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Abstract

Objectives/Scope:

Rock permeability and gas viscosity are two key data inputs required to characterize gas mobility in reservoir modeling. However complexities involving Klinkenberg effects in tight rocks make it challenging to match laboratory observations to values appropriate for reservoir modeling input. As fluid pressure P declines at constant overburden stress and constant temperature T, three mechanisms are at play to alter gas mobility:

Methods, Procedures, Process:

1 The increase in net confining stress causes vertical compaction, meaning reduced porosity, and in response to this change in pore-network geometry, reduced permeability; 2 Since at constant T and composition, bulk-phase gas viscosity is a function of *P*, the bulk gas viscosity changes; and 3 The Klinkenberg effect results when changing flow conditions cause movement across flow regimes between Darcy flow, slip flow, and Knudsen diffusion. Its effect is a level of gas flow resistance below what is reflected by the bulk-phase gas viscosity at prevailing conditions - an effect that is greater with greater confinement, lower fluid pressure, and lighter gas. Therefore a correction to the bulk gas viscosity μ_g^{bulk} is required to determine confined gas viscosity μ_g^{conf}. While the bulk gas viscosity $\mu_g^{bulk}(P)$ is a readily determined function of *T*, *P*, & composition, experiments are needed to determine porosity Φ=f(P), the intrinsic permeability K=f(Φ), and the viscosity confinement factor V_c=f(P) where $\mu_g^{conf}(P) = \mu_g^{bulk}(P) / V_c(P)$.

Results, Observations, Conclusions:

Regarding V_c=f(P), it can be computed from the experimental history of Φ =f(P) and K=f(Φ). Actually V_c=f(P) is a function of not only *P* but also pore size, gas composition, and *T*. Therefore lab-derived $V_c(P)$ can be recomputed at reservoir *T* for each component in the reservoir model, and then applied to the $\mu_g^{bulk}(P)$ table of each component to yield a $\mu_g^{conf}(P)$ table for input into the reservoir model. This framework is novel in its capture of the Klinkenberg effect's compositional dependency, which may be important near the fracture face where pressures are lower and phase compositions are altered by dropping below dew-point. With respect to permeability K=f(Φ), actually laboratory experiments merely measure gas mobility, from which apparent permeability is computed using the bulk-phase value of gas viscosity. This results in a deviation between the computed permeability and the intrinsic permeability, which characterizes the rock's flow resistance resulting from the geometry of its pore network.

Novel/Additive Information:

Fortunately depletion experiments using pulse or oscillation methods can be used to ascertain intrinsic permeability, plus yield important information on the degree of viscosity adjustment needed due to confinement at reservoir conditions. This work includes an example calculation using experimental results from Eagle Ford rock. Also we promulgate a workflow guiding the pathway from appropriate experimentation to proper data input for reservoir modeling.