Progress Report

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Key Observations: (The results of counter-current imbibition will be updated in the next version of the report)

1. The oil contact angle on oil-saturated rock in treated brine is larger than that in untreated brine, which indicates the rock is more water-wet in the treated case.

2. The oil contact angle in 90,000 ppm brine is smaller than that in 40,000 ppm brine for both treated and untreated cases, suggesting higher salinity can make the rock less water-wet.

3. Treated brine has higher IFT values compared with untreated brine.

4. The core plug soaked in treated brine has higher imbibition oil recovery (3.60% initial oil) compared with the one soaked in untreated brine (1.92% initial oil).

1. Materials

1.1 Core Plugs

We used two core plugs drilled from the Montney Formation as shown in **Figure 1**. The properties of the core plugs are listed in **Table 1**. Core 3 and 4 are twin core plugs with porosity of 3.58%. The permeability of core 3&4 is 2.73E-03 mD and 1.87E-03 mD respectively. **Table 2** lists the core plugs' minerology as determined by X -ray diffraction (XRD) analysis. The total clay content is about 35 wt%. The dominant non-clay minerals are quartz (33 to 36 wt%), and dolomite (12 to 21 wt%).

We also used six end pieces cut from two core plugs for the following contact angle measurements. These two core plugs were not the two cores listed in Table 1, but they were drilled from a similar well. The properties of the plugs can be found in **Appendix A**. These core end pieces were saturated with oil using spontaneous imbibition tests.

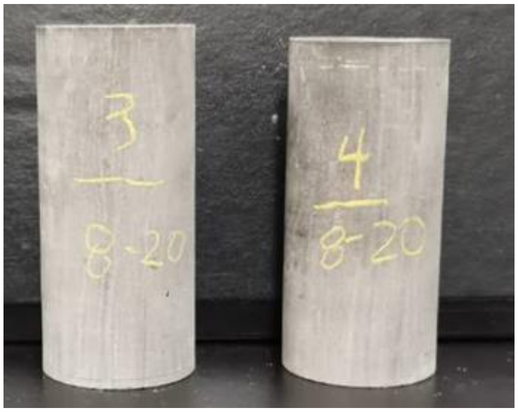

Figure 1 Two core plugs used in this study

Table 1. Properties of the Montney core plugs.

Sample	Depth (m)	Diameter (cm)	Length (cm)	Bulk Volume (cm^3)	Porosity (%)	Permeability (mD)	Pore Volume (cc)
3	2110.1	3.80	8.98	101.84	3.58	2.73E-03	3.646
4	2110.15	3.81	8.64	97.99	3.58	1.87E-03	3.508

Table 2. The mineralogy of the core plugs determined from XRD method.

Sample ID	Quartz (wt %)	K-feldspar (wt %)	Plagioclase (wt %)	Calcite (wt %)	Dolomite (wt %)	Pyrite (wt %)	Total Clay (wt %)
3	33	5	4	0	21	6	29
4	33	5	4	0	21	6	29

1.2 Fluids

The reservoir oil was filtered using a filter paper. The density and surface tension of the oil was 0.822g/cc and 22.3mN/m respectively. A synthetic brine was made by mimicking the chemistry of the reservoir brine with total dissolved solid (TDS) of 130,000ppm. **Table 3** lists the ion concentration of the reservoir brine used in the synthetic brine. The brine was then diluted to 90,000ppm and 40,000ppm. The diluted brine was also treated using clear water plasma AP 1.5 (as shown in **Figure 2**) for the following experiments.

Table 3. Ion composition of brine.

Cations		Anions	
Ion	mg/L	Ion	mg/L
Na^+	42000	Cl^-	76320
K^+	1420	HCO_3^-	130
Ca^{2+}	5600	SO_4^{2-}	369
Mg^{2+}	187	CO_3^{2-}	0.5
Sr^{2+}	175	OH^-	0.5
Fe^{2+}	301		

Figure 2. Plasma AP 1.5 used for water treatment

2. Methodology

In this study, we wanted to investigate: (1) whether treated water works better in waterflooding and by how much; (2) whether salinity matters to the difference in treated water performance

Figure 3 demonstrates the experimental workflow. The treated and untreated brine were used to conduct contact-angle measurements, IFT measurements and core tests to see if the treated water would change the rock wettability and result in higher imbibition oil recovery. The effects of salinity on treated water performance can also be investigated here.

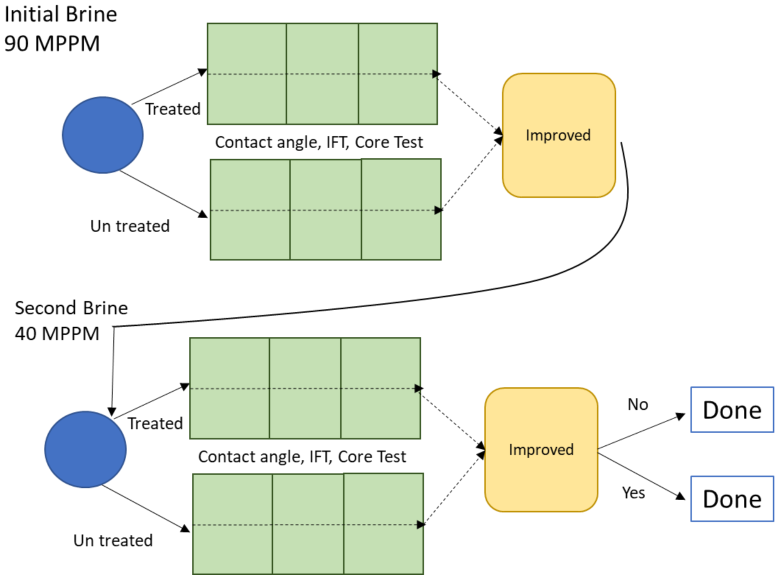

Figure 3. The experimental workflow

2.1 Contact-Angle Measurement.

We measured the CA of oil droplets equilibrated on the surface of rock samples soaked in treated and untreated brine to see if the treated sample could alter the rock wettability. We released an oil droplet on the oil-saturated rock and recorded the CA changes till equilibrium state. The shape of the equilibrated oil droplet was analyzed using a high-resolution camera and its software. The schematic illustration of the contact-angle set-up is shown in **Figure 4**.

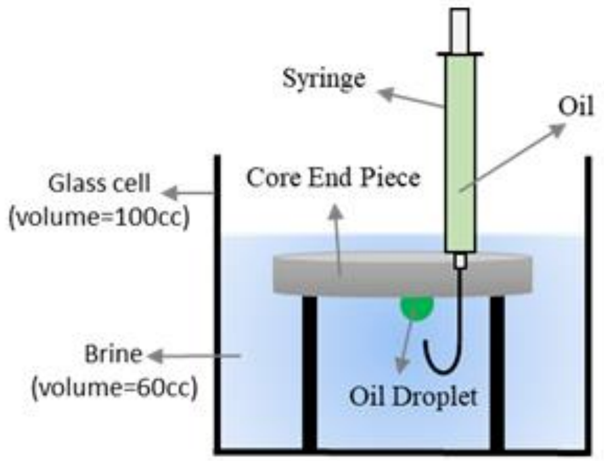

Figure 4. Schematic illustration of the set-up used to monitor the change in contact angle.

2.2 Interfacial Tension Measurements.

The interfacial tensions (IFTs) between the oil sample and brine were evaluated using a Spinning Drop Tensiometer (SDT) (**Figure 5**), which can measure IFT ranging from 10^{-6} to 2000 mN/m with an accuracy of 10^{-6} mN/m. The SDT had a capillary tube filled with surfactant solutions and an end plug filled with the oil sample. The end plug capped the capillary tube. The capillary tube was placed and mounted in the tensiometer with a rotational speed of 3000 RPM. ADVANCETM software was used to analyze the shape of the oil droplet in the capillary tube and calculate the IFT between the oil and surfactant solutions using the Vonnegut equation:

$$\sigma = \frac{(\rho_1 - \rho_2)\omega^2 R^3}{4} \qquad \text{Equation 1}$$

In which ρ is fluid density, ω is angular spinning velocity, and R is droplet radius. Each test was repeated three times at ambient condition and mean values are reported.

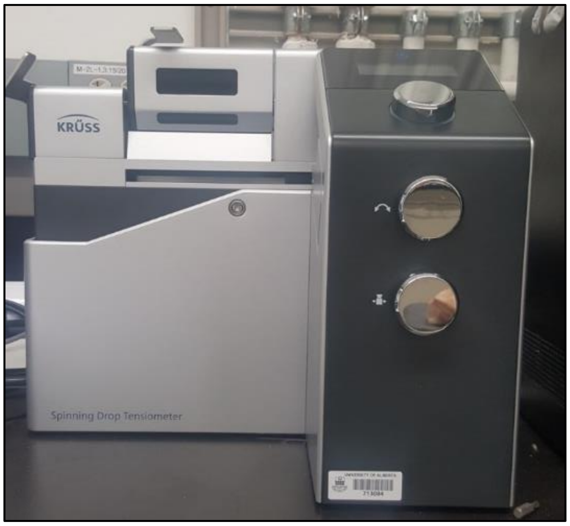

Figure 5. Kruss spinning drop tensiometer for measuring ultralow interfacial tension between oil and surfactant solution.

2.3 Forced Imbibition Tests

Here we used forced imbibition tests to saturate the two core plugs with oil. We put each core plug into the accumulator and set the overburden pressure at 2500psi to conduct forced imbibition for 4 days. The weight of the core plugs before and after forced imbibition tests were recorded to calculate the saturated oil volume. The equipment used for the forced imbibition tests is shown in **Figure 6**.

Figure 6. The set up for forced imbibition tests.

2.4 Counter-Current Spontaneous Imbibition Tests (Soaking Tests)

We soaked the two oil-saturated core plugs in different soaking fluids and then periodically recorded the volume of oil accumulating at the top of the Amott cell. Core 3 and 4 were soaked in 90,000ppm untreated brine and 90,000ppm treated brine respectively.

The purpose of this task was to compare the performance of different soaking fluids on oil recovery. We wanted to know if the treated water worked better in waterflooding.

Results

2.5 Contact-Angle Measurement.

Figure 7 shows the captured pictures of oil droplets equilibrated on the surface of oil-saturated rocks soaked in: (a.1-4) 90,000ppm untreated brine; (b.1-4) 90,000ppm treated brine; (c.1-4) 40,000ppm untreated brine; (d.1-4) 40,000ppm treated brine. The tests were conducted at least four times in each case to check the repeatability. Table 4 shows the measured contacted angle of the oil droplet in treated or untreated brine. From the contact-angle (CA) results, we observed that the oil CA in untreated brine is smaller than that in treated brine, indicating the rock is more water-wet in treated water cases. Also, the oil CA in 90,000 brine is smaller compared to 40,000 brine, suggesting increasing water-salinity can make the rock surface less water-wet.

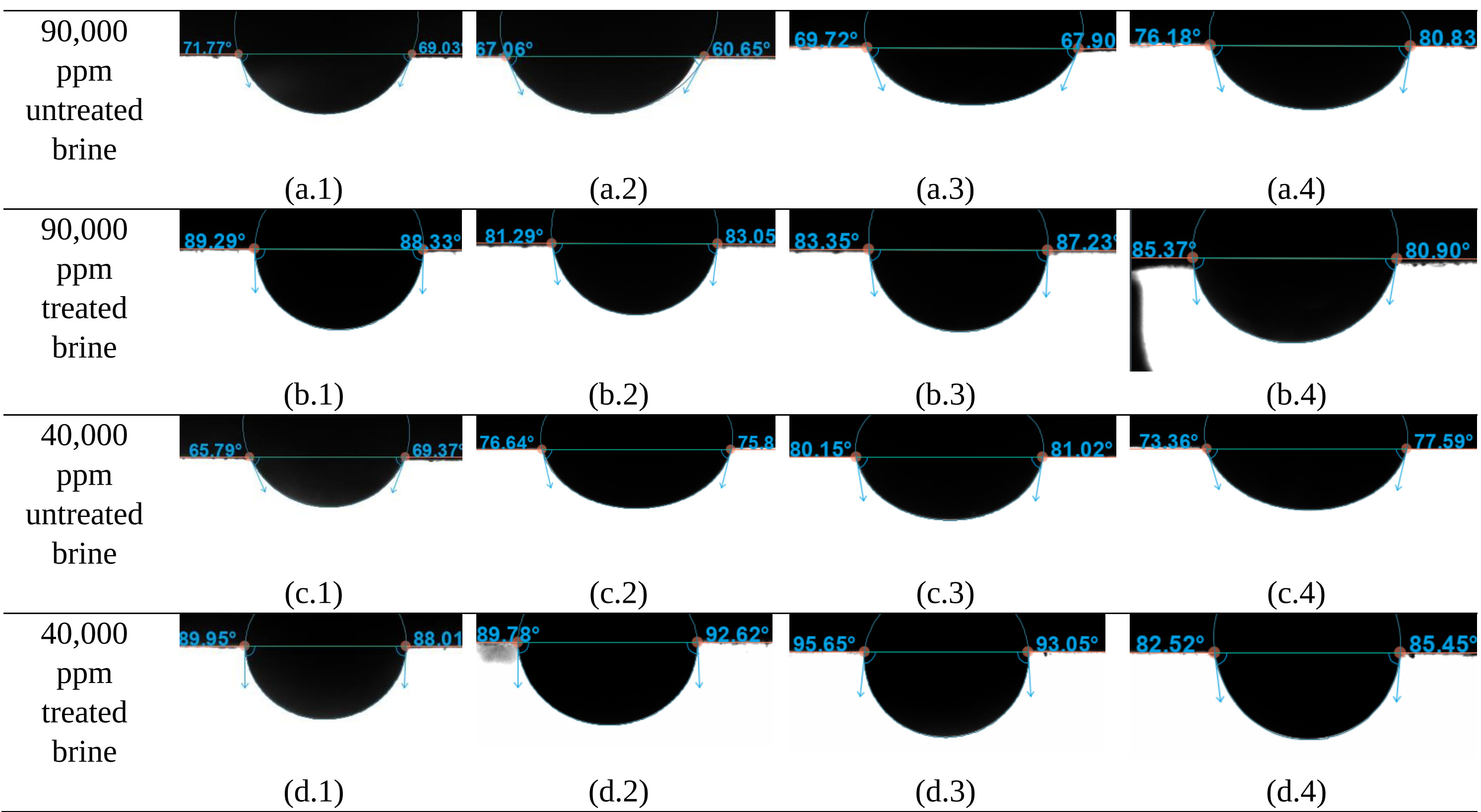

Figure 7. Oil droplets equilibrated on the surface of oil-saturated rocks soaked in (a.1-4) 90,000ppm untreated brine; (b.1-4) 90,000ppm treated brine; (c.1-4) 40,000ppm brine; (d.1-4) 40,000ppm treated brine.

Table 4 Measured contact angle of oil droplet for 90,000 and 40,000ppm treated and untreated brine.

Fluid	Contact angle (º)
90,000 untreated brine	70.12±5.71
90,000 treated brine	84.52±3.31
40,000 untreated brine	74.25±5.37
90,000 treated brine	88.75±4.35

2.6 IFT Measurements.

Figure 8 shows the spinning oil droplets in treated and untreated brine (90,000 and 40,000ppm) when rpm=4500. Table 5 lists the measured IFT values for different cases. The IFT for 90,000 and 40,000ppm brine is 1.79 and 1.72 mN/m respectively. And the IFT for 90,000 and 40,000ppm treated brine is 2.54 and 2.14 mN/m respectively. Treated brine has higher IFT compared with untreated brine.

Figure 8. The IFT between oil and brine (a) 90,000ppm brine; (b) 90,000ppm treated brine; (c) 40,000ppm brine; (d) 40,000ppm treated brine;

Table 5 Measured IFT values between oil and 90,000/40,000ppm treated and untreated brine.

Fluid	IFT (mN/m)
90,000ppm untreated brine	1.79±0.10
90,000ppm treated brine	2.54±0.22
40,000ppm untreated brine	1.72±0.15
40,000ppm treated brine	2.14±0.20

2.7 Forced Imbibition Tests.

Table 6 shows the weight change of the two core plugs before and after forced oil imbibition. The calculated imbibed volumes of oil for Core 3 and Core 4 are 1.88cc and 1.67cc, respectively. The imbibed volumes of oil normalized by pore volume (PV) are 51.45%PV and 47.51%PV respectively for the two cores.

Table 6. Weight of core plugs before and after forced oil imbibition, and the calculated imbibed volume oil.

Sample	Initial Weight (g)	Weight After Forced Imbibition (g)	Imbibed Oil (cc)	Pore Volume (PV) (cc)	Normalized Imbibed Oil (%PV)
3	252.610	254.150	1.88	3.646	51.45
4	242.455	243.825	1.67	3.508	47.51

2.8 Counter-Current Imbibition.

Figure 9 shows the results of the soaking tests on the two core plugs: (a) Core 3 was soaked in untreated 90,000 ppm brine; (b) Core 4 was soaked in treated 90,000ppm brine; **Table 7** lists the values of produced oil and calculated oil recovery factor (RF) for each case. The oil RF is defined as the produced oil volume divided by the initial oil volume in the core plugs. From Table 7, we see that Core 4, soaked by treated 90,000ppm brine, has higher oil RF compared to Core 3 which was immersed in untreated 90,000ppm brine, suggesting treated water can imbibe more into oil-saturated core samples compared to untreated water, which is consistent with the CA results. Please note that the permeability of the treated water core was 32% less than the untreated core (1.87 vs 2.73 in relative terms).

From Figure 9, we notice that there are small oil droplets attached on the rock surface, which didn't accumulate on the top of the Amott cell. We understood that this problem would affect the accuracy of our oil recovery measurement. Therefore, we used small magnets which were put into the Amott cell before the tests to stir the soaking fluid gently to make some of those oil droplets detached from the surface. However, there was still some oil remaining on the core surface after stirring.

We also observed that the oil droplets attached to Core 3, which was immersed in untreated brine, were bigger than those attached on Core 4 which was immersed in treated brine. This could mean more effective liberation of oil stuck to the rock surface.

Table 7 The produced oil and calculated oil RF for each case.

Sample	Soaking Fluid	Initial Oil (cc)	Produced Oil (cc)	Oil RF (%initial oil in cores)
3	Untreated 90,000ppm brine	1.88	0.036	1.92
4	Treated 90,000ppm brine	1.67	0.06	3.60

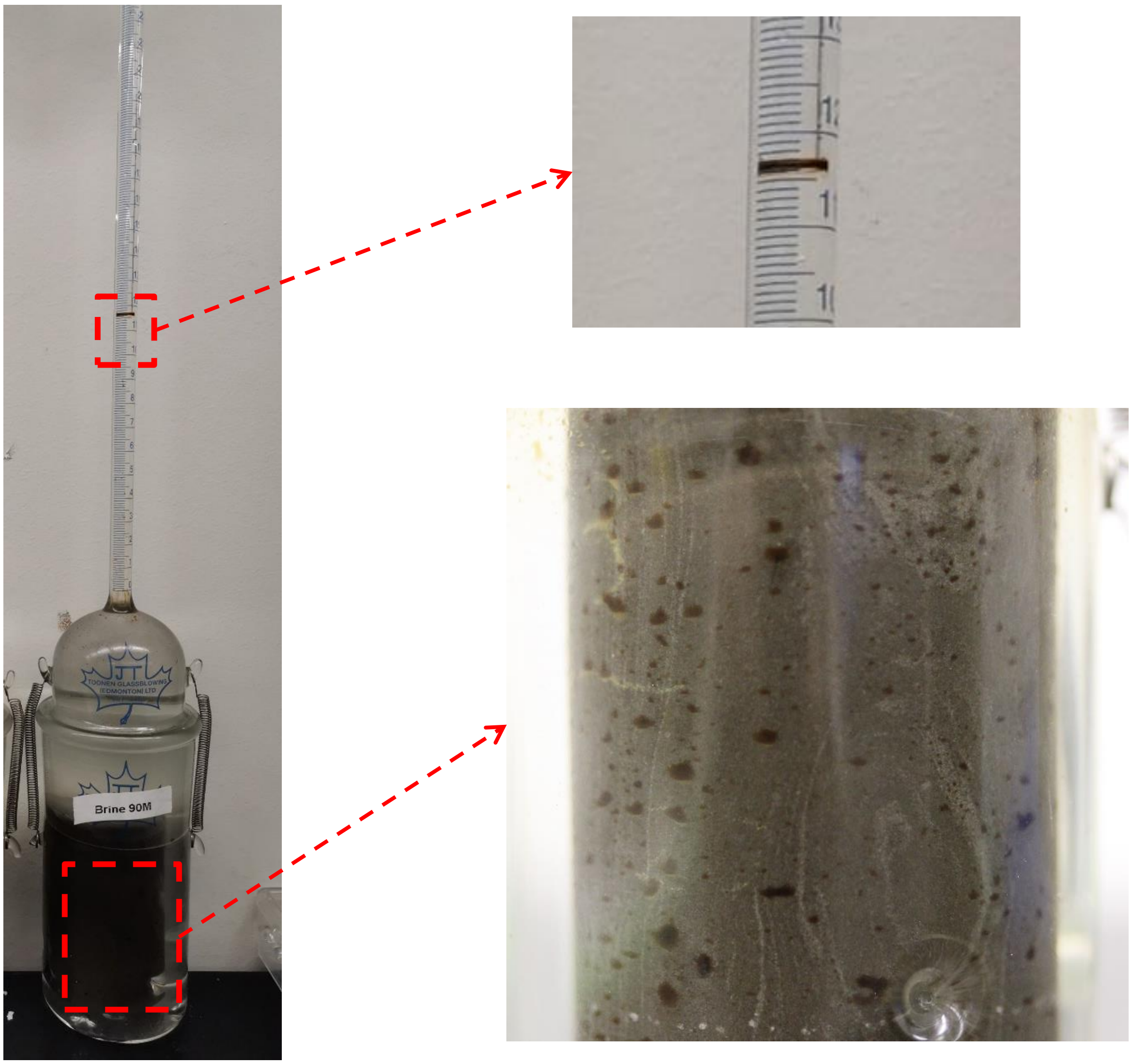

Figure 9 (a) Core 3 soaked in untreated 90,000ppm brine

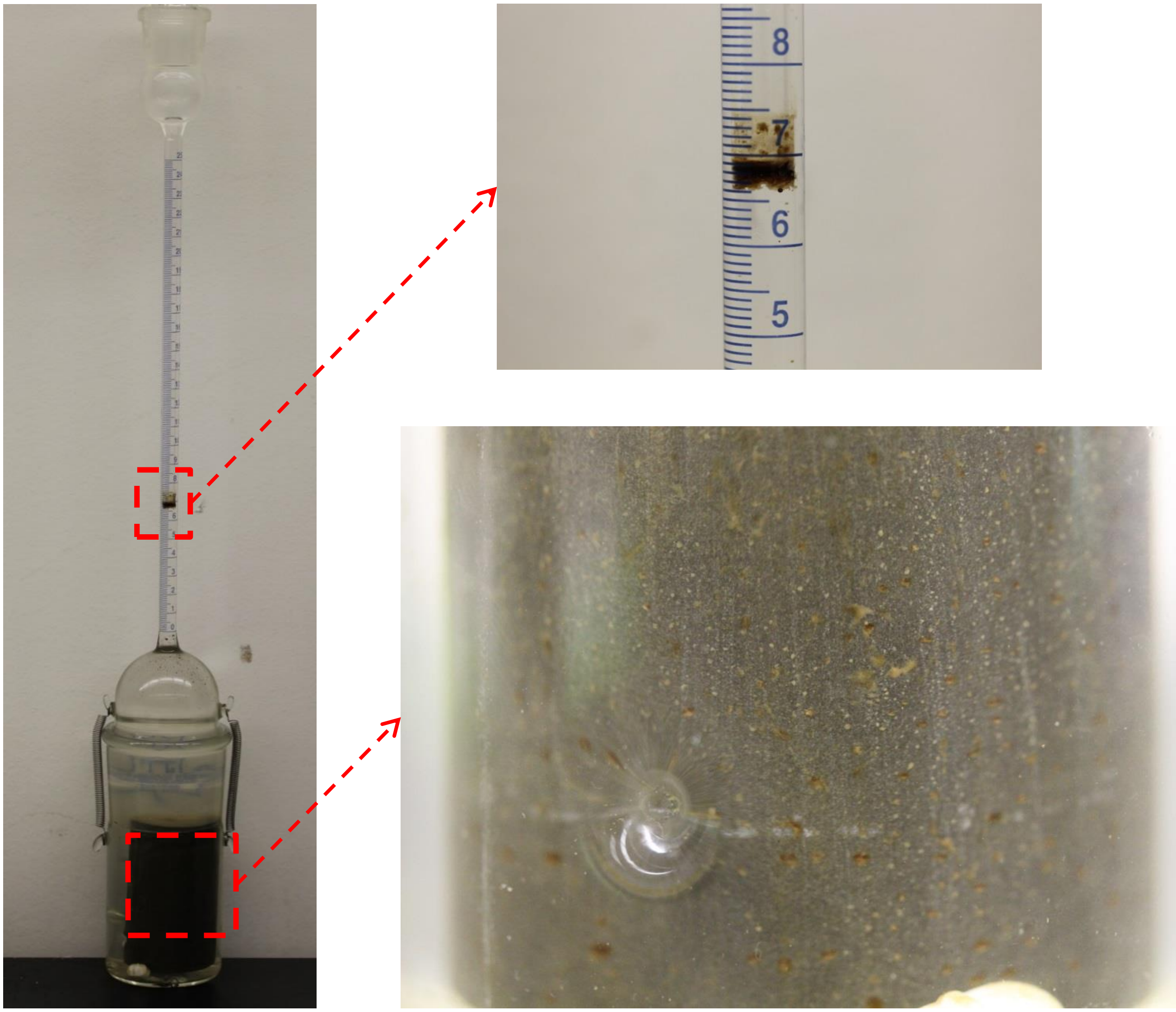

Figure 9 (b) Core 4 soaked in treated 90,000ppm brine

Appendix A. Properties of Core End Pieces for Contact Angle Tests.

We used six end pieces from two core plugs for contact angle measurements. The core plugs were also drilled from the Montney Formation. The properties of the core plugs are listed in **Table A1**. **Table A2** lists the core samples' minerology as determined by X -ray diffraction (XRD) analysis. The dominant clay mineral is illite (3.7 to 7.1 wt%), and the dominant non-clay minerals are quartz (37.3 to 39.9 wt%), K-feldspar (18.6 to 22.2 wt%) and dolomite (18.5 to 36.6 wt%).

Table A1. Properties of the Montney core plugs.

Sample	Depth (m)	Diameter (cm)	Length (cm)	Bulk Volume (cm^3)	Porosity (fraction)	TOC (wt %)
1	2532.48	3.7	6.0	64.51	0.046	0.77
2	2547.00	3.7	6.3	67.74	0.034	0.57

Table A2. The mineralogy of the core plugs determined from XRD method.

Sample ID	Quartz (wt %)	K-feldspar (wt %)	Plagioclase (wt %)	Calcite (wt %)	Dolomite (wt %)	Pyrite (wt %)	Illite (wt %)	Total Clay (wt %)
1	39.9	22.2	7.8	1.7	18.5	1.8	7.1	8.0
2	37.3	18.6	1.6	0.5	36.6	1.0	3.7	4.4