Impact of Dopants on SCAL Experiments, Phase II

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Abstract.

After the publication of Impact of Dopants on SCAL Experiments Phase I in 2024, this second part is the follow up of the investigation of the effects of adding sodium iodide (NaI) to the formation brine and injection brine during laboratory waterflooding experiments. The first paper had pointed towards a non-trivial role of NaI in wettability alteration on sandstone rock. This alteration could introduce a significant bias in the SCAL experiments. These phase II experiments are focused on the study of 6 carbonate samples (Richemont carbonate rock). The samples were initially saturated with undoped or doped brines, brought to irreducible water saturation (Swi) and aged using crude oil at reservoir temperature. The samples were then loaded in Amott cells for spontaneous imbibition before being brought to residual oil saturation (Sor) during centrifuge forced imbibition. The results are showing some divergences with Phase one experiment. The spontaneous imbibition has not shown any correlation between NaI concentration and produced volume. Unlike phase one with sandstone rocks, the main difference between undoped and doped brine effect appears during the forced drainage showing a slight but systematic decrease in recovery factor for samples with NaI doped brine. Further work is still required to assess the impact of iodide in oil phases, such as the impact of organic dopants like iodododecane.

1 Introduction

Wettability is a crucial factor in controlling fluid flow within porous media, as it influences the distribution of fluids within the pore structure, thereby affecting flow properties such as capillary pressure and relative permeability. Imaging equipment such as X-ray scanners (1D linear, 3D CT or micro-CT) have allowed for the observation of pore-scale flow mechanisms, which has facilitated the incorporation of relevant physics into simulators. Additionally, these experiments have been utilized to estimate rock and fluid properties, including wettability. To monitor saturation profiles and to accurately measure the remaining oil saturation during and at the end of a coreflooding experiment, X-ray attenuation method is used. Because oil and water have different X-ray attenuation coefficients, in principle it is possible to differentiate the two phases but a significant contrast between the various fluids is necessary within the pore network. Most of the time, the contrast is too low (typical brines, i.e. sea water, have attenuation coefficients a_w of 0.0208 mm-1 whereas typical oil attenuation coefficient a_o values are around 0.015 mm-1). To enhance this contrast, it is common practice to add dopants to one of the fluids, usually the brine. Sodium iodide (NaI) and potassium iodide (KI) are the most frequently used dopants. Even if some literature [1, 2] is reporting no change in wettability due to the addition of NaI in the experimental brine during their process a recent study presents contradicting findings. Pairoys *et.al* [3] conducted a SCAL experimental investigation on the effect of dopants on spontaneous imbibition dynamics and residual oil saturation. The authors used different NaI brine concentrations, on Bentheimer outcrops. It was found that increasing the concentration of dopants in the connate brine increased the spontaneous imbibition rate, thus enhancing the water-wetness. Residual oil saturations also increased. A key observation was that if the aging step is performed with non-doped connate brine, spontaneous imbibition and residual oil saturation are not impacted, even if a doped brine is used in the later stages of the Amott wettability experiment.

Building on the observations by Pairoys *et al.* [3] and Nono *et al.* [4] that concluded that only sodium iodide significantly influences oil recovery even at low concentrations (as little as 1000 ppm) in the connate brine, this paper reproduces the experiments done by [3] on another batch of outcrops. This time the study is investigating the effects of NaI on Richemont carbonate outcrops in the same experimental conditions. Multiple concentrations are investigated, and the results also indicate a non-negligible effect of doping the connate brine on the recovery.

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As recently shown in Halisch *et al.* [5], NaI significantly impacts the electrokinetic behavior of sandstone samples through modifications in the electric double layer (EDL). This underpins the wettability effects observed in Phase I and offers a mechanistic basis for the ongoing assessment in carbonate systems.

2 Experimental context

Evaluating the effect of dopant concentration (sodium iodide) on oil recovery and wettability is a complex endeavor considering the number of parameters to investigate. Even before considering the use of dopant, parameters like Rock mineralogy, aqueous chemistry (pH, Salinity) oil chemistry, and ageing process (time, temperature) are known to have an influence on the wettability result. For example, Mwangi *et.al* [6] performed an extensive study of the wettability (567 flotation experiments with two procedures) and showed that, in some cases, significant differences in wettability are observed between sandstone and carbonate when the same experimental conditions are applied.

Assuming that each parameter influencing wettability alteration behaves in a binary manner - e.g., rock type (sandstone or carbonate), brine pH (acidic or basic), brine salinity (high or low), oil acidity (high or low TAN), asphaltene content (high or low), and for dopant 3 possibilities, no dopant, high or low concentration. This reduced set of parameters leads to 66 possible combinations. A better solution than investigating all the possibilities could be to use a fractional factorial plan or a Plackett-Burman Design of Experiment (DoE) to study only a part of the full possibilities while obtaining a maximum of information from the experiment [7]. In addition to the number of possibilities, the duration of the reference techniques (as Amott Harvey test or USBM index) to evaluate wettability in petrophysics is known to last between a few months up to a year and then render the task to link wettability change to any of these parameters near to impossible. Although a DoE approach was discussed as an option, this study focuses on systematically varying one parameter – the NaI concentration – under controlled conditions

The initial experimental program proposed for phase 1 and now for this paper is to provide one main insight to the following question:

- Is there or not, an impact on wettability (and thus on relative permeabilities) of using sodium Iodide (NaI) as a dopant in a brine used for special core Analysis?

In order to provide part of the answer, two rock systems were selected. First, in phase one, a clastic rock (Bentheimer sandstone) and for phase two a carbonate rock (Richemont limestone). A crude oil from the Middle East was chosen for the imbibition tests. For the impact of dopant in the brine used three cases are studied:

- A conventional brine without dopant added is used to perform the test on a reference sample
- A brine with NaI added in the initial saturating brine, referred to as the connate brine is used.
- A conventional brine without dopant is used for saturation and wettability restoration, then a brine with NaI is used during spontaneous and forced imbibition cycles.

The full testing program can be summarized as follows:

NaI clastic program, Phase 1: achieved and presented at the SCA in 2023 [3]

Reference test

- Bentheimer sandstone rock with Middle Eastern oil and connate brine containing no Iodide. Imbibition done with connate brine containing no iodide

Impact of NaI in imbibing brine only

- Bentheimer sandstone rock with Middle Eastern oil and connate brine containing no Iodide. Imbibition done with imbibing brine containing 1g/l NaI
- Bentheimer sandstone rock with Middle Eastern oil and connate brine containing no Iodide. Imbibition done with imbibing brine containing 12g/l NaI

Impact of NaI concentration in connate brine (initial saturating brine)

- Bentheimer sandstone rock with Middle Eastern oil and connate brine containing 1g/l NaI. Imbibition done with imbibing brine containing 1g/l NaI
- Bentheimer sandstone rock with Middle Eastern oil and connate brine containing 6g/l NaI. Imbibition done with imbibing brine containing 6g/l NaI
- Bentheimer sandstone rock with Middle Eastern oil and connate brine containing 12g/l NaI. Imbibition done with connate brine containing 12g/l NaI

NaI carbonate program, Phase 2: Achieved and presented in this paper.

Reference test

- Richemont carbonate rock with Middle Eastern oil and connate brine containing no Iodide. Imbibition done with connate brine containing no iodide

Impact of NaI in imbibing brine only

- Richemont carbonate rock with Middle Eastern oil and connate brine containing no Iodide. Imbibition done with imbibing brine containing 1g/l NaI
- Richemont carbonate rock with Middle Eastern oil and connate brine containing no Iodide. Imbibition done with imbibing brine containing 12g/l NaI.

Impact of NaI concentration in connate brine (initial saturating brine)

- Richemont carbonate rock with Middle Eastern oil and connate brine containing 1g/l NaI. Imbibition done with imbibing brine containing 1g/l NaI.

- Richemont carbonate rock with Middle Eastern oil and connate brine containing 6g/l NaI. Imbibition done with imbibing brine containing 6g/l NaI.
- Richemont carbonate rock with Middle Eastern oil and connate brine containing 12g/l NaI. Imbibition done with connate brine containing 12g/l NaI.

3 Summary of the previous results

Pairoys et.al [3] have provided important insights (impact or no impact of NaI on wettability) comparing the 3 cases on a sandstone rock sample (test without dopant, test with dopant in the connate brine, test with NaI only during the imbibition).The wettability was investigated through different angles only on the imbibition part (to reduce the experimental time needed).

During the spontaneous imbibition two main trends were visible:

- 3 samples are producing oil at a very low rate and produced less than 20 saturation units (s.u) during the spontaneous phase. One of these samples is the reference one, the two others are the ones without NaI in the connate brine
- 3 samples are producing at a higher rate, have produced more than 40 s.u (more than the double) and oil production continued steadily throughout the 40-day period. These 3 samples were in the presence of NaI in the connate brine.

Figure.1 below summarizes this information. On the left (light blue) the reference sample production (converted in.s.u) is equal to 16.6 s.u. In the middle, the average production of 15.8 s.u for the two samples without NaI in connate brine. On the right (darkest blue) the average production of 44.6 s.u for the 3 samples with NaI in the connate brine.

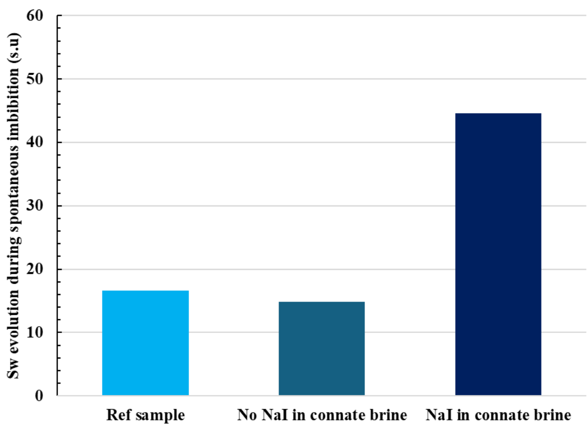

Fig. 1. Summary of the saturation evolution during spontaneous imbibition on the sandstone experiments of phase 1 [3].

A high spontaneous imbibition provides information about the water-wetness of the system studied and, in this case, it was already visible that adding NaI in the connate brine is changing the behavior of the system compared to the reference test. As water index (Iw) calculation from the Amott Harvey technique is based on spontaneous and forced phases, the trends in Iw mirror the observed differences in spontaneous and forced imbibition behavior.

The second part of the experiment in phase one reinforces this first conclusion. At the end of forced imbibition, the residual oil saturations plotted in figure 2 are also far higher for the "NaI in connate brine" group. This observation is also in favor of a more water-wet system (high spontaneous phase but low forced imbibition). On this given system – "sandstone + middle eastern oil" using NaI from the initial stage of experiment (i.e, in the connate brine) considerably alters the wettability.

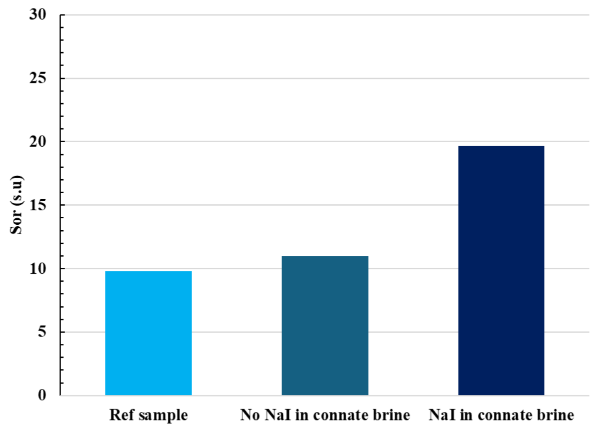

Fig. 2. Summary of the saturation evolution during forced imbibition on the sandstone experiments of phase 1 [3].

The group that experimented with NaI in the imbibing brine but not in the connate brine (in the middle of the 2 graphs above) has not shown remarkable differences with the reference sample. The following parts show the results obtained for the second phase of the experimental program on carbonate samples

4 Rock and Fluid Properties

a) Rock properties

The Carbonate program is performed on Richemont outcrop samples. It is a homogeneous rock with constant mineral composition and intrinsic properties (uniform pore throats radius (PTR) and bodies, with porosity ranging from 27.9 to 30.1% and Klinkenberg corrected permeability ranging from 62 to 72 milli-Darcy).

The properties of the six samples used for our study are listed in Table 1.

Table 1. Conventional Core properties at ambient conditions

Sample ID	Porosity (frac)	KgKl (mD)	Diameter (mm)	Length (mm)
Ri 1	0.287	66	37.98	50.32
Ri 2	0.301	72	37.98	50.34
Ri 3	0.280	66	37.90	50.47
Ri 4	0.282	68	37.93	50.76
Ri 5	0.279	62	37.98	50.50
Ri 6	0.282	67	37.90	50.30

Porosities (φ) and Klinkenberg permeability (KgKl) are almost the same for all the samples.

b) Brine

As for the phase one experiments on clastic rock, the water composition is based on simplified sea water (SW*) composition with sea water (SW) as reference. Three NaI concentrations were added to SW (SW*1 with 1 g/l NaI, SW*6 with 6 g/l NaI, SW*12 with 12 g/l NaI), as shown in Table 2. To ensure that the addition of NaI does not affect the ionic strength of the brine, NaCl concentrations were adjusted accordingly, resulting in a constant ionic strength of ~0.72 mol/L across all NaI concentrations.

Table 2. ionic brine composition and salt concentrations

	SW	SW*	SW*1	SW*6	SW*12
Ion	C (mg/l)	C (mg/l)	C (mg/l)	C (mg/l)	C (mg/l)
Na+	12066	10542	10696	10675	10691
K+	503.5	503.5	503.5	503.5	503.5
Ca2+	819.2	817.8	817.8	817.8	817.8
Mg2+	1482	1482	1482	1482	1482
Ba2+	2.8	0	0	0	0
Sr2+	16.4	0	0	0	0
Cl-	22505	22486	22486	21272	19877
SO42-	3047	0	0	0	0
HCO3-	168	0	0	0	0
I-	0	0	846.6	5079.8	10159
TDS	40593	35831.3	36831.9	39830.1	43530.3
Ionic strength (mol/L)	0.81	0.72	0.72	0.72	0.72

Salt	SW C (g/l)	SW* C (g/l)	SW*1 C (g/l)	SW*6 C (g/l)	SW*12 C (g/l)
NaCl	26.8	26.8	26.8	24.8	22.5
KCl	0.96	0.96	0.96	0.96	0.96
CaCl2, 2H2O	3	3	3	3	3
MgCl2, 6H2O	12.4	12.4	12.4	12.4	12.4
Na2SO4	4.5	0	0	0	0
NaHCO3	0.23	0	0	0	0
SrCl2, 6H2O	0.05	0	0	0	0
BaCl2, 2H2O	0.004	0	0	0	0
NaI	0	0	1	6	12

Table 3 below summarizes the brine properties, density ρw and viscosity µw at 80°C (based on correlation).

Table 3. Brine properties

@80°C	ρw (g/cc)	µw (cP)
SW*	0.995	0.38
SW*1	0.997	0.39
SW*6	1.000	0.39
SW*12	1.002	0.39

c) Oil

The same dead oil as phase one from a Middle Eastern reservoir was utilized in this phase two experiment. Before analysis, the oil underwent filtration through a 0.1µm filter and was then centrifuged at 10,000 RPM at 50°C. To prevent the evaporation of light components at 80°C, the crude oil was heated in an oven at 100°C for two days prior to being used in various tests.

As noted by [8], there are two primary groups of components in crude oils that influence reservoir rock wettability alteration. Group 1 includes polar heteroatoms such as organic acids and bases, while Group 2 consists of asphaltene which are known to adsorb strongly to mineral surfaces.

The results of the crude oil into Saturates, Aromatics, Resins and Asphaltenes (SARA) analysis are presented below.

Table 4. Crude oil SARA, TAN and TBN Analysis

Saturates wt%	42.5
Aromatics wt%	48.8
Resins wt%	8.7
Asphaltenes wt%	2.7
TAN mg KOH/g	0.07
TBN mg KOH/g	0.62

Internal studies at TotalEnergies have shown that even with a low total acid number (TAN) and a moderate level of asphaltenes, this crude oil can make reservoir rock slightly oil-wet following initial core cleaning and Swi establishment using the same crude oil. The Amott-Harvey and USBM wettability indexes were found to range between -0.5 and -0.1. This change in wettability is mainly due to the total base number (TBN), which exceeds 0.5 mg KOH/g. Table 5 summarizes the measured oil properties, density ρo and viscosity μo at 80°C.

Table 5. Measured oil properties

@80°C	ρo (g/cc)	μo (cP)
Crude oil	0.831	3.10

5 Experimental Protocol

Following the preliminary conventional core analysis (CCA), the samples were saturated with brine.

- Ri1 is our reference test. It experiments only Sw* during the entire process from saturation to the end of forced imbibition.
- Ri2 and Ri3 will be saturated with Sw* but brine used for imbibition is doped with NaI (at two different concentrations Sw*1 and Sw*12)
- Ri4 – Ri5 and Ri6 are in the presence of NaI on the brine from the saturation of the sample to the end of the test at 3 different NaI concentration (respectively Sw*1 Sw*6 and Sw*12).

After saturation, all samples underwent a primary drainage cycle in a porous plate setup, using mineral oil as the displacing phase. The porous plate is used to ensure a flat and homogeneous saturation profile all along the rock samples. This technique has been preferred to a conventional centrifuge with reversal at the end as some authors like Nono et.al [9] have shown a possible re-imbibition during the reversal. A multistep approach was utilized to determine the primary drainage capillary pressure (Pc) up to the irreducible water saturation (Swi). Mineral oil was sequentially replaced by toluene and dead oil at 80°C using a conventional core flooding system, which was employed to dynamically age the samples for four weeks.

Following the ageing period, the samples were placed in Amott cells for spontaneous imbibition (SPI) at 80°C for 50 days. After ageing at Swi with dead oil, the samples were immersed in brines with varying NaI concentrations.

Finally, the samples underwent forced imbibition (FI) using a multistep centrifuge method until reaching the remaining oil saturation (ROS). The maximum applied Pc ensured an asymptotic Pc curve, allowing ROS to be considered as the residual oil saturation (Sor). It is important to note that the brines used for forced imbibition (FI) were the same as those tested on the samples during spontaneous imbibition (SPI).

The composition of the connate and imbibing brines used is listed in Table 6 (see also Table 2 for ionic details).

Table 6. Symbols of connate brine and imbibing brines used for each sample

Sample Id	Brine at Swi	SPI and FI brine
Ri 1	SW*	SW*
Ri 2	SW*	SW*1
Ri 3	SW*	SW*12
Ri 4	SW*1	SW*1
Ri 5	SW*6	SW*6
Ri 6	SW*12	SW*12

The experimental objective remains consistent with Phase 1: evaluating the impact of NaI on wettability

As Ri 2 is showing a slightly higher porosity (~2 p.u more than other samples) it was used in the batch of samples without doped connate brine to avoid misinterpretation on the results.

6 Experimental Results

6.1. Primary Drainage

The primary drainage was first performed to set Swi and to determine the capillary pressure curve. Figure 3 shows the Pc curves. The curves of the 6 samples almost overlap. All the rock samples exhibit similar Swi values (summary of Swi in table 7).

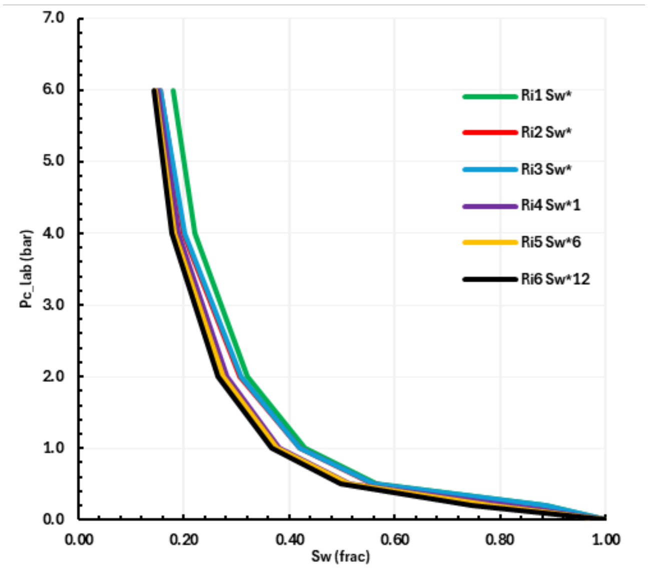

Fig. 3. Primary Drainage Pc curves obtained in laboratory conditions (Brine – mineral oil)

Table 7. Swi values

Sample Id	Brine at Swi	Swi frac.
Ri 1	SW*	0.180
Ri 2	SW*	0.155
Ri 3	SW*	0.155
Ri 4	SW*1	0.151
Ri 5	SW*6	0.145
Ri 6	SW*12	0.143

6.2. Spontaneous Imbibition

The results of spontaneous imbibition are presented in Figure 4. The pronounced spontaneous imbibition observed in sandstone is absent in the carbonate samples. It should be noted that, even if wettability is more than probably involved in this difference, sandstone rock samples used in phase one are also very different in permeabilities (~2000 mD) compared to the Richemont carbonate used here (~60 mD).

The sample Ri4 with 1g/L NaI added in connate brine (purple straight line on Fig.2) seems to show lower spontaneous imbibition than the 5 other samples. Considering an uncertainty range of 0.5 s.u during this part of the experiment, the average difference between samples is so minor that it does not warrant interpretation.

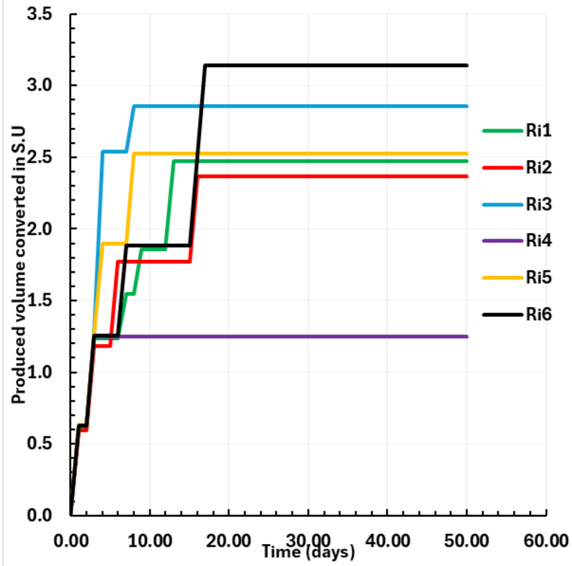

Fig. 4. Spontaneous imbibition production (monitored in saturation unit, s.u.).

It is possible to highlight a general difference between average evolution of saturation during spontaneous phase for sandstone and for carbonates in the same experimental conditions:

- Sandstone: (results for part 2) ~15 s.u. produced for samples without dopant in connate brine and 44 s.u. for sample with NaI in connate brine
- Carbonates: 2.6 s.u. in average for samples without NaI in connate brine and 2.3 s.u. for samples with NaI

In contrast to sandstone, the addition of NaI to the connate brine in carbonate samples did not result in increased spontaneous imbibition. This suggests that the wettability-altering effect of NaI is different in carbonate systems under the tested conditions. At this first step of the experiment, the wettability alteration was either absent or significantly weaker.

6.3. Forced Imbibition

The results of forced imbibitions are presented in figure 5.

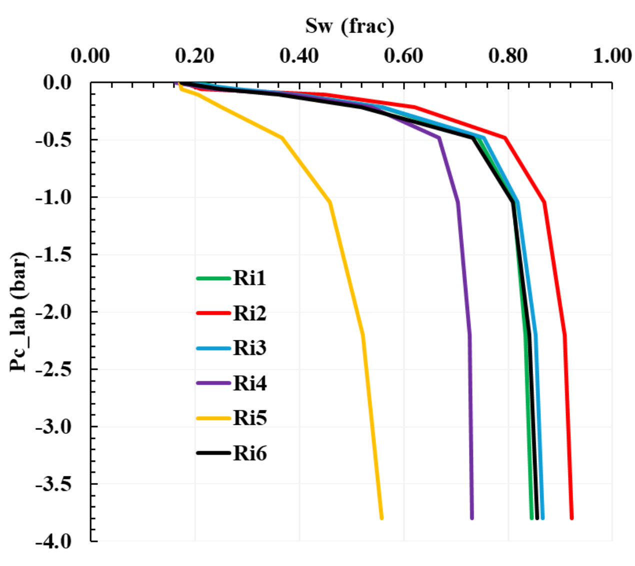

Fig. 5. Forced Pc curves obtained in centrifuge (Average saturation – inlet Pressure)

During this phase of the experiment, significant discrepancies between the samples were observed. First, Ri2, Ri3 and Ri6 have a Pc curve that overlap. Ri1 present a slightly lower residual oil saturation than the 3 precedent and the Pc curve is slightly shifted towards higher Sw values compared to other. Ri4 and Ri5 respectively the samples with 1g/L and 6g/L in the connate brine are showing highest Sor than the 4 other samples and a Pc curve on the left side of the graph. Figure 6 gives a better view of the Sor for each sample.

During the forced imbibition looking at the residual oil saturation helps to obtain insights of wettability. In imbibition (water phase injected in the sample), for the same sample at the same experimental condition, if the rock is water wet then the probability to obtain high residual oil saturation (due to oil trapping) is higher than in the oil wet case (less oil trapping – oil saturation decreases by reducing the oil films on the surface of the pores).

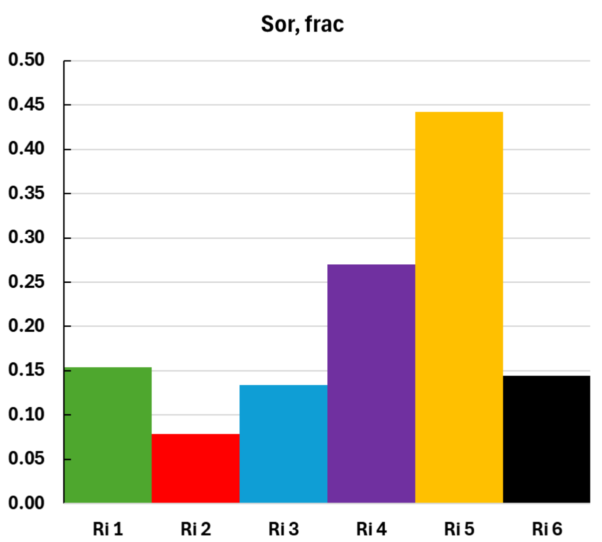

Fig. 6. Sor histograms

For the reference sample Ri1 in green Sor = 15 s.u. For Ri2 and Ri3 (in red and blue) Sor is in average at 11 s.u. The difference is statistically not significant compared to the reference sample.

While sample Ri4 and Ri5 have a far higher Sor (36 s.u. in average) than the reference sample, the Sample Ri6 with 12 g/L of added NaI in the connate brine does not show any difference with the reference sample. In the previous results obtained on sandstone, increasing NaI concentration seems to be linked with the increase of water-wetness (Higher water index Iw at higher NaI concentration). After multiple checks like water analysis at the end of experiment, the non-conforming behavior of sample Ri6 remains unexplained. Possible effects of sample variability or local mineralogical heterogeneity cannot be ruled out.

The two following figures provide complementary insight about wettability looking at other parameters like Recovery Factor (RF) in figure 7. Ultimate oil recovery is equally impacted by a wettability alteration and then, a more water wet sample will provide lower ultimate recovery (as Sor increases).

Figure 8 is about Amott Harvey Water index (to evaluate wettability). This index ranges from 0 (non water-wet) to 1 (water wet). Because this index is based on a ratio between spontaneous and forced imbibition, here the Iw is very low (near 0) for all the samples due to the low spontaneous imbibition observed. Then, even for rock sample Ri4 that is showing higher SoR (lower RF) than the reference sample, its Water wettability Index could appear "less water wet" than the reference sample. This suggests that this Iw index is not the most suited in this case to see any wettability differences between the samples of this experiment. On the other hand, it could be helpful in the following part in order to compare the results presented here on carbonates and previously on sandstone.

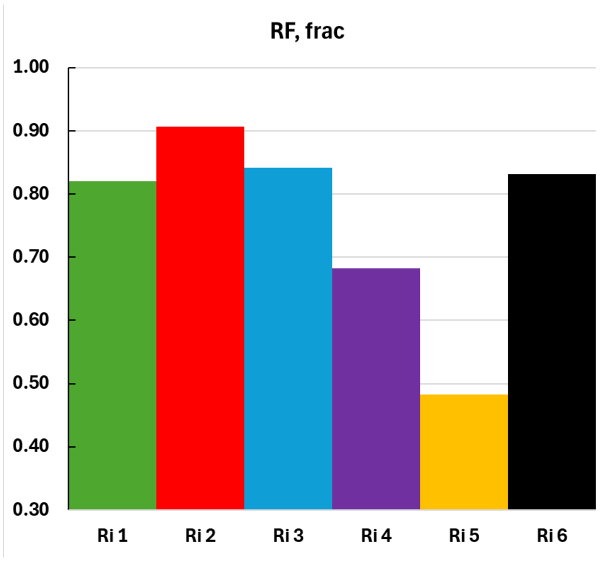

Fig. 7. Recovery factor histograms

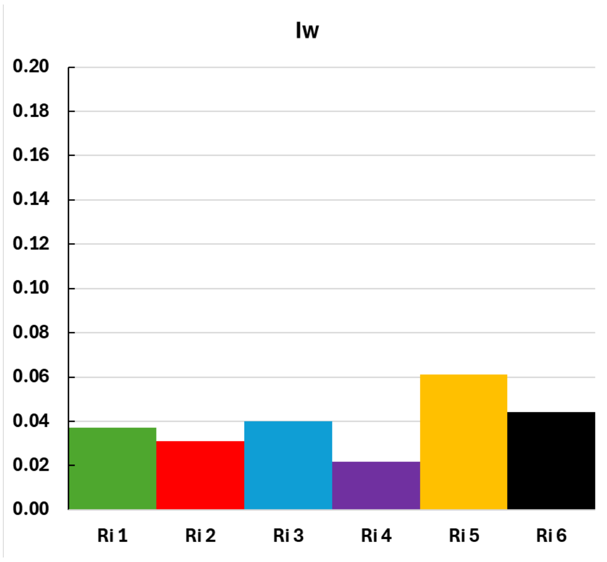

Fig. 8. Iw histograms (Iw full scale is between 0 and 1 but has been shortened here between 0 and 0.2)

7 Summary of results and comparison with sandstone

If the results about the concentration of NaI on wettability alteration is less pronounced than in [3], it is still possible to assess if adding NaI in the brine has an impact or not on the carbonate wettability and then in the SCAL result.

Figure 9 compares the Sor values grouped by brine type. From left to right: the Sor for the reference sample (without NaI in brine), the average Sor of the two samples with NaI in the Imbibing brine but not in the connate brine and the average Sor of the three samples with NaI added in the connate brine (different concentrations). In blue the results obtained and presented in this paper on carbonate and in brown the results presented in [3] and summarized previously on part 3 on sandstone rock.

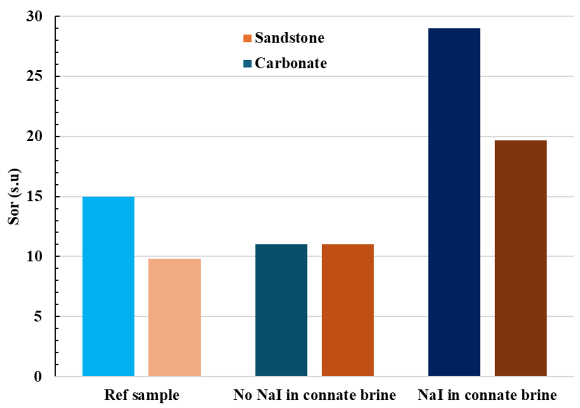

Fig. 9. Sor histogram for 3 group of samples and two types of rock

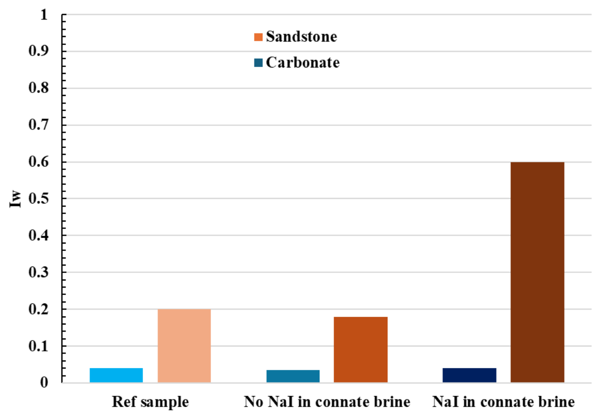

Fig. 10. Iw histogram for 3 group of samples and two types of rock

8 Conclusion

From figure 10 the main comparison is about the differences between sandstone and carbonate wettability responses to the same experimental conditions. Iw is lower for carbonate rock (average Iw ~0.04) than for the sandstone (average Iw ~0.3) in the 3 investigated cases. This carbonate rock (Richemont) is then "less water wet" than sandstone (Bentheimer). As described in the part 2 "Experimental context" this observation, even if interesting in this context, is near to impossible to generalize in another context or experimental setup. It's an added information to the common assumption that "usually carbonates are less water wet than sandstones". While the observed wettability changes in carbonates are less pronounced, the electrokinetic response to iodide exposure – as discussed in Halisch *et al.* (2024) [5] – suggests that EDL-related effects may still play a role, albeit weaker in carbonate systems due to mineralogical differences. Their study, based on systematic zeta potential measurements in sandstone samples, highlighted the sensitivity of mineral surfaces to iodide exposure in brines. The comparatively inert response observed here in Richemont carbonates could be attributed to mineralogical differences in surface charge behavior, as carbonates are known to exhibit lower EDL sensitivity. Thus, although Halisch *et al.* focused on sandstones, their findings offer a valuable mechanistic contrast for interpreting the limited effects seen in carbonate rocks.

For the investigation of the wettability alteration due to dopant, Sor has been a more relevant parameter to observe.

The presence of NaI in the imbibing brine but not in the connate brine seems not to affect (or at least very little) the water wettability of the two rocks (Sandstone and carbonate). Finally, the presence of NaI alone in the connate brine has proven to have a strong impact on the water wettability on the sandstone and here again in the carbonates by increasing the Sor (lowering the RF). During this test, one rock sample, Ri6 with 12g/L of NaI did not behave as we expected. With this amount of NaI sandstone has shown higher water wettability than sandstone with lower concentrations of NaI. Ri6 is not following this trend and have the same behavior than the reference sample.

This outlier should not discard the entire results of the experiments, on average 5 samples (3 sandstone – 2 carbonates) over 6 have shown clear signs of wettability alteration in presence of NaI in the connate brine. Considering the results obtained on the two phases of this dopant study a first global advice is to avoid using NaI in brine as a dopant when it is possible (precaution principle). If its utilization is necessary, then this study demonstrates that the impact of NaI should be negligible when it is introduced during the imbibition. In summary, results from both sandstone and carbonate tests converge to the same conclusion: using NaI in the connate brine would lead to major wettability effects and thus, introduce uncertainties in SCAL experiments.

The electrokinetic findings from Halisch *et al.* [5] demonstrated that the presence of iodide in brines significantly alters the zeta potential of sandstone surfaces. To date, these results provide the most comprehensive mechanism for wettability change due to iodide in brine. Although this effect was not directly tested on carbonate minerals, the weaker wettability response observed in Richemont samples may be attributed to the inherently lower surface charge sensitivity of carbonates.

Further work is still needed to investigate the effect of doping the oil phase or using other oil (with different properties).

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