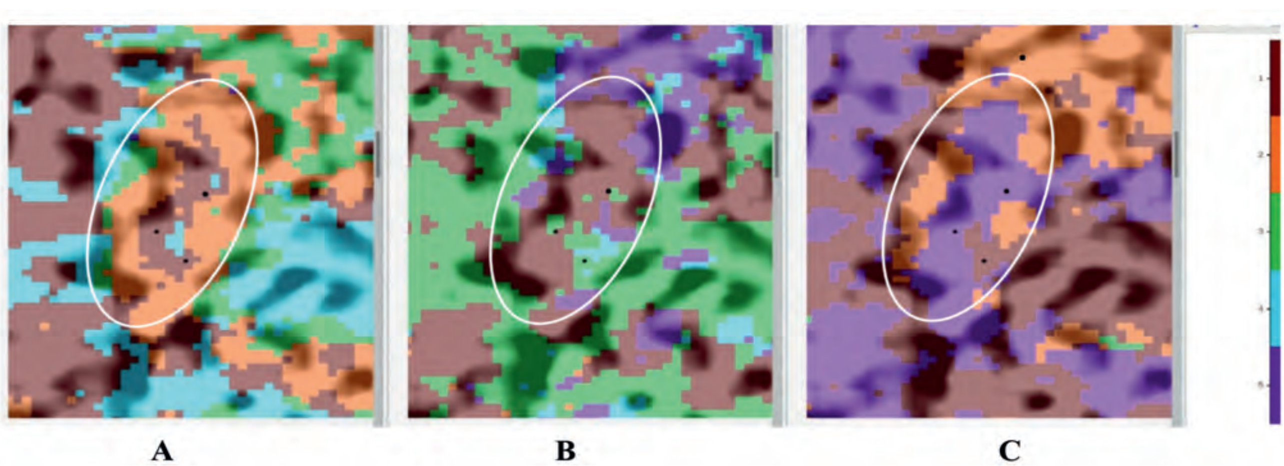


**Figure 5** Distribution of seismic facies in a carbonate reservoir depending on the azimuthal direction of the stack sectors. (A) along the HTI axis of symmetry, (B) across the HTI axis of symmetry, (C) full-azimuthal stack.

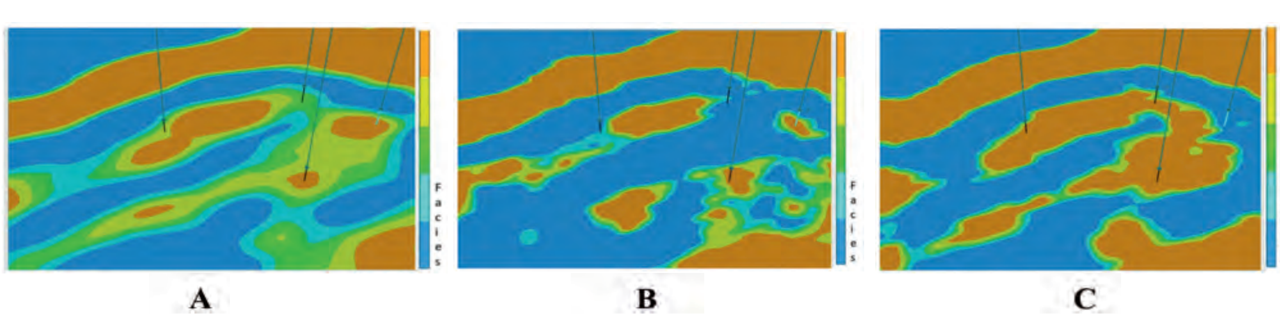


Figure 6 (A) Predictive map of seismic facies analysis, obtained through traditional analysis using the full-azimuth stack: 0-360°. Productive wells in the target interval are highlighted in black, non-productive wells in blue. (B) Predictive map of seismic facies analysis obtained with the proposed FACIVAZ technology using the azimuth sector oriented along the fracture. (C) Predictive map of seismic facies analysis obtained with the proposed FACIVAZ technology using the azimuth sector oriented across the fracture.

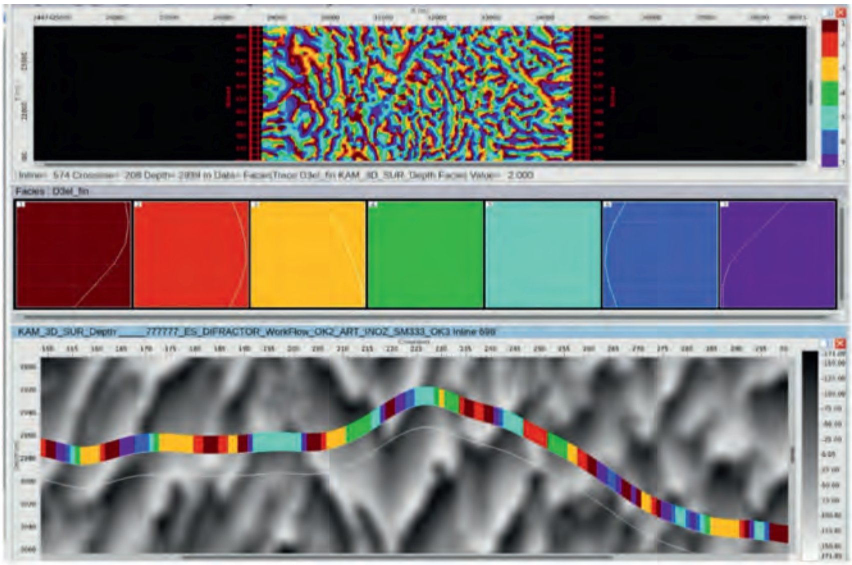

**Figure 7** The selection of classes in the narrow depth interval for machine learning using the diffraction cube obtained in LAD domain processing.

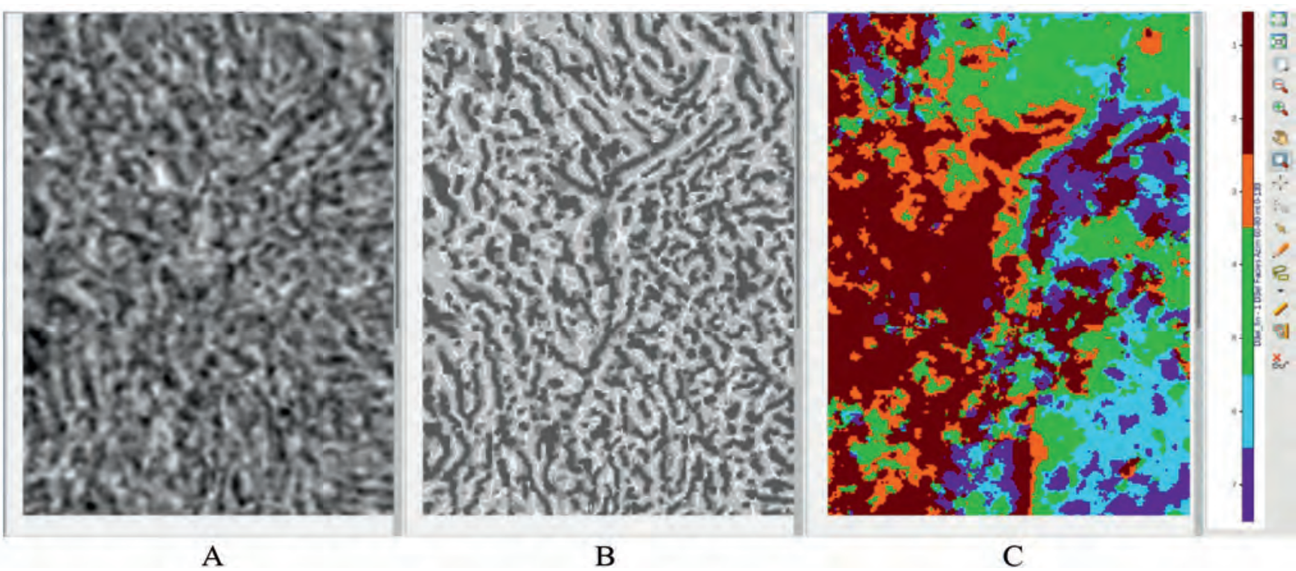


**Figure 8** Interpretation of two maps showing fault/fracture systems and a seismic facies map: (A) Fault map obtained with the diffraction filter technology from directional gathers. (B) Fault map obtained from diffraction cube through machine learning using the principal component method. (C) A map of seismic facies in the azimuthal sector along the HTI axis of symmetry.

In the process of optimizing the selection of the narrow depth interval for calculating classes and their number, optimal parameters were established: the calculation interval is 10-20 m and the number of classes is 7. Figure 7 shows that the classes (etalons) for machine learning have a rather sharp difference. In general, this forms the precondition for a detailed identification of the fault signatures.

Figure 8 shows a comparison between the final maps of disturbance fault systems and the map of seismic facies analysis obtained as a result of machine learning in the azimuthal sector along the HTI axis of symmetry.

By comparing the different options, one can see that the disturbance map (B) after an additional application of machine learning is much more detailed than without machine learning. The map clearly shows a regional fault disturbance along the length of which the barrier reef was formed. The local system of faults associated with the regional faults is also distinguished with greater detail and resolution along the lateral.

## Conclusions

This paper presents a new approach to seismic facies analysis referred to as FACIVAZ, which is based on the physical effects of azimuth-dependent absorption. It is aimed at providing more accurate qualitative seismic facies prediction of permeable fracture zones than that achieved through traditional seismic facies analysis. The practical results of using FACIVAZ give more reliable information for predicting the distribution of seismic facies and their relationship with oil-saturated fractures. The borehole information confirms the promise of a wider use of FACIVAZ technology in the study of terrigenous and carbonate fractured hydrocarbon reservoirs. The results are more consistent with well productivity data and can serve as valuable information when planning new wells. The accuracy and consistency of the FACIVAZ results and the well information give rise to the use of the technology as an additional tool for improving accuracy in high-quality reservoir prediction. A new approach to the detailing of fault systems based on machine learning along target map levels provides higher resolution and lateral detailing of the existing fault systems that comprise the tectonic skeleton of the oil and gas field. In the case of seismic facies interpretation, both approaches increase the reliability of predicting promising areas for drilling.

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