MODELING AND SIMULATION WORKFLOW FOR A FRACTURED CARBONATE CO_2 HUFF 'N' PUFF: A CASE STUDY IN THE WILLISTON BASIN, NORTH DAKOTA, USA

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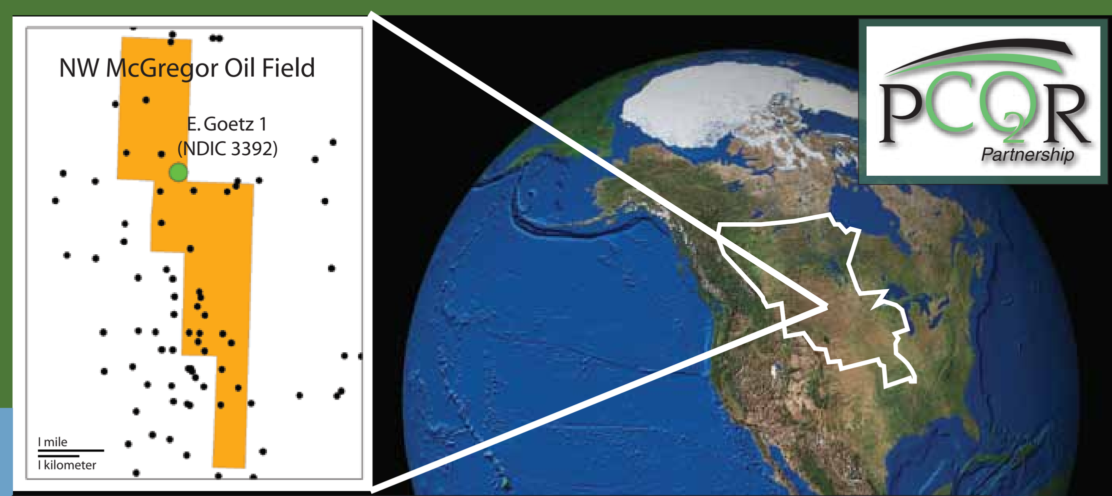


ABSTRACT

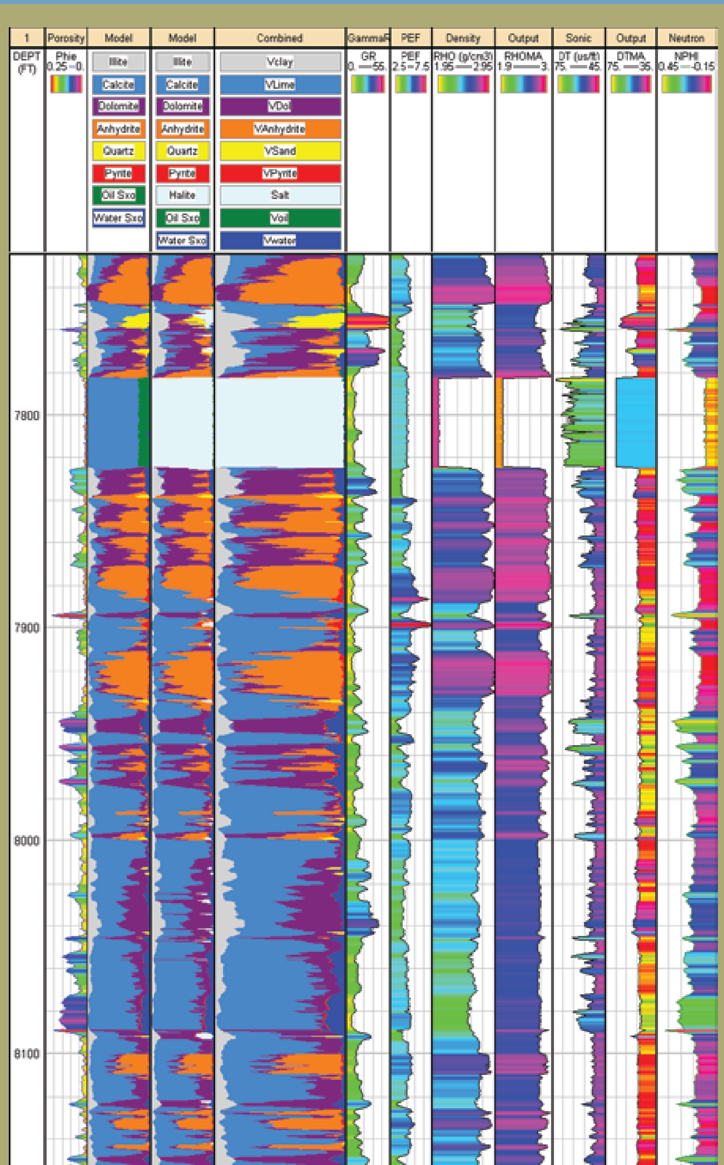
A CO_2 huff 'n' puff (HNP) enhanced oil recovery (EOR) project was carried out in the E. Goetz 1 well located in the Northwest McGregor Field of Williams County, North Dakota, USA. The HNP is one of the Plains CO_2 Reduction (PCOR) Partnership Phase II pilot projects in which CO_2 was injected into the Mississippian Mission Canyon Formation, a fractured carbonate reservoir, for the dual purpose of CO_2 EOR and associated CO_2 storage. The workflow for building the static geologic model for this study involved data collection and normalization, petrophysical and facies modeling, and dynamic simulation with history matching. The small-scale injection model contained only one well, so a larger-scale model containing several wells was built using sequential Gaussian simulation (SGS) and indicator simulations to determine trends and anisotropy. Then a smaller downscaled injection model was built using discrete and continuous multiple point statistics to model the gradational mudstone to grainstone sequence common with platform carbonates while using a cropped portion of the large-scale model as a covariable. Through the analysis of core and drill stem test (DST) data, it was determined that, to more accurately model the reservoir, a fracture model was needed which was constructed using discrete fracture network (DFN) simulation. The DFN model was then upscaled to the injection grid to produce a heterogeneous dual permeability and porosity model. This dual property model was then exported into the Computer Modeling Group's (CMG) generalized equation-of-state model compositional reservoir simulator (GEM), and SGS and indicator simulation were used to adjust the static model's petrophysical properties, assisting in the history match of the reservoir's historical production. Finally, the modeling and simulation work was integrated with time-lapse reservoir saturation tool (RST) data and vertical seismic profile (VSP) data to accurately account for the injected CO_2 and the produced water, oil, and CO_2. By following this type of workflow, the complicated nature of the CO_2 HNP was modeled and matched to the monitoring, verification, and accounting (MVA) techniques, displaying how this type of a workflow can be applied to other CO_2 storage projects.

The Plains CO_2 Reduction (PCOR) Partnership is a collaborative program assessing regional CO_2 storage opportunities. Its primary sponsor is the U.S. Department of Energy National Energy Technology Laboratory, with additional support from its more than 80 partners.

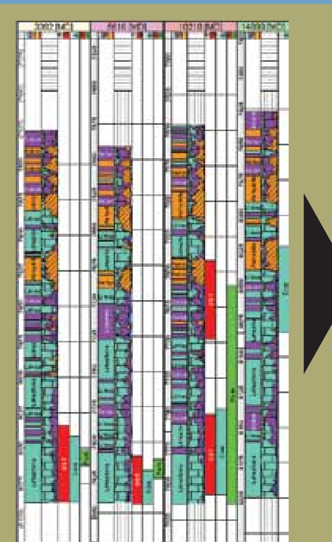
DUAL POROSITY AND PERMEABILITY MODELING WORKFLOW

MATRIX (M)

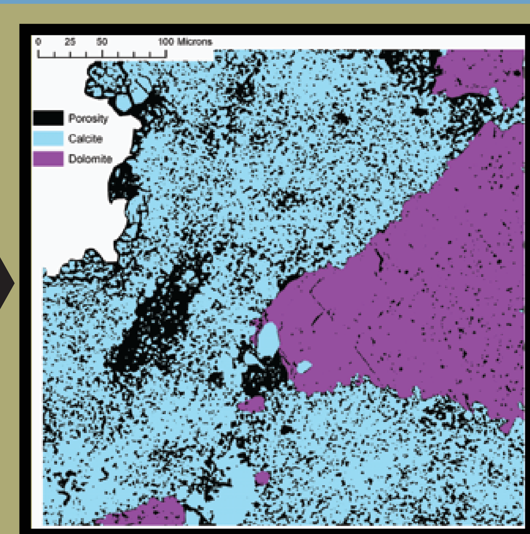
FRACTURE (F)



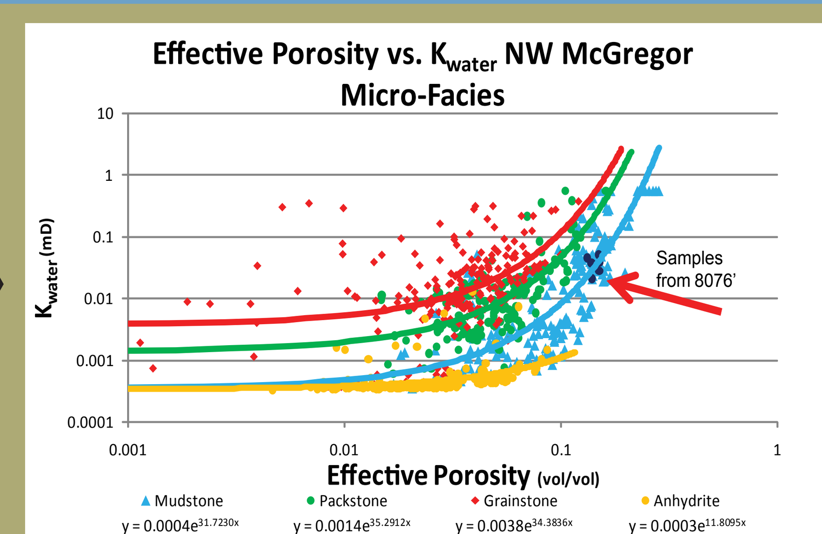
Step 1: A multimineral petrophysical analysis (MMPA) was completed after well log normalization and synthetic curves were created for missing curves using neural networks.



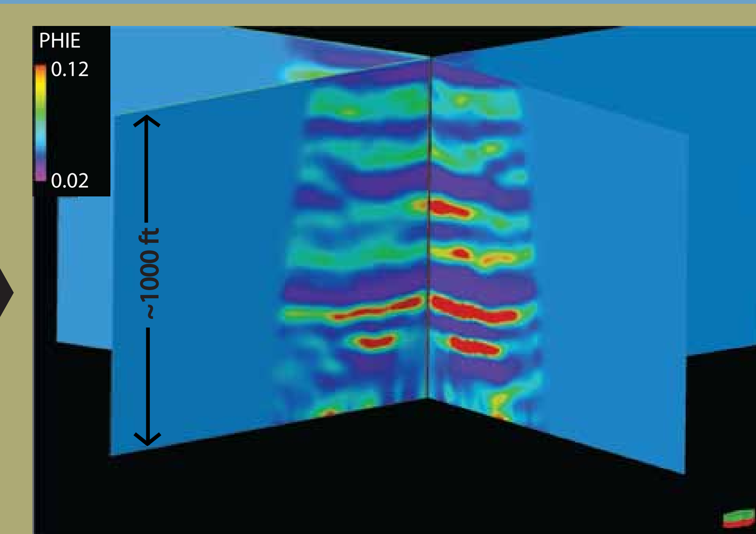
Step 2M: The MMPA was then completed in all wells in the study area.



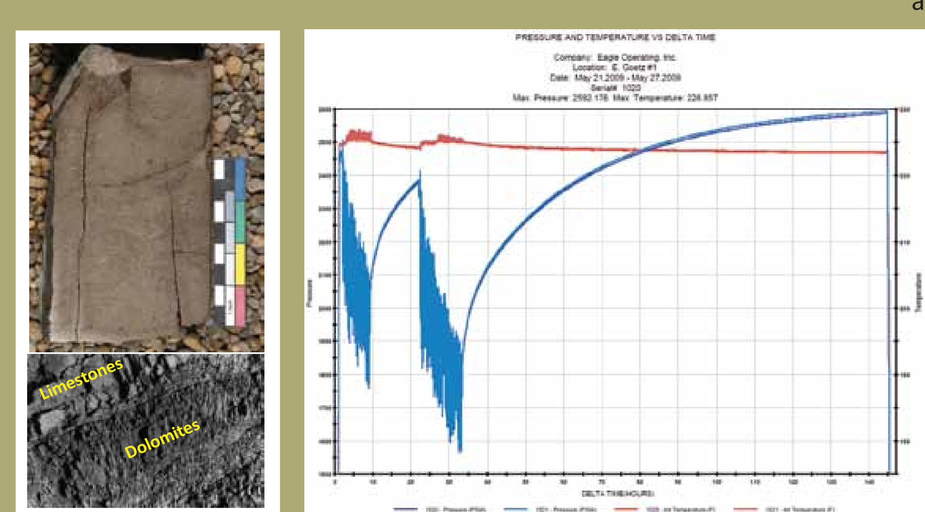
Step 3M: Results were verified with QEMSCAN analysis. The sample above was from approximately 8076' md.



Step 4M: This graph helps illustrate the relationship between micro-facies, effective porosity, and permeability to water. This graph, along with the QEMSCAN analysis in Step 3M, helps verify the petrophysical analysis.



Step 5M: Seismic inversions were performed on VSP to acquire spatial variability in porosity and absolute acoustic impedence (AAI).



Steps 2F and 3F: The fracture intensity was quantified with core, and the other fracture properties were populated using MMPA and pressure buildup analysis.

$k_f = k_f^2/k_m$ (1)

k_f = fracture permeability (mD)
k_d = average permeability from DST (mD)
k_m = core permeability (mD)

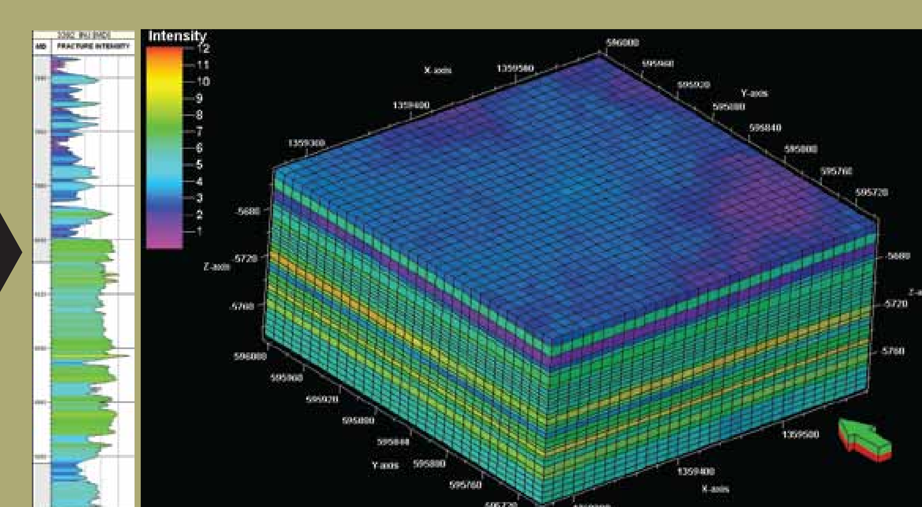
$k_e = k_m + \Phi_f * k_f$

k_e = effective permeability ~ DST permeability (mD)
Φ_f = fracture porosity

$k_f = 84.4 \times 10^5 \times W^3/Z$ (2)
$\Phi_f = W/Z \times 100$

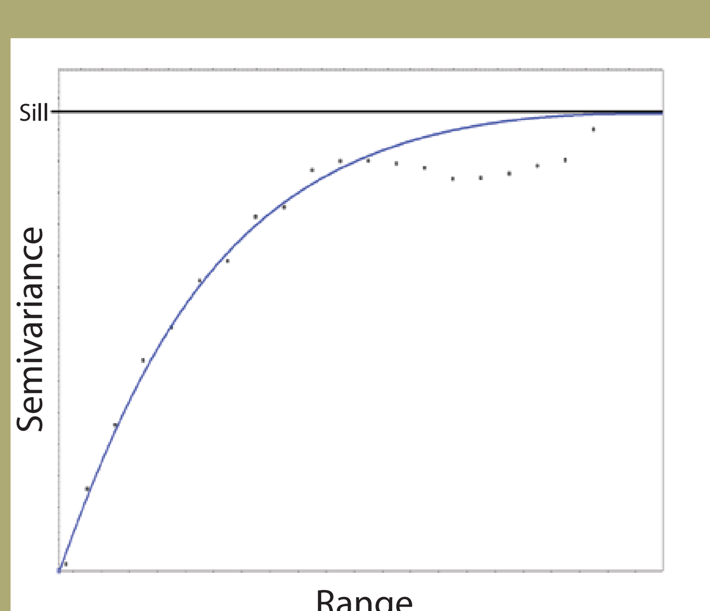
Z = fracture spacing (cm)
W = fracture width (cm)

Step 4F: Fracture widths, spacing, permeability, and porosities were approximated using the above formulas.

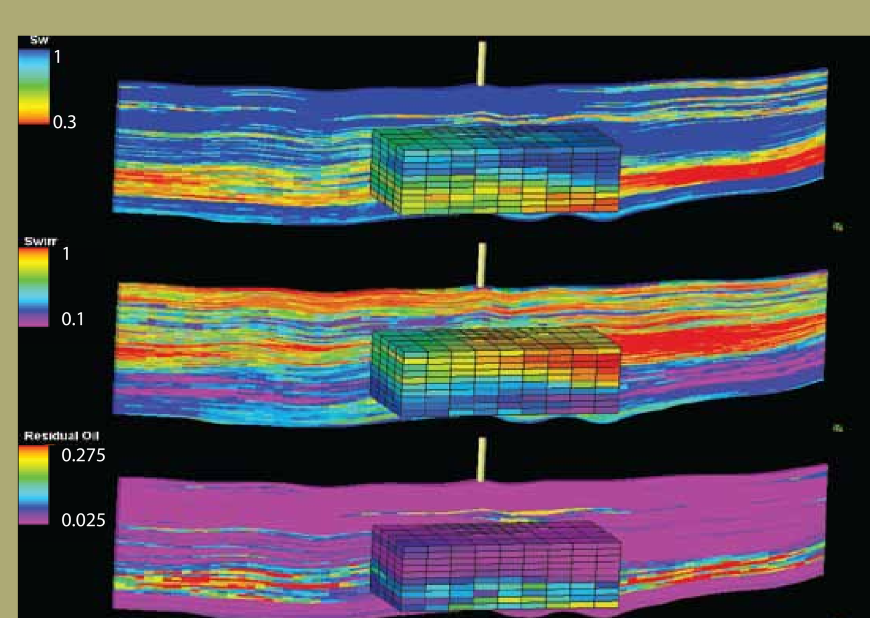


Step 5F: Using synthetic logs of fracture intensity, along with SGS, a fracture intensity volumetric grid was produced which was the input for DFN modeling.

MATRIX (M)

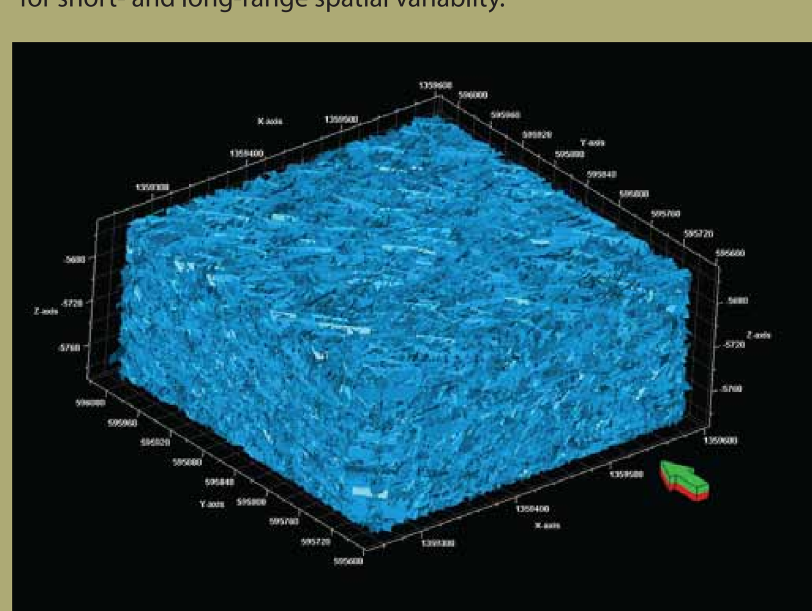


Step 6M: A semivariogram analysis of the inverted VSP porosity was used to acquire a better horizontal correlation for short- and long-range spatial variablity.

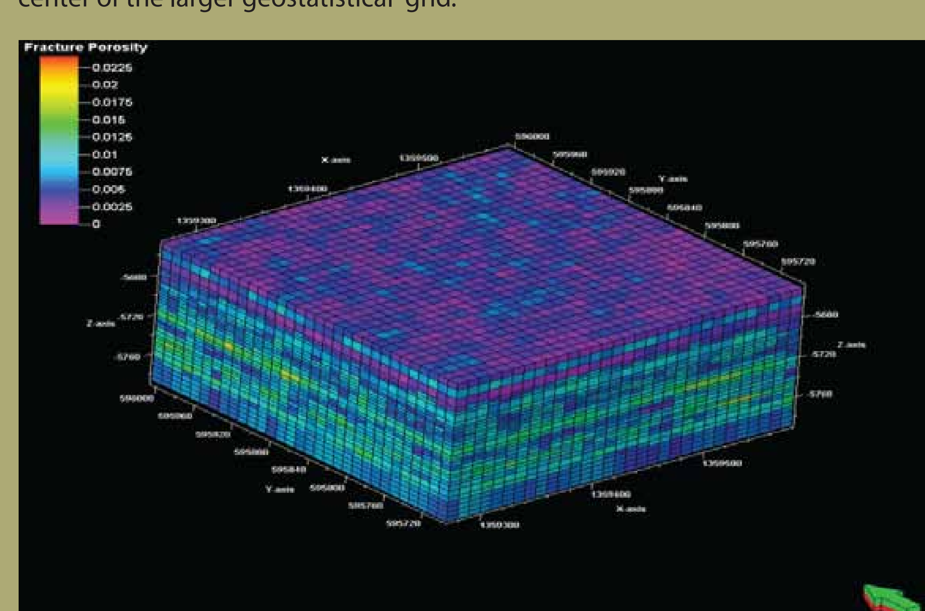


Step 7M: Reservoir properties were populated using inverted VSP as a covariable for SGS. The smaller upscaled injection grid is shown in the center of the larger geostatistical grid.

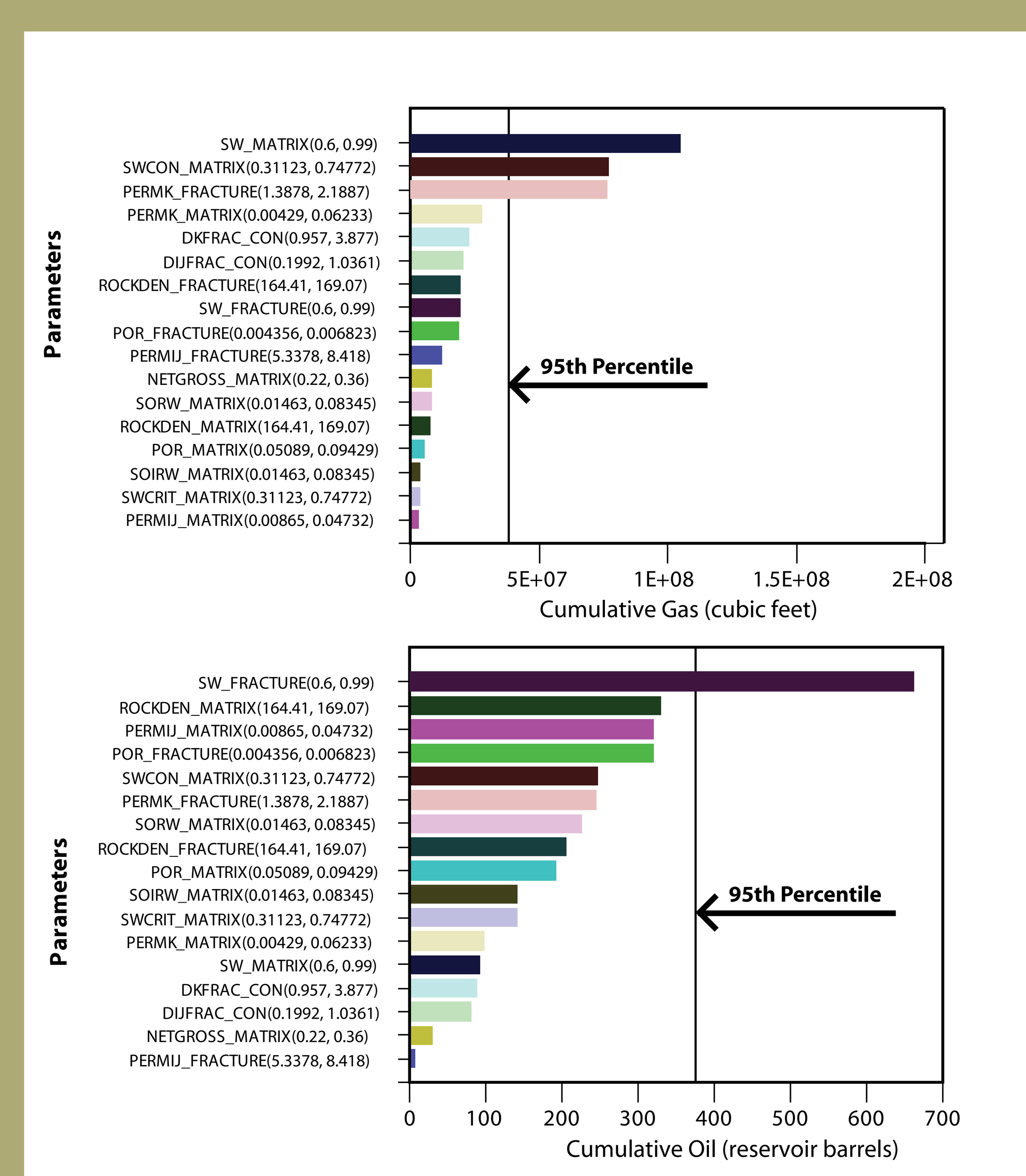
FRACTURE (F)



Step 6F: Based on the volumetric grid of fracture intensity, DFN modeling was performed to produce discrete fractures.

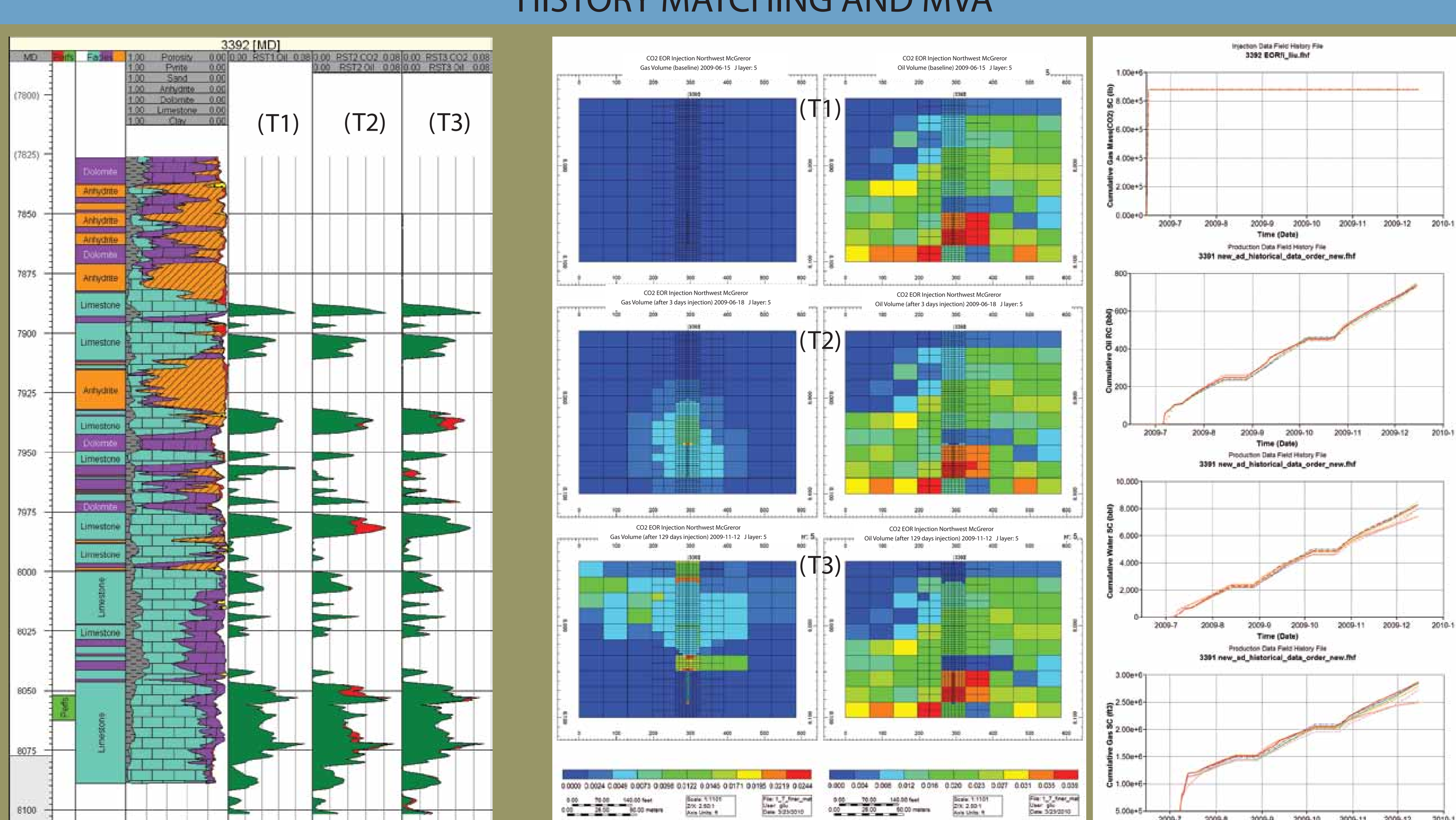


Step 7F: The DFN was then upscaled and populated with volumetric properties such as fracture porosity and permeability for input into the simulation grid.



Step 8: Prior to simulation, an uncertainty analysis was performed using CMG's CMOST to estimate which parameters most affect injection and production history matching.

HISTORY MATCHING AND MVA



Steps 9 and 10: Time-lapse RST log and production were matched using CMG's GEM and CMOST. After hundreds of simulation runs and adjusting the heavy hitter variables, a decent match was obtained. More simulations will be run to adjust the final few months of history to form a better match for future incremental recovery estimates, as well as predicting long-term CO_2 fate.

SUMMARY

The primary goals of this PCOR Partnership pilot project included determining the short- and long-term fate of a small volume of injected CO_2 (440 tons) and determining if a CO_2 HNP in this type of reservoir could be effective. In order to determine the fate of the injected CO_2 and the potential incremental oil production, time-lapse RST and VSP were used along with detailed static and numerical modeling. The VSP was an excellent tool for acquiring modeling parameters such as property semivariograms, near wellbore horizon vertical deviations, and production of covariables for petrophysical simulation. However, because of the highly fractured nature of the reservoir and the extremely low pore volume of the fractures, which contained most of the CO_2, from the repeat surveys, it appeared unlikely that the location of the injected CO_2 could be detected. The baseline and repeat RST logs were found to be an excellent tool for determining the vertical extent of the injected CO_2 near the wellbore, and the modeling and history-matching activities give good support for the overall extent of the injected CO_2 and will lead to better predictions of future incremental oil recovery.

References:

(1) Lucia, F. J., 2007, Carbonate reservoir characterization, 2d Ed.: Springer Publishing.
(2) Djebbar, T., and Donaldson, E., 2004, Petrophysics, theory and practice of measuring reservoir rock and fluid transport properties, 2d Ed.: Gulf Publishing.

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