Geophysical Research Abstracts
Vol. 19, EGU2017-4980-1, 2017
EGU General Assembly 2017

The estimation of CO_2 storage potential of gas-bearing shale complex at the early stage of reservoir characterization: the case of Baltic Basin (Poland).

Adam Wójcicki and Marek Jarosiński
Polish Geological Institute - National Research Institute, Warsaw, Poland (awoj@pgi.gov.pl)

For the stage of shale gas production, like in the USA, prediction of the CO_2 storage potential in shale reservoir can be performed by dynamic modeling. We have made an attempt to estimate this potential at an early stage of shale gas exploration in the Lower Paleozoic Baltic Basin, based on data from 3,800 m deep vertical well (without hydraulic fracking stimulation), supplemented with additional information from neighboring boreholes. Such an attempt makes a sense as a first guess forecast for company that explores a new basin. In our approach, the storage capacity is build by: (1) sorption potential of organic matter, (2) open pore space and (3) potential fracture space. the sequence. our estimation is done for 120 m long shale sequence including three shale intervals enriched with organic mater. Such an interval is possible to be fracked from a single horizontal borehole as known from hydraulic fracture treatment in the other boreholes in this region.

The potential for adsorbed CO_2 is determined from Langmuir isotherm parameters taken from laboratory measurements in case of both CH4 and CO_2 adsorption, as well as shale density and volume. CO_2 has approximately three times higher sorption capacity than methane to the organic matter contained in the Baltic Basin shales. Finally, due to low permeability of shale we adopt the common assumption for the USA shale basins that the CO_2 will be able to reach effectively only 10% of theoretical total sorption volume. The pore space capacity was estimated by utilizing results of laboratory measurements of dynamic capacity for pores bigger than 10 nm. It is assumed for smaller pores adsorption prevails over free gas. Similarly to solution for sorption, we have assumed that only 10 % of the tight pore space will be reached by CO_2. For fracture space we have considered separately natural (tectonic-origin) and technological (potentially produced by hydraulic fracturing treatment) fractures. From fracture density profile and typical permeability of fractures under lithostatic stress we inferred negligible open space of natural fractures. Technological fracture space was calculated as an potential for hydraulic stimulation of vertical fractures until, due to elastic expansion of reservoir, the horizontal minimum stress equals the vertical one. In such a case, horizontal fractures start to open and the stimulation process gets to fail. Based on elastic anisotropy and tectonic stress differentiation, the maximum hydraulic horizontal extension was calculated for separated shale complexes. For further storage capacity we assumed that technological fracture space create primary pathway for CO_2 transport is entirely accessible for the CO_2.

In general, the CO_2 sorption capacity makes the predominant contribution and fracture space capacity is comparable or smaller than pore space contribution. When compare this with the best recognized Marcellus shale basin we can see that our calculations for the 35 m depth interval comprising formations with the higher TOC content show a slightly lower value than in the case of Marcellus.