AAPG Datapages/Search and Discovery Article #90314 ©2017 AAPG Middle East Region GTW, Decision Based Integrated Reservoir Modeling, Muscat, Oman, October 30 – November 1, 2017

Tight Gas Formation Permeability-Thickness Modelling

Khalil Al Rashdi[1]

[1]BP, Oman

ABSTRACT

Major tight gas layered fields seldom have a full field dynamic simulation model, due to large number of cells required and the extreme heterogeneity of the system. In these cases, estimating the well profiles depends mainly on two variables: the gas-initially-in-place (resource) density (GD, bcf/km2) and permeability thickness (Kh, md.ft) for each well type. Permeability thickness is an important parameter controlling initially flow rate, so it is used to help select well type (horizontal vs vertical). This poster illustrates how to generate a permeability thickness map for tight gas reservoir (Barik Formation, Khazzan Field, Oman) utilizing sparse data. It supports the decisions of well type selection and well profile generatin which ultimately will outline the number and spacing of wells required for field development.

Permeability thickness has two elements: effective gas permeability (Keg), which is a function of the absolute permeability under a given fluid saturation and the relative permeability to that phase, and flowing interval thickness (H, ft) which changes as a function of pressure drop. Tight gas reservoirs require hydraulic fracture stimulation to deliver economic flow rates. Thickness changes with pressure depletion in layered systems and in pressure transient analysis (PTA) the effectively stimulated interval is not accurately known. Therefore, the effective thickness is uncertain. The petrophysical rock type model allows us the generate both porosity and absolute permeability (Kabs) as well as fluid saturation from well-data. A linear relationship in well-data allows us to correlate average porosity to average permeability (Kabs) and the average Permeability (Kabs) to average Effective Permeability (Keg) as a function of fluid saturation. The remaining uncertainty is the effective thickness in which the total thickness is estimated using log net reservoir cutoffs and the cutoff is changed for changing delta pressure. This method if compared to a full field model has saved time and effort as well as provided fit for purpose results in accordance with the geological model. The full field model major benefit is modeling pressure drop with time however, since the project has just started producing and the KegH map is required to model initial flow, this method is adequate. Updating the KegH map with new data is a lot simpler, easier and straight forward with this method compared to a full field model. It is also easy to figure out the areal uncertainty and it is close to the required resolution, as no vertical resolution is required. Hence, this method is selected to serve the decisions.