Scale Management during Unconventional Recovery

Shale gas brine chemistry analysis

Basic data analysis:

The shale gas reservoir used for data collection locates in the Western Canadian Sedimentary Basin [1]. The cross-section of the Horn River Basin area is illustrated in Figure 1 below.

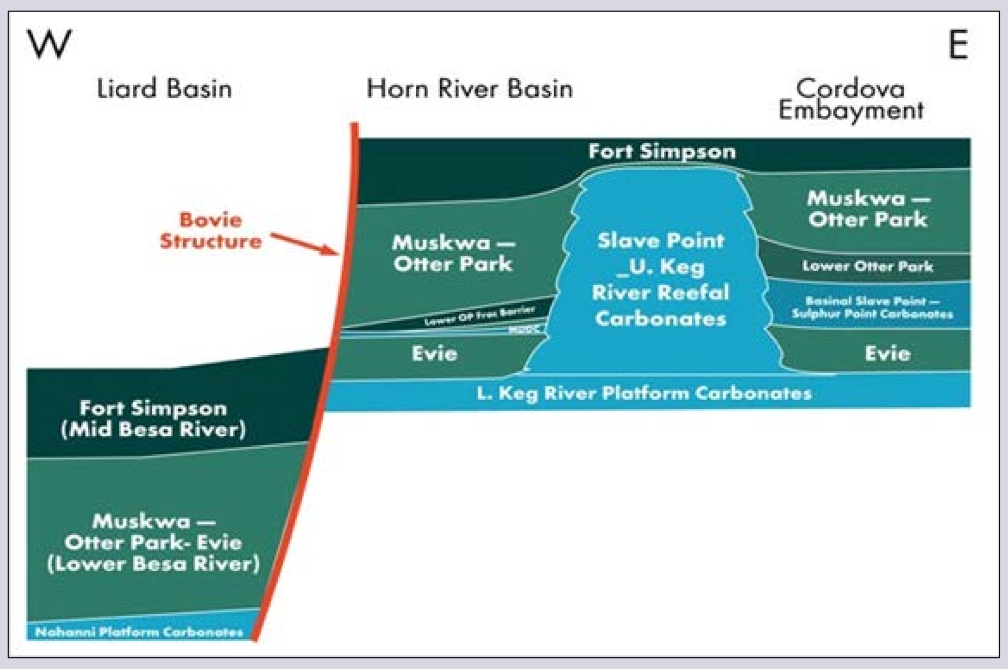

Figure 1 The cross-section diagram of the Horn River Basin

The shale gas geochemical database in Horn River Basin area contains a number of key items, as listed below: 1.) The initial reservoir conditions; 2.) Mineralogy information from core samples around target wells; 3.) The composition of fracture fluid; 4.) The composition of flowback / produced fluid; 5.) The gas chemistry; 6.) The production profiles for target wells (produced water / gas ratio, pressure information etc).

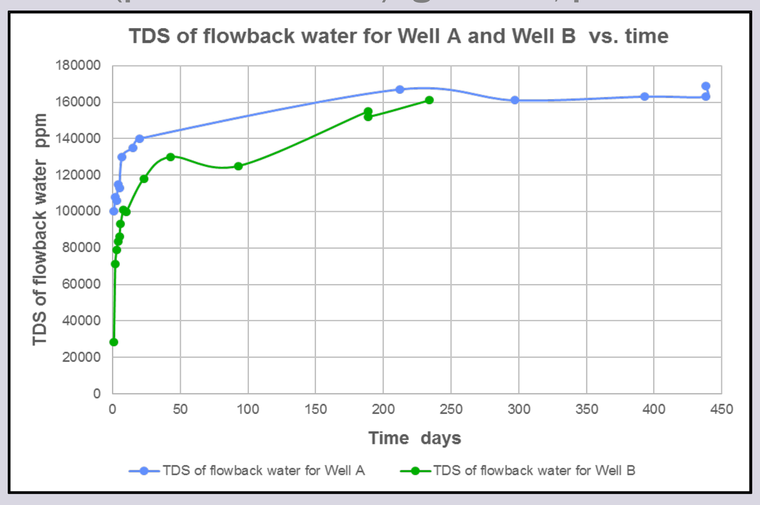

Figure 2 Flowback water TDS vs. fraction (%) of injection water recovered

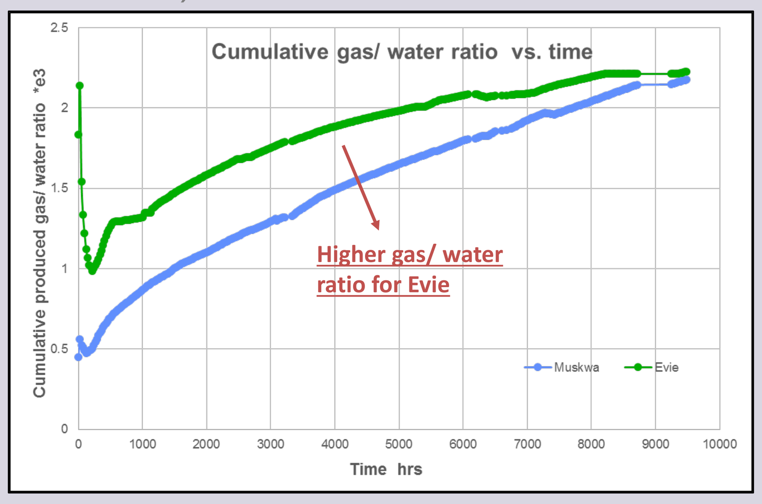

Figure 3 Cum gas/water ratio in Muskwa & Evie members vs. time

The increase in TDS in flowback water is because under normal conditions, within the first couple of weeks the recovered water is called flowback water, which is a mixed fluid containing both fracture fluid and formation water.

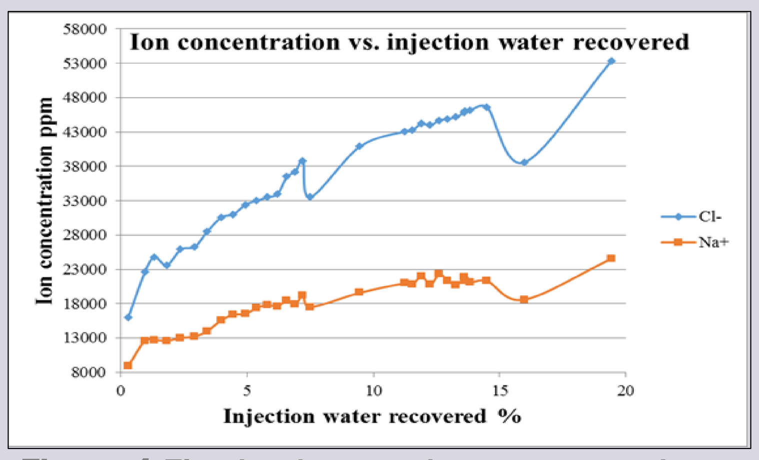

Figure 4 Flowback water ion concentrations vs. fraction (%) of injection water recovered

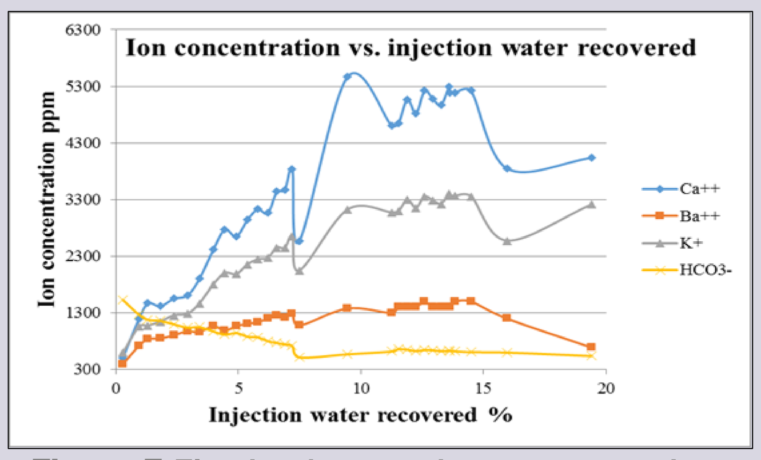

Figure 5 Flowback water ion concentrations vs. fraction (%) of injection water recovered

From the flowback water composition data, it can readily be seen that there is an increase in the concentrations for most of the ions detected, except HCO_3. This study aims to answer the reasons for flowback water composition changing during shale gas production: 1.) Mixing between fracture fluid and formation water; 2.) The geochemical reactions between fracture fluid and minerals within shale gas formation; 3.) Both of the conditions mentioned above.

Barium study:

It is assumed that the two stages have the same production profile (high Ba produced back at the end of the first production profile and high SO_4 produced back at the beginning of the second production profile). The $BaSO_4$ scaling risk could be serious. The illustration of the multi-stage hydraulic fracturing model and the return production profiles for the two stages of hydraulic fracturing process is shown in Figure 6.

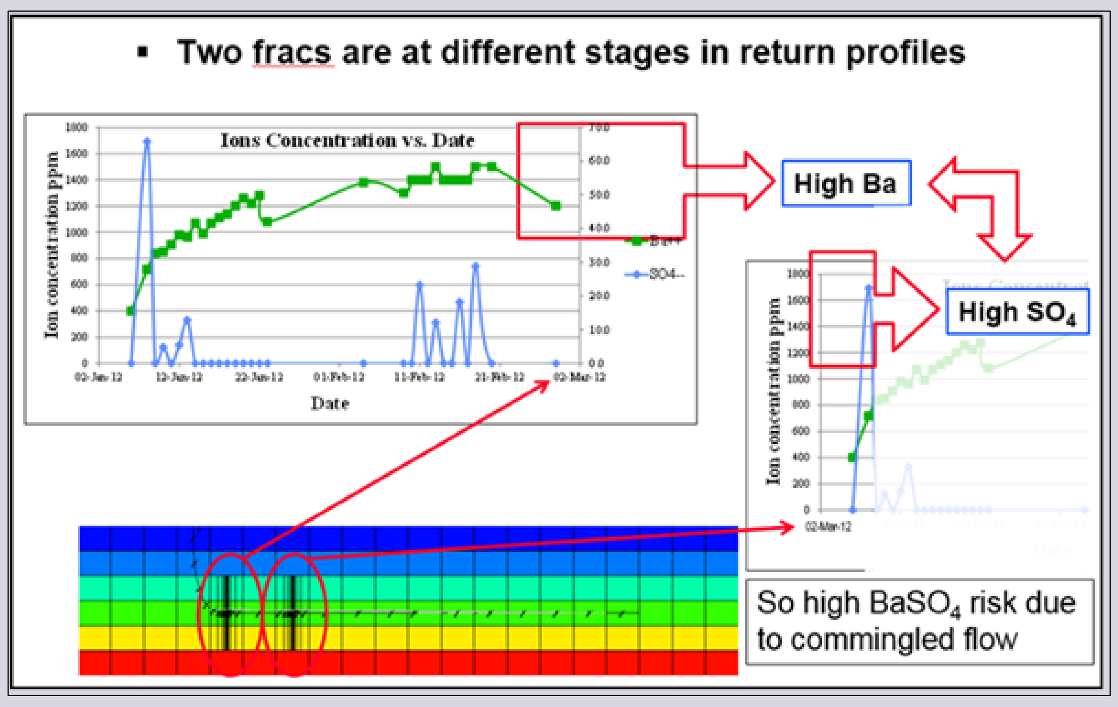

Figure 6 $BaSO_4$ scaling risk prediction for the vs. multi-stage hydraulic fracturing production

Calcium & bicarbonate study:

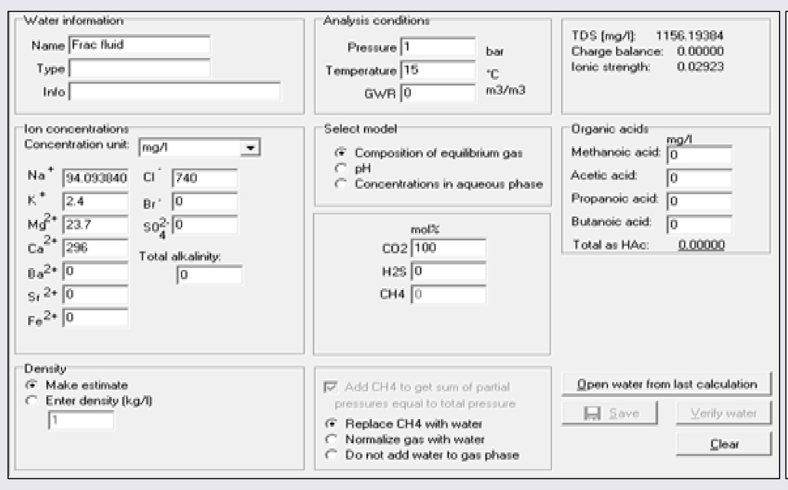

Figure 7 Fracture fluid composition used in MultiScale

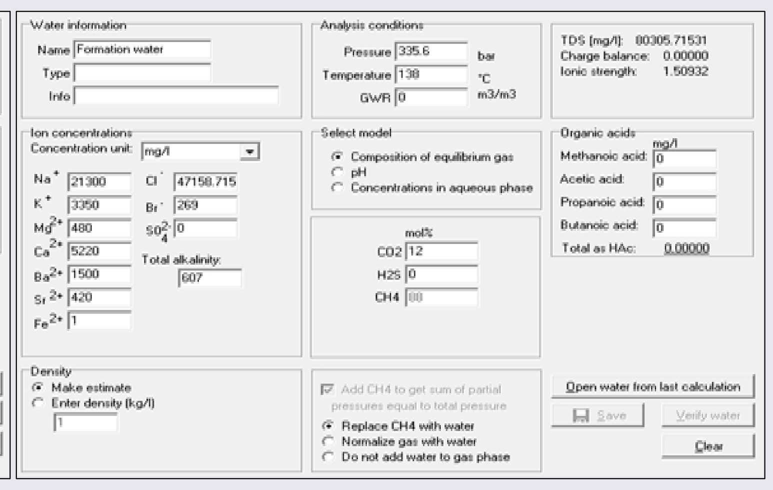

Figure 8 Flowback water composition used in MultiScale

The MultiScale model developed with fluid mixing between fracture fluid and each of the produced water samples. These modelling cases are used to calculate the final ionic equilibrium for the mixture of the two fluids with the minimum fraction of CO_2 in gas phase required.

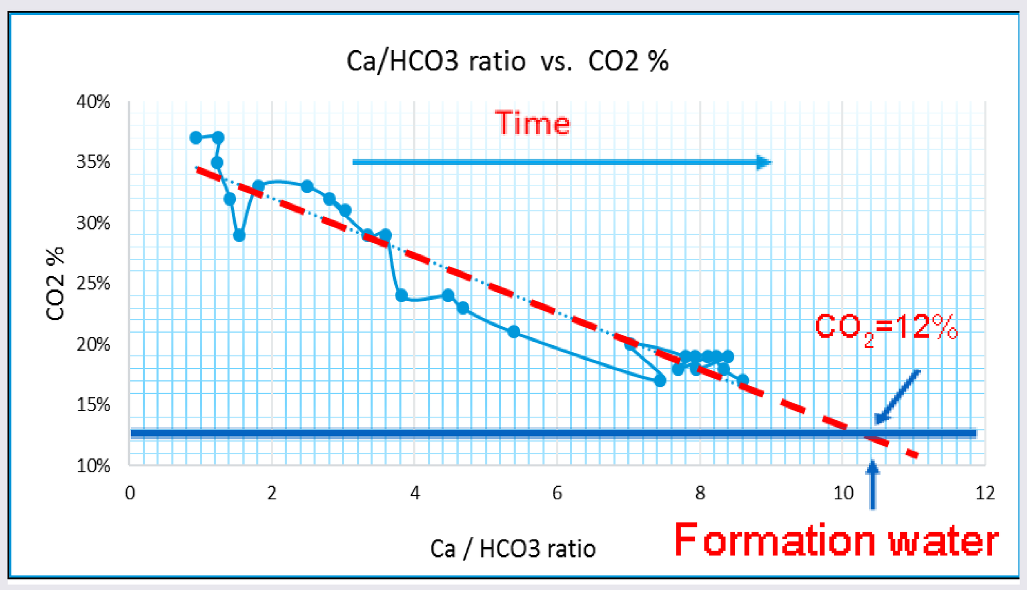

Figure 9 Ca/HCO_3 ratio in flowback water vs. fraction (as %) of CO_2 in gas phase

From Figure 9 it can be seen that: 1.) The requirement of minimum fraction of CO_2 content in the gas phase is generally decreasing; 2.) All the minimum CO_2 are still higher than 12%; 3.) High risk of $CaCO_3$ scale; 4.) The Ca/ HCO_3 ratio in formation water could be aprox 10.4.

Shale gas produced water modelling study

IMEX model setup:

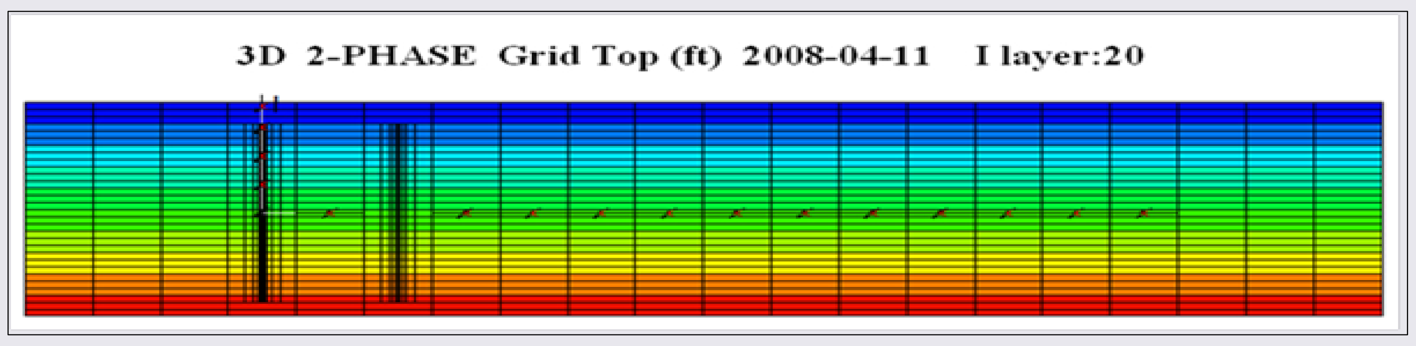

Figure 10 The cross section for each hydraulic fracturing stage in J-K direction

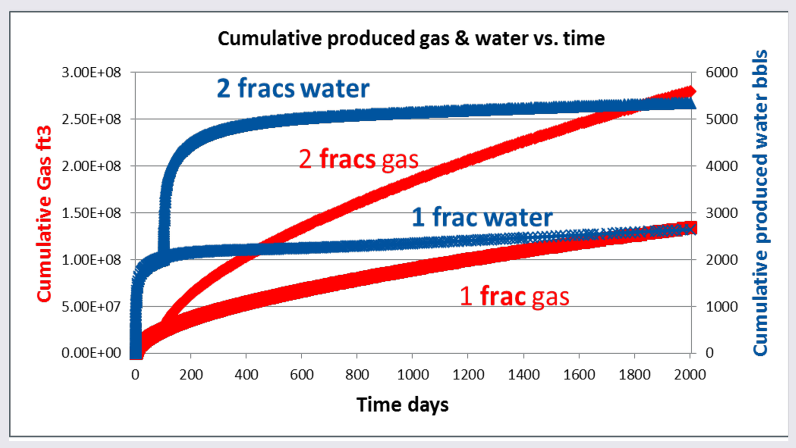

Figure 11 Cumulative produced gas/water vs. time for single/ two frac(s) model

It can be seen that the fraction of cumulative produced water towards the injection water volume is nearly 89% for both of the cases, which is high compare with the flowback water volume in real cases (from 10% to 40%).

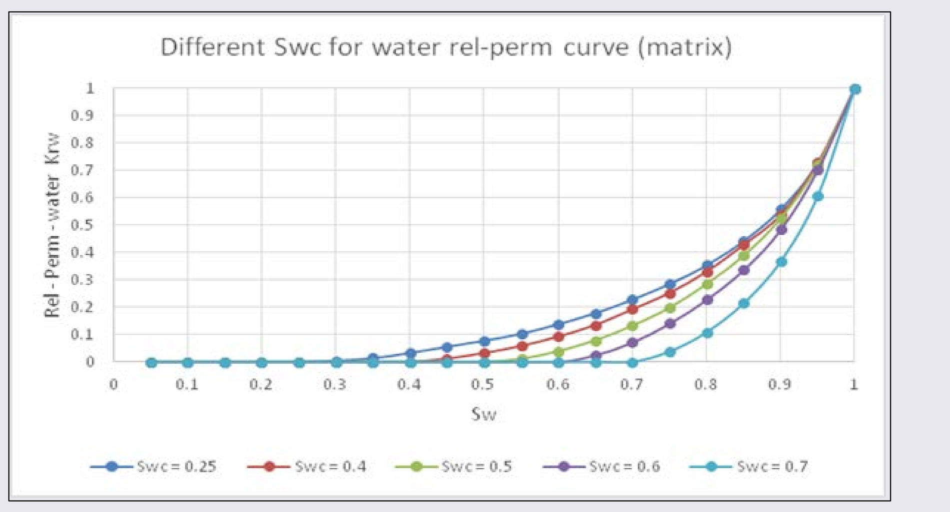

Figure 12 Relative permeability curves, showing various critical water saturations used

By changing the critical water saturation (Swc) value of the shale matrix, it can be observed that as the Swc increases, the volume of flowback water produced drops down (around 50%).

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References:
[1] Mossop, G.D. and Shetsen, I., (compilers), Canadian Society of Petroleum Geologists (1994), "The Geological Atlas of the Western Canada Sedimentary Basin, Chapter 11: Devonian Beaverhill Lake Group of the Western Canada Sedimentary Basin", Alberta Geological Survey.