Modeling in Carbonates: Where is the Geology?*

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Abstract

Building reservoir models in carbonate reservoirs that can support reliable predictions of future reservoir performance is a well-acknowledged difficulty in our industry. The complexities unique to carbonate reservoirs provide a set of challenges quite different from those in siliciclastic reservoirs. The impact of diagenesis on rock properties and reservoir geometry and continuity is complex. Additionally the impact of natural fracturing on flow behavior represents a level of complexity, which is typically beyond our means to adequately describe and predict. The focus of this paper is on matrix-dominated systems and will not fully address the impact and complexity of natural fracturing.

Current industry practices for carbonate reservoir characterization and modeling fail to adequately define the distribution and continuity of the permeability extremes. The ability to both map and predict the continuity of low permeability barriers to flow and the high permeability flow conduits is not an EXPLICIT output of our workflows. Rather we tend to assume that by providing detailed interpretations of rock fabric, stratigraphic architecture, EOD geometries, rock typing, petrophysics etc. we will end up with a “good” model.

Discussion

Multiple nested geostatistical steps in the modeling process can lead to models becoming “heterogeneously homogeneous”, causing the relationship between input geological concepts and final perm distribution to be almost completely lost (Figure 1). When you combine these nested stochastic processes with the (typically) wide range of permeabilities by rock type then it is easy to see how the final permeability model has a very noisy statistical character with little or no apparent geologic controls. Additionally the geostatistical processes will never reproduce the interpreted continuity of thin low permeability mudstones without being “forced” to do so.

The general industry starting point for reservoir modeling is that we know all reservoirs contain heterogeneity that we do not adequately sample with well and seismic data. We accept that representing this heterogeneity in our models is important for reliable reservoir performance predictions. Accordingly, we use geostatistical algorithms to produce a statistically valid, stochastic representation of the heterogeneity. The use of geostatistical algorithms is the industry-standard approach and no fully satisfactory alternatives have been developed. In their most basic form these geostatistical algorithms do not require or explicitly use any geologic concepts or principles. However, we do have some "tricks" to make them seem more geologically reasonable. The use of a wide range of methods to incorporate conditioning data has enabled us to allow these algorithms to produce less unrealistic models. Despite these "tricks", the overall stochastic 3D modeling process causes us to lose touch with the geologic controls on permeability distribution. The geostatistical algorithms seek to be correct on average but are of course wrong at any specific location in the model. With sufficient data and performance history there is usually a set of preferred flow pathways in the reservoir that are critical to represent in the model. Our current tools do a poor job at representing these flow pathways.

This issue of the representativeness of our flow unit characterization in the models leads to another serious issue with modeling in carbonate reservoirs. It takes too long. With large fields with hundreds of wells and long production histories, the iterative process of building and testing the models against performance data can take one to two years. The root causes of this are the nature of geostatistical algorithms and the inherent complexity of "finding" the correct 3D permeability structure require to achieve an acceptable history match in the reservoir simulator.

In addition to these modeling method-related issues, there are also serious issues with our approaches to data analysis, interpretations and conceptual models. Based on the large cell sizes typically required to effectively model our fields, we are commonly challenged to appropriately capture and represent a range of key but subtle features such as thin-bedded intervals, stylolites and microporous intervals. Our large model cell sizes can lead to sampling and subtle data analysis biases that further exacerbate our models' utility.

Conclusion

When we examine modern analogues and outcrop analogues and we compare these to our geological models created using geostatistics, we see very different expressions of geometry and continuity. We have become so accustomed to looking at these geostatistical models that we no longer find them to be either unacceptable or geologically unreasonable. We should not accept these representations and we need to work towards developing capabilities to better capture our geological concepts and interpretations in our reservoir models.

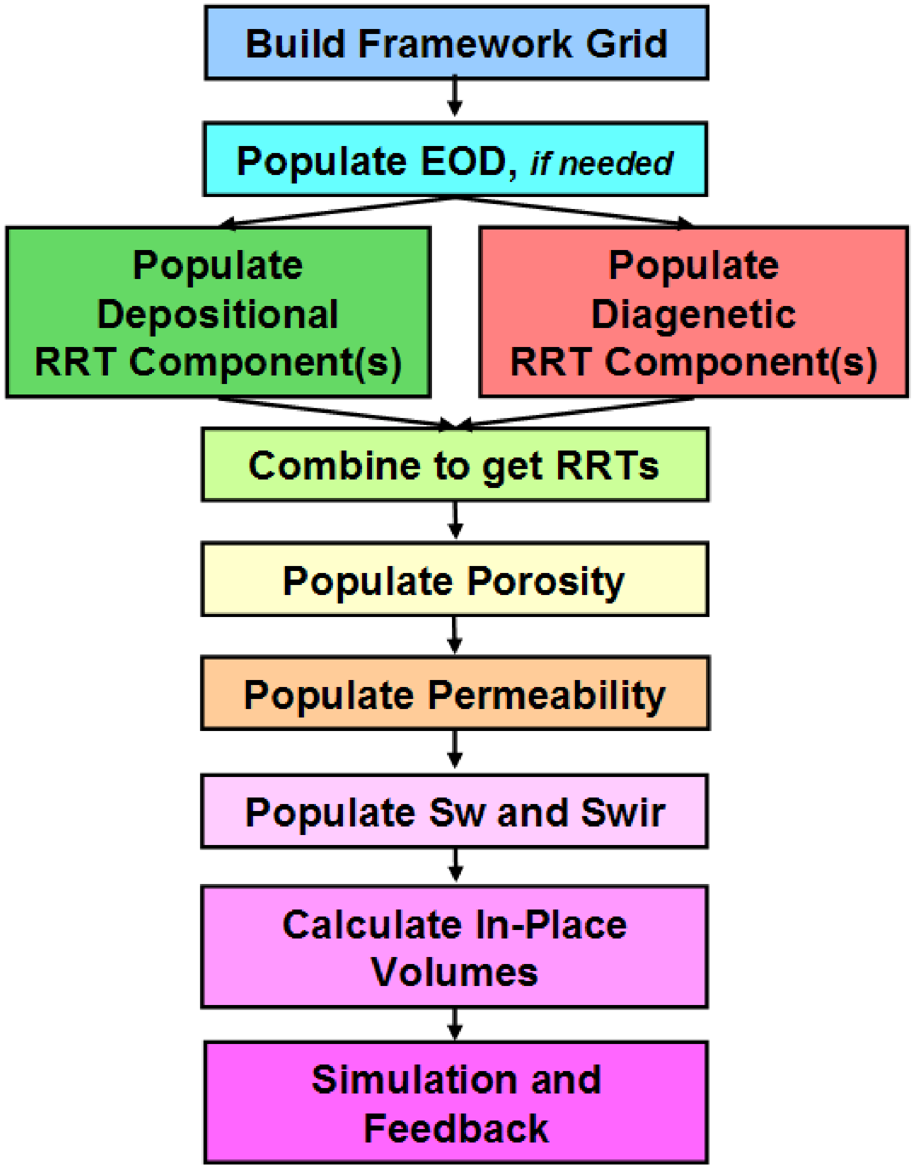

Figure 1. Preferred carbonate modeling workflow.