



## UNCONVENTIONAL OIL AND GAS ACCUMULATIONS IN THE LOWER PALAEOZOIC SHALE RESERVOIRS OF THE CENTRAL AND EASTERN EUROPE – A REVIEW

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### Introduction

Development of a gigantic scale shale gas production, and subsequently also shale oil one, in US and Canada brought global attention to an innovative petroleum system concepts related to shale reservoirs. Success of North American shale exploration encouraged analysis of shale oil/gas potential applied during the last decade to numerous basins across the World, including also several European petroleum basins. In Europe the main exploration efforts were concentrated on the Lower Palaeozoic organic-rich shale, and to a lower extend also on the Upper Palaeozoic and Mesozoic ones. The Lower Palaeozoic basins with shale gas and shale oil potential are developed mainly at the western slope of the East European Craton (EEC) within Caledonian foredeep basin system, i.e. the Scandinavian slope of the EEC (SSEEC), the Baltic Basin (BB), the Lublin-Podlasie Basin (LPB), the Biłgoraj-Narol Zone (BNZ), and the Volyn-Podillya-Moldavia Basin (VPMB), as well as on other adjacent tectonic blocks, i.e. the Malopolska Block (MB) and the Moesian Platform (MP). Exploration concentrated so far mainly on the BB and LPB, where 63 new wells were drilled last decade. Moreover, in southern Scania (SSEEC) 3 shallow wells were drilled. In the other sectors of the Central and Eastern European Lower Palaeozoic basins shale oil/gas potential was studied so far based on legacy data, in particular core and geophysical data evaluation. Current study aims to recapitulate for these basins an outcome of the hitherto unconventional oil/gas exploration and related research.

### Methods

For evaluation of shale oil/gas potential several geological/geochemical/geophysical criteria were applied. The key aspect of the evaluation were analysis of lateral and vertical TOC content distribution within the basins. Quality of the shale reservoirs were determined also with other RockEval data, in particular with primary Hydrogen Index, as well as by determination of kerogen type. Type of hydrocarbons saturating reservoir was determined with thermal maturity data, as well as with legacy oil and gas shows. Shale porosity and permeability data, as well as mineralogical data (XRD) were analysed for both new exploration wells and legacy ones. Gas saturation analysis were available for new exploration wells only. Gross or net thickness of reservoirs, their burial depth, and degree of tectonic deformation was determined as well.

### Results

Deposition of organic-rich shale at the western slope of the EEC is diachronic. In the SSEEC and the NW part of the BB it begun during the Middle/Upper Cambrian (Alum shale). In the central BB the main phase of organic-rich shale deposition took place during the Caradoc time, while in the Eastern BB and northern LPB during the Llandovery. In the southern LPB and in the VPMB it begun only during the Wenlock time. Throughout all that time interval organic-rich shale deposition was restricted from the east by sedimentation of shallow marine carbonates, while from the west it was eventually limited by the influx of detritus derived from Caledonian collision zone.

Within the analysed Lower Palaeozoic shale formations the TOC content varies significantly, both laterally and vertically. Its highest values, commonly exceeding 5-10 %, are characteristic of the (Middle-) Upper Cambrian Alum shale. High average TOC content is observed also for the Caradoc and lower Llandovery shale reservoirs in the central BB, and in the second case also in the NW part of the LPB, where is riches typically 3-5 %. Significantly lower average TOC content characterizes the lower Wenlock shale in the LPB and the VPMB, where is hardly exceeds 1-1.5 %. TOC content for the Tandarei Fm in the MP ranges from 0.1 to 3.5 %. All analysed shale formations in general contain mostly the II type of kerogen.



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Gross thickness of organic-rich shale in the whole analysed area is in a range of a few to several tens of meters. Net reservoir thickness, defined only for the Polish sector of the study area, is the highest in the central BB, where it could reach 20-40 m at maximum. The lower Wenlock TOC-lean shale in the LPB and VPMB is characterized by high thickness, being in a range of several tens of meters.

Mineralogical composition of the analysed shale formation is variable, both laterally and in a vertical section. However, in general the shale is clay rich. Brittleness of the shale reservoir is controlled mainly by moderate to high quartz content, and locally by high carbonate content. Nonetheless, moderate to high brittleness factor indicate reservoir suitable for hydraulic fracturing. In the BB and LPB porosity of the Lower Palaeozoic shale is moderate, while permeability is low as for shale reservoir.

The recent burial depth to the Lower Palaeozoic shale reservoir at the western slope of the EEC increases from the east and northeast towards west and southwest. In the MB burial depth of the shale reservoir increases towards the south, while in the MP towards the north. In all the regions thermal maturity of the reservoir changes the same direction. At the major part of the study area the analysed shale reservoirs are matured to the oil or liquids windows. Extend of the gas window is limited, and restricted to the deep part of the basin (> 3500-4000 m), except of the SSEEC and the BNZ, where the Lower Palaeozoic shale is matured to the dry gas window at low burial depth. There is no indication for reservoir overpressures at the major part of the study area. This is due to early hydrocarbon generation and subsequent significant uplift, as well as to tectonic deformation. In a case of SSEEC tectonic deformation and magmatic activity released nearly all gas from the reservoir, and current gas saturation is lower than shale sorption capacity. Further to the SE a degree of tectonic deformation is lower, being very low in the BB, and generally moderate in the remaining area. More significant tectonic deformation characterizes the central part of the LPB, and even more the area to the west of the LPB, i.e. the BNZ.

So far exploration activity was concentrated mainly on the BB, the LPB, and the NBZ, where 63 new wells were drilled on shale targets. Among them, however, there were only 5 lateral wells with representative multi-fracturing test results. Most of exploration wells drilled up to date were located in the liquids window or oil window, more difficult for hydrocarbon production than in a case of dry gas window. None of the exploration wells gave commercial flow rates. The maximum initial gas production rate was in a range of 15 Mcm/d, however the flows were measured mostly for the wet gas zone, and few tested wells avoided considerable technical problems. The up-scale potential for further exploration in the basin is related to adjustment of fracturing design to local conditions, and to larger vertical expansion of fractures, so they could cover two target formations together with one stimulation.

### Conclusions

The key European basins with shale gas/oil potential are the Lower Palaeozoic ones located at the western slope of the EEC, mainly the Baltic Basin, and to the lesser degree also at the Moesian Platform (MP). The most important shale reservoir formations are the Upper Cambrian, the Caradoc, the lower Llandovery, and the lower Wenlock ones. Within a range of recent burial depths not exceeding 3000-3500 m, the analysed shale formations are mostly condensate and oil saturated. Dry gas saturated zone at the western slope of the EEC is located at the depth of 3500-4000 m or more. The analysed shale might be generally classified as a moderate to low quality unconventional reservoir. The key exploration risk factors are moderate to low: (-) average values of TOC contents, (-) net pay thickness, (-) porosity and permeability, (-) reservoir gas saturation, as well as apparent lack of reservoir overpressures. Due to these factors the initial gas flow rates were so far low, below a level of commerciality. A design of fracturing, which would allow to cover at least two target formations together with one stimulation, is expect to improve test results considerably.

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