A technique to fight against formation damage via turbulence control for saltwater disposal

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Abstract: Due to environmental concerns, operators are often required to dispose their produced saltwater into disposals, i.e., SWD wells. The key challenge is that the saltwater contains varieties of damaging species with compositions varying batch-wise. In addition, the compelled turbulence during pumping worsens the situation further. As the results of constant formation damage and lack of turbulence-taming measure, SWD wells frequently experience rapid pressure escalation during operation, which is a major hurdle holding back this industry. In this report, we walk through the identification of key issues facing SWD, followed by the proposal of a prospective solution. The solution consists of primarily a real-time well stimulation via turbulence control with a non-damaging friction reducer that works essentially in all common oilfield brines. The qualification and screening of this friction reducer, as a technique to fight against formation damage via turbulence control, is described, followed by the corroboration with field results.

Keywords: saltwater disposal; SWD; friction reducer; turbulence control; well stimulation; formation damage mitigation; SWD pressure taming.

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1 Introduction

Oil and gas are among the most indispensable energy sources and raw materials for contemporary society (Speight, 2011; Hsu and Robinson, 2017). According to Rapier (2018), the world reached a record annual oil production of 34 billion barrels in 2018. In the meantime, oilfield brine or saltwater is produced at a magnitude of 3~5 times of the volume of crude (Panorama, 2011). Therefore, rather than being an oil producer, E&P companies are more of saltwater generators, with annual saltwater production estimated to be 102~170 billion barrels. For illustration purpose, the overall volume of Dead Sea is merely 925 billion barrels (Water Authority of Israel, 2015). Therefore, the oil and gas industry may have to reuse, recycle or otherwise dispose equivalently one whole Dead Sea every 5~9 years without inflicting environmental consequences. This is obviously an appalling task that is troubling this industry, who is already in hotbed with environmentalists (Bakke et al., 2013).

Although in some cases, the produced saltwater can be reused, e.g., via mixing with freshwater for fracking, it eventually returns to the surface as flowback water, that has to be disposed (Kondash et al., 2018). Recycling efforts such as those involving distillation, are also made, but often at prohibitive costs (Pierce et al., 2010). Moreover, recycling typically is not 100%. Therefore, some disposal still has to be conducted. If one assumes a $1/bbl cost, the overall expense for recycling all the oilfield brine is $102~175 billion per year. If one takes the year 2018 as an example and assumes an oil price of $50 per bbl, the annual sales of the whole industry is approximately $1700 billion (Rapier, 2018). Thus, the recycling cost alone is to bite 6%~10% of the overall revenue.

Besides the efforts on reuse and recycle, the majority of saltwater is disposed, either back to the original reservoirs, or to saltwater disposal (SWD) wells that are specifically designed for this purpose. There are normally tailored programs and regulations in place to ensure the proper disposal for surface and groundwater protection. For example, the construction of disposal wells often requires "multiple layers of cement and steel to ensure that shallow, usable quality water is not impacted", according to Texas Railroad Commission (TRRC, https://www.rrc.state.tx.us/about-us/resourcecenter/faqs/oil-gas-faqs/). Currently, there are approximately 8,100 disposal wells in Texas (TRRC *injection and disposal wells*), and about 30,000 in the USA, according to FracTracker.org and the EPA.

The primary issue with SWD is that the compositions of these waters usually vary from batch to batch, with unpredictable and damaging salts, fines and residual chemical additives commingled or to be commingled downhole in the formation. Thus, scale-forming ions such as calcium and carbonate, although from differed batches, may eventually meet in the reservoir creating scales along the flow paths, impeding further water intake. Moreover, residual chemicals such as guar/xanthan gums and friction reducers are often damaging in nature (Kolb, 1971; Woodroof and Anderson, 1977). Although scale inhibitors (SIs) and surfactants are sometimes attempted to prevent potential scale deposition and to ease pumping, their ultimate performance is often hard to quantify. One only confirms the failure when the surface pumping pressure escalates, as a result of accumulated formation damage, along with untamed turbulence resistance. In this instance, although the pumping pressure on surface is high, the remaining pressure, before hitting the target zone downhole, is drastically reduced. Thus, the weakened jetting is inadequate to induce fresh flow channels, leaving damaging materials accumulated overtime until the well is inoperable due to safety concerns or government regulations.

In this report, we walk through the challenges associated with SWD, and the process of identifying a technique to fight against formation damage real-time via simultaneous turbulence curbing, instead of remediation. Two commercial friction reducers, namely, FR-B and FR-2 were chosen as examples for assessing their capabilities of coping with common oilfield species, which dictate their applicability for well stimulation with no trace left behind. It is demonstrated that the adoption of an all-brine applicable, non-damaging friction reducer creates a unique measure fighting against formation damage via turbulence control, the effect of which is corroborated by independent field trials.

2 Experimental

2.1 Materials

All the chemicals used herein are reagent grade until noticed otherwise. Ferric chloride ($FeCl_3$, 10%) was from BerTeck Chemical Laboratory Materials. A number of commercial friction reductions (FRs), although with little description, were assessed. It should be noted that it is a common practice in the industry to minimise disclosure on commercial products for IP protection. For illustration and comparison with simplicity, two distinctive FRs were chosen, with one being a common inverse emulsion (‘water-in-oil’) acrylamide-based FR, namely, FR-B, along with an FR that is a polymer hybrid colloidal dispersion that was labelled as FR-2, which leads to complete dissolution in water. Hybrid herein means a dispersion of colloidal particles, rendered from solvents, surfactants, and macromolecules that differ in charge and charge densities. No hydrophobic associative properties were reported regarding any of these friction reducers. A commercial SI, that is polyacrylic-based, was selected as well. The identity and source of these commercial products are intentionally omitted to avoid sensitivity. Both FR-B and FR-2 led to greater than 70% friction reduction according to laboratory friction flow loop assessment in freshwater and were used previously in the field for hydraulic fracturing. The freshwater has less than 0.05% dissolved salts with cations primarily of Ca^{2+}, Mg^{2+}, Na^{+} and K^{+} and anions primarily of bicarbonate (HCO_{3^-}), chloride (Cl^{-}) and sulphate (SO_4^{2-}). The comparative assessments are accounted separately with a detailed report on FR-2 retrievable from previous publications (Wu, 2019; Wu et al., 2017).

2.2 Water analysis by ICP-OES and IC

The analyses of cations in water samples were conducted by inductively coupled plasma optical emission spectroscopy (ICP-OES) on a PerkinElmer Optima 5300 DV, following US EPA Method 6010, targeting 39 elements, including all the major oilfield metal ions such as lithium, sodium, potassium, calcium, magnesium, barium, strontium, aluminium and iron. Ionic chromatography (IC) was used for the identification of anionic species.

2.3 Solid analysis by XRD

All solids samples were washed with heptane, xylene, isopropyl alcohol (IPA) to remove organics that might coat on the solids. The washed and dried solids samples were first pulverised to fine powder and then heated in a muffle furnace at 800°C for two hours, before they were characterised on a Rigaku Miniflex 600 X-ray diffractometer (XRD) with a monochromator. During XRD measurements, a focused X-ray beam interacts with the electrons within the crystalline structure of a mineral, recording the regular and diagnostic patterns. Characteristic diffraction peaks were used to identify the solids compositions.

2.4 Solids precipitation from saltwater

Two random saltwater samples from New Mexico and Texas, were taken and placed into two transparent bottles, respectively, before they were allowed to sit at room temperature for one week. The appearances of these two water samples before and after settling were recorded as photographs for comparison purposes.

2.5 Friction flow loop experiments

The basic principle for FR% determination is via measuring the fluid pressure drop within a fixed distance of the interior of a flow loop in the presence or absence of an FR, which is injected to the loop on-the-fly to mimic field scenario. The regular testing specs are: temperature = ambient, interior diameter (ID) = 0.394 in (10.0 mm), flow rate = 7.9 gal/min (30.0 L/min), and FR dosage = 1,000 ppm.

The FR% is then calculated through equation (1):

$$FR\% = \frac{\Delta P_0 - \Delta P}{\Delta P_0} \times 100 \tag{1}$$

where $FR\%$ is the percentage friction reduction, ΔP_0 is the differential pressure in the absence of an FR at a specific flow rate, and ΔP is the pressure drop at the same velocity after adding FR. The tests were conducted using 10% KCl, 10% $CaCl_2$ and 10% $FeCl_3$, respectively. These brine concentrations are arbitrary for comparison purpose only. In one set of experiments, both FR-2 and FR-B were hot-rolled in an oven pre-heated at 130°C (266°F) for 13 hours. Whilst FR-2 remains fluid with somewhat darkening, FR-B turned to be a brownish one-piece ‘goo’. Thus, only this aged FR-2 was assessed on friction flow loop for FR% at 1,000 ppm.

2.6 Spray bottle experiments

The purpose of this experimentation is to provide a quick and simple way to assess if a friction reducer of interest may mitigate the power loss during flow. This is especially meaningful to field engineers, who have limited access to sophisticated laboratory instruments, in view of the compositional variation of their incoming saltwater to be disposed. A sprayer or spray bottle (model: HDXTM; volume: 1 quart or 946 mL) is acquired from The Home Depot. The following protocol is adopted to illustrate the effectiveness of FR-2 on altering the spray of saltwater:

1 Remove nozzle from sprayer, fill with saltwater (800 mL), screw nozzle back on with proper tightening.

2 Pull trigger with two fingers to demonstrate misting; mind how weak the spray is.

3 Add FR-2 dropwise into sprayer (ultimate FR-2 concentration is ca. 1,000 ppm); once nozzle is properly tightened, shake sprayer vigorously for 20 times.

4 Pull trigger with the same two fingers to demonstrate trajectory shooting of stream; mind how strong hydraulic power/jetting is.

Videos and photographs were taken, before and after adding FR-2, for comparison. One sees that more orderly and powerful spray is the result, in the presence of FR-2, corroborating power loss mitigation. FR-B led to massive precipitates in the presence of saltwater and therefore was not further assessed with either spray bottle or coiled tubing.

2.7 Coiled tubing experiments

A coiled tubing, with a rotary nozzle at the tip, was used to allow water to run through at 2 bbl per min (0.32 m^3/min), with and without FR-2 (1,000 ppm). Videos were recorded and photographs were taken to compare the hydraulic sprays, in the presence and absence of FR-2.

2.8 FR compatibility and damage to porous space

The compatibility of FR-B and FR-2 in 10% NaCl, 5% $CaCl_2$ and 200 ppm $FeCl_3$ were examined. Each FR was added dropwise to corresponding salt solution in a transparent bottle, to render a suspension or solution of FR at 1,000 ppm. The agitation was continued for 3 min. to ensure homogeneous mixing. Photographs were taken to assess compatibility.

Synthetic quartz cores with a diameter of ca. 0.98 in (2.5 cm) and a length of ca. 3.15 in (8.0 cm) were utilised for core damage assessment. A typical core has a porosity of ca. 20% and a permeability ranging from 40 to 200 mD. The permeability before damage (K_1) and after damage (K_2) were measured by letting N_2 flow in the inlet of the core holder at a flow rate below the critical flow rate to assure the applicability of Darcy's law. The permeability (K) is calculated via equation (2) below. The details of this process can be accessed from previously published references (Wu et al., 2017; Wu, 2019).

$$K = 10^{-1} \frac{2Q\mu LP_0}{\left(P_1^2 - P_0^2\right)A} \tag{2}$$

where Q is N_2 flow rate in cm^3/s, μ is N_2 viscosity in mPa·s, L is core length in cm, P_1 is inlet pressure reading plus atmospheric pressure in MPa, P_0 is atmospheric pressure in MPa and A is core cross-section area in cm^2.

In one other set of experiments, two freshwater samples (250 mL each) were prepared with using FR-B and FR-2 to render an FR concentration of 1,000 ppm, respectively, before being poured into the bulb reservoirs of two parallel glass columns containing previously-packed (with using water for assistance) 200-mesh sands (200 g). The fluids were then allowed to flow out of the column with flow rate measured as drops/min and with a graduated cylinder. The flow rates were used to estimate the time for elution completion. The same procedure was repeated for water samples made of ferric chloride at 200 ppm in the presence of FR-B and FR-2, respectively.

In a third set of experiments, FR-2 and FR-B (1,000 ppm) in freshwater or in brine (130 mL) was poured onto filters with average pore size of 20 μm, respectively to assess relative damage, in comparison with the case of using freshwater alone.

2.9 Static scale deposition

Two model saltwater samples containing sodium/magnesium/calcium/strontium cations and chloride/bicarbonate/sulphate anions, respectively, were mixed as baseline, to assess scaling tendency. The same procedure was repeated in the presence of FR-2, and a commercial SI at 1,000 ppm, respectively, to assess the retardation on scale deposition. The detailed compositions of these two bulk solutions were listed in Table 1. For the cations, the concentrations were: Na^+ 28,748 ppm, Mg^{2+} 900 ppm, Ca^{2+} 20,000 ppm and Sr^{2+} 600 ppm. For the anions, the concentrations were: Cl^- 77,172 ppm, HCO_{3^-} 4,000 ppm and SO_4^{2-} 240 ppm. Both solutions have total dissolved solids (TDS) of 133,077 ppm. FR-B was not assessed in this case, as it formed cloudy suspension in both freshwater and brine.

The mixtures (1:1 v/v) of bulk solution A (cationic; BS-A) and bulk solution B (anionic; BS-B), and aliquots containing FR-2 and SI at 1,000 ppm (chemical dosed into bulk solution B before mixing), respectively, were aged at 120°F for various times, before photographs were taken. The same bulk solutions were utilised for dynamic scale loop experiments to elucidate the effects of FR-2 and SI on mitigating scale deposition, which is described below after this subsection.

Table 1 Composition of bulk solutions A and B

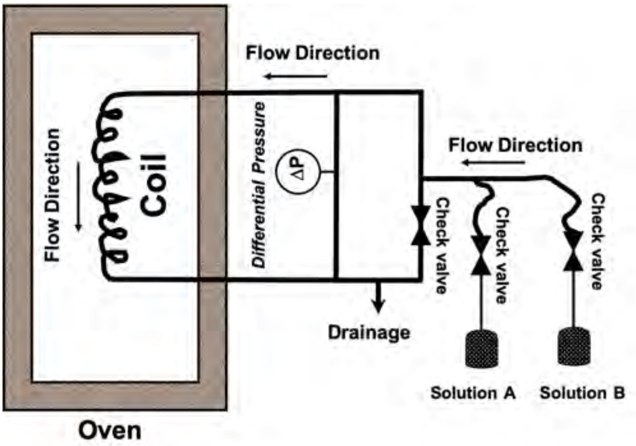
Salt	*BS-A (cationic)*	*BS-B (anionic)*
NaCl (g)	146.165	254.430
$MgCl_2$ (g)	7.051	-
$CaCl_2$ (g)	110.767	-
$SrCl_2$ (g)	2.171	-
$NaHCO_3$ (g)	-	11.014
Na_2SO_4 (g)	-	0.710
Total (g)	266.154	266.154
[C] (mg/L)	133,077	133,077

Note: 2 L of each, BS: bulk solution.

2.10 Dynamic scale deposition

Two bulk solutions A and B (BS-A and BS-B) containing sodium/magnesium/calcium/strontium and chloride/bicarbonate/sulphate (ref. Table 1), respectively, were prepared before they were allowed to run at 5 mL/min into a common tubing for mixing. The pH of the bulk solutions was ca. 7.0. The differential pressure of a certain distance was then followed to monitor the pressure evolution that is regarded as the indication of the process of scale deposition under flow conditions. The schematic of this experimentation is illustrated in Figure 1.

Figure 1 Schematic of dynamic scale loop experimentation



Note: Two bulk solutions (A and B) containing sodium/magnesium/calcium/strontium cations and chloride/bicarbonate/sulphate anions were mixed on-the-fly to elucidate the effect of additives on dynamic scale deposition.

In one parallel experiment, FR-2, was dosed in the bulk solution B, which contains chloride/bicarbonate/sulphate, before it was allowed to mix with the bulk solution A containing sodium/magnesium/calcium/strontium brine. The ultimate FR-2 concentration was 1,000 ppm. As was described previously, the differential pressure was followed along the same distance to monitor the scale build-up. The monitoring was automatically shut down once the differential pressures hit 20 psi.

In one third set of experiments, SI, was dosed in the bulk solution B, before it was allowed to mix with the bulk solution A, to render an ultimate SI concentration of 50 ppm and 25 ppm, respectively. As was described previously, the differential pressure was followed to monitor the scale build-up, before it shut down at 20 psi.

3 Results and discussion

In this section, we delineate the water, rock and regulation natures that compel the challenges facing the SWD industry. A prospective solution is proposed, followed by the screening and qualification of a friction reducer to realise the solution, which is substantiated by field applications. The solution consists of creating a measure to fight against formation damage real-time via simultaneous turbulence curbing, instead of remediation. The key threshold here is to identify an all-brine applicable friction reducer that is non-damaging to the reservoir.

3.1 Water, rock and regulation natures pertaining SWD

Basically, the SWD industry copes with injecting varieties of oilfield brines into porous geological formation, the process of which is normally under government regulations. Therefore, grasping the natures of the waters, rocks (or formation solids) and regulations are the most critical first step. As shown in Table 2, four water samples were analysed with ICP-OES and IC to illustrate the presence of various cations and anions. These cationic and anionic species may co-mingle once they are pumped downhole into porous reservoir. Moreover, the disposed waters may contain other flow-restricting species such as crude oil, guar/xanthan and FR residues, which further complicate the situation.

Table 2 Ions in various saltwater samples

Ion (ppm)	*SP#1*	*SP#2*	*SP#3*	*SP#4*
Na^+	60,423	371	2,520	574
K^+	1,497	12	60	15
Ca^{2+}	16,558	358	775	412
Mg^{2+}	2,137	159	180	111
Ba^{2+}	2.8	0.02	0.12	0.06
Sr^{2+}	791	16	22	8
Al^{3+}	0.5	0.01	0.10	0.02
Fe^{3+}	33	0.4	71	3.3
Cl^-	130,278	564	4,980	857
SO_4^{2-}	308	2.1	4.6	1.5

Note: SP: sample.

Next, we turn our attention to the prospective minerals in oilfield formations. These minerals may be intrinsic or post-generated during previous operations. As can be seen from Table 3, formation solids may contain varieties of metal ions such as zinc, barium and iron, which gradually release into formation fluids over time. Thus, it is not surprising that the formation waters themselves contain trouble-making ions that need to be considered before implementing any treatment program.

Table 3 Composition of various formation solids

	SP#1	*SP#2*	*SP#3*	*SP#4*
Mineral	CuCl and ZnS	NaCl	FeO	$BaSO_4$
[C]	50% and 19%	37%	6%	88%

Note: SP: sample.

Regulation wise, government agencies typically impose pressure ceiling on pumping. For example, in New Mexico, an SWD well is not allowed to operate when pumping pressure exceeds 2,400 psi (or 16.55 MPa). In the meantime, complaints were frequently filed by citizens within the SWD vicinity regarding ‘earthquake’ that was presumably arising from the vibration when pumping against high turbulence resistance and accumulated formation damage (Kolb, 1971; Woodroof and Anderson, 1977; Seismological Society of America, 2019). Thus, a keen need exists to address the pressure escalation issue that is associated with SWD.

3.2 Formation damage/turbulence interplay and a prospective solution

As was discussed above, the presence of solids and other damaging substances such as guar and crude are to hinder disposal. As was illustrated from Figure 2, solids were coming out of the saltwater when allowed to sit at room temperature for merely one week. These solids may be either in the form of fines or newly formed scales. The quantity of these solids is expected to be massive once a well is operated for extended period of time. Thus, these solids are surely to accumulate along the pathways of SWD with the ultimate consequence being pumping pressure escalation and minimised water intaking capacity. On top of accumulated formation damage, disposal compels turbulence, attributing further to the pumping pressure build-up. The calculations below demonstrate the presence of substantial turbulence during SWD.

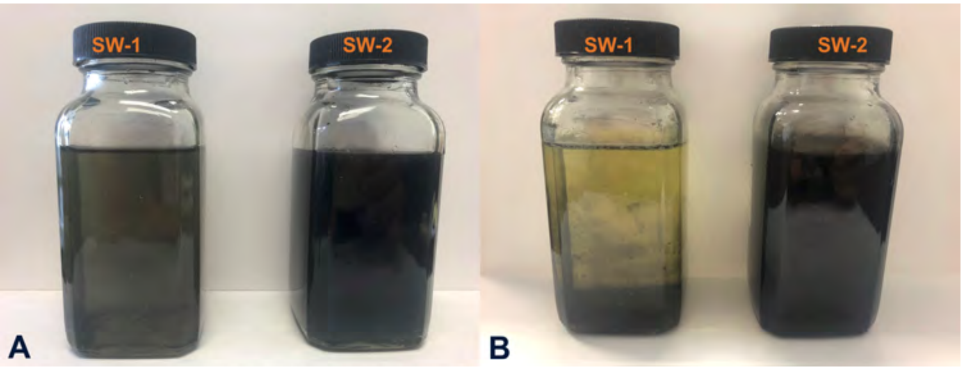
Reynolds number (*Re#*), a parameter representing the extent of turbulence of a fluid in a tubular, can be calculated, according to equation (3):

$$Re\# = \frac{4Q}{\pi D v} \tag{3}$$

where Q is the volumetric flow rate in m^3/s, D (in metre) is the ID of the tubular and v is the kinematic viscosity (in m^2/s) of the fluid being pumped.

If one takes the kinematic viscosity of freshwater as that for saltwater, at ambient temperature, the value is 1.0 mm^2/s (10^{-6} m^2/s). For a 4.65 in (0.118 m) pipe at 88 bbl/min (14.0 m^3/min or 0.233 m^3/s), the *Re#* is calculated to be 2,514,108. When the pipe ID goes down to 2.325 in (0.059 m) and pumping at 2.0 bbl/min (0.0053 m^3/s), the *Re#* is 114,376, which is substantially above the critical *Re#* of 2,900 for turbulence flow (Schlichting and Gersten, 2017; Holman, 2002). Therefore, SWD wells experience extensive turbulence resistance when pumping, even at a rate as low as 2.0 bbl/min (0.32 m^3/min). The unfortunate scenario is that although high hydraulic power is applied at the wellhead, it undergoes substantial energy loss once hitting downhole, leaving weak stream that is inadequate to break the formation, allowing damaging materials to build-up, contributing further to the pumping pressure escalation.

Figure 2 The appearance of saltwater (SW-1 and SW-2) before and after sitting at room temperature for one week (see online version for colours)



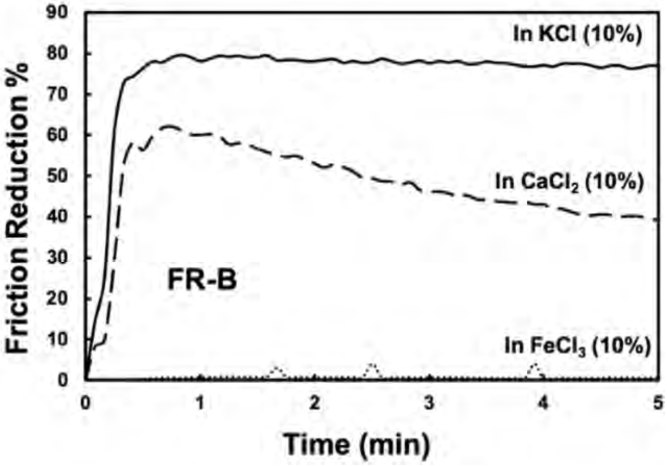
Note: SW-1: a random sample from Texas and SW-2: a random sample from New Mexico

However, the formation damage/turbulence interplay can be turned around, if turbulence resistance is suppressed to such an extent that the net hydraulic power downhole is preserved to exceed the rock-breaking point. What is needed is a 'broad-spectrum' non-damaging friction reducer that is able to cope with common oilfield species. Thus, it creates a measure fighting against turbulence, the sequential result of which is to stimulate the well while leaving no trace behind, which is in turn enabled by the non-damaging nature of this FR, to assure and sustain the enhanced conductivity/injectivity arising from well stimulation. The sections below elucidate the identification, qualification and field trials of such a friction reducer. It should be noted that this article is not meant to be all inclusive or exhaustive, but rather to provide a direction for readers to trial under the same protocol with details tailored to their specific needs.

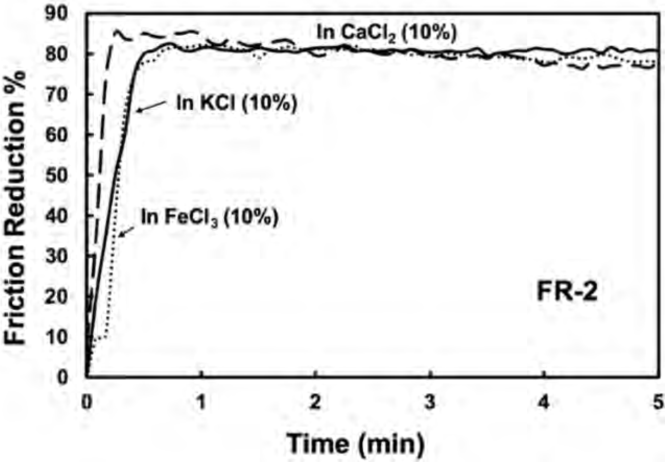
3.3 *Screening and qualification of FR for SWD*

Hundreds of various friction reducers (with some being perhaps identical although under different names) were assessed in terms of their FR% performance in various brines. Since the specific performance of any particular FR is not within the scope of this report, merely two distinctive samples were chosen for illustration purpose with simplicity. Readers are encouraged to follow the same procedure/experimentation to identify FR candidates for their needs. As can be seen from Figure 3(a), regular FR (FR-B) shows performance dependency on brines. With the increase of brine valency, FR-B loses its performance when the brine evolves from monovalent KCl, to divalent $CaCl_2$ and then to trivalent $FeCl_3$, all at 10% concentration. In contrast, FR-2 leads to performances that are independent of brines [Figure 3(b)]. In one set of experiments, the effects of temperature on both FR-2 and FR-B were assessed. After heating at 130°C for eight hours, FR-2 remained fluidic with somewhat darkening. However, the FR% remained essentially unchanged. In contrast, FR-B turned to be a one-piece brownish 'goo'. As such, FR-B was not evaluated further.

Figure 3 FR% performance of a regular FR (a) FR-B and (b) FR-2 in the presence of various brines



(a)

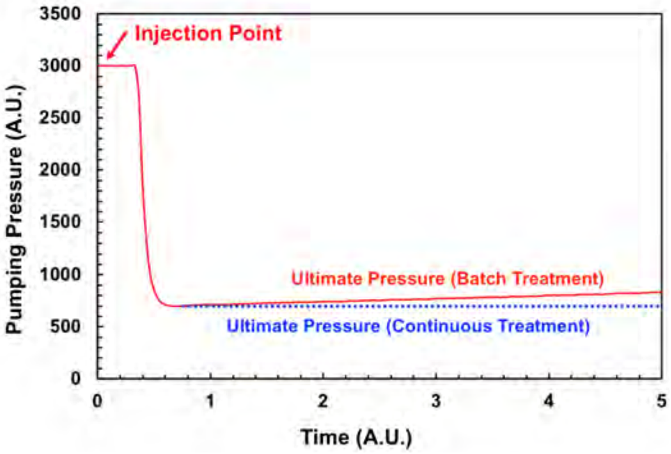


(b)

Note: Solid line: 10% KCl, dashed line: 10% $CaCl_2$, dotted line: 10% $FeCl_3$ and FR dosage: 1,000 ppm.

Figure 4 is a transformation by converting the FR% data in Figure 3 to pumping pressure. One sees that FR-2 can be rapid at reducing pressure, when the well is operated at constant pumping rate. It should be noted that the pumping pressure taming is certainly a function of well depth, nature of rock, degree of formation damage, etc. Thus, the actual pumping pressure curve is to vary.

Figure 4 Presumable pressure taming while pumping, with using FR-2 at 1,000 ppm (see online version for colours)



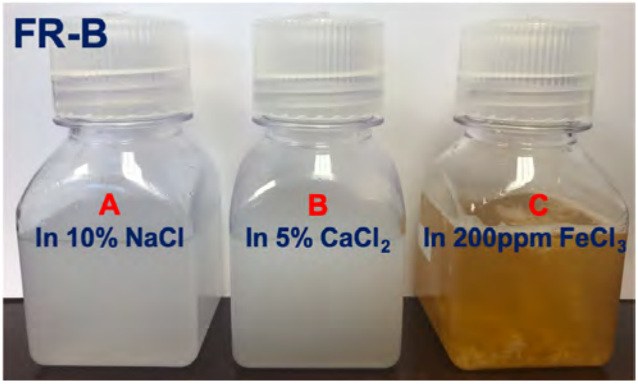
Notes: The data (red line; representing batch treatment) was converted from those in Figure 3(b). The blue dotted line is presumptively representing a continuous treatment. AU stands for arbitrary unit.

Figure 5 Water spray by spray bottle in the absence and in the presence of FR-2 at 1,000 ppm; (a) in the absence of FR-2 (b) in the presence of FR-2 (see online version for colours)

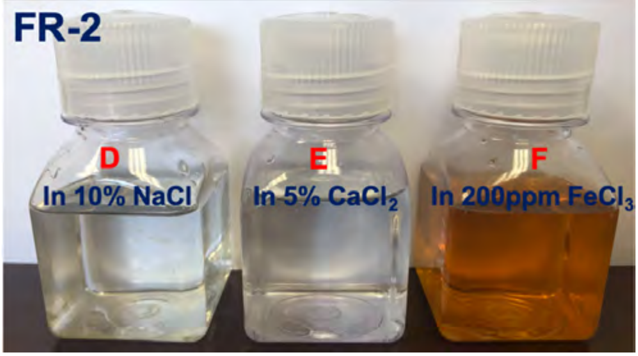
Figures 5 and 6 show how the presence of FR-2 at merely 1,000 ppm or 0.1 v% suppresses the randomness of the spray, from both a spray bottle and coiled tubing tests. From a spray bottle, the otherwise random and wide spray was tamed to such an extent that the saltwater spray became almost one straight line. When used in coiled tubing, it was observed, that the presence of FR-2 led to much stronger jet with clear-cut edges without fogging. Moreover, there was no foamy water accumulation on the ground. In contrast, under identical conditions, when FR-2 was absent, the jetting was obviously much weaker with curvy edges along with heavy fogging. Moreover, massive amount of foamy water accumulated on the ground.

Figure 6 Water spray through coiled tubing with a rotary nozzle, (a) water only (b) water with FR-2 at 1,000 ppm (see online version for colours)

Figure 7 Appearances of (a) FR-B and (b) FR-2 in various brines (see online version for colours)



(a)



(b)

Note: A/D: 10% NaCl, B/E: 5% $CaCl_2$, C/F: 200 ppm $FeCl_3$ and FR dosage: 1,000 ppm.

It is important that the friction reducer chosen for SWD be non-damaging. As can be seen from Figure 7, FR-2 is compatible with NaCl, $CaCl_2$ and $FeCl_3$ [Figure 7(b)], that are meant to represent monovalent, divalent and trivalent metal ions, respectively. In contrast, FR-B leads to cloudiness even massive precipitates in the same brines [Figure 7(a)].

Other than broad spectrum performance in various brines to overcome the uncertainty of saltwater, it is more crucial that the candidate FR be non-damaging. Three tests are conducted to assess the non-damaging nature of FR-2, namely core flood experiments, elution through sands pack and filtration through filter paper. From core experiments, it was shown that the regained perm was nearly 100% when using FR-2. In contrast, the case by FR-B was less than 1.0%. Moreover, the tests on sands pack and filter papers show that the use of FR-2 basically did not inflict any additional damage to the porous space other than that intrinsic from the saltwater. In contrast, the same process was slowed down due to the presence of FR-B, by up to 20,000 folds.

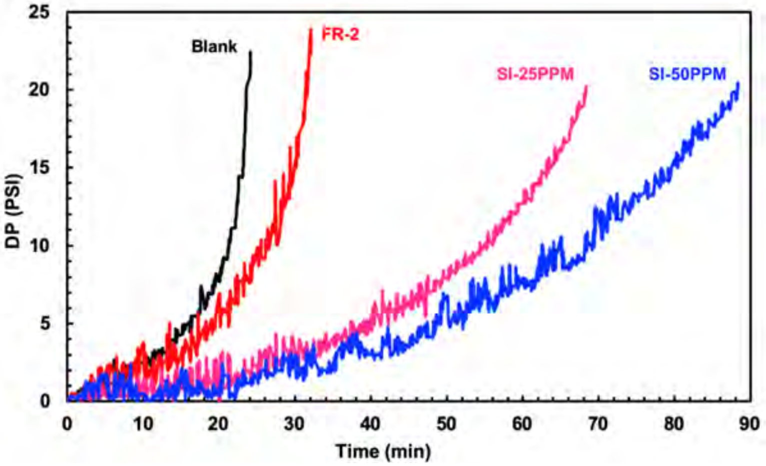
It should be noted that although SI slows down the scale deposition, it is a kinetic process rather than a thermodynamic phenomenon. As can be seen from Figure 8(c), scales eventually came out of the solution, i.e., when time is long enough, the SI loses its effectiveness entirely. It should be noted that during disposal, the saltwater never flows back out of the SWD well. Therefore, the time for scale deposition, although in the presence of SI, is essentially infinite. Thus, it is fair to conclude that the SI would not be able to mitigate formation damage within a SWD reservoir in the long run.

Figure 8 Scales formed when two water samples mixed together (bulk solution A and bulk solution B; SI or FR-2 was mixed with bulk solution B first before mixing with A), the mixtures were heated at 120°F (49°C) for different periods of time, (a) 0 min, (b) 20 min and (c) 20 hours (see online version for colours)

One interesting observation is that the use of FR-2 led to retarded scale deposition as well, statically. As can be seen from Figure 8(b), there was only small amounts of solids dropping out of the solution when aged at 120°F (49°C) for 20 min, with some solids appear to be suspended in the fluid.

It should be noted that SWD is a dynamic process. Thus, it is meaningful to manifest how SI and FR-2 retards scale deposition dynamically. An interesting observation was that FR-2 retards scale deposition to some degree, although not as effective as that by SI (Figure 9). However, its effect is expected to be amplified due to better dispersion, as a result of flow easing and solids pulverisation arising from sustained hydraulic power. From the previous discussions, one learns that the turbulence control through FR-2 is to enhance the otherwise lost hydraulic power downhole, before saltwater is gushing into reservoir. Thus, the pulverisation of scale, before it is getting tightly deposited onto the porous space within a reservoir, is a sequential event and benefit, as a result of turbulence control. On the other hand, with saltwater penetrating into formation farther, this preserved hydraulic power and pulverisation effect may still ultimately die down, which nonetheless should not eradiate the aforementioned positive contributions that otherwise do not exist. It should be noted that 'pulverisation' herein is a somewhat equivalent term to either stimulation or fracking, although it refers to situations where scales are crushed into finer and more suspend-able particles, due to substantially sustained hydraulic power. Illustratively, when the surface pumping pressure is 2,000 psi (13.8 MPa) and it is without turbulence control, the downhole pressure is 400 psi or 2.8 MPa (pressure loss of 1,600 psi or 11.0 MPa) and the rock-breaking point is 1,200 psi or 8.3 MPa, this low downhole pressure is perhaps not adequate for either scale pulverisation or matrix stimulation. However, when 80% power or pressure loss is prevented, as a result of using FR-2, the bottom hole pressure may be as high as 1,680 psi or 11.6 MPa (pressure loss of 320 psi/2.2 MPa instead of 1,600 psi/11.0 MPa, from the surface pumping pressure of 2,000 psi/13.8 MPa), which exceeds the fracture pressure of 1,200 psi/8.3 MPa. Thus, the jetting after turbulence control would be adequate to pulverise, stimulate or create fractures so that reservoir remains conductive. If FR-2 is applied continuously, the anti-agglomeration, pulverisation and stimulation effects are to be maintained, with enhanced reservoir conductivity, allowing continued saltwater intakes.

Figure 9 Inhibition of scale deposition by the presence of FR-2 (1,000 ppm) and SI at 25 ppm and 50 ppm (see online version for colours)



Note: Black line: blank, red line: in the presence of FR-2 at 1,000 ppm, pink line: in the presence of SI at 25 ppm and blue line: in the presence of SI at 50 ppm.

Based on the discussion in the previous sections, FR-2 is believed to be a best candidate to tame pressure loss, i.e., turbulence so as to preserve hydraulic power for well stimulation. Three field trials were conducted for corroboration. One was a small batch treatment in Lea County, New Mexico (Case 1), whereas the other was a larger continuous treatment out in Archer County, Texas (Case 2). Case 3 was in Williston, North Dakota. In all the cases, FR-2 was dosed at ca. 1,000 ppm, and was introduced 'on-the-fly'into saltwater stream.

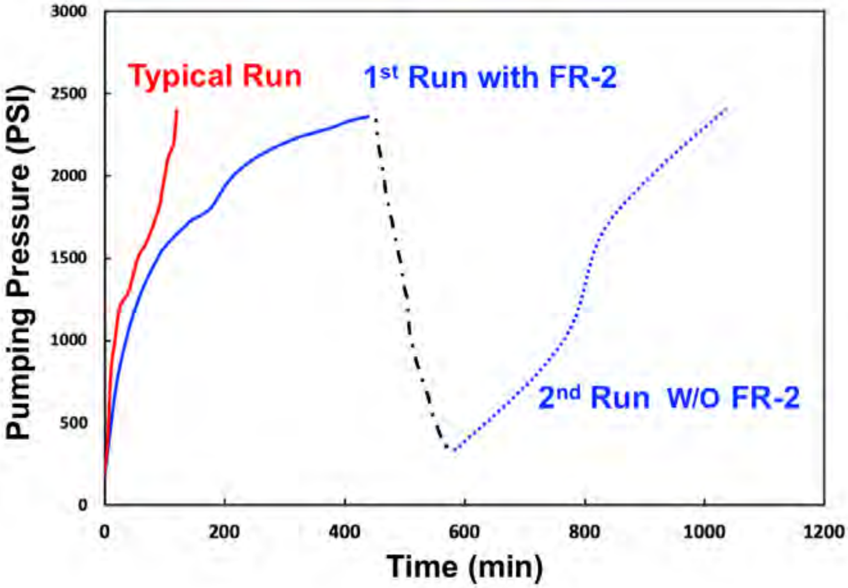
For Case 1, the problems were:

1. when started pumping saltwater, pressure increased quickly (e.g., 2 h) to trigger automatic shutdown at 2,400 psi (16.5 MPa)
2. the well had to remain shut down for days before re-taking water.

The injection rate was ca. 2.0 BWPM (0.32 m^3/min, BWPM: bbl water per min) against a 10,000 ft. long tubing with an OD of 3.5 in and an ID of 2.992 in. The success for Case 1 was observed from the following:

1. When FR-2 (35 gallons or 132.5 L) was metered, the overall pumping time was elongated four times before automatic shutdown.
2. Before FR-2 was metered, the pressure ramped up at 7 psi/min (48 KPa/min); with the addition of FR-2, it eventually dropped to 0.4 psi/min (2.8 KPa/min).
3. The well pumped ca. 900 bbl (144 m^3) the first run, whereas it triggered water retaking the same night and sucked additional 1,200 bbl (192 m^3), which was even more than the quantity of the first run, confirming the well was effectively stimulated.

Figure 10 Pumping pressure escalation with and without injecting FR-2 (Case 1 in Lea County, NM) (see online version for colours)



Note: Red line: typical run without FR-2, blue solid line: 1st run with using FR-2 at 1,000 ppm; black dash-dot line: pressure dropping after automatic shutdown and blue dotted line: 2nd run on the same day without adding FR-2.

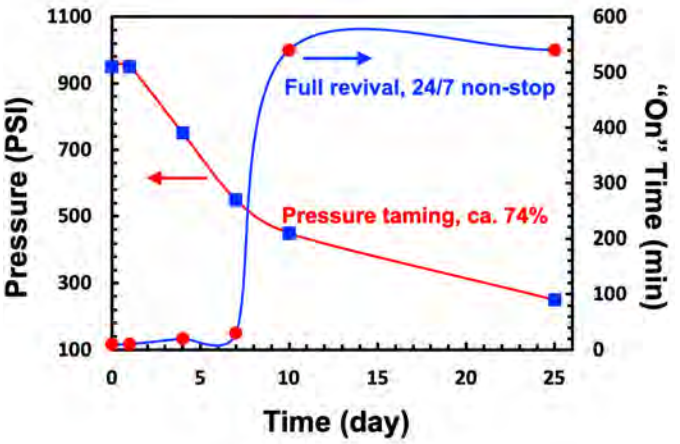
Figure 10 shows the pressure escalation during a typical run without FR-2 and those during the first run with using FR-2 at 1,000 ppm and the following (2nd) run without additional FR-2.

For Case 2, the problem was that when started pumping saltwater, pressure increased quickly (e.g., 5–10 min) to trigger automatic shutdown at 900 psi (6.2 MPa), although it could reach a 'plateau' pressure of ca. 950 psi. However, this pressure exceeded the arbitrary limit, which was set due to safety concerns. The rate was ca. 0.5 BWPM (0.08 m^3/min, BWPM: bbl water per min) and the injection was against a total tubulars length of ca. 11,000 ft. including 4,000 ft. 2 in pipeline, preceding a 4 in casing of 7,000 ft. The success for Case 2 (Figure 11) was observed from the following:

1. Over the span of three weeks, the 'plateau' injection pressure was curbed from ca. 950 psi to be ca. 250 psi, which was ca. 74% pressure taming.
2. The 'on' cycle (pump running) time was increased from 5–10 min at the beginning to 24/7 non-stop.

This was a full revival of the SWD well, with an 'infinite' fold of improvement, from 'on' time perspective. The well had to be manually shut down due to saltwater depletion in the nearby tank. This was why the 'on' time (*y* axis on the right in Figure 11) reached a peak of 540 min, which was the actual pump running time before manual shutdown. The pressure data in Figure 11 appears to be in agreement with those in Figure 4, in terms of both pattern and ultimate degree of pressure taming (74% vs. 80%).

Figure 11 'On' cycle time improvement and injection pressure taming vs. time in the presence of FR-2 (Case 2 in Archer County, TX) (see online version for colours)



Note: Blue line: 'on' time starting from 5–10 min until 24/7 non-stop (well manually shut down after ca. 9 hours, due to saltwater depletion from nearby tank) and red line: injection pressure dropping from ca. 950 psi down to ca. 250 psi.

For Case 3 in North Dakota, where produced saltwater was known for its high TDS of over 33%, the casing OD was 4.5 in, whereas the well depth was 5,400 ft. The injection was against a constant pressure of 1,500 psi, with variable rates. An injection rate enhancement of over 25% (from 6,800 to over 8,500 BWPD) was observed in less than 20 min after FR-2 was introduced, with the upward trend continued. This elevated injectivity means added revenue and enhanced assets value, which are in turn dictated by a well's saltwater intaking capacity.

4 Conclusions

Due to the presence of the varieties of salts, fines and residual chemical additives with compositions vary from batch to batch, formation damage and turbulence are major factors contributing to pressure escalation during oilfield SWD. To turn around the interplay of turbulence and formation damage, a technique was identified utilising a friction reducer's broad-spectrum compatibility with brines, its capability of taming turbulence and fluidity in saltwater. A pair of model friction reducers, namely FR-B and FR-2, were assessed in terms of their broad-spectrum compatibility in monovalent KCl, divalent $CaCl_2$ and trivalent $FeCl_3$ brines. The FR% performance in the same brines was also evaluated to manifest each friction reducer's feasibility with regard to turbulence control. With the increase of brine valency, FR-B loses its performance when the brine evolves from monovalent KCl, to divalent $CaCl_2$ and then to trivalent $FeCl_3$. In contrast, FR-2 leads to performances that are independent of brines, which was further substantiated by its suppression of the randomness of the fluid flow through spray bottle and coiled tubing tests. In addition to the broad-spectrum performance in various brines to overcome the uncertainty of saltwater, core flood, sands pack and thin layer filtration experiments, were conducted. In comparison with FR-B, FR-2 was shown to be non-damaging, which enabled a quicker flow by up to 20,000 folds. Three field trials were conducted, corroborating that FR-2 was effective at taming formation damage, turbulence and thus pressure escalation. Based on the lab and field results, the use of the all-brine non-damaging friction reducer is a unique approach fighting against formation damage real-time instead of remediation. Therefore, it is expected to fundamentally alter the landscape of the SWD industry.

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