Methodology for Assessing Uncertainties Affecting STOOIP and Production in the Zama F Pool, Zama Subbasin, Alberta, Canada

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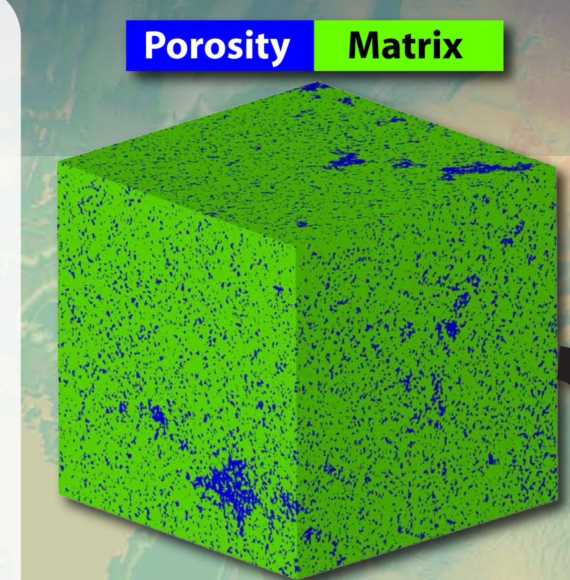
Abstract

Since October 2005, the Zama oil field in northwestern Alberta, Canada, has been the site of acid gas (approximately 80% carbon dioxide [CO_2] and 20% hydrogen sulfide [H_2S]) injection for the simultaneous purpose of enhanced oil recovery (EOR), H_2S disposal, and CO_2 storage. Injection began in December 2006 and continues through the present at a depth of 4900 feet into the Zama F Pool, which is one of over 800 pinnacle reef structures identified in the Zama Subbasin. To date, over 90,000 tons of acid gas has been injected, with an incremental production of over 50,000 barrels of oil. The primary purpose of this work is to verify and validate stored volumes of CO_2, with the ultimate goal of monetizing carbon credits.

Pinnacle reefs have very complex geologic and facies relationships, and as a result, a thorough understanding of the geology is necessary in order to properly monitor and predict fluid movement in the reservoir. Borehole image logs were used to more accurately identify the different facies and determine each facies' properties along the wellbores. Seismic attribute data interpretations were used to identify the reef versus nonreef facies to aid in the distribution of the facies in the reservoir. These properties were then spatially distributed throughout the theoretical reservoir model using a combination of multiple-point statistics and object modeling workflow to produced equiprobable reef facies, structure, and volumetric realizations.

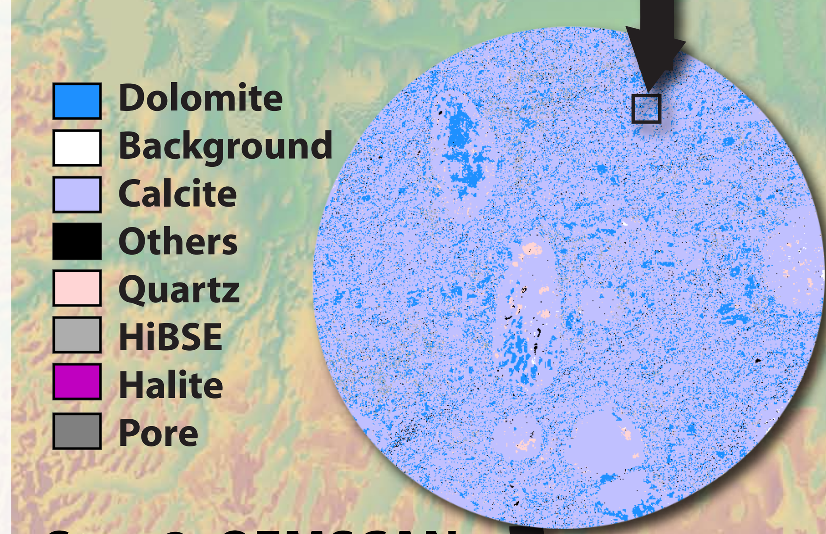
Initial model results suggest that reservoir volume, porosity, and net to gross are major uncertainties that will most affect stock tank original oil in place (STOOIP). This initial uncertainty analysis also provides some insight into which properties may need more rigorous conditioning in order to acquire defendable history matches. History-matching activities will be focused on matching historic production and injection into the reef and will be used to help condition the geologic models. Of utmost importance will be matching the historic production and injection volumes, individual fluid rates, and bottomhole pressures. These data will then be used to predict future incremental oil recovery, validate long-term acid gas storage, and identify areas of unswept hydrocarbons.



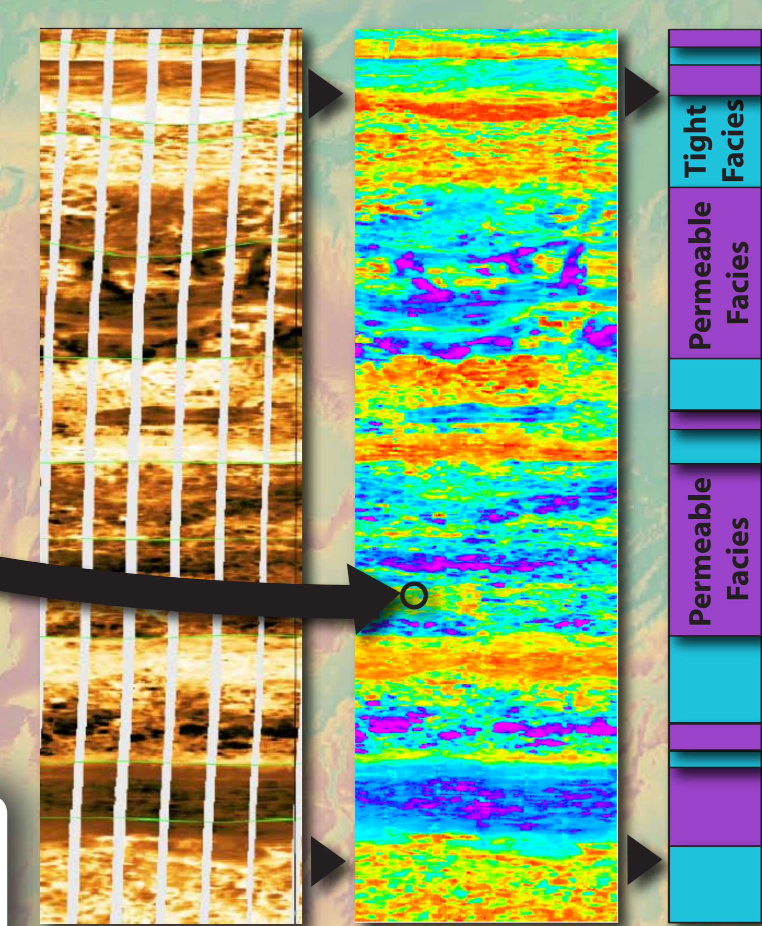
Step 1. Micro-CT scan
(nm to µm scale)

UPSCALE

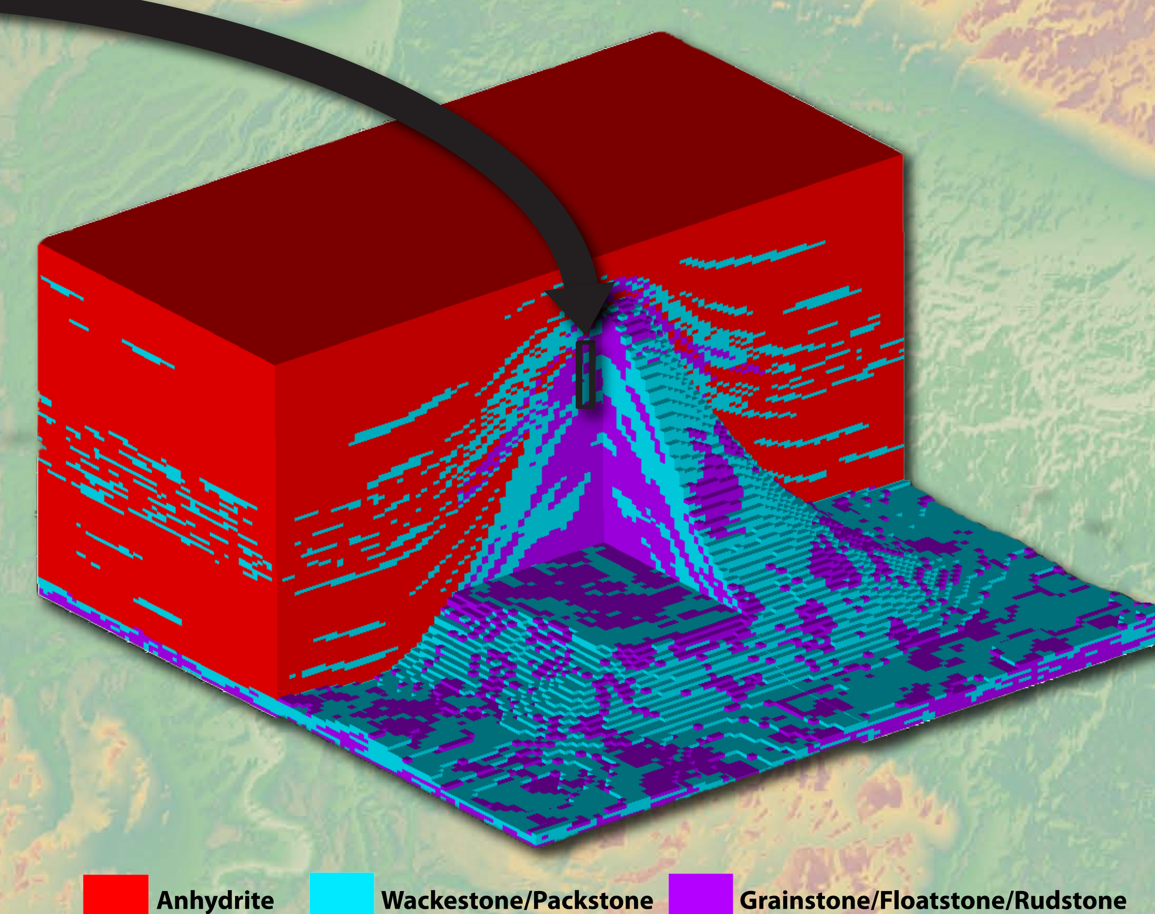
Zama F Pool



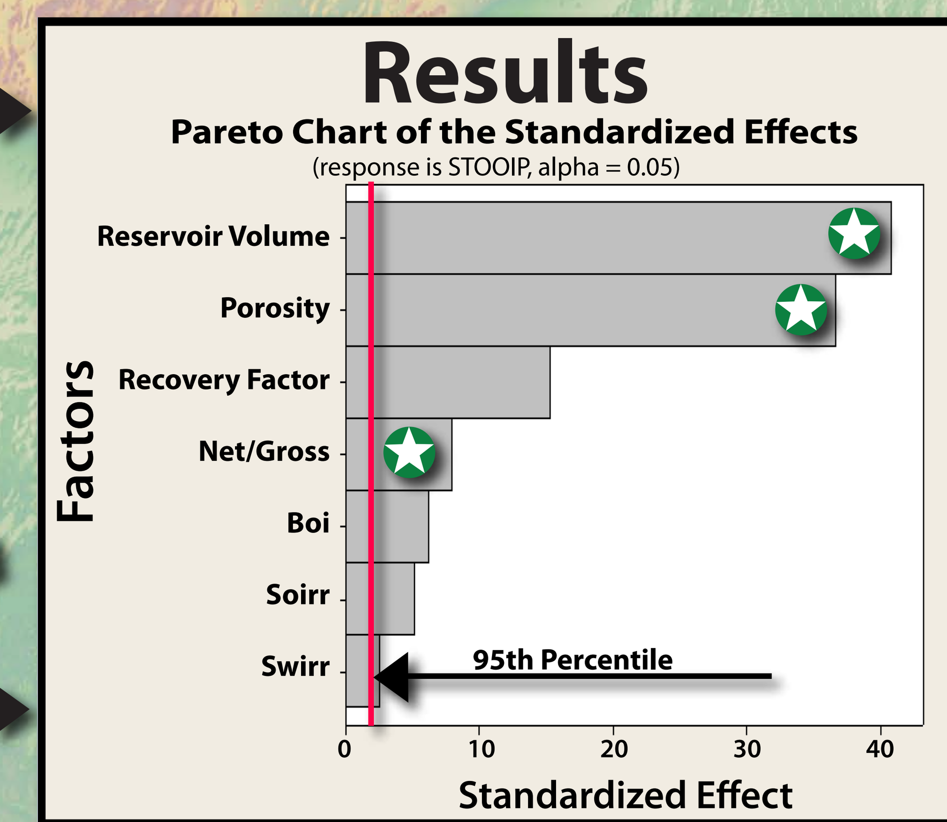
Step 2. QEMSCAN
(µm to mm scale)



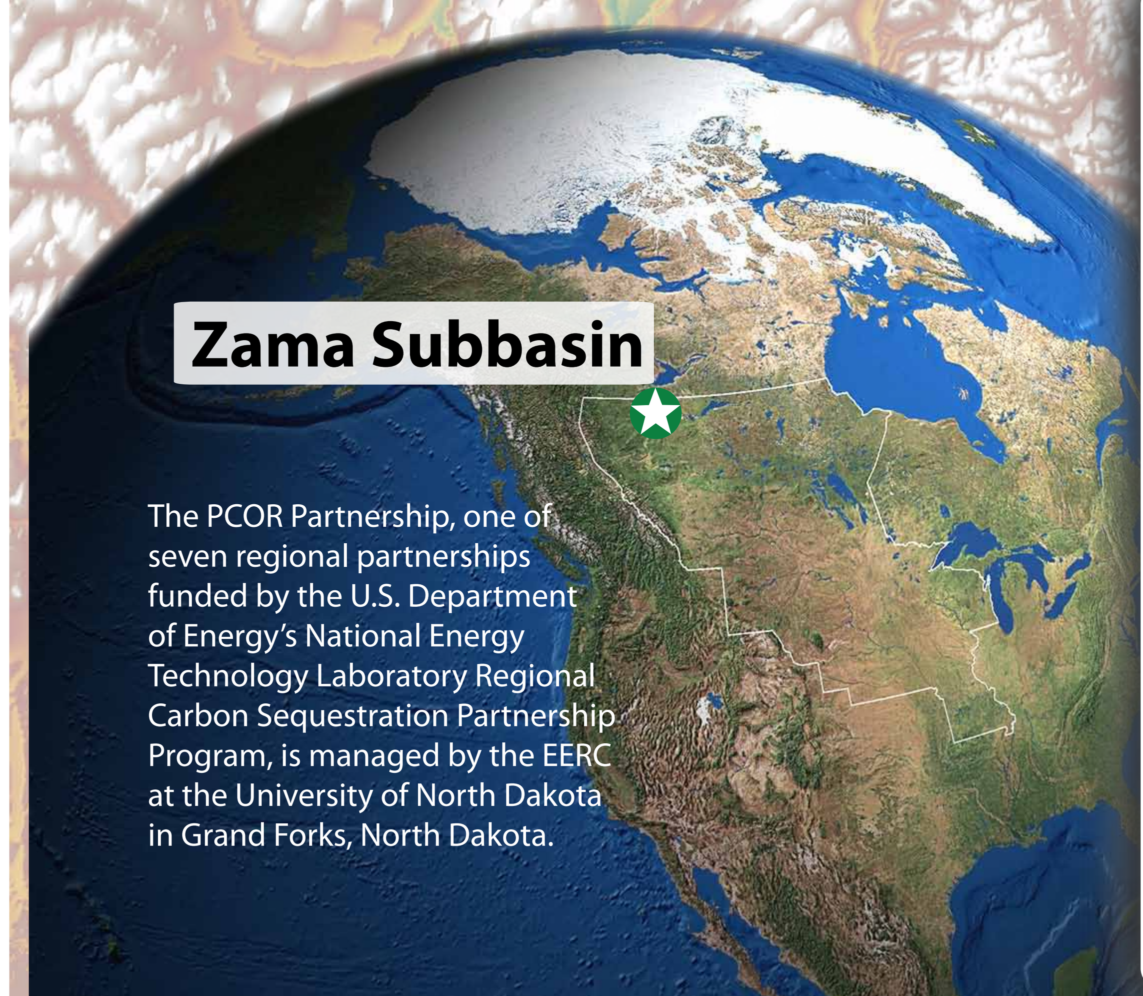
Step 3. Formation Micro Imaging (FMI) Log Processing
(cm to m scale)



Step 4. Form Analog Reservoir Model
(10s of m to km scale)



Step 5. Perform Uncertainty Analysis
(Major geologic factors affecting STOOIP are marked with a star.)



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PCOR Partnership 2003 – Present

Conclusions

1. In addition to identifying fractures and bedding planes, FMI logs in combination with simple laboratory measurements can be used to develop advanced formation- and facies-specific data such as effective horizontal and vertical permeabilities, relative permeabilities, and capillary pressures.
2. Multiple-point statistics (MPS) is becoming a valuable tool at all levels of reservoir characterization from micro to macro scale by allowing modeling that was not able to be done with classic geostatistical algorithms such as sequential Gaussian simulation (sGs) and sequential indicator simulation (SIS). However, these classic algorithms are not outdated as they are used to form inputs into MPS workflows.
3. In this specific case, there was no control for the flanks of the reef except for seismic data which are not considered hard data like wireline, core, and well top data. Being soft data, seismic was used to form macro-facies probabilities that were input into the MPS algorithm, the result was that the total reservoir volume had the greatest effect on STOOIP uncertainty.