CHAPTER I
INTRODUCTION

Petroleum reserves are an important source of value energy situated in subsurface rock formations. This petroleum is normally formed by degradation and chemical transformation of organic materials over millions of years. They are usually utilized to produce oil for refineries but also used as feedstock for producing several petroleum derivatives such as benzene, toluene, xylene etc. As a result in increasing the demand of energy consumption today, it becomes essential to have an effective means for acquiring all the petroleum from the subsurface. Hydrocarbon substances (crude oil and natural gas) can be accessed by drilling a well into a reservoir where they are then drived up to surface by natural pressure gradient. This first period in petroleum production is called " Primary Recovery or Primary Production". A reservoir may approach the end of its primary life having produced only a small fraction of the oil due to the depletion of pressure gradient. Even with the best primary production methods, however, as much as 75 percent of the oil may be left behind (Willhite, 1986).

To recover this remaining oil, secondary oil recovery methods are employed. There are many methods for improving oil productivity such as water flooding, gas injection, chemical flooding and thermal recovery, however; the most widely used method in secondary oil recovery is " water flooding technique " In this technique, brine water is injected into the formation through injection wells in order to move the remaining oil in the pores of formation into the production wells. Unfortunately, during this process, formation water containing significant contents of various dissolved ions can be spontaneously mixed with injected brine water resulting in sudden changes in produced fluid conditions such as pH, pressure, temperature etc.

This mixing of two incompatible waters or changing of fluid conditions result in formation of undesirable solids referred to as scales. The release of carbon dioxide during reservoir depletion also contributes to the formation of scales (Vetter, 1972). Scales can be formed and deposited anywhere in a production system such as wellbore formation, downhole pumps, flowlines and heater treaters etc.

It has been reported that a majority of the 700,000 oil, gas and service wells in the U.S. have appreciably reduced productivity or injectivity because of scale deposited in the wellbore, perforations, the formation matrix, or in formation fractures (Plummer, 1945). Scale formation and deposition cause a large number of costly pulling jobs, fracturing of wells to bypass scales, and other remedial work each year in both production and injection wells. Therefore, it becomes extremely important to control this scaling problem in order to minimize the maintenance cost and to gain the maximum productivity. One of the most widely used techniques to combat the scaling problems is to inject threshold scale inhibitors along with brine water into a formation where they can be able to slow or prevent scale nucleation and crystal growth. This injection technique is commonly referred to as "squeeze treatments" There are two major types of squeeze treatments having different dominant retention/release mechanisms which are precipitation and adsorption squeeze treatment. This study is only concentrated on studying precipitation squeeze treatment because previous works have shown that precipitation squeeze treatment offers longer squeeze lifetime (Carlberg, 1987; Browning and Fogler, 1993).

In precipitation squeeze treatment, the injected threshold scale inhibitors react with divalent cations in formation water resulting in the formation of scale inhibitor precipitates. This scale inhibitor precipitates are slowly dissolved back into the produced fluid where they can prevent scale from

calcium ion concentration in formation water, however other divalent cations such as magnesium may also have potential to form precipitate with scale inhibitors as well (see Table 1.1).

Table 1.1 Characteristics of some formation waters from Illinois fields (Howard *et al.*, 1987).

System	Formation or Field	Subsurface Depth (ft)	Concentration (mg/l)					
			Ca^{2+}	Mg^{2+}	Na^+	HCO_3^-	SO_4^{2-}	Cl^-
Mississippian	Waltersburg	2,437	2,970	1,020	32,220	390	1,620	56,700
Mississippian	Cypress	2,960	6,600	1,680	47,900	1,660	3,840	83,200
Ordovician	Trenton	672 to 4,000	7,500	1,830	41,830	960	1,350	82,400
Mississippian	St.Genevieve	1,104 to 3,519	18,430	3,460	47,660	1,470	2,990	95,400

It is not known whether the magnesium ion adsorbs onto or co-precipitates along with calcium-scale inhibitor precipitates resulting in the change of dissolution rate when the production is resumed. Several previous works have been done on magnesium-free solutions (Meyers *et al.*, 1985; Browning and Fogler, 1993, 1995, 1996; Rerkpattanapipat, 1996; Wattana, 1997; Raju, 1998; Suwannamek, 1998; and Liwsrisakul, 1999), therefore, the present study was mainly focused on the effect of magnesium ion in modulating the formation and the properties of calcium-scale inhibitor precipitates.