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EOR: Challenges of Translating Fine Scale Displacement Into Full Field Models Part 3

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Abstract

The use of numerical finite-difference models to substantiate EOR implementation decisions has significantly increased, along with the need for accurate numerical representation of the driving forces and processes dominating the fluid flow. As reservoir characterization improves, so does the need for more representative models, since the perception appears to exist that increased accuracy and therefore predictive power, is linearly dependent on model size. Technology advances in hardware and software have overcome many of the past limitations on numerical model size, but not eliminitated them; hence correct upscaling is not only relevant but still very necessary to breach measurement scale gaps which are not limited to the traditional geocellular-to-numerical processes but probably now critical at the core/log to geomodelling stage previously overlooked by most reservoir engineers.

Numerical simulation of chemical flooding incorporates different challenges to those observed in miscible and immiscible flooding; flow mechanisms and EOR agent interaction with the reservoir have a higher degree of complexity with advanced numerical formulations (along with resolution requirements) to depict the fluid flow in a finite-difference space. This paper is a continuation of our previous work on miscible and immiscible flooding; we investigate the effect of grid size on the displacement behavior of a polymer flood, in terms of force balances, concentration changes and polymer rheology using different reservoir architectures, and discuss the potential caveats for application of more complex chemical processes and highlight the scale at which such modeling retains the underlying physical character.

Introduction

Effect of measurement and finite-difference model scale on fluid displacement has been discussed by several authors (Veedu 2010, Lelung 2010 and Kaxempour 2014). Of particular relevance when dealing with chemical flooding is the interaction of the EOR agent with the reservoir, which is usually characterized through a series of experiments, including core floods. Such measurements represent the commingled effect of the EOR agent properties and core plug heterogeneity in terms of pore tortuosity as well as surface chemisty. Numerical calibration is necessary in order to de-convolute the properties required by the full field simulators, making these EOR agent (interaction) properties a function of finite difference grid size.

The results of our previous papers confirmed the relevance of displacement velocity (capillary number), dispersive flow and force balance on the overall contacted oil and sweep efficiency, highlighting the caveats of mis-application of coarse models to predict enhanced oil recovery behavior.

Chemical flooding involves several non-linear interactions of the chemical agent with the reservoir rock (Han 2007), fluid and other agents, resulting in a complex interaction of physical processes which is often difficult to translate onto fine resolution grids not to mention coarse ones. Direct application of experimental characterization information to the numerical models without accounting for scale, mineralogy, residence time and chemical agent degradation will bring a higher level of uncertainty (and risk) to a process with inherent physical characterization challenges.

Leung et al (2010) highlighted the effect of reservoir heterogeneity on the apparent polymer viscosity and shear rate. The authors used the volume averaging technique to account for the effect of sub-scale heterogeities on the shear and apparent viscosity in the coarse numerical simulations. Mahdi et al (2014) investigated the effect of upscaling on ASP flooding, particularly when translating coreflood results to full field scales. Of interest of their work is the high sensitivity found of microemulsion behavior to parameters which are not easily measured in the lab but used by reservoir simulators to predict chemical flood behavior even at small scale. Their work deals not only with the limitations of the current finite-difference formulations but also laboratory measurement shortcomings.

Veedu et al (2010) discussed a methodology for upscaling chemical flooding, their findings pointed towards concentration modeling of the EOR agents as being one of the sensitive parameters affecting the overall oil recovery. Smearing of the chemicals and its influence on phase behavior (often causing operation on less then optimum salinity conditions) were discussed and two upscaling methods were proposed, one involving use of a pseudo salintity (to account for dilution on the larger grid cells) which would ensure the expected phase behavior is achieved in the model and another using pseudo IFT. The authors concluded that while it was possible to reproduce the expected behavoiur with either method, they are not robust and their use needs to be evaluated on a case-by-case scenario. Fadili et al (2009) discussed some of the industry standard mathematical models which are used in polymer flooding, showing the different adaptations to the main diffusivity equation to account for the effect of the polymer and salinity. Mixing rules (much as the ones on early non-compositional solvent models) following a Todd and Longstaff type are used to define effective viscosities in the presence of two different media (polymer, water, chase water, etc). This approach has similar challenges as the ones mentioned on our previous paper in relation of EOR agent and hydrocarbon contact within a grid cell.

In order to address the issue of scale, residence time and concentrations a subset of the models used in our miscible investigation (Moreno 2011 and 2013) were used, starting at a fine scale (~2in on the vertical direction) and gradually coarsenting to typical full field model size thicknes. Models were originally built at a finer than typical scale used to construct fine geological models to ensure the transition from actual core plug to simulation model scale was correctly covered. The overall model dimension, ignoring the additional well cells, was 240ft $\times$ 10ft $\times$ 20ft (length, width, height), typical in X, Y and Z dimensions of a single cell from the full field model. Table 1 shows the details of the resolution used in the models.

Table 1—Numerical Model Resolution

X cell length (inch or feet)	Z cell thickness (inch or feet)	#cells in I Direction*	#cells in K direction	#cells(incl well cells)
6″ (0.5ft)	2″ (0.167ft)	480 + 2	120	57840
12″ (1ft)	4″ (0.33ft)	240 + 2	60	14520
18″ (1.5ft)	6″ (0.5ft)	160 + 2	40	6480
3ft	1ft	80 + 2	20	1640
6ft	2ft	40 + 2	10	420
15ft	5ft	16 + 2	4	72
30ft	10ft	8 + 2	2	20
60ft	20ft	4 + 2	1	6

Two different strategies were tested within this paper, the first one following the same model dimensions and heterogeneity which we used on our previous papers and another one where these properties were slightly modified to represent a more realistic case suitable for chemical flooding.

A simple polymer model was used with a maximum adsorption of 36μg/gm and with a 0.2PV pre-flush followed by 0.5PV slug with a 0.3%wt concentration of polymer and 0.3PV chase water was used in the simulations. Shear thinning was considered on the simulations. Adsoption was modeled as reversible process. Tables were left unchanged on the different scales and velocities.

The second case involved a new geological distribution where structural dip was removed, and clear heterogeneity was introduced allowing water to underrun as shown in Figure 1. As with the previous works, vertical permeability was distributed as a constant of the horizontal permeability, in this case 0.3x in the fine model and subsequently upscaled along with porosity. Dip was removed to minimize the effect of gravity differences on the sweep. Polymer properties were also altered to present those of a typical HPAM flood with an effective viscosity of around 10x the water in an attempt to emulate the flood deep into the reservoir rather than near the injectors.

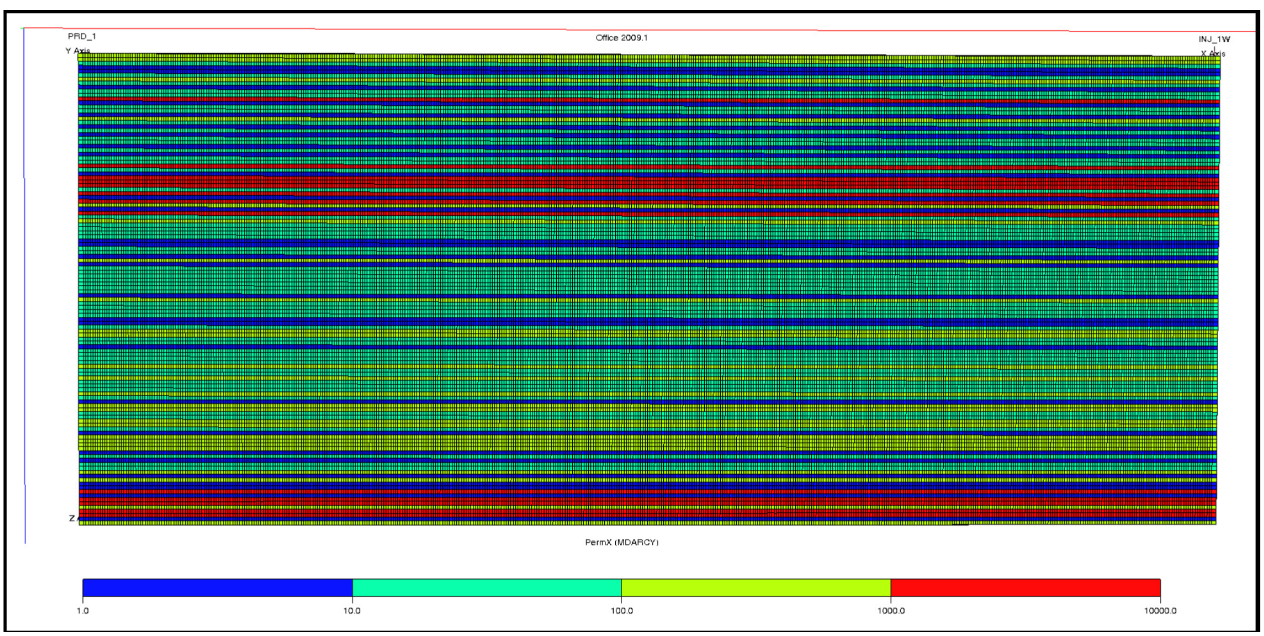

Figure 1—Revised permeabilty distribution of 2″ model

The properties of this second case were chosen to achieve a typical watercut response to polymer flooding and were modeled at the 2″, 6″, 1ft and 5ft vertical numerical cell size at block frontal advance rates of 1ft/d and 10ft/d. Other sizes and velocities were attempted, however, often failed to converge illustrating the limits of using commercial full field simulators to such modeling.

Using water displacement as the base case, three different cases were then modeled:

- Continuous polymer injection
- 0.3PV Slug followed by chase water
- Waterflood followed by injection of a 0.1PV polymer slug followed by chase water

Results

The results from low, mid and high velocity injection rates on the first model (consistent with our previous papers) on the coarsening and fining upward distributions are shown in in Figure 2. As expected polymer responded better to the reservoir heterogeneity saturating the high permeability areas first and then sweeping the lower permeability ones, resulting in a better volumetric contact of the hydrocarbon and overall recovery. There are still differences among the different displacement velocities, controlled both by gravity forces and shear thinning of the polymer. Lower velocities consistently showed early breakthrough followed by a higher slope recovery (where polymer started banking the mid and low permeability zones) up to the 1PV injection where recoveries started to flatten. Mid and high velocity cases showed a different behavior with a later breakthru (~5–10% injected PV) and a smoother recovery curve. The behavior is still consistent with the ones observed in the gas immiscible and miscible injection cases, albeit, the recovery differences are not quite as pronounced in this case given the more stable frontal advancement in presence of polymer. Coarser grid sizes tended to over estimate the recovery with the largest differences observed in sizes beyond 5ft.

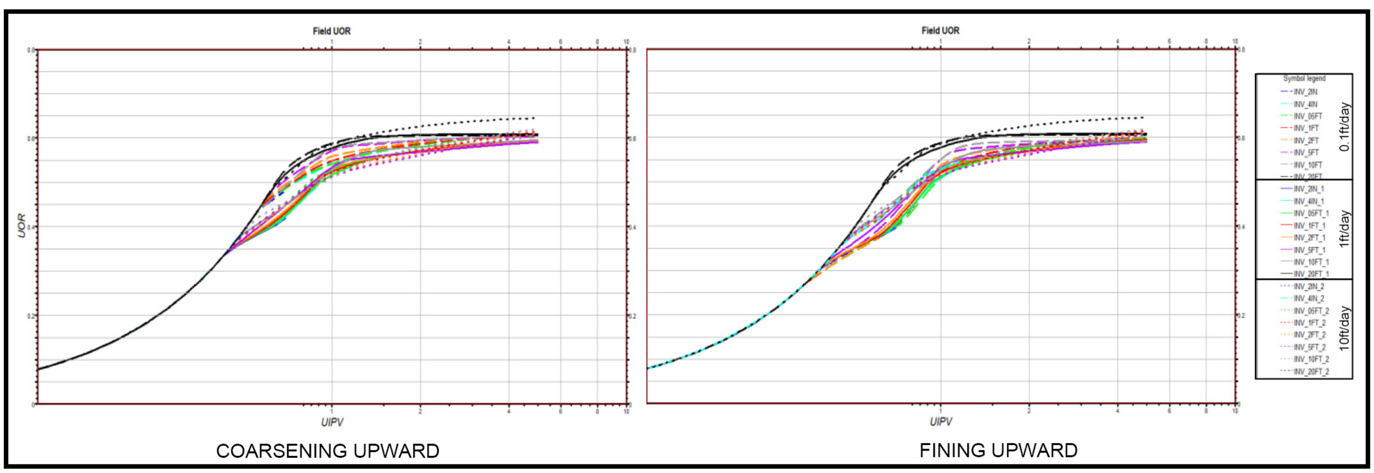

Figure 2—Coarsening and fining upward models recovery vs injected pore volume; dashed lines correspond to 0.1ft/day frontal velocity, solid lines 1ft/day and dotted lines 10ft/day for different model sizes (ranging from 2in in blue to 20ft in black). HCPV=1296rb, PV=1600rb

Figure 3 shows the water cut behavior for the coarsening and fining upward cases; here the effect of grid size and frontal velocity is more evident. Mid and high velocities have an early breakthru (nearly 0.2PV difference) than the low velocities on the coarsening upward case, and about 0.1PV difference on the fining upward case. A larger oil bank was observed in the fining upward case as expected. Grid sizes beyond 1ft started to show differences on both arrival time and size of the oil bank. The oil bank is lost altogether on the 10ft and 20ft case.

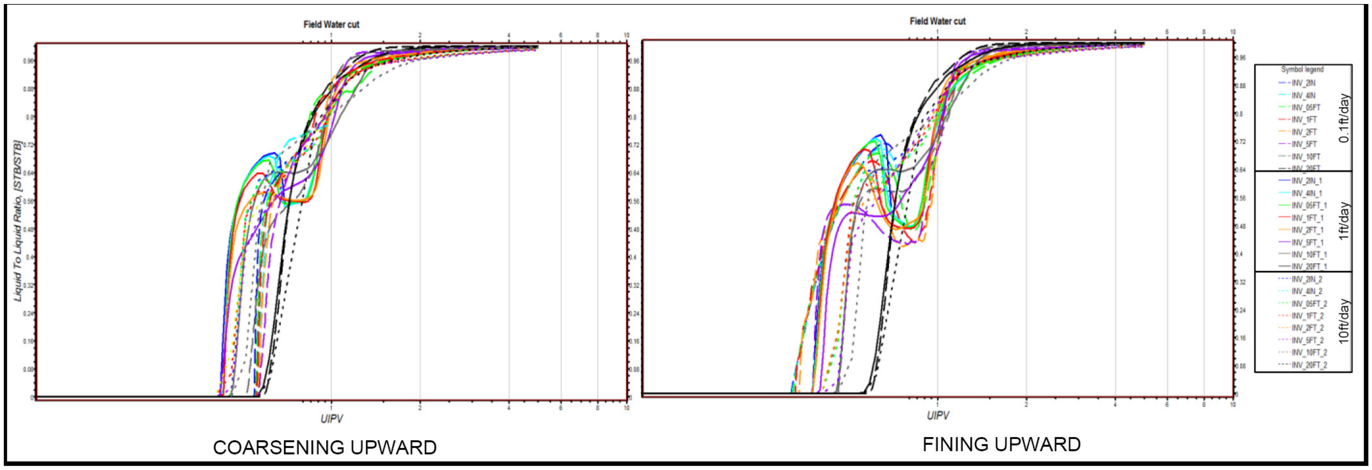

Figure 3—Coarsening and fining upward models watercut vs injected pore volume; dashed lines correspond to 0.1ft/day frontal velocity, solid lines 1ft/day and dotted lines 10ft/day for different model sizes (ranging from 2in in blue to 20ft in black). HCPV=1296rb, PV=1600rb

Figure 4 shows the total polymer adsorption in the field opposite to the polymer production with respect to the injected pore volumes in the fining upward case (similar results were obtained on the coarsening upward case). Effect of grid resolution is strongest here and, as expected, coarser grids show higher retention of the chemical agent in the reservoir and a lower concentration at the producers (for the same cumulative EOR agent injection). Displacement velocity had minimal impact on coarser grids but was more significant as the grid size reduced and so the local grid velocity increased. Should the adsorption tables not be scaled to grid size (and lesser extend displacement velocity) it can be severely over estimated in the reservoir (nearly 100% on the 20ft case) which consequently affect the size and shape of the oil bank with a differnet local sweep efficiency. Similar conclusions maybe reach when looking at the polymer production.

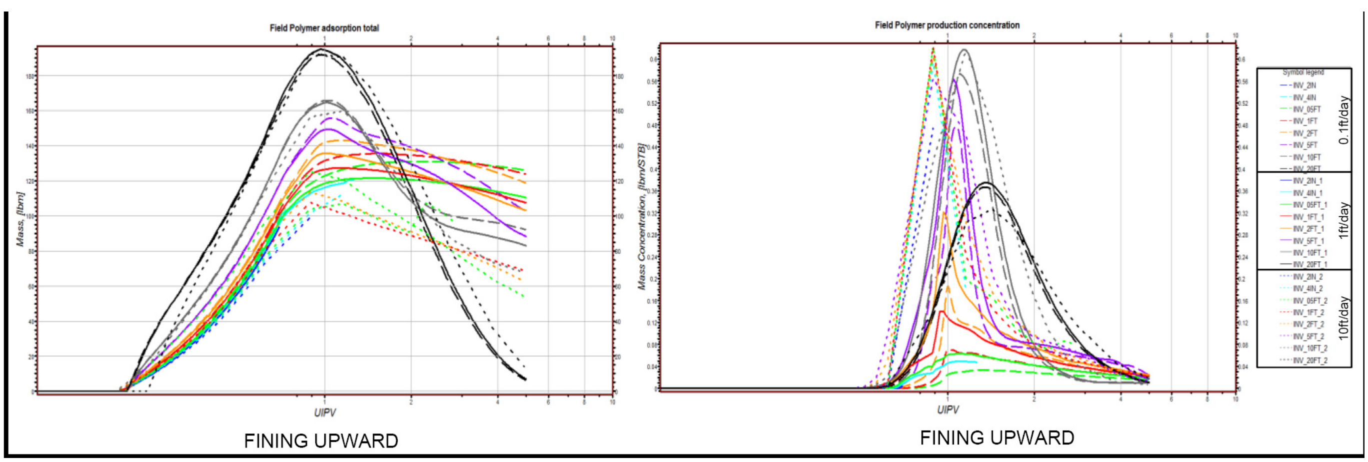

Figure 4—Polymer adsorption and production vs injected pore volume on fining upward case; dashed lines correspond to 0.1ft/day frontal velocity, solid lines 1ft/day and dotted lines 10ft/day for different model sizes (ranging from 2in in blue to 20ft in black). HCPV=1296rb, PV=1600rb

The effect of polymer degradation as a function of velocity is compared with a no-shear case in Figure 5, it is clear that as the grids get coarser so the effect of degradation diminished, allowing a better sweep beyond the injector; causing a difference of 2 to 10% in the recovery for grid sizes larger than 1ft. Pressure behavior in the finite model also highligths the non-linear nature of the problem with models beyond 1ft following significantly different pressure (and therefore effective viscosity) regimes. Results are of course case dependant and a function of the specific chemical agent properties.

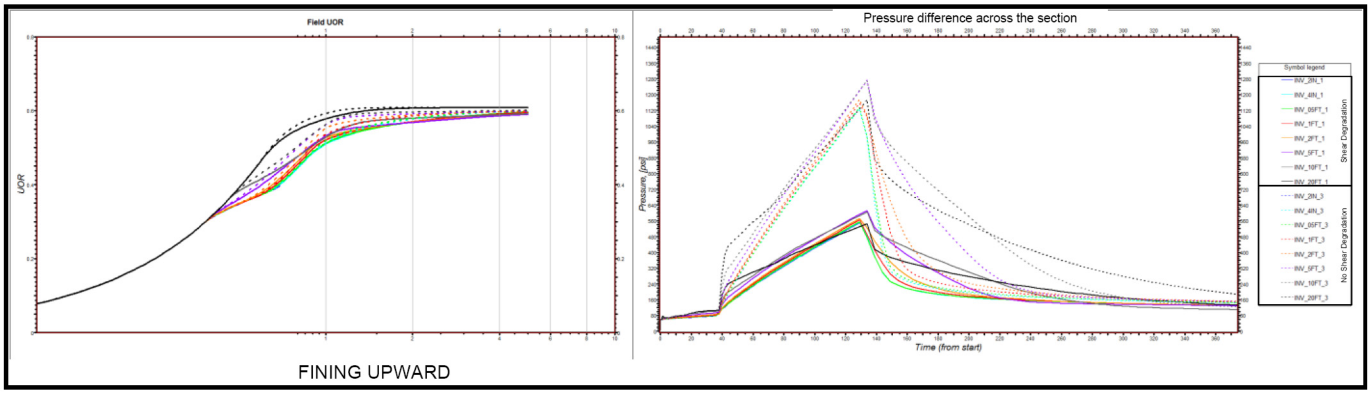

Figure 5—Comparison of the effect of polymer shear degratadion on fining upward model. Figure to the right showing recovery vs injected pore volume, left figure shows pressure difference across the section for 1ft/day displacements with different model sizes (blue 2in to black 20ft); displacement velocities are 1ft/day; solid lines represent the case with shear degradation and dotted lines the non-shear cases

Results from the second model illustrate the potential drift on water breakthrough alone first with the 5ft model already smearing out the effect of the thief zones to such an extent that there was no discernible impact of polymer injection whereas if the 2in case is compared, there is a dramatic flateening of the water cut curve, as shown in Figure 6. Although there is some spread on the results (the 4in case often suffered from convergence problems), the 1ft and below models all exhibit the same character in that polymer arrests the water cycling and sweeps into other zones.

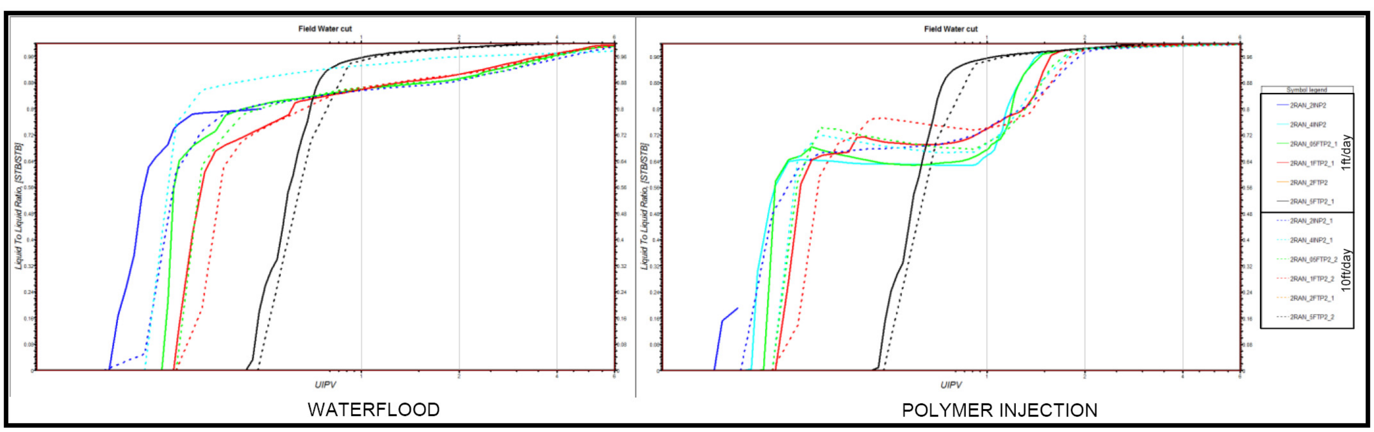

Figure 6—Water cut response for continuous waterflood and polymer injection vs injected pore volume in model 2; solid lines 1ft/day and dotted lines 10ft/day for different model sizes ranging from 2in in blue to 5ft in black.

Effluent polymer concentration (Figure 7) and polymer adsorption again also show that 5ft is too coarse a scale at which to capture the polymer displacement with adsorption peaking far earlier and polymer breakthrough delayed until over 2PV of fluid has been injected. This impact of polymer contacting far more ‘rock’ in an upscaled case than would be the case with underlying thief zones has significant impact, and whilst it can be scaled away by altering the adsorption rate, it requires that every cell in a coarse model be upscaled for this parameter from the underling grid. It is reasonable to conclude that the effects of adsorption loss in any coarse grid simulation are an overestimate of the actual situation, and that polymer will be more ffective, earlier, than such modeling would predict.

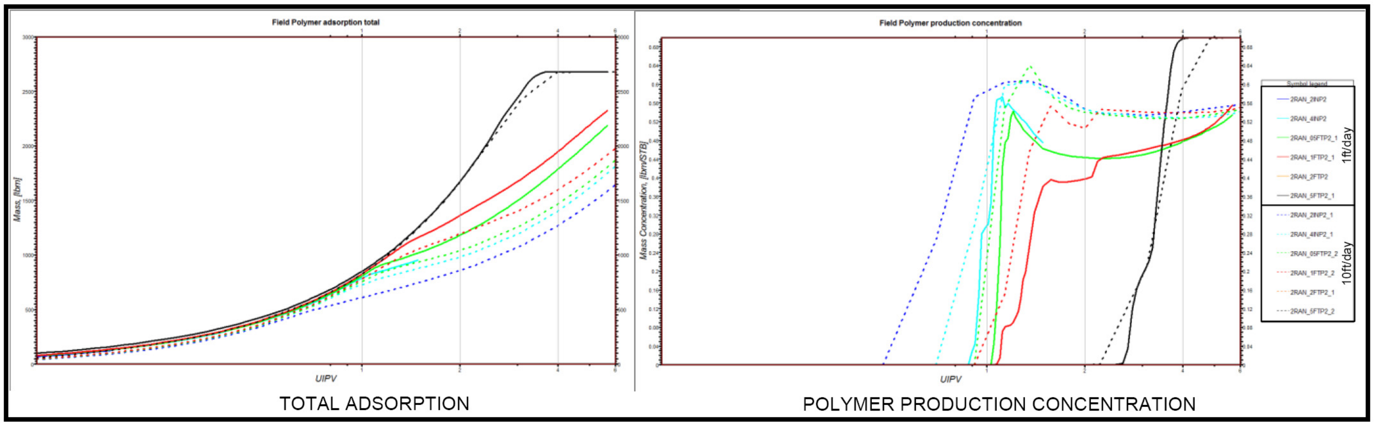

Figure 7—Polymer adsorption and effluent concentration response for continuous polymer injection vs injected pore volume on model 2; solid lines 1ft/day and dotted lines 10ft/day for different model sizes ranging from 2in inblue to 5ft in black.

The cases of waterflood and continuous polymer are really the end members of how polymer floods are usually conducted – with it being more normal for a slug of polymer to be injected (often preceeded by some sacrificial agent to minimize adsorption losses). In an attempt to highlight the challenges associated with the passing of a slug through the system, and the loss of definition due to smearing the two slug cases were introduced. Figure 8 presents the results from these simulations in terms of watercut and Figure 9 for the adsorption and effluent concentration. Again, similar conclusions can be reached that aborption losses are significantly overestimated in the coarse models, which would lead to conclusions on increased dosage and chemical costs.

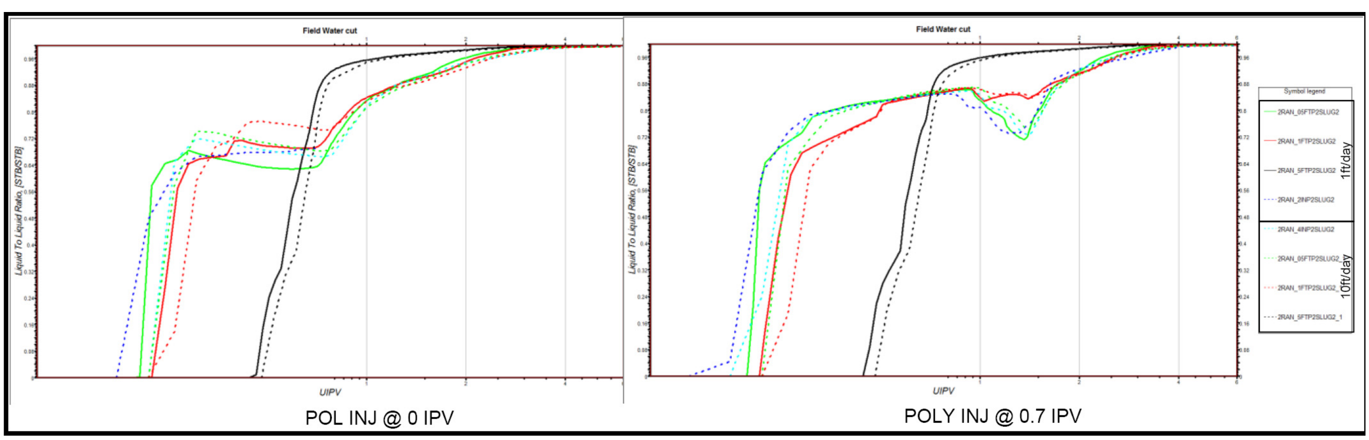

Figure 8—Water cut response for polymer injection at the start and 0.7 pore volume waterflood on model 2; solid lines 1ft/day and dotted lines 10ft/day for different model sizes ranging from 2in inblue to 5ft in black

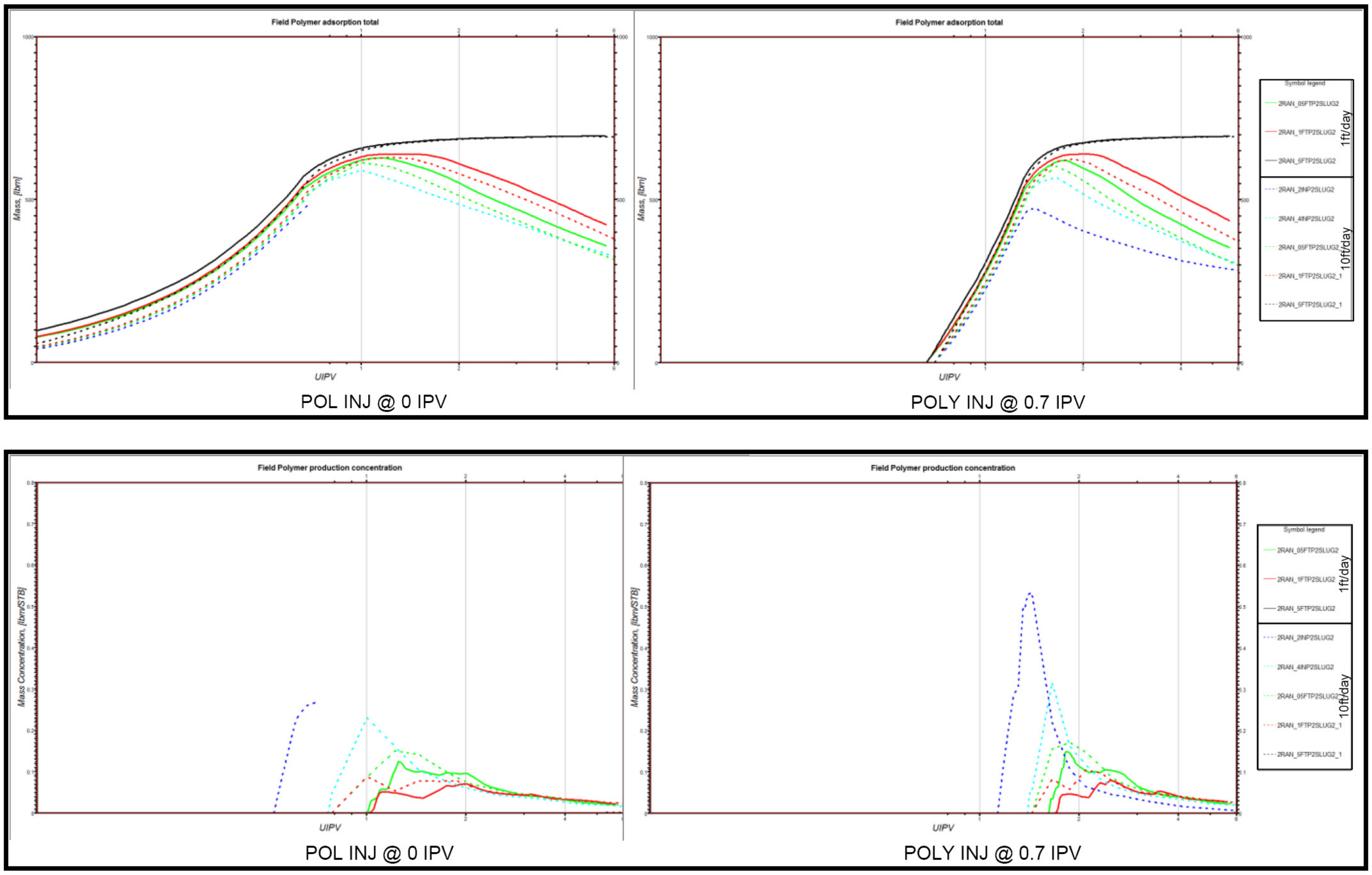

Figure 9—Polymer adsorption and effluent concentration response for injection at the start and 0.7 pore volume waterflood on model 2; solid lines 1ft/day and dotted lines 10ft/day for different model sizes ranging from 2in inblue to 5ft in black

Also of importance to polymer flooding is the effective viscosity of the fluid – as can be seen in Figure 10, the resultant pressure differential from the injecting to the producing side of the cell produces an effective viscosity of some 3x for 10ft/day and 4x for the 1ft/d case – again, the 5ft/d case has a significantly different response to this effective viscosity, especially when the slug case is considered.

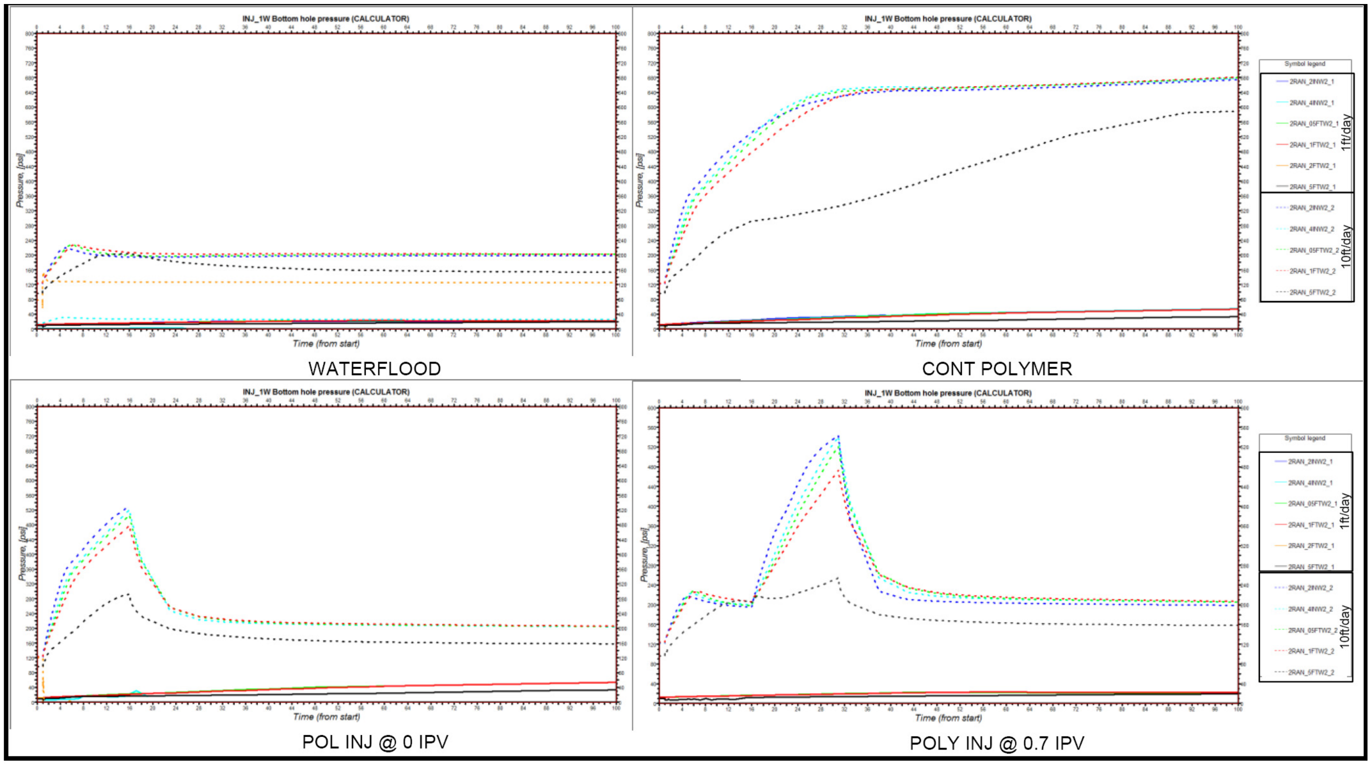

Figure 10—Pressure difference across the model section for waterflood (top left), continuous polymer injection (top right), polymer slug at the start of water injection (bottom left) and polymer slug @ 0.7 injected pore volume (bottom right); solid lines 1ft/day and dotted lines 10ft/day for different model sizes ranging from 2in inblue to 5ft in black

Discussion

On our previuos papers we investigated the effect of velocity, dispersive flow and gravity-viscous force balance on reservoir conformance and ultimately recovery prediction due to the injection of an EOR agent under miscible and immiscible conditions. We highlithed the importance of recognition, design and proper utilization of pseudo relative permeabilities to account for accurate translation of fine front advancements onto coarser models when using finite-difference grids.

The work presented herein further confirms our conclusion of the fit-for-purpose numerical model design, where upscaling and pseudos are designed to fit the specific challenges at hand, particularly if dealing with chemical flooding where level of interaction of the EOR agent with high and low quality rock considerably affects the quality and stability of the displacement front, which in turn due to higher associated cost of the EOR agent may limit the application on a field otherwise well suited.

Chemical flooding poses a more complex challenge for finite difference modeling, one where the interaction between the chemical agent and reservoir rock and fluids is modelled using a more simplistic representation (usually through two-dimensional tables) of these phenomena, based at best on indirect laboratory measurements. A detailed appreciation of the details of the finite-difference model approach is therefore fundamental to understand the inherent model challenges and relevant data requirements. Moreover when dealing with properties/processes which use concentration and velocity to predict the behavior of the chemical agent, direct application of laboratory data without proper scaling is discouraged. The belief that core measurements are sufficient for all purposes on fine scale geological models is again challenged here as we did on our previous papers, requiring a proper understanding of the recovery process, heterogeneity, and impact of scale before the predictive power of the numerical models is acceptable.

Proper reservoir characterization of all rock facies (including the ones considered non-reservoir) is fundamental to understand the level of chemical interactions between the reservoir agent and rock facies. Any upscaling, and/or chemical degradation needs to therefore consider the effect of all rock qualities and not rely solely on the convective flow to guide the analysis.

From this work, we would recommend those screening for polymer flooding as a sweep agent to keep their models to a vertical scale of 1ft or less in order to capture the heterogeneity present in many reservoirs. Indeed, the often forgotten step of using 2D models to understand the displacement drivers first before moving to 3D is once again highlighted.

Conclusions

This paper investigated several finite difference modeling issues when dealing with polymer injection on heterogenous reservoir media. The results were consistent with our previous experience on displacement processes, highlighting the effect of convective and dispersive forces on the efficiency of displacement and reservoir conformance:

- Effect of fluid velocity on the convective flow is significantly augmented with polymer shear degradation, limiting the size of finite difference grid suitable for accurately representing polymer front advancement.
- Use of coarse models to screen for polymer EOR can substantially over predict recovery and chemical agent utilization. With the existing model limitations a proper upscaling of both saturation functions and chemical agent-reservoir interaction is required if the recovery efficiency of the fine scale models is to be reproduced.
- Chemical flooding, and in our case, polymer requires a higher resolution reservoir characterization in order to properly describe the front advancement, contacted oil and chemical stability. These processes are not only scale for the convective and dispersive forces but also reservoir mineralogy dependent for chemical stability and degradation.
- Detailed appreciation of the finite difference chemical modeling approach is fundamental to design the proper numerial model scaling.

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