Understanding CaCO₃ precipitation during oil recovery

Extended abstract

by

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Introduction

Deposition of CaCO₃ scale in production wells and surface facilities is a complex process that is dependent on many different interrelated factors including pressure, temperature, water composition, petroleum composition, and precipitation kinetics. Although the influence of each individual factor on the scaling risk is generally understood, the relative importance of each factor is rarely evaluated because, with the exception of operating pressure, it is not usually possible to modify them to reduce the scaling risk. Not only is little known about the relative importance of each factor in determining the level of scaling risk on individual developments, no previous studies have sought to explain why the risk differs from one field to another. This raises the questions: what are the most important factors determining the level of CaCO₃ scaling risk in oilfield developments and under what conditions are each of these factors dominant? Factors controlling the CaCO₃ scaling risk include:

- Formation water composition:
  - Ca²⁺-concentration
  - Anion/cation ratio
  - Salinity
  - Alkalinity
- Temperature and pressure gradients:
  - Their effects on mineral solubility
  - Their effects on water evaporation/condensation
  - Their effects on CO₂ migration between water and gas phase
- Water rate
  - Absolute water rate
  - Water cut
- Petroleum CO₂

The effects of Ca²⁺-content, salinity, water cut and CO₂ pressure on the scaling risk under various conditions are investigated thoroughly. In doing so, not only have we been able to identify those conditions where CaCO₃ scaling risk would be expected to be negligible, we have also determined what combination of factors and conditions give rise to the ‘perfect storm’.

Selected results and Discussion

There are many speculations associated with when a CaCO₃ scale problem may be significant. One is the very simple assumption that formation waters with high Ca²⁺-content give larger scale problems than formation waters with low Ca²⁺. To some extent
this is true for topside facilities if a basic H$_2$S scavenger has to be used to reduce the amount of H$_2$S that could otherwise be produced. Generally, however, the statement is not correct. Some calculations were performed to investigate the effects of a changing Ca$^{2+}$-content in formation water (FW). The following production path was used for a large part of the calculations:

Reservoir P&T: 699 bar, 160°C
Well toe inlet P&T: 600 bar, 162°C
Well heal outlet P&T: 550 bar, 159°C
Separator P&T: 40 bar, 90°C

Figure 1 shows the CaCO$_3$ scaling potentials (SR and kg/day) as a function of Ca$^{2+}$-content in the FW when producing water and hydrocarbons from reservoir conditions; 699 bar and 160°C to well inlet conditions; 600 bar 162°C. The hydrocarbon phase contained 1mole% CO$_2$ and the water cut at standard conditions was 1.2%. It can be seen that while SR is close to constant over the range of Ca$^{2+}$-concentrations investigated, the amount that can precipitate depend very much on the Ca$^{2+}$-content. For this particular case there is a peak in precipitated CaCO$_3$ when the Ca$^{2+}$ concentration is approximately 280mg/l. This concentration is rather low compared to most formation waters (Warren and Smalley, 1994). In general, this means that a low Ca$^{2+}$-content increases the scale problem while a higher Ca$^{2+}$-concentration reduces the problem. In short, this can be explained by means of low pH buffer capacity in a FW with high Ca$^{2+}$ and consequently low HCO$_3$-/CO$_3$$^{2-}$ at a given SR compared to a FW with low Ca$^{2+}$ and high HCO$_3$-/CO$_3$$^{2-}$ at the same SR. A more detailed explanation and discussion will be given in the presentation.

![Figure 1: Amount of CaCO$_3$ precipitation and SR as a function of Ca$^{2+}$-concentration in formation upon producing water and hydrocarbons from reservoir conditions; 699 bar and 160°C to well inlet conditions; 600 bar 162°C. The hydrocarbon phase contained 1mole% CO$_2$ and the water cut at standard conditions was 1.2%.](image-url)
The effects of changing amount of CO$_2$ in the hydrocarbon (HC)-phase were also investigated. Figure 2 shows the changes in amount of CaCO$_3$ precipitation as a function of Ca$^{2+}$-content and mole% CO$_2$ in the HC-phase. It can be seen that the CO$_2$ content plays a major role for the potential CaCO$_3$ scale problem as the amount of scale that can form increases with the CO$_2$ content. This is somewhat counterintuitive since more CO$_2$ would lower the pH and increase the solubility of CaCO$_3$. However, since the reservoir is calcite cemented this simply means that more CaCO$_3$ is dissolved in FW to give SR = 1 at reservoir conditions. More dissolved CaCO$_3$ gives a higher alkalinity, which in turn increases pH and buffer capacity of the FW. Peak-Ca also shifts towards higher calcium content with increasing CO$_2$. Further discussions and explanations will be given in the presentation.

Figure 2: Amount of CaCO$_3$ precipitation as a function of Ca$^{2+}$-concentration in FW and CO$_2$ in HC-phase upon producing water and hydrocarbons from reservoir conditions; 699 bar and 160ºC to well inlet conditions; 600 bar 162ºC. The water cut at standard conditions was 1.2%.

In addition to the Ca$^{2+}$-content and CO$_2$ in HC-phase, the effects of salinity and water cut will be presented and discussed in the presentation. It will be shown under which conditions each parameter seems to be of more or less importance.
Some additional key findings:

- SR$_{\text{CaCO}_3}$ along a production path is relatively unaffected by changes in FW Ca$^{2+}$. The mass of CaCO$_3$ precipitated (kg/day), however, strongly depends on FW Ca$^{2+}$.
- SR$_{\text{CaCO}_3}$ along a production path is relatively unaffected by changes in the amount of CO$_2$ in the HC-phase, whilst the mass of CaCO$_3$ precipitated does depend on this CO$_2$.
- Low water cut produces more extreme SR$_{\text{CaCO}_3}$ due to more relative water evaporation, which means that a higher MIC is required to stop precipitation. However, the mass of CaCO$_3$ precipitated increases almost proportionally with the water cut, given that the pressure and temperature gradients do not change with the water cut. A change in water cut does not change the relative effects of Ca$^{2+}$-content in FW and CO$_2$ in the HC-phase on the amount of CaCO$_3$(s) formed.
- The effect of salinity is more complex. In general, however, increased salinity increases the CO$_2$ solubility in the FW at reservoir conditions while it reduces the CO$_2$ solubility at separator conditions. The net result is an increased scaling risk at separator conditions with increasing salinity. At the well inlet no such correlation was observed in the calculated data.

Reference: