Article

Magnitude Estimation of Overpressure Generation Mechanisms Using Quantitative Stochastic 2D Basin Models: A Case Study from the Danube-Tisza Interfluvium Area in Hungary

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Abstract: The overpressure formation in the Pannonian basin, Hungary, was investigated but has not been properly understood for the last 40 years because at least two different explanations were delineated. The first explanation considers the hydrocarbon generation as the main overpressure generation mechanism with some undercompaction contribution. On the contrary, another explanation assumes tectonic stress as the main trigger of abnormal pressure. The following research delivers a suitable workflow to understand which generation mechanisms were active in the study area and estimate the quantitative contribution of the mechanisms. The developed workflow relies on the basin modeling principles that were designed to simulate subsurface processes on a geological timeframe. Moreover, the uncertainty of input parameters was considered, and the joint application of a heuristic Monte Carlo simulation scheme and improved basin modeling resulted in stochastic pore pressure models. The most frequent value (MFV) method was applied on the simulated values to test a robust statistical method in pore pressure prediction. The study has identified not only the four main overpressure generation mechanisms, but it could calculate the individual contribution to the subsurface pressure. Finally, two independent and stochastic pore pressure prediction methods have been developed that could be used in the pre-drill well planning phase and the real-time prediction during drilling.

Keywords: overpressure generation mechanisms; pore pressure prediction; basin modeling; uncertainty; stochastic predictions; MFV method

Citation: Nagy, Z.; Baracza, M.K.; Szabó, N.P. Magnitude Estimation of Overpressure Generation Mechanisms Using Quantitative Stochastic 2D Basin Models: A Case Study from the Danube-Tisza Interfluvium Area in Hungary. *Appl. Sci.* **2021**, *11*, 2841. <https://doi.org/10.3390/app11062841>

Academic Editor: Giuseppe Lacidogna

Received: 19 February 2021

Accepted: 16 March 2021

Published: 22 March 2021

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1. Introduction

Three main pressure types have been applied to describe subsurface pressure conditions: the hydrostatic, the pore, and the lithostatic pressure. The hydrostatic pressure is the pressure of the water column, while the lithostatic is the pressure of the overburden rock mass at a given depth. Finally, the pore pressure means a pressure value that is measurable in the pore fluids. The hydrostatic pressure regime is present when the pore pressure is equal with the hydrostatic pressure. An abnormal pressure regime occurs when the pore pressure is smaller or higher than the hydrostatic pressure. Underpressure is the condition when the pore pressure is lower the hydrostatic; this is the less frequent situation. However, overpressure is present when the pore pressure exceeds the hydrostatic conditions; it is known from several young sedimentary basins [1–6]. The overpressure generation mechanisms have been divided into three groups in case of sedimentary basins. The first group is triggered by the increase of compressive stress, which inherits the disequilibrium compaction and the tectonic stress generated overpressure. The disequilibrium compaction

or under-compaction is the process when a huge amount of shale-rich sediments has been deposited within a short period. The compaction of the sediments is not able to follow the fast burial, so the pore fluid will be captured in the pore space, which increases the pore pressure, this mechanism is frequent in case of Cenozoic basins with a high sedimentation rate [7]. Volume of the pore fluid can be increased that is able to generate abnormal pressure conditions, the volume expansion mainly has been controlled by aquathermal and diagenetic processes, hydrocarbon generation, or cracking. The third mechanism group has been resulted by the fluid and pressure allocation, due to the osmosis, hydraulic head, buoyancy, and lateral transfer [8,9]. The overpressure difference between the deep basins and the basin margin could be smoothed by the hydraulic linkage of connected tilted reservoirs, which can result a higher pore pressure on the basin margins than could be expected based on the overlaying shales. The different overpressure generation mechanisms simultaneously make an impact on the subsurface pressure regime, so the understanding of the mechanisms is necessary for planning and carrying out successful hydrocarbon exploration wells.

Two main explanation groups have been developed to explain the abnormal pressure regime in case of the Pannonian Basin. According to the first explanation, the overpressure has been generated by the hydrocarbon generation; the disequilibrium compaction and the chemical compaction may affect the pressure conditions, but the last mechanism has not been investigated [10]. However, the second group explains the overpressure generation with the increase of the tectonic stress that is originated from the subduction of microplates [11,12]. Previous studies have not dealt with the individual quantitative contribution of the overpressure generation mechanisms to the whole subsurface regime.

The aim of this study was not only identifying the generation mechanisms but delivering information about the individual contribution of them; thus, 2D basin models have been developed to evaluate the magnitude of the different mechanisms. The applied workflow has been improved that resulted in a stochastic numerical simulation workflow to pore pressure prediction. The test area is selected in the Danube-Tisza Interfluve, which is located in Hungary, East-Europe (Figure 1).

Figure 1. Topographic map of the Pannonian (modified after [13]) basin with the main subbasins; the yellow outline represents the political border of Hungary, and the red lines show the direction of the Section_01 (from NW to SE) and Section_01A (from NE to SW). The map uses EOY (Uniform National Projection system), which is a plane projection system

used uniformly for the Hungarian civilian base maps and spatial informatics. Coloured squares represent the wells that were used to calibrate the basin models. Orange squares represent wells with measured porosity and pore pressure data, the green squares represent wells with porosity, pore pressure, and temperature data and purple wells represent porosity, pore pressure, temperature, and vitrinite reflectance data. Wells without colour squares were not applied to calibration due to the lack of measured data.

2. Geological Setting

The convergence of African and European plate fragments has controlled the development of the Carpathian Pannonian region [14], because the repeated convergence and divergence resulted in the opening and closing of several oceans from the Triassic to the Eocene [14]. The composition of the Pannonian lithosphere is heterogeneous but can be divided into two major megaunits [15]. The northern megaunit is the Alp-Carpathian-Pannonian (ALCAPA) and the southern is the Tisza-Dacia megaunit. The megaunits are sutured by smaller fragments, which are separated by tectonic boundaries [16–18]. Megaunits have been juxtaposed along the Mid-Hungarian Fault Zone in the Neogene after the closure of the Neotethys, but the megaunits stayed movable along the Mid-Hungarian Fault Zone [19].

Low-angle normal faults and strike-slip faults have been manifested in an extensional tectonic regime during the Middle Miocene that resulted the opening of diachronous sub-basins [20–23]. The opening and the subsidence history are different in case of the unique subbasins based on recent studies [24]. The Pannonian Basin has been lost its connection with the Paratethys due to the uplift of the Alp-Carpathian orogen and a sea level drop [25]. Isolation of the Lake Pannon resulted in the development of a major unconformity between the Middle and Late Miocene series [26]. The age of the unconformity has been interpreted to be coeval with the peak of the East Carpathian collision [11,27]; the accompanying erosion could remove a part of the Middle Miocene sediments [28]. The following post-rift thermal subsidence resulted in the development of deep subbasins [29], the Pannonian basin was only partly flooded in the early Late Miocene. The increased water depth resulted in the forming of underfilled troughs with 800–1000 m water depth [25,30] and sublacustrine highs with condensed sediment series. The limited sediment influx has resulted in the deposition of calcareous (Tótkomlós Member) and clay marls (Endrőd Formation), which are controlled by the terrigenous input and the position of the photic zone. The largest water coverage in the Pannonian basin was reached 9.8 Ma ago; then, prograding delta systems controlled the sedimentation, which were delivered the siliciclastic material from northwest and northeast directions (Figure 2). The delta morphology was affected by the basement morphology and the water depth. The self-margin could prograde approximately 400 km in 6 Ma to the S-SE direction, but minor progradation directions have been identified [31–34]. The complex delta series have been divided into lithostratigraphic units based on the different depositional environments [35–38]. Seismic correlation of magnetostratigraphic and radiometric well data has defined a chronostratigraphic framework in case of the Lake Pannonian [39–41].

Turbidite series of the Szolnok Formation, which overlays the deep water calcareous and clay marl series, build up from the alteration of fine-grained sandstones and pelites. The lateral extent of sandstone bodies is generally limited; thus, the correlation of sandstone bodies on the long distance are problematic. Delta slope siltstones and clay marls formed the Algyő Formation that contains only a minor amount of sandstone lenses originated from mass flows. The overlaying, mainly sandstone series represents the Újfalú Formation that is covered by the alluvial plain sediments (Zagyva Formation). Two unconformities have been identified within the Late Miocene Pliocene sediment series. The oldest one, approximately 6.8 Ma, was interpreted as a result of a lake-level fall [33,42] or a large canyon incision [43] or a result of different progradation directions [43]. The unconformity near the Late Miocene Pliocene boundary was interpreted as a result of basin inversion [32,44,45] or a sedimental response to the Messinian Salinity Crisis [46]. The uplift was mainly affected the subbasins margins and kept the basin centres subsiding [47]. The compressional stress field

significantly affected the sediment fill, which has been tilted from the margins to the basin centres. This study focuses on the Miocene and younger part of the stratigraphic column; Figure 3 shows a simplified stratigraphic chart with the main lithostratigraphic units.

Figure 2. Schematic model of the Late Miocene, Pliocene prograding delta system with the depositional environments and the deposited lithostratigraphic units (modified after [38]).

Figure 3. Stratigraphic and petroleum system elements chart of the Great Hungarian Plain (modified after [48,49]): 1 = Alluvial plain; 2 = Lacustrine, self-edge deltas, delta front; 3 = Lacustrine, delta slope; 4 = Lacustrine, deep basin turbidite system; 5 = Lacustrine, deep basin (clay marl); 6 = Lacustrine, shallow to deep basin (calcareous marl); 7 = Lacustrine, rocky shore, shoreface; 8 = Brackish, shoreline, and near shore; 9 = Brackish, shoreline, and abrasional shore; 10 = Marine, shallow marine reef; 11 = Marine, open basin; 12 = Abrasional basal breccia, conglomerate and sandstone.

3. Materials and Methods

An integrated workflow has been implemented for a dual role. On the one hand, the pore pressure development has been evaluated on a geological timescale, but on the other hand, a stochastic pore pressure prediction procedure has been developed (Figure 4).

Figure 4. Developed workflow with the three main phases that can deliver the stochastic pressure models to predict and evaluate the subsurface pressure regime on a basin scale.

3.1. Well Log Data

As a numerical simulation input, it is important to know the lithostratigraphic unit distribution in every well and the quantitative lithological composition of unique formations [50]; thus, the integral natural gamma-ray logs have been used to identify the Late Miocene and Pliocene formations. The spontaneous potential logs were applied for a more reliable lithology evaluation, and the gamma ray or spontaneous potential logs have been combined with deep resistivity logs. The main lithostratigraphic units have been identified within the Late Miocene and Pliocene series, but the delta front (Újfalú Fm.) and the alluvial plan (Zagyva Fm.) sediments have not separated. The hydrostatic pressure regime is present within the delta front and alluvial sediments, which is controlled by the topography-driven flow system above the overpressured confined pressure regime [12,51].

Shale volume has been calculated with the Larionov formula (Tertiary) that was applied to develop unique compositional lithologies as an input [52]. The filtering out of the non-shale samples to the identification of top of overpressure has been carried out based on the shale volume values. Moreover, the overpressure generation mechanisms have been identified on the physical properties of shale samples that were separated based on the shale volume values, too.

Porosity values for the whole Late Miocene and Pliocene series have been calculated from bulk density logs [53]. The porosity values take part in the calibration of numerical simulation and delivered the input values to the porosity-depth relationships to describe

the compactional behaviour of the unique lithologies. The density porosity has been derived from a linear response function:

$$\phi_{DEN} = \frac{(\rho_{matrix} - \rho_{bulk})}{(\rho_{matrix} - \rho_{fluid})},$$

where ϕ_{DEN} is density porosity, ρ_{matrix} is matrix density, ρ_{bulk} is measured density, ρ_{fluid} is pore fluid density and the fluid density derived from the measured water density values. Matrix density has been back calculated from measured core porosity data, and the calculated porosity values have been calibrated with measured data.

Acoustic P-wave travel-time logs have been applied to determine the top of the overpressure; previously, the non-shale intervals have been filtered out with calculated shale volumes. The acoustic travel time values have been converted into compressional wave velocities (V_p) and were visualized on V_p -depth plots (Figure 5). According to the V_p -depth plots, the normal compactional trend was identified, because the compressional wave velocities increase linearly with depth in case of hydrostatic pressure conditions [51]. The presence of overpressure can result in a lag between the measured and normal compactional trends, so the top of the overpressured zone is identifiable. Depth intervals have been used as an indirect calibration point to the numerical simulations. The V_p -depth plots also can show information about the overpressure generation mechanisms, because the wireline log signatures are unique in case of the main overpressure generation mechanisms.

Figure 5. The effect of the two main overpressure generation mechanisms on the compressional wave velocity and the pore pressure-depth profiles: (a) typical profiles of the undercompaction driven overpressure; (b) effects of the fluid expansion.

The non-equilibrium compaction results in almost constant compressional wave velocities with the increase of depth and the generated overpressure increases continuously with depth, i.e., it does not show pore pressure jumps. The compressional wave velocities will not catch up to the normal compactional trend in the case of under-compaction [54]. On the contrary, the fluid expansion triggers a fast pore pressure build up that results in sharp pressure increases on the pore pressure-depth plots. An important difference between the two mechanisms is that the overpressure is only present in a well-defined interval (i.e., the source rocks) in case of the fluid expansion, but the under-compaction resulted overpressure is present below a given depth value [54].

Compressional wave velocity vs. density cross-plots have been made based on the shale samples data (Figure 6) that delivered the identification of two more overpressure gen-

eration mechanisms [55]; the Bowers trend line shows the route of the shale samples when under-compaction or hydrostatic pressure conditions are present. Chemical compaction participates in the forming of the overpressure when the measured shale compressional wave velocity stagnates, and the bulk density values increase [55]. The unloading is the geological process, when a previously buried layer moves to a shallower depth that could be resulted by an erosional event or the melting of the subsurface ice cover [56]. The layer, which is covered by a proper seal, can preserve the original pore pressure condition during the uplifting, while the original pore pressure in shallower depths will be the source of the overpressure. The unloading mechanism results in the opposite physical change in the shale samples compared with the chemical compaction, because the compressional wave velocity decreases, but the bulk density stagnates.

Figure 6. Bulk density and the compressional wave velocity routes in case of different overpressure generation mechanisms. Normal compaction and under-compaction result in the increase of compressional wave velocity and bulk density; thus, deviation from this route suggests the contribution of another mechanism(s).

3.2. Pre-Screening Input and Calibration Parameters (Pressure, Porosity, and Permeability)

The basin modeling workflow might be able to deliver a proper pore pressure and overpressure sections, which could be able to provide pre-drill pressure values to well planning at an undrilled location. The predicted pressure models could be acceptable when the calculated pore pressure values match with the measured data at the existing wells [50]. Numerical simulations do not have a direct connection with the measured data, only modeling the main processes (mechanical, chemical compaction, hydrocarbon generation, uplifts) on a geological timeframe and calculating the subsurface pressure conditions in case of every time step. However, the distance between the measured and the simulated values could be reduced during the calibration phase.

3.2.1. Pressure Data

Pore pressure data have been collected into a database in order to make the calibration process easier. The static pore pressure data that were measured during the drill stem tests (DST) are the most reliable data for pressure calibration [57]. Ten DST-derived static pressure values were available from the evaluated wells, which only deliver information about

the pressure conditions of two layers (Middle Miocene and the Late Miocene turbiditic reservoirs). More pressure proxy should have been involved to handle the lack of static pressure data and reach a proper pressure calibration.

Static pressure values are not available from DST in case of several wells, due to the very short build up period of the DSTs or the low permeabilities of the tested intervals. However, the maximal measured data have been recorded during the tests, and the maximal detected pressures could be interpreted as the minimal value of the pore pressure. Moreover, the mud weight data had been available, so the equivalent pressures were calculated that represent the theoretical maximum pore pressure. The maximal measured pressure and the equivalent mud pressure values determine the pore pressure interval that is suitable to calibrate the numerical simulations (Figure 7).

Figure 7. The most typical pore pressure proxies that have been used for the calibration of basin models. The overlapping intervals can delineate the most probable magnitude of the pore pressure. Mud weight drop is the process when the pore pressure exceeds the equivalent mud pressure (calculated from mud weight) and the pore fluids could enter into the borehole that lead to the dilution of the mud weight with less dense brines (mud weight drop down) or hydrocarbons (gas kick).

3.2.2. Porosity, Permeability, and Compaction Trends

Next to the pore pressure, the porosity, permeability and compaction trends have been calculated during the numerical simulation [50].

Core-based measured and well log-derived porosity values belong to a given depth. The effective stress value can be calculated to the specific depth if pore pressure data is available near the porosity value. Continuous bulk density logs can deliver the lithostratigraphic pressure values when the vertical stress is bigger than the horizontal stress. The difference between the lithostratigraphic and the pore pressure value is the effective stress that controls the compaction of the sediments [58].

The continuous bulk density log was available only in the case of one well from the evaluated dataset, so the lithostratigraphic pressure calculation was not feasible; bulk density log has been upscaled and applied as calibration data to lithostatic pressure simulation. Moreover, the pressure data deficiency has been mentioned previously at the pressure database. As a result of the insufficient dataset, the porosity-depth trends were calculated first, and after that, they were transformed into porosity-effective stress relationships. A porosity and a permeability measurement program have been carried out in case of underrepresented lithostratigraphic units. Shale-rich formations (delta slope, prodelta, and pelagic sediments) were underrepresented, due to its low hydrocarbon reservoir

perspectives [59,60]. The measure program delivered that the finalized porosity-depth and porosity-effective stress trends rely on measured core-based and calculated well log-derived porosity values. The well log-based porosity values have a few centimetres of vertical spacing, the high resolution is not an issue in case of regional compaction trends, but the huge dispersion of porosity data could be. The well log-based porosity values were upscaled with 10 m spacing.

Calculation of the porosity-depth trends rely on Athy's law [61], so the calculated or measured porosity values were the known part of the compaction equations, and Athy's factor has been back calculated. Athy's factor and the initial surface porosity let the porosity-depth trend extrapolate for the missing intervals, which were not sampled by calculated or measured values [61]

$$\phi = \phi_0(e^{-kz_e}), \quad (1)$$

where ϕ is the porosity, ϕ_0 is the initial porosity, k is the Athy's factor, and z_e is the equivalent hydrostatic depth. Not only the porosity values decrease with the burial, the permeability values also reduce during the compaction. The size of the pore throats is decreasing in the first phase; after that, the pore throats are closed, and the pore connectivity decreases drastically [62,63]. To properly simulate this dual process, Kozeny–Carman-type poroperm relationships have been implemented in the numerical simulation [50] that rely on two different exponential factors, one for the early phase burial and the second one for the pore separation phase.

3.3. Basin Modeling

The geological, geophysical, and reservoir mechanical parameters have been incorporated into the 2D basin models during the model building phase [64] that was carried out with the Schlumberger PetroMod software (version 2017.1). Moreover, recently published calibration models have been added to the Calibration Editor. The main purpose of the 2D basin modeling studies focus on the better understanding of the hydrocarbon systems or providing a more adequate regional overview [65–67]. This study delivers an alternative usage in case of 2D basin models; the original concept was to extend the application of basin modeling in the field of engineering sciences. Depth-converted seismic horizons delivered the timeframe and the sedimentation rate to the simulated geological sections that starts from the deposition of the Middle Miocene. The seismic horizons have been correlated from magnetostratigraphic absolute age well picks [68–73]. The continuous sedimentation has been interrupted three times by discordance surfaces. The amount of eroded strata thicknesses is variable along the sections, but both have been integrated into the numerical simulations. The layers between the depth horizons consist of more lithofacies, because the sedimentation has been controlled by a prograding delta series from the Late Miocene (Figure 8). Twelve layers have been separated during the model building phase; the layers consist of 5 to 20 sublayers due to the lithological heterogeneities within the prograding delta series (195 sublayers). The direction of Section_01 is parallel with the sediment transport direction and 168 km long, but the Section_01A is perpendicular to the sediment influx with 189 km total length. The delineation of lithofacies is relied on the evaluation of the lithology-sensitive well logs and the identified clinoforms [28]. One lithofacies has been attached to every Late Miocene and younger formations; only the prodelta turbidites (Szolnok Fm.) have been divided into two parts (shaly siltstone and silty sandstone) with the calculated shale volumes. A unique porosity-effective stress trend has been assigned to every lithofacies, and a poroperm trend has been fitted to the compaction trends that are consistent with the measured permeability data (Hg saturated, Nano-K).

Two boundary conditions have been estimated for every time step as thermal boundary conditions, the sediment water interface temperature (SWIT) and the basal heat flow. The SWIT represents the upper thermal boundary or the initial sediment temperature when

the burial started. The SWIT has been calculated with the built-in model from paleo water depth values [74] that originated from laboratory reports and published data [75].

The paleo heat flow has been reconstructed with the McKenzie [76] crustal heat flow model that is able to estimate the stretching factors from the current and the paleo burial curves along the simulated section. The stretching factors change along the simulated sections, the magnitude of the crustal stretching factor falls into the 1.4–2 interval, but the stretching of the lithospheric mantle has a higher variance (3 to 5). The applied factor values are coherent with the non-uniform stretching concept that was suggested by previous studies in case of the Pannonian Basin [77,78]. The basal heat flow has been calculated from the stretching factors along the models and published thermal parameters have been considered [21,79].

Figure 8. Simulated sections with the chronostratigraphic horizons (black lines) and the lithofacies: (a) Section_01 is parallel with the direction of paleo deltas; (b) Section_01A is perpendicular to sediment influx. Horizons were converted into 2D models in Schlumberger PetroMod software.

The simulation of the basin models is a multi-phase iterative process that aims to reduce the difference between the simulated and the measured parameters. At least four recommended parameters must be involved in the calibration (pore pressure, porosity, temperature, and maturity) [48]. The calibration has a logical order that starts with the pore pressure, because it determines the effective stress, which controls the porosity. The porosity affects the total volume of the pore fluid in the rock matrix, so the higher the water volume, the slower the warming of the layers, due to the high heat capacity of the water. Finally, the lower temperature results in slower maturity and hydrocarbon generation.

The temperature and the maturity calibration are also important from the pore pressure prediction point of view, because the chemical compaction as an overpressure generation mechanism is controlled by the temperature. Moreover, the hydrocarbon generation and cracking are driven by the thermal maturity and the temperature, so the complete calibration workflow has been carried out. Temperature values were acquired from DST, and the core-based vitrinite reflectance data have been used as maturity proxy (Figure 9). The calibration process was supplemented with the bulk density, because the lithostatic pressure originated from the bulk density, when vertical stress is the highest. The bulk density logs have been upscaled to 10 m spacing. The difference between the lithostratigraphic pressure and the pore pressure creates the effective stress that controls the mechanical compaction and the permeability reduction within the sediments.

Figure 9. Temperature-depth and vitrinite reflectance-depth 1D extraction from the 2D basin models: (a) extraction of the W-09 well on the Section_01; (b) extraction of the W-53 well on the Section_01A. Extractions show a good fit between the simulated values and the measured data. Temperature- and vitrinite reflectance-depth plots show that the simulations were successfully calibrated.

Data from several wells have been used simultaneously to calibrate the models (Figure 1), but the wells have been drilled for 40 years, which means that the measuring protocol was updated several times. The pore pressure data types have different reliability but have been considered with the same weight. To handle the data diversity and reliability issues, the calculated parameters have not been matched to the individual measured datapoints. The Gaussian square (x) had been calculated in case of every datapoint, and the repeated calibration–simulation cycles aimed to decrease the sum Gaussian square value (d is the estimated value; m is the measured data; and σ is the standard deviation of measured data).

$$x^2 = \sum_{i=1}^N \left(\frac{d_i - m_i}{\sigma_i} \right)^2 \quad (2)$$

The low permeability is one of the most frequent overpressure triggers. Permeability reduction occurs during the under-compaction, but the cement precipitation also reduces the porosity and the permeability during the chemical compaction [7]. The low source rock permeability prevents the primary migration, so the generated hydrocarbons could hardly leave the pore space that also can generate overpressure. The burial depth is controlled by the input depth maps in simulations that could be uncertain, because the interpretation is reliable above the basement highs, due to the well control. However, the accuracy of the maps reduces in the direction of the deep basin. Moreover, the overpressure generally

is the highest at the deep basins, where interval velocities are not available, so the depth conversion could be also uncertain. The above assumptions indicate that the permeability and the depth maps have been considered as the most uncertain input parameters.

The calibrated but deterministic best-case models have been supplemented with an enumerative Monte Carlo-based approach to evaluate the effects of the above uncertainties. The permeability and depth are treated as probability variables. Uniform distribution was assumed in case of the permeability (Schlumberger verbal communication), and the laboratory-measured dataset suggested a ± 1 magnitude logarithm of dimensionless permeability (before normalization, it is originally given in mDarcy) variance for every porosity interval. The depth has been handled as a probability variable only in case of shale-rich layers, so that was the input of the Monte Carlo simulation. Normal distribution with $\pm 20\%$ standard deviation (compared to mean values) has been considered in case of depth horizons uncertainty [80]. The combination of Monte Carlo simulation and basin modeling has resulted in stochastic pore pressure and overpressure models, where the standard deviations has been calculated next to the minimum, maximum, and average pressure values.

The applied basin modeling software (PetroMod) is able to calculate the standard deviation and the minimum, maximum, average pore, and overpressures, so they rely on the least-square method, and it means that we assume normally (Gaussian) distribution. The measured data could be different distribution, because some errors and outliers could be expected, so the application of least-square norm (L_2 -norm) is not a robust solution in case of the earth sciences [81]. Steiner [82] introduced the maximal reciprocal principles in order to remove the weakness of low effectiveness and high sensitivity to the rarely sampled datasets

$$\sum_i \frac{1}{X_i^2 + S^2} = \max \quad (3)$$

where X_i is the residuals and S denotes the measurement error. Application of the most frequent value (MFV) procedure has been proposed by Steiner [83,84]. The solution scheme can determine the scaling parameter in a way to ensure the minimization of the information divergence (relative entropy) denoting the information loss during the calculation; the scaling factor ε is called dihesion. Application of the MFV procedure, as a new efficient robust method, has been proved in the field of earth sciences [83–86]. The MFV value and the dihesion could be calculated via iteration; the appropriate formula of iterations, in the $(j + 1)$ th step of the MFV procedure for the MFV M , is

$$M_{j+1} = \frac{\sum_{i=1}^n \frac{\varepsilon_{j+1}^2}{\varepsilon_{j+1}^2 + (x_i - M_j)^2} x_i}{\sum_{i=1}^n \frac{\varepsilon_{j+1}^2}{\varepsilon_{j+1}^2 + (x_i - M_j)^2}}, \quad (4)$$

where x_i is the observed data, and the ε_j is calculated with the below formula,

$$\varepsilon_{j+1}^2 = \frac{3 \sum_{i=1}^n \frac{(x_i - M_j)^2}{[\varepsilon_j^2 + (x_i - M_j)^2]^2}}{\sum_{i=1}^n \frac{1}{[\varepsilon_j^2 + (x_i - M_j)^2]^2}}. \quad (5)$$

The initial value of the ε can be calculated by

$$\varepsilon_0 = \frac{\sqrt{3}}{2} (x_{\min} - x_{\max}), \quad (6)$$

and the starting M value or M_0 for the iteration is originated from the average value of the measurements. Steiner's most frequent value procedure can deliver an alternative stochastic pore and overpressure prediction method, which is not sensitive to outlying

data. The dihesion parameters were denoted as an estimation error in case of the expected pore and overpressure values, which is calculated automatically with the MFV procedure.

4. Results

The normal shale compaction trend has been identified based on the V_p -depth plots in case of the Late Miocene and Pliocene series that allow identifying the top of the overpressured zone [55]. According to the dataset, the abnormal pressure regime has been identified below the 2100–2400 m depth. The well log signature of V_p -depth plots suggests that the disequilibrium compaction is the main overpressure generation mechanism (Figure 10), because the measured compressional wave velocity values do not decrease with increasing depth.

Chemical compaction and the unloading mechanisms have been evaluated on the V_p -Den cross plot [56]; the effect of unloading has not been proved on the cross plots, but only in case of two wells have been evaluated. The chemical compaction could be present due to the identified sharp bulk density increase (Figure 10). The density starts increasing at 105–110 °C, which could be explained by the smectite–illite transformation [56].

Figure 10. (a) Compressional wave velocity-depth plots from W-59 that suggest a slight lag from the normal compaction trend; (b) Compressional wave velocity-depth plots from W-13 that clearly show the lag from the normal compaction trend from 2400 m; (c) Compressional wave velocity and bulk density cross plots prove the presence of chemical compaction or clay diagenesis as an overpressure generation mechanism.

The lack of the static pore pressure data triggered that alternative pressure proxies had to involve the calibration process. The two indirect pore pressure intervals have been involved, which is blundered by the maximal measured pressure and equivalent mud pressure. The drilling incidents (gas kicks, pipe sticking, mud density drops) could deliver the second indirect proxy. Drilling incidents happen when the pore pressure exceeds the equivalent mud pressure; thus, the pore fluids could enter into the borehole that lead to the dilution or drop down of the mud weight due to the less dense pore fluids (brines, gases, or fluid hydrocarbons). Experiences relating to the calibration suggest that the alternative pore pressure proxies can deliver a more accurate pressure calibration if enough data are available (matured basins). The several overlapping pore pressure intervals can highlight the most likely and narrow pore pressure interval.

Athy's factors have been estimated from the calculated and measured porosity-depth datapoints; thus, the missing part of the compactional trends could be extrapolated. Porosity-depth trends have been constructed for every lithostratigraphic unit. The porosity-depth relationships have been converted into porosity-effective stress trends and were

extended with poroperm relationships that originated from laboratory measurements (Hg permeability and Nano-K).

Section_01 is parallel to the direction of the sediment influx, so it is more representative from the pressure regime development point of view (Figure 11). According to the results of Section_01, the abnormal pressure regime could have formed 9.2 Ma ago, when the subbasins were buried rapidly. Overpressure was increased continuously in the subbasins until the Late Miocene–Pliocene boundary, but the magnitude of generated overpressure differs in case of the subbasins. The NW part of Section_01 was uplifted at the Late Miocene–Pliocene boundary, and the burial of the north western parts has been stopped. The southeast part of the section subsided during the Pliocene that resulted in the increase of overpressure. The subsidence stopped 2.58 Ma ago at the Pliocene–Quaternary boundary that resulted in the decay of the overpressure, because the pore fluids could slowly leave the pore space. The subsidence has continued in the Quaternary, so the increased overburden stress has triggered again the overpressure generation.

According to the basin models and the well log evaluation, the overpressure has been formed in the lowermost part of the shale-rich delta slope sediments (Algyő Fm.) at the deepest part of the subbasins. However, the hydrostatic pressure regime is dominant in the delta slope sediments above the basement highs and the margin of the basin system. Generation of the overpressure in the delta slope sediments is controlled by the burial, because undercompaction could trigger the forming of overpressure, where the slope sediments could reach the 2100–2400 m depth.

The prodelta turbidite system has been divided into two lithofacies, a shaly siltstone and a silty sandstone. Compaction properties and the porosity–permeability relationships are significantly differing in case of the two identified facies. The shaly siltstone lithofacies could be able to cause an overpressure increase in the formation due to its low permeability. However, the permeable layers could lead away the pressure surplus due to the lateral transfer. The generated overpressure in the deepest part of the subbasins can disintegrate into the direction of the margins within the sandstone bodies. The generation mechanism has a dual role in the subsurface pressure regime; it can generate overpressure above the basement highs and at the margin of the subbasins, but it can reduce the overpressure of the deepest parts of the subbasins. The effectivity of lateral transfer depends on the reservoir parameters, the connectivity, and the horizontal distribution of the sandstone bodies [8].

According to the numerical simulations, the magnitude of the overpressure increases in the pelagic clay marl, marl, and calcareous marl series (Endrőd Fm., Tótkomlós Mmb.), which is controlled by the fast burial and the isolation of pores. The pore fluid is not able to leave the isolated pores due to the limited permeability that causes the continuous increases of overpressure due to the dis-equilibrium compaction. The fluid expansion, the unloading, the chemical compaction, and the hydrocarbon generation have been taken into consideration during the numerical simulations. According to the basin modeling and the well log evaluation, the fluid expansion mechanisms and the unloading contribution to the overpressure are negligible in the study area. Chemical compaction has been simulated in case of Middle Miocene shales and marls and the Late Miocene pelagic marls, calcareous marls [59]. Simulations suggest that the chemical compaction could generate some overpressure at the middle of subbasins, but the absolute overpressure surplus is less than 1.8 MPa or 3%. Source rocks have been identified in the Middle Miocene, Late Miocene pelagic series [87] that have 2 wt % total organic matter (TOC) and 300 mg/g hydrogen index (HI) based on published data [88–90]. Numerical simulation has not proved the contribution of the hydrocarbon generation and cracking in the overpressure generation, because the models suggest only 0.5 MPa locally extra overpressure.

Figure 11. Development of the subsurface pore pressure system during the last 8.3 Ma. According to the simulation, the most significant pressure anomaly could form in the deepest part of the subbasins.

The heterogeneous Middle Miocene series generally starts with breccias and conglomerates that are overlaid by sandstones or limestones, depending on the depositional environment. The pelagic shales and marls have deposited only in the deepest parts of the paleo-basins or the deepest point of the subbasins, which were overprinted by a Quaternary uplift. The lateral transfer is the main overpressure generation mechanism that controls the pressure system within the Middle Miocene series, because the basal breccias and conglomerates have regional distribution. The generated overpressure in the subbasin centres are scattered in the direction of basement highs. This scattering mechanism generates vertical pore pressure jumps, when the Middle Miocene series are penetrated at the basin margins. According to the basin models, the generated extra overpressure from the lateral transfer could be 4 MPa. The magnitude of the lateral transfer distributed overpressure depends on the pore pressure conditions of the deep subbasin.

The stochastic pore pressure models delivered a predicted pore pressure interval along the simulated sections that was calibrated to the existing well data. According to the sensitivity analysis, the depth uncertainty has only a minor effect on the subsurface pressure regime, because it is produced only a 3.8 MPa standard deviation, which means 8–11% uncertainty in the simulated pore pressure values. However, the permeability uncertainty was one magnitude higher, 17.1 MPa absolute or 34% relative overpressure differences (Figure 12).

Figure 12. The uncertainty of the input parameters results in different magnitudes of subsurface pressure uncertainties along Section_01: (a) the depth uncertainty could generate only a slight deviation; (b) the permeability has one magnitude higher importance in the subsurface pressure development.

The simulated minimum, maximum, and average pore pressure values have been used as input parameters to iteratively determine the most frequent pore pressure values and the dihesion parameter. The MFV method resulted in slightly higher dihesion values compared with the calculated standard deviations, the maximum difference between the two parameters is 8.7 MPa when the pore pressure value reaches 90.7 MPa. Steiner's MFV

procedure systematically resulted in higher predicted minimal, most frequent, and maximal pressure values. A data-driven numerical simulation-based stochastic pore pressure simulation workflow has been developed that can deliver two unique pore pressure predictions at a given location with the expected errors (Figure 13).

Figure 13. Predicted stochastic pore pressure–depth plots at the middle of the deepest point of Section_01: (a) predicted minimum, maximum, and average pore pressure; (b) minimum, maximum, and the most frequent pore pressure.

5. Discussion

Porosity reduction and compaction have been investigated in the 1980s in the Pannonian Basin; that study focused on only some lithofacies, namely sandstones, marls, and shales [91]. Moreover, only core-based measured data have been incorporated into the previously published compaction trends. The proposed compaction trends have considered the measured and the calculated porosity values that were created for every Late Miocene and younger lithostratigraphic units, so Szalay's and the proposed compaction trends are just partly comparable. Szalay's marls trend could fit well with the Late Miocene prodelta marly sediments (Endrőd Fm.), the Szalay's sandstone trend could be equal with the Late Miocene–Pliocene turbidite sandstones (Szolnok Fm.–silty sandstones), and the Szalay's siltstone trend correlates well with the delta slope shale-rich sediments (Algyő Fm.).

Szalay's and the proposed compaction trends have generally less than 5% absolute porosity differences, which is just a slight deviation (Figure 14). Szalay's sandstone and the proposed Szolnok silty sandstone trend have a good correlation; both show very similar shapes with just minor porosity differences. Szalay's marls and siltstones trends start from the same initial porosity; then, there are the proposed Algyő and Endrőd Formation trends, but Szalay's trends consider slower compaction that resulted in higher porosity values on the 500–3000 m depth interval. The different trends reach the maximal absolute differences

around 1000 m that are not higher than 10%, but the deviation between the Szalay's and the proposed trends vanished below 3000 m. This study emphasized that the pore pressure models are mainly sensitive to the permeability, so the porosity has a minor impact on the pressure condition. Only the initial porosity controls the pore fluid volumes at the sediment deposition, so the higher fluid volume could result in higher overpressure during the under-compaction mechanism. The initial porosities are almost the same in case of Szalay's trends, and the proposed ones that result in only slight differences from the pore pressure prediction point of view.

Figure 14. Porosity-depth trends of the main Late Miocene and Pliocene lithostratigraphic units to describe the mechanical compactions of different sediments: (a) proposed trends that rely on well log-based and measured porosity data; (b) Szalay's compaction trends for marls, siltstones, and sandstones.

The initial and reduction of the permeability are more important from the pore pressure point of view. Poroperm trends have not been published previously from the Pannonian Basin; only permeability-depth relationships were identified that were controlled by the lower limit of the laboratory tools [10]. Average permeability intervals have been collected by Tóth and Almási [12] for the main Late Miocene and younger formations, the permeability intervals rely on measured core and calculated data from drill stem tests (DST). The permeability of the aquifer units is represented by a similar interval that the evaluated core-based permeability covers; the biggest differences have been identified in the case of the shale-rich sediments, but the difference could be explained with the data sources. The shale-rich sediments contain a sand lens, and if the perforation covered a sandstone body during a DST, the calculated $k \cdot h$ value results in information about the matrix permeability of the sandstone. It is supported by several well tests from the clear shale and marls layer, which resulted in no inflows. The highest difference between the published and the currently measured permeability values have been identified in case of the pelagic marl and calcareous marls, because the published data mentioned a -1 to 0 log mD interval, but the lowest measured permeability values fall into the -6 to -8 log (K) interval. The lower measuring limit of the standard laboratory permeability meter was -1 log mD in the 1980s–1990s [10]. One part of the measured samples originates from the fractured part of the formation [60], so the measured higher permeability values do not deliver information about matrix permeability.

Two conceptual groups have been formed relating to the overpressure generation mechanisms in case of the Pannonian Basin. The first group explains the abnormal pressure conditions with the combined result of the hydrocarbon generation and the disequilibrium compaction [10,92]. The hydrocarbon generation has been identified as the main mechanism, because evaluation of the pore pressure-temperature plots suggest that the overpressure is present above the 120–125 °C temperature in case of the Békés Basin. This interval is the lower temperature of the gas generation window, so Spencer et al. [10] have identified this mechanism. According to Szalay [92], the under-compaction has participated in the forming of overpressure, while the minimal depth of the abnormal pressure has been identified at 2000 m in the Békés Basin. Chemical compaction has been mentioned, but the applied dataset was not enough to prove the contribution of the mechanism [10].

Evaluated well log data and the numerical simulations suggest that the under-compaction is the main overpressure generation mechanism, which partly fits with the first explanation group. Basin models suggest that the hydrocarbon generation and the cracking can generate local 0.5 MPa overpressure, which has only a local impact on the subsurface pressure regime. Source rocks were identified in the Tótkomlós Member and the Middle Miocene series in the Makó and the uppermost part of Hajdúszoboszló Formation (Figure 3). Pliocene biogenic hydrocarbon systems have not been simulated, because overpressured Pliocene sediments are unknown in the Hungarian Great Plain. Moreover, the 120–125 °C temperature interval is around 2000–2500 m depth, considering the average geothermic gradient of the Pannonian Basin [93]. The evaluated V_p -depth plots and the log signatures have proved that the disequilibrium compaction is present below this depth. Studies from analogue basins, where Tertiary prograding shale-rich delta systems controlled the sedimentation, have proved that the hydrocarbon generation was not able to affect the subsurface pressure regime [94]. According to the study from the Bohaiwan Basin (China), the main overpressure generation mechanism is the under-compaction, but the hydrocarbon generation had a minor role, too [95]. Three main parameters have been published from the Williston Basin (Bakken Shale) that controls the abnormal pressure generation in case of hydrocarbon generation and cracking [96], which are the regional distribution, the thickness, and the TOC. Source rocks of the Pannonian Basin meet the regional distribution and the thickness requirements, but the TOC values are generally one order of magnitude lower compared with the Bakken Shale [88–90]. The quality deficiency of the source rocks within the Pannonian Basin could be the bottleneck from the overpressure generation point of view during the source rock maturation, whose conclusion is supported by the numerical simulations, too. Chemical compaction has been considered, but the simulations have not suggested more than 3% overpressure contribution from this mechanism.

The second explanation group is assuming the tectonic compression as the main overpressure generation mechanism [11,12], which relies on the highest relative overpressure being present above the basement highs. However, the disequilibrium compaction should be present in the deepest subbasins [12]. The observation of pore pressure that jumps above the basement highs can be explained by the lateral transfer [97] because of the regional lateral distribution of the Middle Miocene breccias and conglomerates, which are proved hydrocarbon migration pathways in the Pannonian Basin [88]. The effective lateral transfer theory is supported by the presence of effective migration pathways within the Middle Miocene series. Moreover, the current 2D basin models and published 3D basin models also could simulate this mechanism [97]. According to the current study, the contribution of the tectonic stress in the abnormal pressure regime is not negligible, but results suggest that tectonic stress is not necessary to form the current subsurface pressure conditions.

Experimental studies suggest that the aquathermal expansion is only able to generate relative overpressure of a few percent, when the rock matrix has lower permeability than $-12 \log \text{ mD}$ [98]. According to Osborne and Swarbrick [7], the mentioned low permeability conditions could be present near evaporites. The lowest measured permeability values from the Late Miocene marls, calcareous marls are not lower than $-8 \log \text{ mD}$, and only thin

evaporites have been deposited in local restricted subbasins during the Middle Miocene [99]. The log signatures have not supported the presence of a fluid expansion mechanism in the overpressure generation.

The contributions of overpressure generation mechanisms have been studied in the Carnarvon Basin [100], where the main abnormal pressure generation mechanism was the under-compaction. According to the study, the hydrocarbon generation, the chemical compaction, and the fluid expansion mechanisms has only a minor impact on the subsurface pressure conditions, so the under-compaction had one magnitude order higher impact. Effect of the lateral transfer has not been incorporated in the Carnarvon Basin study. The two most important overpressure generation mechanisms are the disequilibrium compaction and the lateral transfer in case of the study area. Hydrocarbon generation and chemical compaction have been identified as minor phenomenon with local pore pressure anomalies mainly in the basin centres. According to the numerical simulations, the under-compaction makes one order of magnitude higher impact on the overpressure values than other identified mechanisms. The results of the basin simulation indicate that the absolute maximum contribution of the unique mechanisms: under-compaction 58 MPa, lateral transfer 4 MPa, chemical compaction 1.8 MPa, and hydrocarbon generation and cracking 0.5 MPa (Figure 15).

Figure 15. Maximum contribution of the different overpressure generation mechanisms based on the simulated two sections. Models suggest that the lateral transfer, chemical compaction, and the hydrocarbon generation have only minor roles in the development of the subsurface pressure regime.

6. Conclusions

This study could prove that the overpressure that is present from the Algyő Formation (delta slope sediments) is higher than the hydrostatic pressure gradient during drilling, when the burial depth of the Algyő Formation is higher than 2100 m. Lateral transfer controls the pressure regime within the Late Miocene turbidite sediments, which could result in a higher than hydrostatic pressure gradient above the basement highs and its margins. However, a lower than hydrostatic pressure gradient could develop in the deepest subbasins, due to the pressure equalization within the sandstones. The overpressure increases within the pelagic series (Endrőd Fm., Tótkomlós Mmb.), due to the disequilibrium compaction, when the series could reach the more than 2100–2400 m burial depth. The increasing overpressure means that it is higher than the hydrostatic pressure gradient, which generally results in pipe sticking due to the high shale content, but gas kicks have been experienced, when lenticular sandstone beds were penetrated. The lateral transfer

controls the Middle Miocene pressure system that easily can result in an abrupt pore pressure increase above the basement highs, even if the penetrated Late Miocene series had a hydrostatic pressure regime. On the contrary, the lateral transfer can drain the overpressure in the deepest basin parts, which could result in mud losses when the high mud weight was not reduced after the drilling of the under-compacted Late Miocene series. Next to the under-compaction and the lateral transfer, the chemical compaction and the hydrocarbon generation could be able to modify locally the subsurface pressure regime, although on the regional scale, both are negligible.

The calibrated deterministic models have been transformed into stochastic simulations that delivered the pore pressure prediction possibility in undrilled locations. According to the sensitivity analysis, the permeability uncertainty has the highest impact on the calculated pore pressure values, so a laboratory measuring program has been carried out. Next to the expected pore pressure values, the standard deviations have been calculated, which resulted in the first stochastic pressure prediction. Moreover, Steiner's most frequent values and dihesion have been estimated from the simulated minimum, maximum, and mean pores pressure values that resulted in another stochastic prediction. Predictions have very similar results in case of the predicted mean and the most frequent pore pressure values. The developed method is applicable not only for the pre-drill well planning but could also be useful in the real-time monitoring and prediction during the drilling.

Author Contributions: Conceptualization, Z.N.; methodology, Z.N., M.K.B. and N.P.S.; software, Z.N.; validation, Z.N., M.K.B. and N.P.S.; investigation, Z.N., M.K.B. and N.P.S.; resources, Z.N., M.K.B. and N.P.S.; writing—original draft preparation Z.N., M.K.B. and N.P.S.; writing—review and editing, Z.N.; visualization, Z.N., M.K.B. and N.P.S.; supervision, Z.N.; project administration, Z.N. All authors have read and agreed to the published version of the manuscript.

Funding: The research was founded by the GINOP-2.3.2-15-2016-00010 'Development of enhanced engineering methods with the aim at utilization of subterranean energy resources' project of the Research Institute of Applied Earth Sciences of the University of Miskolc in the framework of the Széchenyi 2020 Plan, funded by the European Union, co-financed by the European Structural and Investment Funds.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Acknowledgments: We would like to express our most sincere gratitude to MOL Plc., the Sámuel Mikoviny Doctoral School of Geoscience for University of Miskolc, and the Research Institute of Applied Earth Sciences of the University of Miskolc for the data and their technical support. To Schlumberger for providing PetroMod under license to MOL Group.

Conflicts of Interest: The funders had no role in the design of the study; in the collection, analyses, or interpretation of data; in the writing of the manuscript, or in the decision to publish the results.

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