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3D geological modelling for prospectiveness evaluation of shale formations

The article presents the possibilities of applying geological modelling methods in data integration processes for the purpose of the exploration of shale formations and the evaluation of their prospectiveness in terms of the occurrence and quality of unconventional hydrocarbon reservoirs. The analysis involved an onshore part of the Baltic Basin, where Silurian and Ordovician shale formations are the subjects of exploration. The study was carried out in two stages of data integration, i.e.: the integration and interpretation of a wide range of borehole data, and the analysis, integration and processing of coherent well logs and 3D seismic data using the methods of geostatistical 3D modelling. A workflows are presented for modelling the spatial variability of the petrophysical and geochemical parameters determining the prospectiveness of shale formations, i.e. porosity, the organic matter content TOC, as well as the saturation of pore space with reservoir fluids. The validity of the use of 3D seismic data with respect to the prognosis of shale formation parameters has been evaluated. The possibilities of the application of geological modelling results in the identification of zones with the most favourable rock properties, and in the evaluation of the resource potential of shale formations, are also discussed.

Key words: 3D geological modelling, shale formations prospectiveness, Silurian and Ordovician shales, Baltic Basin.

Modelowanie geologiczne 3D w procesie oceny perspektywiczności formacji łupkowych

W artykule przedstawiono możliwości zastosowania metod modelowania geologicznego w procesach integracji danych dla celu rozpoznania formacji łupkowych i oceny ich perspektywiczności pod kątem występowania niekonwencjonalnych złóż węglowodorów. Analizie poddano lądowy fragment basenu bałtyckiego, gdzie przedmiotem eksploracji są formacje łupków syluru i ordowiku. Przeprowadzone prace obejmowały dwa etapy integracji danych, tj.: integrację i interpretację szerokiego zestawu danych otworowych oraz analizę, integrację i przetwarzanie metodami geostatystycznego modelowania 3D spójnych profili otworowych oraz danych sejsmiki 3D. Zaprezentowano tok postępowania w procesie odtwarzania przestrzennej zmienności parametrów petrofizycznych i geochemicznych determinujących perspektywiczność formacji łupkowych, tj. porowatości, zawartości substancji organicznej TOC oraz nasycenia przestrzeni porowej mediami złożowymi. Ocenie poddano celowość aplikacji danych sejsmiki 3D w zagadnieniach prognozy parametrów formacji łupkowych. Omówiono możliwości wykorzystywania wyników modelowania geologicznego w identyfikacji stref o najkorzystniejszych właściwościach skał oraz ocenie potencjału zasobowego formacji łupkowych.

Słowa kluczowe: modelowanie geologiczne 3D, perspektywiczność formacji łupkowych, sylurskie i ordowickie formacje łupkowe, basen bałtycki.

Introduction

An evaluation of geological formations in terms of their prospectiveness as potential unconventional hydrocarbon reservoirs consists in a number of actions involving, e.g.: petrophysical, geochemical, geomechanical laboratory examinations, macro- and microscopic descriptions of core

material and sedimentological interpretations, as well as the processing and interpretation of geophysical borehole logging data and seismic data.

Considering the above, actions involving geological modelling constitute a form of synthesis for the results of the above-

mentioned partial analyses, since the information integrated as part of a 3D geological model results from the performed interpretations of borehole, laboratory and seismic data.

The paper presents a study of the exploration of Silurian and Ordovician shale formations in the area of one of the concessions within the onshore part of the Baltic Basin,

executed as part of the research conducted in recent years in the Department of Geology and Geochemistry of the Oil and Gas Institute – National Research Institute, the Blue Gas project (Fig. 1).

The work included the integration and interpretation of a wide set of drilling and seismic data, along with their analysis and processing using the methods of 3D geostatistical modelling. The results of the conducted modelling constitute a prognosis of spatial variability of the shale formation parameters, primarily those which decide about its prospectiveness as an unconventional gas (shale gas) or oil (shale oil) reservoir. Integration of all the available data was handled in two stages; in the first one, a complex interpretation of the data obtained in borehole profiles was conducted, e.g. by: distinguishing the prospective shale intervals (a total of 6), and performing an interpretation of

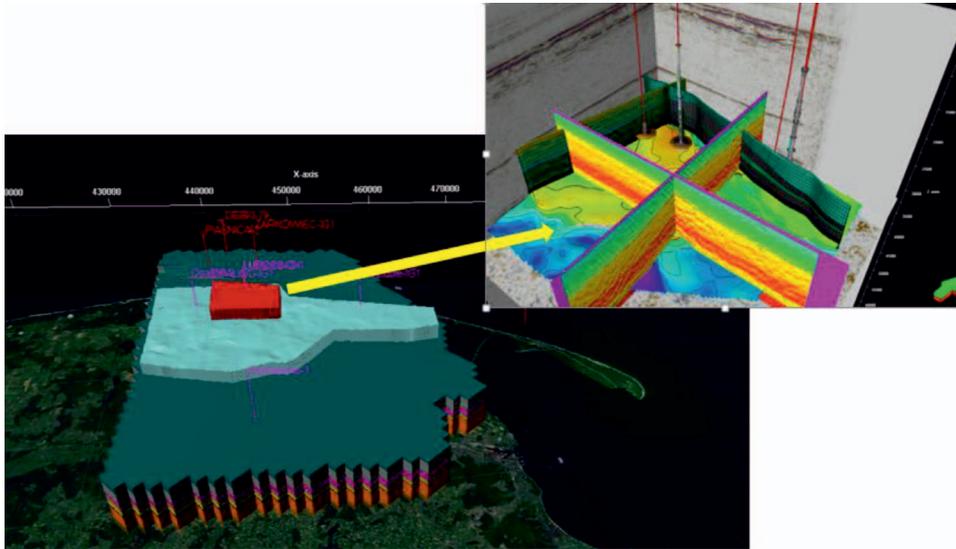


Fig. 1. Location of the analysed area: red marks the block of the presented model against the extent of the concession (dark green)

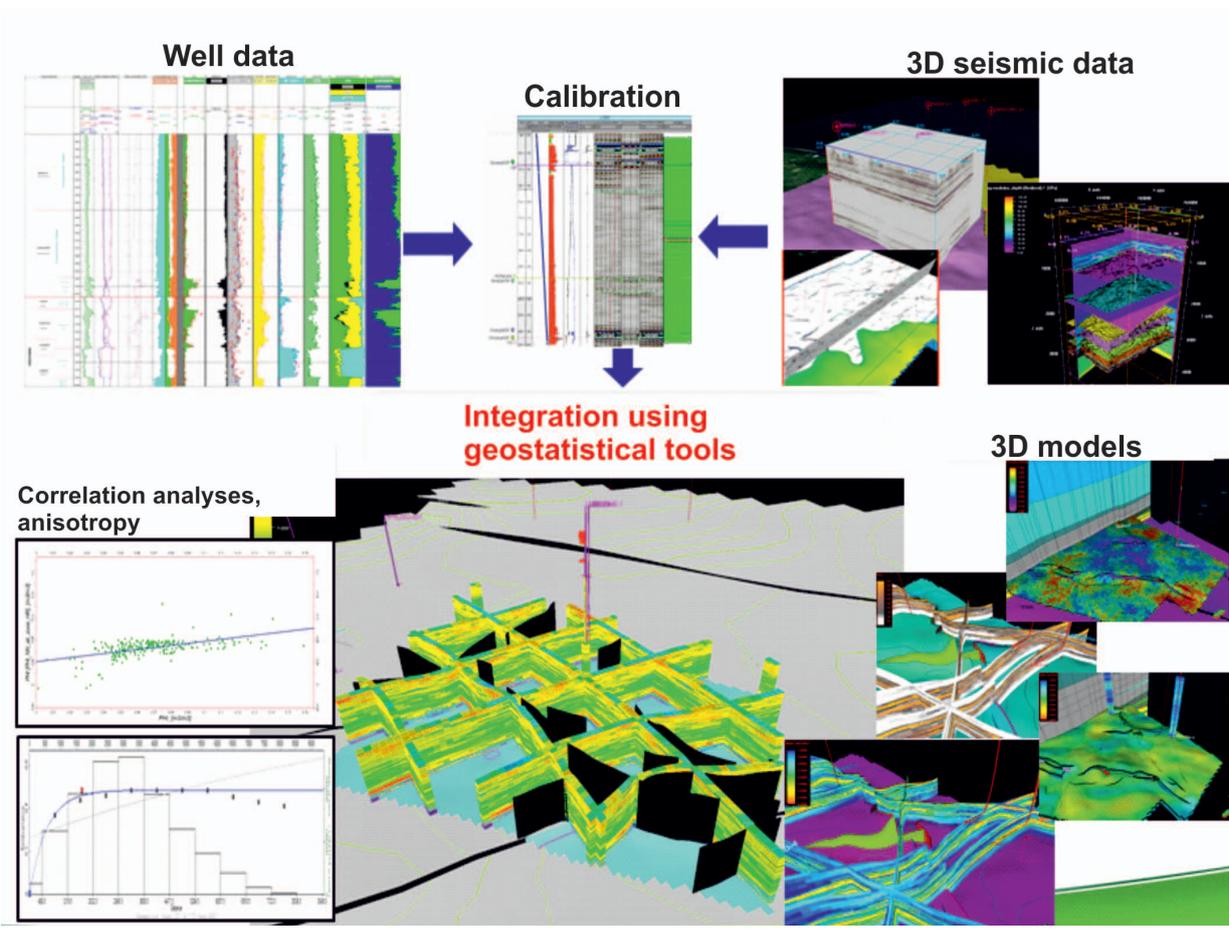


Fig. 2. A chart of a two-stage process involving the integration of the borehole and seismic data related to 3D geological modelling of shale formations

the mineralogical, petrophysical and geochemical parameters, the character of fluid saturation, etc. During the second stage, a spatial structural model was developed, which defines the geometry of geological formations, including the demarcated prospective intervals. The calibration and integration of borehole profiles with the results of the qualitative and quantitative interpretation of seismic data has also been conducted. The final stage involved 3D quantitative modelling of the distributions of primary shale formation parameters (Fig. 2).

The analysis of unconventional reservoirs required putting special emphasis on the modelling of a wider range of features and the parameters of the reservoir rock (being also the source rock). These are, apart from geometry and the architecture of facies and spatial distributions of reservoir and filtration parameters, also other rock properties. These properties determine the prospectiveness of shale formations, e.g.: the organic matter content (TOC), as well as the

mineralogical composition of the rocks, determining their susceptibility to the hydraulic fracturing procedures.

In the process of structural modelling and quantitative modelling of shale formation parameters, two independent blocks of geological – geophysical data are applied at the same time (wellbore and seismic data), allowing for a more credible prognosis of the characteristics of geological formations in the inter-borehole zones.

The results of geological modelling, realised in a spatial form, allow for a quantitative evaluation of the prospectiveness of shale rocks, meaning the demarcation of depth intervals with the best parameters and the most promising zones of the studied area, located externally in relation to the boreholes (sweet spots). Properly processed results of geological modelling also allow for a spatial form of the prognosis of the distribution of hydrocarbon resources accumulated in unconventional shale formations.

Integration of data in borehole profiles

An important element distinguishing the reservoirs of natural gas and oil contained in the clayey-mudstone rocks is the fact that the gas is present in the source rock, where it was generated. Therefore, the source rock also serves the function of a reservoir rock, and considering the petrophysical properties of clayey rocks and the high required thickness of such a complex, they can also be classified as a sealing rock. Under such conditions, natural gas is generated in situ, and the migration occurs on a micro-scale or does not take place at all [5, 11, 12]. This has crucial importance in the process of the integration of various data acquired from laboratory examinations of drill cores, the results of the conducted interpretation of geophysical borehole logging, as well as the data obtained from the performed fracturing procedures. The critical problems, which the interpretation of petrophysical shale rock parameters must face, are e.g.: the complicated and nonuniform structural model of the mineral frame, as well as the presence of a considerable amount of clay grains,

which in the case of Polish shale formations recurrently exceeds 50% of their volume. Furthermore, the presence of organic matter (kerogen), occurring at a specified degree of thermal transformation, and the complicated structure of rock porosity, especially the presence of porosity within the organic matter, caused difficulties in the quantitative estimation both in the laboratory and during the development of mathematical models. Additionally, the necessity to take into account the adsorption of gas on the surfaces of organic grains completes the scale of difficulty encountered when attempting to methodologically approach data integration and the quantitative analysis of the petrophysical parameters of source rocks being a potential source of hydrocarbons. The procedure of the integration of data in borehole profiles presented in the paper is not limited in its form, and at the current stage of exploration of Polish shale formations brings up important methodological problems from the standpoint of resource estimation.

The organic matter content TOC (Total Organic Carbon)

The problem of the continuous estimation of the organic carbon content TOC, whose proper level conditions categorise the studied formation as a potential source rock, has been discussed for years in the worldwide literature. The most common methods used for its determination are: correlation with the uranium content [1, 7], provided the spectrometric measurements of natural gamma radiation are available, and the fully quantitative Passey method, [9] modified by Bowman [2]. Based on the geochemical RockEval laboratory measurements,

a method based on an acoustic-resistivity cross-plot has been used to determine this parameter. The analysis of this relation leads to the determination of the so-called Low Resistivity Shale Line (Fig. 3), by means of which it is possible to convert the logarithm of resistivity readings LogRT into acoustic readings DTR presented in $[\mu\text{s}/\text{m}]$ [2]. The difference between the readings of the original DT and the recalculated DTR loggings ΔDT is a function of the TOC content, which may be presented analytically by a linear relation (1):

$$TOC = C \cdot \Delta DT \tag{1}$$

where:

C – calibration constant,
 $\Delta DT = DT - DTR$.

The calibration constant C is calculated using the linear regression method based on the laboratory data.

Although the abovementioned approach gives generally good results, attention should be paid to the fact that this is not a universal concept. This method is to be used with due care, taking into account the possible impact on the shape of the curves of factors other than the TOC content, such as: the presence of free hydrocarbons in the formation, and lithological changes, e.g. increases in the carbonate content. These factors cause ambiguity of the obtained results. In general, it should be concluded that the calibration procedure and calculation of the C constant is to be limited to uniform fragments, in terms of sedimentation conditions, of the profile.

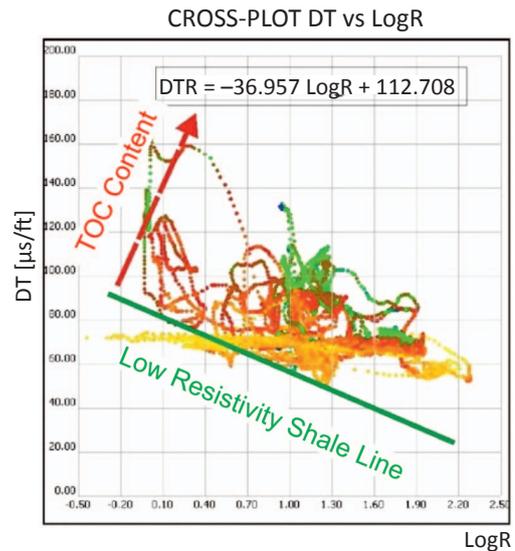


Fig. 3. A sample cross-plot for determination of the LRSL (Low Resistivity Shale Line). The colours on the chart represent the values of natural gamma radiation logging for the individual points (red – highest readings on the curve, green – lowest readings)

Construction of a mineralogical model

The discussed model is the main element for the integration of laboratory data: XRD, porosimetry, the NMR data, the geochemical RockEval data, the Dean-Stark measurements, as well as the geophysical borehole logging data. It is an effect of a compromise between the variability of the values of individual laboratory results and the effect of the action of the quantitative interpretation algorithm being at the interpreter's disposal and organised into separate software systems (Techlog, Interactive Petrophysics, ProGeo etc.). Most algorithms seek a solution based on a function of minimum discrepancy between the input data (geophysical borehole logging) and the results of a solution for a simple multidimensional problem, meaning the theoretical loggings resulting from the current execution of the solution. An example of the quantitative interpretation of an arc profile is presented in Figure 4.

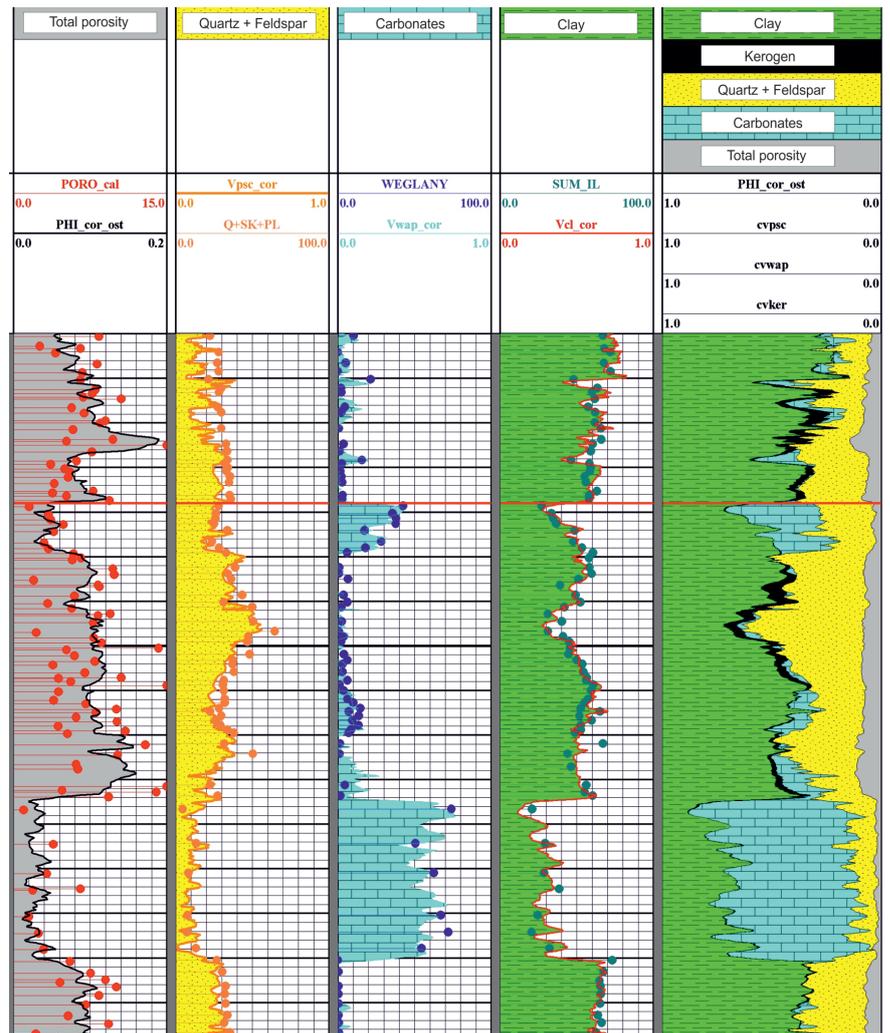


Fig. 4. A fragment of the profile with the interpretation results for mineral composition and total porosity. Description of individual tracks: 1 – porosity, 2 – Q + Sk + P (quartz + feldspars + plagioclases), 3 – carbonates, 4 – clay content, 5 – lithological listing

Porosity analysis

Adequate resource estimation depends on the proper determination of the effective porosity, creating the space for the accumulation of hydrocarbons. However, determining porosity in highly clayey sediments which also contain kerogen is not easy. Porosity of organic matter is a function of the degree of thermal maturity and the type of kerogen, and it depends on the decomposition of organic matter during the generation of hydrocarbons. The porosity of organic matter usually highly affects the total calculated porosity of the rock.

It has been assumed that due to their hydrophilic nature, the pore space of clay minerals is filled with water, and the total porosity should be diminished by the water bound with clay minerals.

Effective PHI = total PHI – PHI of clay minerals

The total porosity diminished by the porosity of clay minerals – the effective PHI – has been calculated by the Techlog software using the neutron-density method, taking into account the impact of the clay content, using the commonly known geophysical formulas (2).

$$\begin{aligned}\Phi_T &= \frac{\rho_{ma} - \rho_B}{\rho_{ma} - \rho_f} \\ \Phi_{Tsh} &= \frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f} \\ \Phi_{De} &= \Phi_T - (\Phi_{Tsh} \cdot V_{sh}) \\ \Phi_{Ne} &= \Phi_N - (\Phi_{Nsh} \cdot V_{sh}) \\ \Phi_{ND} &= \sqrt{\frac{\Phi_{Ne}^2 + \Phi_{De}^2}{2}}\end{aligned}\quad (2)$$

where:

Φ_{ND} – effective porosity, being an average of Φ_{Ne} and Φ_{De} porosities,

Φ_{Ne} – neutron porosity diminished by the porosity of clay,

Φ_{Nsh} – neutron porosity of clay,

Φ_T – total porosity,

Φ_{Tsh} – porosity of clay minerals,

Φ_{De} – effective porosity calculated from the density curve,

ρ_f – density of liquid,

ρ_B – bulk density, read off from the density curve,

ρ_{ma} – rock matrix density,

ρ_{sh} – bulk density of clay minerals,

V_{sh} – volume of clay.

The porosity determined in such a manner does not, however, correspond to the pore space occupied only by free hydrocarbons and water. Depending on the size of pores, both free and adsorbed gas will accumulate in kerogen. Microporosity, where the clearance of pores is below 10 nm, will instead be a place of accumulation for the adsorbed gas, and it is associated with diffusion processes. Pores with diameters above 10 nm, which is the size at which the flow of reservoir fluids is possible, have been classified as open porosity, in which free hydrocarbons accumulate. An attempt has been made to determine open porosity.

It was possible to determine open porosity due to the availability of the XRD laboratory examinations, calculating the percentage of individual minerals within the rock.

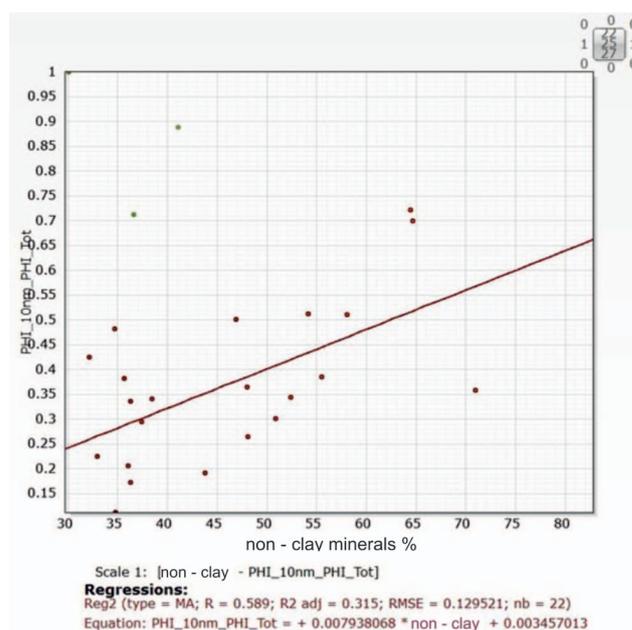
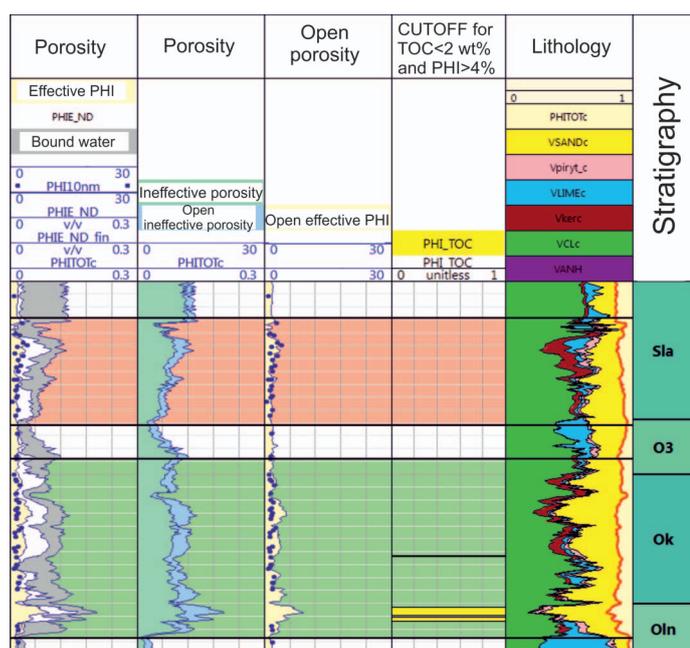


Fig. 5. Sample results of the calculation of porosity (left). A cross-plot of the relation between the open porosity (PHI 10 nm) and the total porosity (PHI_Tot), including non-clay minerals (forming the rock matrix) (right)

In boreholes where the laboratory measurements of porosity were available for pores with diameters >10 nm (PHI_10 nm), a cross-plot was charted for the relation between PHI_10 nm and the total porosity (PHI_Tot) including non-clay miner-

als (quartz, limestones) (Fig. 5). This relation allowed for the determination of the share of open porosity in the total porosity, which constitutes the space for the occurrence of free hydrocarbons and water.

Pore space saturation analysis

Natural gas is present in shales in its free form within the pore space, as well as within fractures and microfractures. Furthermore, shales contain gas adsorbed by insoluble, hydrophobic organic matter. Due to their hydrophilic nature, clay minerals adsorb mainly water. A model of an unconventional reservoir rock is presented below (Fig. 6).

Proper assessment of saturation in shale gas type reservoirs has key significance for the correct estimation of the resources using the volumetric method. The total saturation with hydrocarbons is the sum of free gas filling the pore space of both the organic and inorganic matter, the clayless part of the rock and the adsorbed gas connected to the sorption capacity of the organic matter. A considerable amount of gas is accumulated in shaley reservoirs in very small pores within the organic matter, several nanometres in size. These pores are characterised by good sorptive properties, the gas is adsorbed as a monolayer according to the Langmuir equation on the inner pore walls, by doing so reducing the space available for the accumulation of free gas.

The Langmuir sorption curve determined for samples by means of laboratory examinations has been used to assess the adsorbed gas content. The sorption isotherm indicates the maximum amount of gas which can be adsorbed under the specified conditions of pressure and temperature.

$$VS = \frac{VSL \cdot p}{PL + p} \quad (3)$$

where:

VSL – the Langmuir sorption capacity, the volume of adsorbed gas under maximum reservoir pressure,

PL – the pressure under which half of *VSL* will be desorbed,

p – reservoir pressure,
VS – calculated based on a cross-plot of *VS* (charted for all the available samples from the boreholes located within the studied area) against the TOC content [wt%].

The amount of free hydrocarbons present in a sample and released during pyrolysis at a temperature of up to 300°C – S1, determined in a laboratory during the Rock Eval examinations was used to assess the saturation with free hydrocarbons.

The cross-plot of the S1 value against the organic matter content TOC allowed for the calculation of the oil content curve for individual boreholes based on the laboratory data.

Simultaneously, the calculations of saturation with free hydrocarbons were conducted according to the Simandoux method, used as a standard for sandy-clayey formations, and taking into account the impact of clay content. The results of calculations involved the open porosity considered as the effective porosity, in which the diameter of pores exceeds 10 nanometres. The resistance of the unaffected zone *R_i* and the volume of clay minerals *V_{sh}* were also used as input data. The calculated saturation with water was calibrated with the saturation with water measured in a laboratory using the Dean-Stark method.

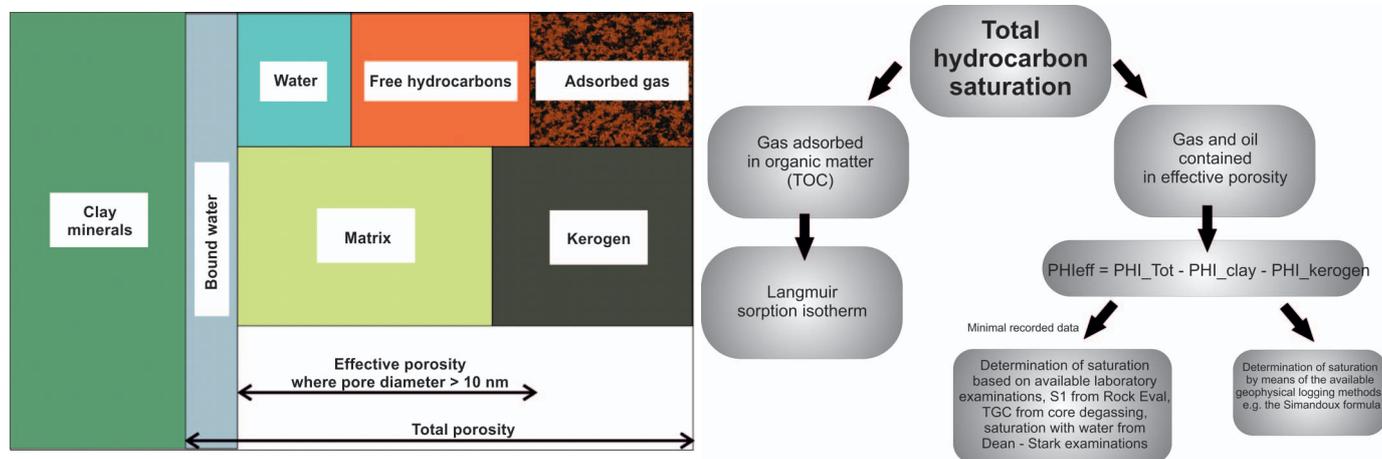


Fig. 6. A suggested distribution model for saturation with water and hydrocarbons in shaley deposits, unconventional reservoir rock (left); the model is adapted for the calculations of saturation in Lower Palaeozoic shaley sediments of the Baltic Basin (right)

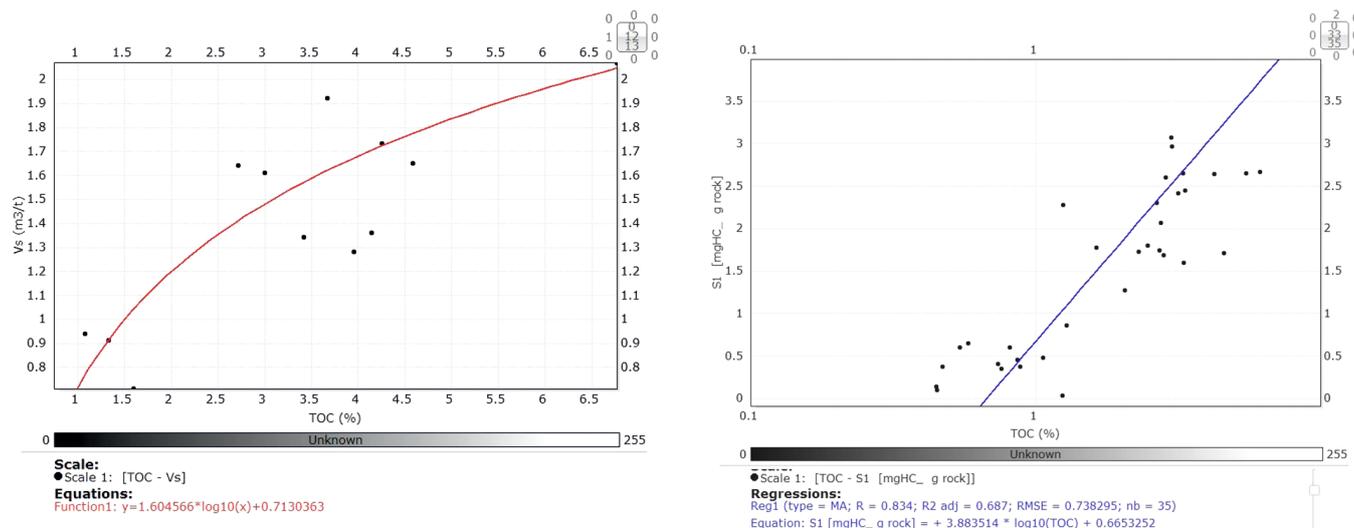


Fig. 7. The relation between sorption capacity V_s [m³/t] and the TOC content [wt%] (left), a cross-plot of the TOC content and the free hydrocarbon content of oil (S_1) (right)

$$\frac{\phi_e^m}{a \cdot R_w} \cdot S_w^n + \frac{V_{sh}}{R_{sh}} \cdot S_w - \frac{1}{R_t} = 0 \quad (4)$$

where:

ϕ_e^m – open effective porosity, diameter of pores > 10 nanometres, m – cementation exponent, $m = 1.8 \div 2$,

R_w – reservoir water resistance,

V_{sh} – the volume of clay minerals, clay content,

R_t – resistance of the unaffected zone,

R_{sh} – resistance of clay,

S_w^n – saturation with water, n – saturation exponent, $n > 2$.

The source levels

The presented methodology of the integration of all the available data allowed for the demarcation of six source levels in the profiles of the analysed boreholes, located within the Polish part of the Baltic Basin, correlated virtually over the whole area. The characteristics of the intervals are described below:

Source 0 – comprises the Upper Wenlock and Ludlow sediments. Represented by the Peplin claystone formation, on the western side gradually replaced by the Kociewie claystone and mudstone formation with lower organic matter content [12]. This is the thickest level, and the contained organic matter is often dispersed. The average TOC content is 0.68 [wt%].

Source I – represented by the Pasłek claystone formation (Upper Llandovery) and the overlying Peplin claystone formation (Wenlock). These rocks are the product of fine-clastic sedimentation which also continued in Ludlow and Příklad. However, with time the amount of mudstone and marly sediments tended to increase in the profile [8]. The average TOC content of this section amounts to 0.96 [wt%].

Source II – comprising the Jantar member of bituminous claystones (part of the Pasłek claystone formation). These claystones belong to the black claystone sub-facies. It consists of black claystones and shales, characterised by fine horizontal lamination manifested by the parallel position of illite flakes and the interchanging darker (clayey or clayey-organic) and

brighter (more muddy) laminae. The black claystone sub-facies is characterised by the presence of deep sea organisms (planktonic graptolites, inarticulate brachiopods) [10]. The high organic matter content reaches an average of 2.41 [wt%].

Source III – the Sasino claystone formation represented mainly by the Caradoc claystones with graptolites, separated from the older Kopalino limestone formation (Llanvirn) by a distinct eroded interface. These are black, dark grey and greenish claystones, commonly bituminous, locally limey. The grain size of the pyroclastic material observed in thin sections indicates a not-so-distant transport of the material to the sedimentary basin [13]. The average organic matter content reaches 2.4 [wt%].

Source III bis – represented by the Arenig Sluchowo glauconitic claystone formation. This level is characterised by varying organic matter content, amounting to an average of 0.54 [wt%] for the Pomeranian boreholes.

Source IV – represented by bituminous shales of the Upper Cambrian, constituting the source rock for conventional hydrocarbon deposits present in the Middle Cambrian sediments [14]. This level features the highest organic matter content, amounting to an average of 5.3 [wt%].

Figure 8 presents the distinguished source intervals based on an example of two mutually correlating boreholes: L-1 and O-2.

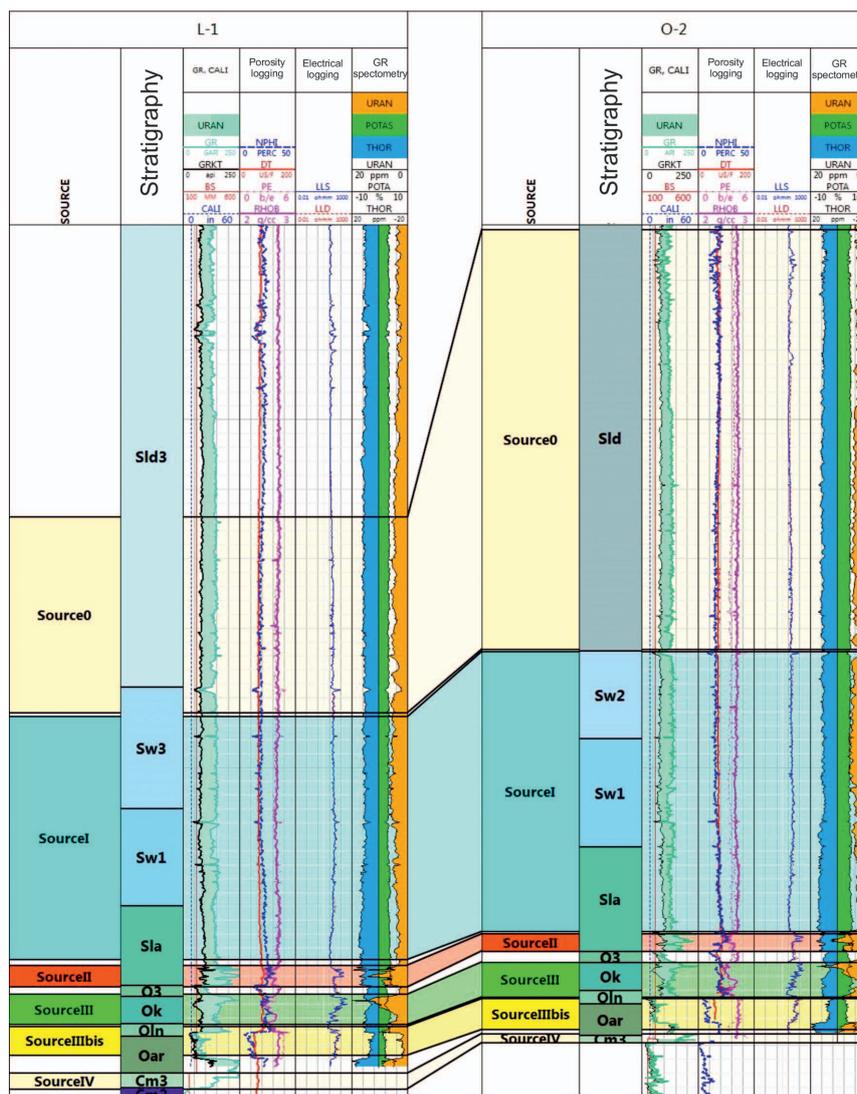


Fig. 8. Correlation of source levels of the Lower Palaeozoic in the Baltic sedimentary basin

Structural model

A parametric characterisation of the reservoir interval requires, at an earlier stage, the construction of a structural model limited vertically and horizontally, determining the volume within which the spatial distributions of the key parameters of geological formations are modelled. The top surface of the model was constituted by a structural plane interpreted based on the 3D seismic data, corresponding to the top of the Reda member of limey mudstones (Middle Silurian limestones) marked by the symbol Sb, while from the bottom the model is limited by the Cm2 surface, corresponding to the top of the Middle Cambrian. In order to allow for correlation analyses to be conducted for the wellbore and seismic data during a later stage, a detailed calibration was performed for these groups of data (Fig. 9).

A set of borehole data (stratigraphic and lithostratigraphic units, TOC curves) has been used in the construction of a structural model, along with the results of the structural interpretation

of the seismic data. The intervals characterised by the elevated concentration of organic matter (TOC) were identified based on the interpretation results for this parameter in borehole profiles, subsequently being demarcated in the geological model as the prospective intervals (Figs. 8 and 10). In total, between the Sb and Cm2 interfaces, 6 zones were distinguished for which the recorded organic matter content TOC exceeded the value of 0.5%. These intervals were investigated as potential levels for the accumulation of natural gas and petroleum (shale gas/shale oil). Among the demarcated source formations, the most prospective ones are the intervals corresponding to the Sasino formation and the Jantar member.

A feasibly precise reconstruction of the geometry of the individual units is particularly important in the case of resource analyses, because the capacity of reservoir intervals is a parameter which in a decisive manner affects the resource potential of the hydrocarbons accumulated within them.

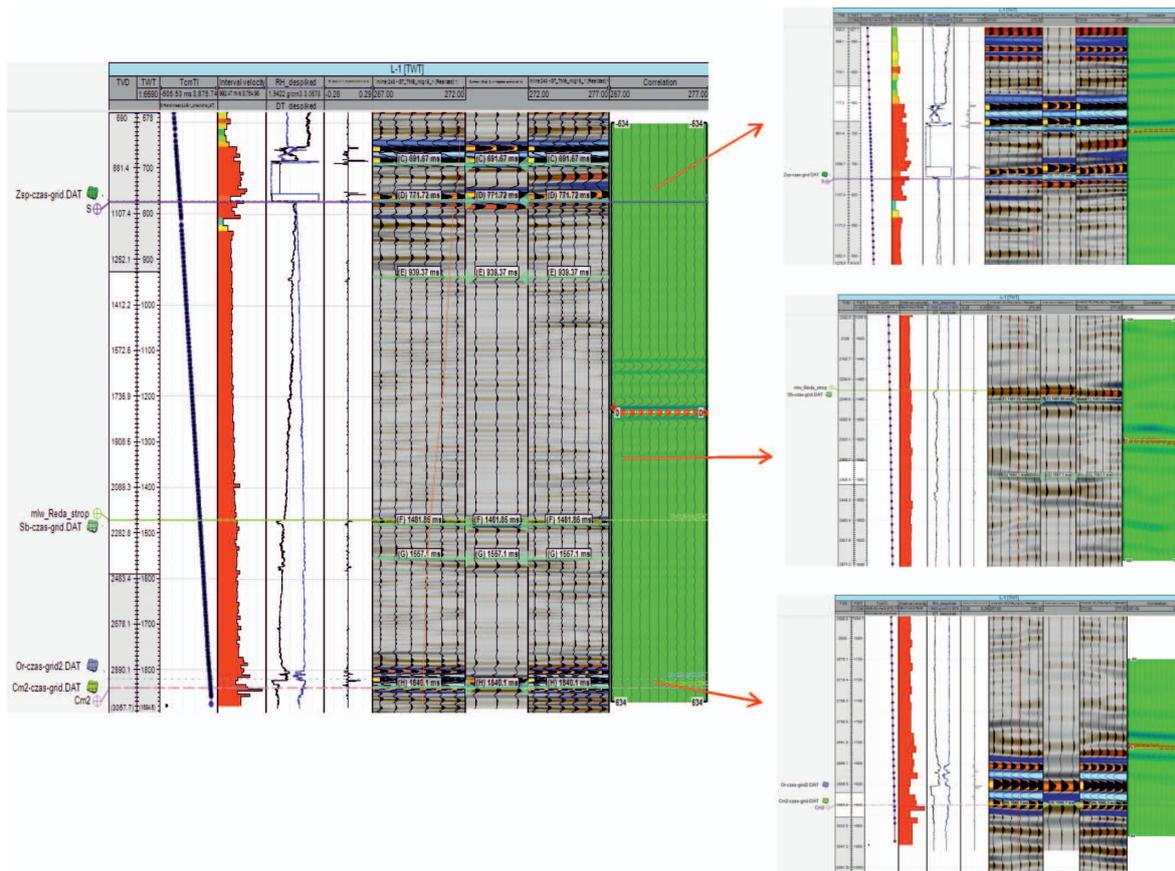


Fig. 9. A synthetic seismogram for one of the boreholes in the studied area. Description of the individual scales: 1 – depth scale, 2 – time scale, 3 – acoustic logging calibrated by measurements of average velocities, 4 – the interval velocity, 5 – density logging (blue) and acoustic logging (black), 6 – values of the reflection coefficients, 7 and 9 – actual seismic traces, 8 – synthetic seismic trace, 10 – discrepancy scale for the actual and synthetic seismic traces

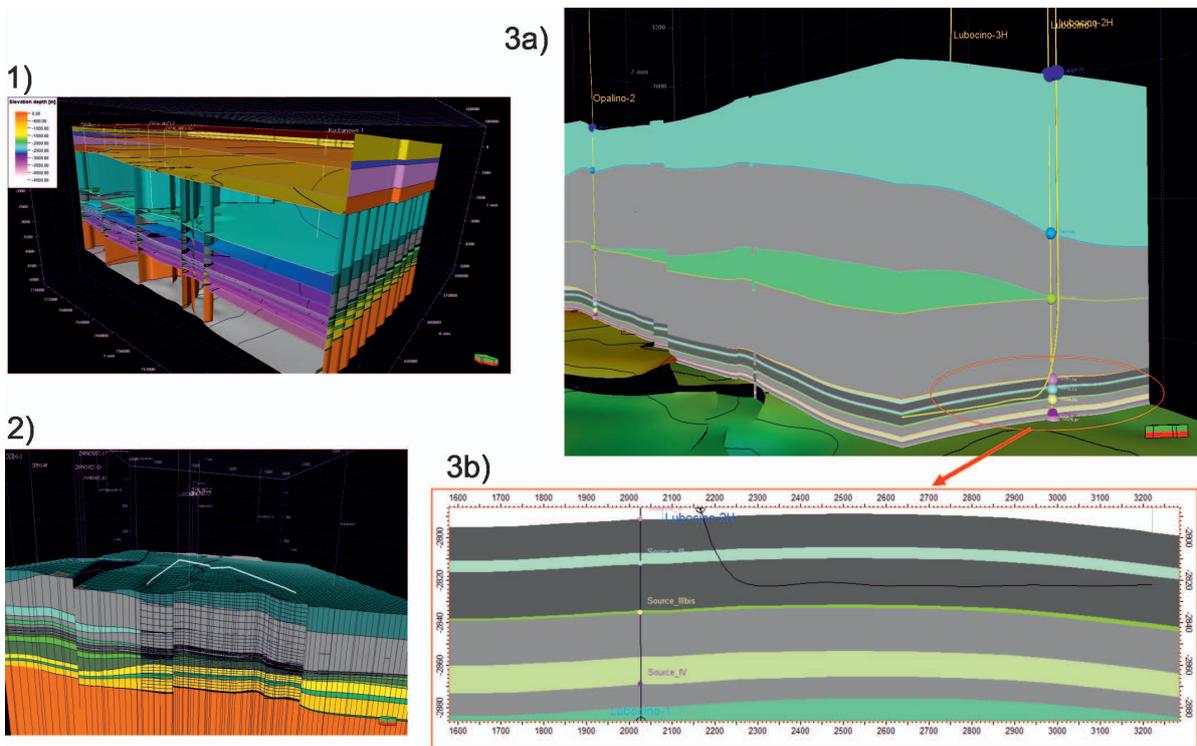


Fig. 10. A structural model of the studied area within the Sb – Cm2 interval with demarcated prospective intervals (grey): 1 – visualisation of the structural surfaces in the whole interval, 2 – the modelled prospective intervals within the Sb – Cm2 interval, 3a and 3b – location and trajectories of vertical and horizontal wells against the structural model

3D models of petrophysical and geochemical parameters of shale formations

Assessment of the prospectiveness of shale formations requires the development of spatial distribution models for parameters indicating their resource potential. In order to calculate the resources of hydrocarbons accumulated within intervals comprising the Jantar member and Sasino formation sediments, 3D distributions have been modelled for the following petrophysical and geochemical rock properties: bulk density, total porosity and effective porosity, organic matter content (TOC), saturation of the pore space of shale rocks with reservoir water (S_w), and the S1 parameter, indicating the free hydrocarbon content of the rock sample undergoing pyrolysis. The results of laboratory measurements, the effects of the interpretation of geophysical borehole logging data, and seismic data in the form of simultaneous inversion results and seismic attributes were used as input data.

In this light, the application of seismic data in the process of modelling the variability of reservoir properties is particularly challenging due to the low contrast of the values of the modelled petrophysical parameters, as well as the seismic attributes within the relatively uniform shale type rocks. Undoubtedly, an advantage of the simultaneous application of two independent blocks of data in the modelling processes for the spatial distributions of geological formation properties results from the fact that the whole studied area or a part of it is covered with

geological-geophysical information, constituting the potential of the higher credibility of prognoses regarding the zones distant from the boreholes with the available more credible laboratory data and the measurements of geophysical borehole logging. A condition for the validity of the use of secondary (indirect) data is the existence of an adequately strong relation between the seismic parameter and the modelled physical feature of the rock. As part of the conducted work, correlations between the abovementioned groups of data were analysed, confirming the validity of using the adequately transformed 3D seismic data in the process of modelling the spatial distributions of porosity, bulk density of the rocks, and indirectly, via the density parameter, and also the organic matter content (TOC).

Total and effective porosity

Porosity of the shale formations is a parameter which to the highest extent affects the amount of the unconventional resources accumulated within them. This is because the volume of the pore space determines the existence of volume for the accumulation of the so-called free hydrocarbons, which along with the adsorbed hydrocarbons contribute to the total sum of hydrocarbons accumulated in shale type formations. In the light of the literature data, the free hydrocarbons account for the major part of the total resources of the shale

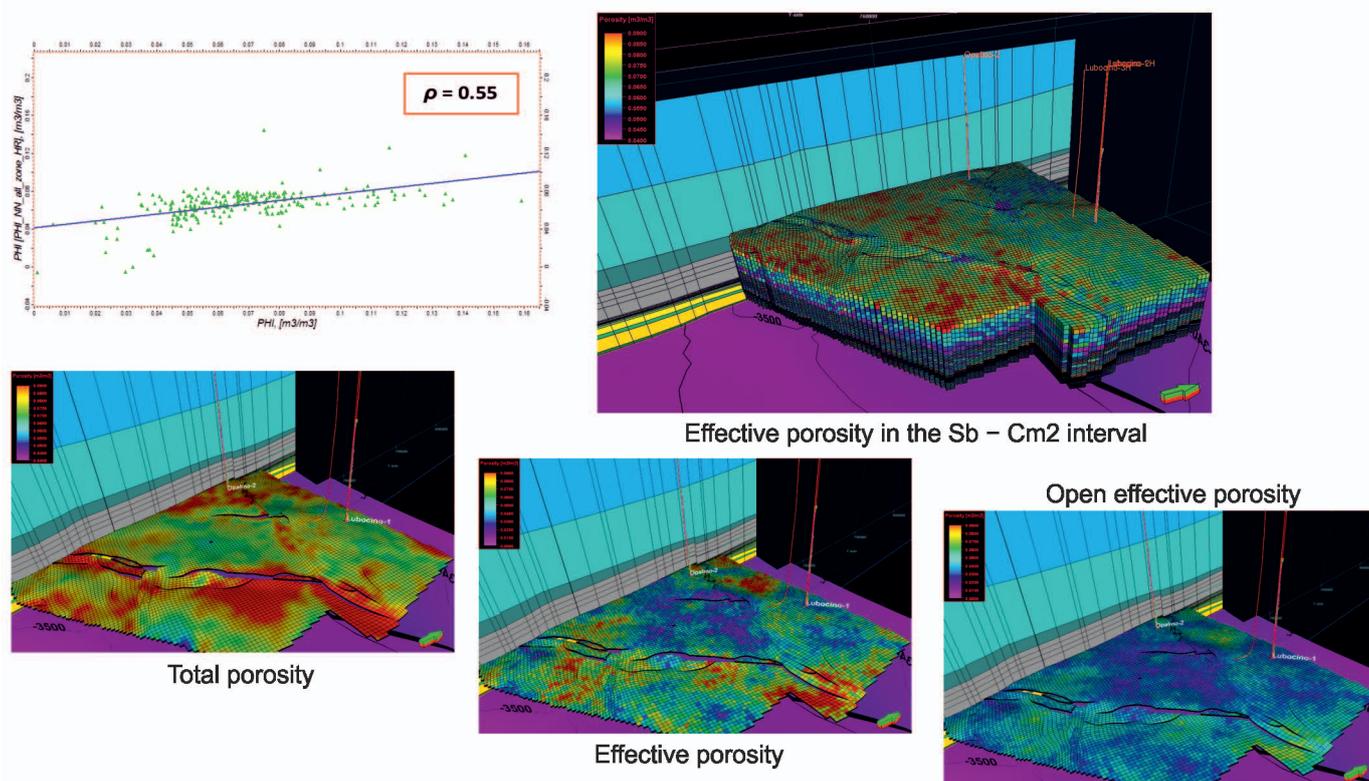


Fig. 11. Results of spatial distribution modelling for the total, effective and open effective porosity; in the top left corner: relation between the total porosity and the seismic meta-attribute of porosity (ρ – linear correlation coefficient)

formations. Moreover, they exhibit a much higher production potential [4]. In the process of modelling the spatial variation of the total porosity, the authors have attempted to adjust the methodology developed for the conventional reservoirs, which uses the seismic parameters for that purpose. The relations between porosity and a number of seismic parameters investigated individually, as well as the meta-attributes, being the combination of several seismic attributes, have been analysed, resulting in a quite significant correlation between borehole loggings of this parameter and the correspondingly transformed seismic data. Calculation of the resulting spatial models of porosity (applying borehole data and seismic data at the same time) has been conducted using the algorithms based on the co-kriging equation [6]. Apart from the total porosity parameter, based on the relations observed in the borehole profiles, distributions of the effective porosity and the open effective porosity have also been constructed (with pore diameters exceeding 10 nm) (Fig. 11).

The organic matter content (TOC)

In the shale type formations, being the source rocks and at the same time constituting the reservoir intervals for the accumulation of hydrocarbons, the organic matter content of shale

formations is one of the primary parameters determining the prospectiveness of such rocks for unconventional hydrocarbon exploration. On the one hand, the knowledge of the initial and current TOC values allows for the estimation of the amount of generated hydrocarbons, and on the other hand, the current organic matter content determines the amounts of gas which can be accumulated in shale rocks as the adsorbed gas [3]. In the procedure creating the spatial TOC models, geophysical borehole logging and laboratory calculations of the current TOC values conducted in individual points (considered to be calibration data) are used in the first place for the estimation of continuous TOC loggings. A geostatistical analysis of TOC borehole loggings proved the existence of a relatively strong correlation between the bulk density of the rocks and the organic matter content. A strong relation between those two parameters makes it possible to determine the anisotropy of the variability of TOC, and to calculate the spatial distributions of this parameter via the application of the density model as the secondary data, controlling the distribution of the value of the modelled feature. Similar to porosity and density, the spatial distribution of TOC was modelled using the method based on the variogram function, along with the algorithms based on the co-kriging equation (Fig. 12).

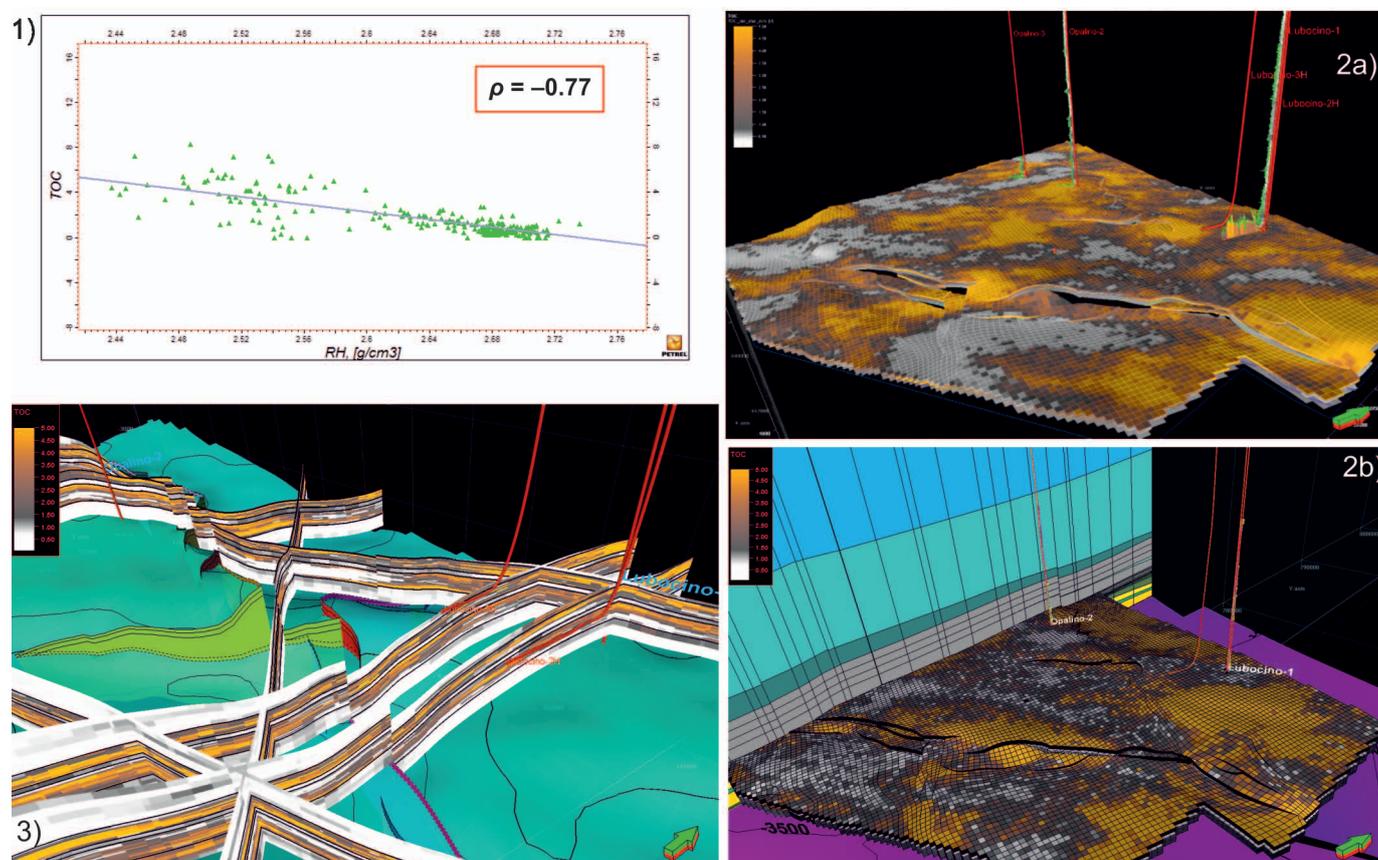


Fig. 12. The results of spatial modelling of the organic matter content TOC in the Sb – Cm2 interval: 1 – the chart of the relation between the TOC content and density (ρ – correlation coefficient), 2 – spatial distribution of TOC in the interval from a) the Sasino formation, b) the Jantar member, 3 – the location of boreholes against the modelled TOC parameter, 4 – the result of the spatial modelling of TOC in the Sb – Cm2 interval

Saturation of pore space with reservoir water

The character of saturation of the reservoir formation, in terms of the types of the saturating fluids and their occurrence in the specified proportion, to a considerable extent determines the hydrocarbon resources accumulated within the pore space. This is also related to the shale formations, accumulating the hydrocarbons in two forms: free, filling the pore space, and adsorbed on the surface of kerogen. Assessment of the resources of this first type requires, apart from the knowledge on rock porosity, also the knowledge about the proportion in which the pore space is filled with water and hydrocarbons (oil and gas).

An attempt to model the variability of the proportion of the saturation of shale formations with hydrocarbons and reservoir water was accomplished in two stages: first, in-depth analysis, integration and interpretation were conducted for saturation variability borehole loggings. Subsequently, using the methods of geostatic 3D modelling, the prognosis of the spatial variability of the parameters describing the saturation of shale formations (S_w , S_o , S_g) was accomplished. In the case of saturation of shale formations with hydrocarbons, the dependence of this parameter on the organic matter content TOC was observed (Fig. 13).

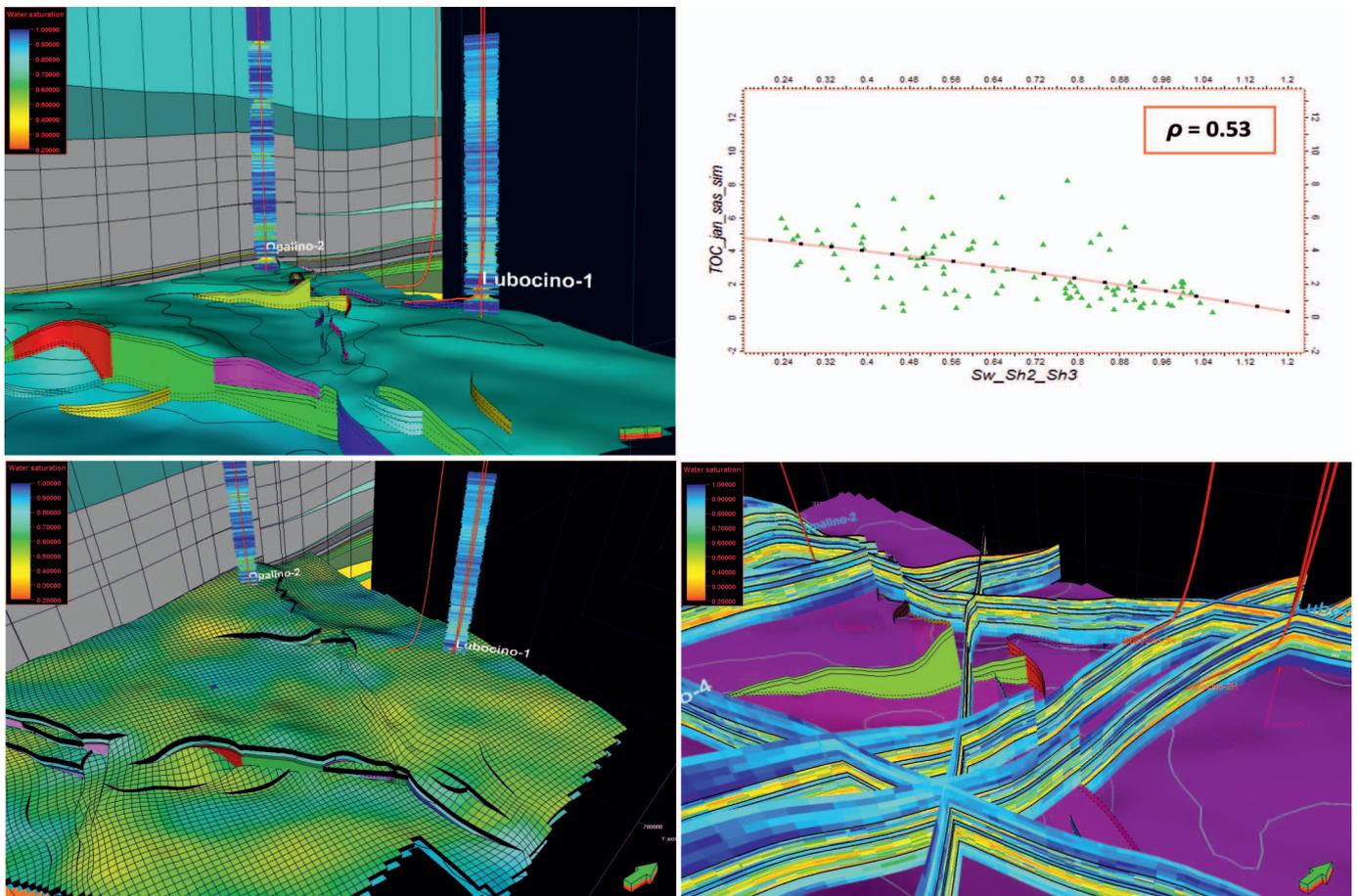


Fig. 13. The results of spatial modelling of the saturation of shale formations with reservoir fluids in the Sb – Cm2 interval and a chart of the relation between the TOC content and the saturation with water in the source intervals – the Jantar member – Sh2, the Sasino formation – Sh3

Summary

The authors’ attempt at the use of geostatistical modelling methods for shale formations indicates the validity of using similar data interpretation and integration tools as for conventional reservoirs. The differences in the methodological approach result primarily from the different, more complex nature of the analysed rock formations and the wider spectrum

of rock parameters being predicted. The availability of 3D seismic data with sufficient vertical resolution allows a more credible modelling of the variability regarding the physical features of shale formations, but also of the geometry of the prospective intervals within them. The results of seismic data processing, and in particular the results of using the

inverse procedures, also indicate usefulness in spatial variability modelling of the petrophysical parameters of shale rock intervals, such as porosity, bulk density, and indirectly, via the density parameter, also TOC. The 3D geological model (structural and parametrical), developed using the

abovementioned methods for the area of prospecting for unconventional hydrocarbons, constitutes a firm basis for the identification of zones with the most advantageous rock properties, for the planning of exploratory boreholes and the trajectory of horizontal drillings.

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