



CHAPTER I INTRODUCTION

In many reservoirs, the produced water contains mixtures of dissolved ions that are unstable and tend to precipitate. Inorganic scale deposition has been recognized to be a major operational problem. Scale deposition is usually caused by the mixing of two incompatible brines or because of changes in produced fluid conditions- i.e., temperature, pressure, and pH. The common type of oil field scales are calcium carbonate, calcium sulphate, barium sulphate, and strontium sulphate. If left unchecked, the deposition of inorganic scale in or around the perforations, or within the wellbore or production string can significantly decrease the productivity of a well.

The most widely used method to prevent the problem of scale is to inject (i.e., “squeeze”) threshold scale inhibitors into the formation to prevent or to slow the nucleation and growth of scale. In typical squeeze treatment, a slug of scale inhibitor, along with a brine overflush, is injected into a reservoir, where it is shut in for 24 hours. After the shut-in period, production is resumed and the inhibitor is released back into the produced fluid, where it prevents scale from forming. The subsequent release of inhibitor into the produced water provides protection against scaling; the treatment is repeated when the concentration of inhibitor in the produced water falls below the threshold level for effective inhibition (usually 1–20 ppm). (Rabaioli, 1996)

The two inhibitor squeeze technologies currently used by the industry are categorized by the mechanisms by which inhibitor is retained within the formation.

1. Adsorption squeeze An inhibitor is retained by adsorption onto the reservoir rock and is released by desorption.
2. Precipitation squeeze An inhibitor is retained within the formation as a (solid or liquid) precipitate (Miles, 1970). In this method, a homogeneous and mildly acidic solution of inhibitor is injected into the formation and then positioned several meters from the wellbore by means of a brine post-flush. The inhibitor precipitates as an insoluble Ca^{2+} salt during shut-in.

The majority of field applications and/or research works in the area of squeeze treatments has focused on adsorption/desorption treatments. Despite the fact that precipitation squeeze treatment have shown the potential to enhance squeeze lifetimes, oil producers have been reluctant to incorporate these treatment techniques because: 1) they are exclusive to reservoir systems that contain sufficient amounts of calcium (or other divalent cations); and 2) they may cause precipitation in the near well bore region of reservoir system (which is what inhibitors are supposed to be preventing), possibly resulting in loss of fluid conductivity, i.e. formation damage (Carlberg, 1987). However, recent studies have shown that precipitation squeeze treatments can be efficiently used with low divalent cation containing reservoirs (often non-carbonate reservoirs). In this process, a single solution containing chelated calcium and inhibitor are injected (squeezed) into a well where at elevated temperatures, an ion exchange occurs producing an inhibitor precipitate. The rate of precipitation must be controlled to avoid pore plugging and formation damage. Hence, great promise exists for precipitation squeeze treatments, although a limited amount of research has been carried out to provide a fundamental understanding of the precipitation kinetics behind this type of treatment. Consequently, the goal of this work was to provide a basic understanding of the kinetics precipitation of Ca-ATMP.