Simulation of Sand Production in Waterflooding of Heavy Oil Reservoirs by A Coupled Reservoir and Geomechanical Model

M. Nassir, and D. Walters, Taurus-CGG Geoconsoulting Inc.; D.P. Yale, ExxonMobil Upstream Research; and R. Chivvis and J. Turak, BP Exploration (Alaska) Inc.

Summary

Optimizing the efficiency of the waterflood displacement process in heavy oils is critical to reaching the oil recovery goals. However, in the process of finding an economic and stable throughput for the process, in some cases significant sand production and generation of wormholes have resulted in premature water breakthrough and channelling destroying volumetric efficiency. In order to understand such events, a simulation study using a coupled reservoir and geomechanical simulator was used to determine the physics controlling the initiation and propagation of dilated zones resulting from sand production giving the premature breakthrough. An attempt was made to identify the importance of well configuration and what operating constraints can be altered to reduce the risk of these breakthrough events.

The complex physics of sand production during oil recovery requires it to be modeled as a coupled process: multiphase fluid flow causing transient pressure gradients and geomechanics to calculate the resultant stress variation, permeability enhancement and shear/tensile failure around the induced dilated zone and finally coupling failure criterion for the dilated zone propagation combining pressure gradient and effective stress. A force balance criterion calculates the threshold fluid pressure gradient for sand mobilization based on the effective confining stresses in each numerical element. The stress variation across the loosely supported sand body (damage zone) at the edge of a dilated zone is captured by an elasto-plastic constitutive model using a Mohr-Coulomb shear failure surface combined with softening of the Young's modulus.

The application of the coupled simulator in modeling waterflooding reveals critical insights regarding the significance of different factors contributing to the sand production problem. Multiphase flow, over vs. under-injection, and inter-well pressure gradient effects are critical to controlling the sand production initiation and evolution. Gas liberation below bubble point pressure conditions causes excessive pressure gradient and increases the possibility of sand production. The oil/water relative permeability impact emerges if the mixture mobility at a certain fraction is lower than the end points. As dilated zone geometry appears to follow the weakest zones often associated with high permeable layers; it highlights the significance of the reservoir heterogeneity in contributing to the sand production problem. The results of the current study add understanding to the significance of different mechanisms contributing to sand production and may be used to help mitigate the premature breakthrough problem observed in many waterflooding operations.

Introduction

Alaska's North Slope Heavy Oil Sands have huge potential. There are 7 to 15 billion of barrels of oil in place (Burton et al., 2005) and hundreds of millions of barrels potentially recoverable. The less viscous of the heavy oil sands are currently being produced from the Orion and Polaris reservoirs in the Greater Prudhoe Bay Unit and also at the adjacent West Sak and Milne Point reservoirs. The Orion reservoir has 3.2 billion bbls of original oil in place and has 12 production wells and 31 injection wells. The Polaris reservoir bears about 1 billion bbls of original oil in place and has 9 production wells and 17 injection wells (BP, 2013). A waterflood process is currently being used to maximize production. The producing wells are generally horizontal with slotted liner completion. The slotted liner allows some sand production but has better economics due to higher productivity and lower well costs than a sand control completion (Burton et al., 2005).
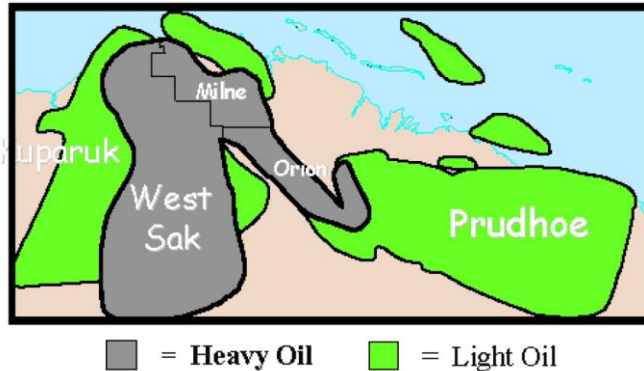
Figure 1 – North Slope heavy and light oils (Burton et al., 2005)

The biggest challenges in waterflooding of unconsolidated sands are Matrix Bypass Events (MBEs) associated with sand production. MBEs are characterized by a premature breakthrough of water from the injector to the producer. This occurs where there is a short circuit between the injector and the producer in this unconsolidated sandstone reservoir. Injected water bypasses the oil contained in the sandstone matrix and goes directly to the producer. An MBE substantially reduces oil recovery since the injected water no longer sweeps the oil from the matrix. In addition to its causal nature for the MBEs, sand production itself also causes problems in producing these oil sands. The sand can clog the well tubing, reducing or stopping the flow of oil and increasing well operating costs. Excessive sand production can also damage surface pipes and valves and reduce the efficiency of separation equipment.

The exact cause of the MBE is unknown but thought to be a combination of events. Our studies suggest that channel or wormhole development from sand production, injection induced fracturing or a combination of both were suspected candidates. However modeling shows the need for more stress field and fracture reorientation for induced fracture to impact MBEs. Therefore, the contribution of injection induced fractures on MBE is limited in the studied fields and sand production induced channels or wormholes more likely the key mechanism for MBEs. Other areas may have close horizontal stress magnitudes and lower permeability that could lead the injection induced fracture to be a more significant cause of premature water breakthrough. Geomechanical modelling has been identified as a method to improve the economics of the North Slope heavy oil production. In a parametric study by a coupled reservoir/geomechanics simulator, the authors have attempted to analyze the influence of different operational controls in water flooding operations in order to mitigate the MBE occurrence and the respective production impact.

Theory and/or Method

In this paper the simulation tool developed in authors previous work (Nassir et al., 2015) will be implemented to model dilated zone growth in some waterflooding example problems selected from unconsolidated sandstone fields in Alaska. The coupled flow and geomechanical model implements a force balance criterion (Wang et al., 2011 and Yale et al., 2013) to model the hydrodynamic sand erosion problem within the continuum mechanic domain. Multiphase flow, especially the liberated dissolved gas, plays a significant role in triggering the sand production problem.

The reservoir fluid flow model is a standard finite difference solution which it has been coded based on the conservations of mass and energy, Darcy's law and equations of state (Aziz and Settari, 1979) for all constituting phases and components. In each solution time step water and gas saturations, oil phase pressure and temperature are calculated by the reservoir flow simulator.

The geomechanical module implements a finite element numerical model in which Galerkin's weighted residual technique is used to approximate the quasi static equilibrium equations in all directions. Variations

in pressure and temperature from reservoir flow model act as external forces in geomechanical solution in every time step. In return the updated stress from geomechanical model will be used to update the permeability and porosity terms in flow solution.
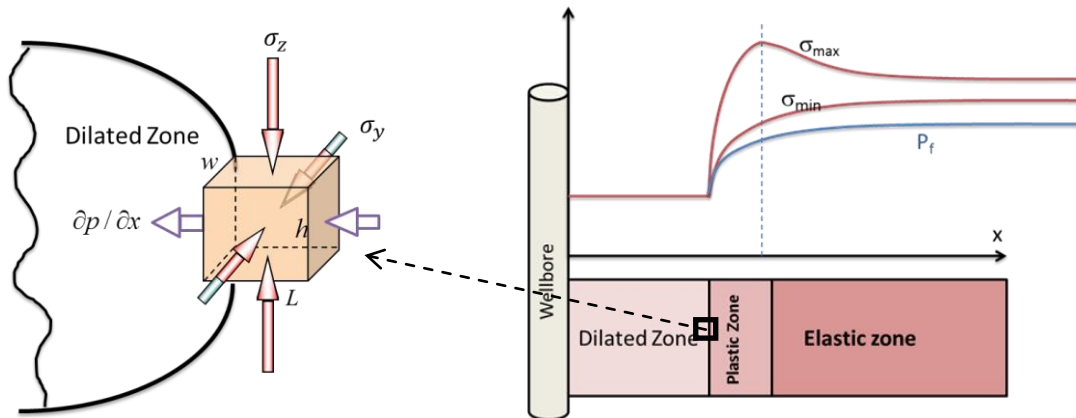

Figure 2 – A cavity edge block, the respective confining stresses and fluid pressure gradient (Nassir et al., 2015)

The dilated zone is assumed to begin its evolution from a weak point along the production well. The borehole cavity grows dimensionally if the force balance criterion assumed for sand block erosion is met. The blocks at the cavity edge are regularly checked for dilated zone propagation according to the erosion criterion. As sketched in Figure 2, an edge block is switched to cavity in the code when the equivalent force from fluid pressure gradient overcomes the forces from the confining stresses. Following the picture drawn in Figure 2, the force balance equations in x and y directions are written as follows (Yale et al., 2013),

$$-\frac{dp}{dx} = \frac{2(\sigma'_z \tan\phi + C)}{h} + \frac{2(\sigma'_y \tan\phi + C)}{w}$$

$$-\frac{dp}{dy} = \frac{2(\sigma'_z \tan\phi + C)}{h} + \frac{2(\sigma'_x \tan\phi + C)}{L}$$

(1)

where C is the cohesion, ϕ is the friction angle, p is fluid pressure and w, h and L are the block's dimensions.

Reservoir heterogeneity plays a significant role in geometry of the evolutionary dilated zone (Nassir et al., 2015). In the propagation journey between the producer and the injector, the dilated zone penetrates through the weakest layer with a width proportional to the layer thickness. Heterogeneity in horizontal direction adds tortuosity in the channel path between the wells. In this study the cavity is triggered from an assumed weak point along the horizontal production well. Also, the zone is only allowed to move dynamically through a narrowed channel between the producer and the injector.

The sand stress-strain constitutive model plays a paramount role in success of the coupled sand production model. Shear failure in the weak sand creates an elasto-plastic region in front of the cavity-sand interface along which the contrast between the maximum and minimum effective stress is directly controlled by residual shear strength of the failed material. As a result, the low maximum and minimum effective stresses at sand-cavity edge blocks make the confining effective forces fall within the scale of fluid flow drag forces allowing the growth in the dilated zone possible. In this study, modified form of Duncan's hyperbolic model (Settari et al., 1993) with beyond shear surface stress correction scheme (Nassir and Walters, 2014) is implemented to capture the elasto-plastic behaviour of failed sand. The constitutive model has been presented to efficiently configure the correct stress distribution and arching around the propagating dilated zone (Nassir et al., 2015).

Examples

Conclusions

By means of a coupled reservoir/geomechanical model equipped with sand production tool, we have attempted to identify the significance of various operational controls that may reduce the risk of premature water breakthrough events in unconsolidated reservoir waterflooding. Low voidage, high interwell gradient, dissolved gas liberation and relative permeability effects have been investigated as significant factors in increasing the localized fluid pressure gradient and the subsequent MBE occurrence. The authors recommend the following mitigation strategies for the MBE reduction in the types of reservoir and under the production scenarios studied here,

- The producer has much more of an influence on MBE's than the injector. Preliminary work on the studied fields has presented minor reorientation of induced fracture and limited injection induced fracture length (compared with interwell spacing) due to high formation permeability and fluid leakoff in these particular fields.

- Sand Control is very important. Since the producer is the dominating factor in MBE's, the modeling shows that if sand is not produced, the wormholes do not propagate significantly as sand voidage must be created to propagate. Therefore sand control methods in the producer well such as gravel pack, frac pack and screens should be investigated. Due to the fine grained nature of the fields' sands, some plugging of the control methods may occur, but potentially can be remediated with flush treatments and acid treatments.

- Interwell gradient and voidage are indicators of MBE risk. Higher interwell pressure gradient along with more positive voidage increases the MBE risk; whereas negative voidage with lower interwell regions are operationally less risky. There exists a nonlinear critical boundary separating the low from high risk regions. For any particular well spacing, the voidage vs. interwell gradient needs to separately be configured.

- Well management to control the BHP, the pressure gradient (including transients) around the producer and voidage are the key to reducing the risk of MBE. There is a significant reduction in MBE risk through negative voidage or raising the average reservoir pressure. BHP below the bubble point pressure induces more drag forces for sand production around the production well. Injectors have been realized to have a low risk in wormhole initiation. Therefore, in order to attain the favourable interwell pressure gradient, increase in the injectors' pressure is recommended. Special care must be taken when excessive pressure drop is induced due to oil-water mixture relative permeability effect. Feathering back in production rate at water breakthrough time (increase in production well's water cut) might lower the MBE risk.