

Calcium Sulfate Risk Assessment throughout the Injection and Production System

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Abstract /

The formation of calcium sulfate (CaSO_4) mineral scale is a persistent flow assurance problem in the oil and gas industry. To establish an effective mitigation strategy, it is essential to understand the scaling potential and severity at different production units. In this work, the CaSO_4 scaling risk is assessed for the entire production system, all along the seawater injection unit, production well, surface flow line, separator, and disposal well.

The results show that the CaSO_4 could deposit at the seawater injection well and restrict the seawater injectability. The formation of CaSO_4 deposits could partially block the super-K zone and delay seawater breakthrough into the production well. When seawater breakthrough occurs, the formation of CaSO_4 in the near wellbore area of the production wells could cause severe blockage, depending on the mixing ratio of formation water and seawater, reservoir temperature, etc.

At the surface facilities, such as long flow lines and separators, CaSO_4 can also form, especially when introducing incompatible produced waters from different formations/reservoirs. After the separator, the mixed produced water could be finally injected in the water disposal wells to reduce the negative effect on the environment. CaSO_4 could deposit in the near wellbore region of disposal wells due to the higher temperature at downhole of the disposal wells, and significantly reduce the injectivity.

Introduction

Scale formation is one of the flow assurance problems encountered in the oil and gas industry. It can deposit from reservoir, downhole tubing, to topside facilities. Once formed, it could have a significant impact on production, including tubing and valve blockage, interference of well intervention, and even well abundance^{1,2}.

Calcium sulfate (CaSO_4) is one of the common scales formed in the oil fields. CaSO_4 scale is usually formed due to mixing of incompatible waters, i.e., waters containing high calcium, such as calcium-rich formation water in carbonate reservoirs, and high sulfate waters, such as seawater or sulfate rich produced water from reservoirs flooded with seawater. It could also form when the saturation of scaling water increases to a certain level due to the change of operation conditions, especially for the increase of temperature. CaSO_4 can form in the reservoir³, near wellbore area⁴, production tubulars, topside facilities, and produced water re-injection wells^{5,6}.

CaSO_4 scale can be in three forms: gypsum ($\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$), anhydrite (CaSO_4), and hemi-hydrate ($\text{CaSO}_4 \cdot 0.5\text{H}_2\text{O}$). CaSO_4 dihydrate (gypsum, $\text{CaSO}_4 \cdot 2\text{H}_2\text{O}$) is commonly precipitated at low temperature less than 100 °C and CaSO_4 (anhydrite, CaSO_4) often precipitates at elevated temperatures above 100 °C in the oil fields⁷.

Figure 1 shows the XRD diffractogram of a scale sample deposited in the oil field at surface facilities at 70 °C. Gypsum is the most common scale observed in the oil field, especially at a temperature < 100 °C.

Figure 2 shows the solubility of common scales as a function of temperature. With an increase of the temperature, the solubility of CaSO_4 decreases, which indicates that the CaSO_4 is more favorable to deposit at a higher temperature. A higher temperature also accelerates the scaling kinetics.

To establish an effective mitigation strategy, it is essential to understand the scaling potential and severity at different production units. In this work, the CaSO_4 scaling risk is assessed for the entire production system, all along the seawater injection unit, production well, surface flow line, separator, and disposal well.

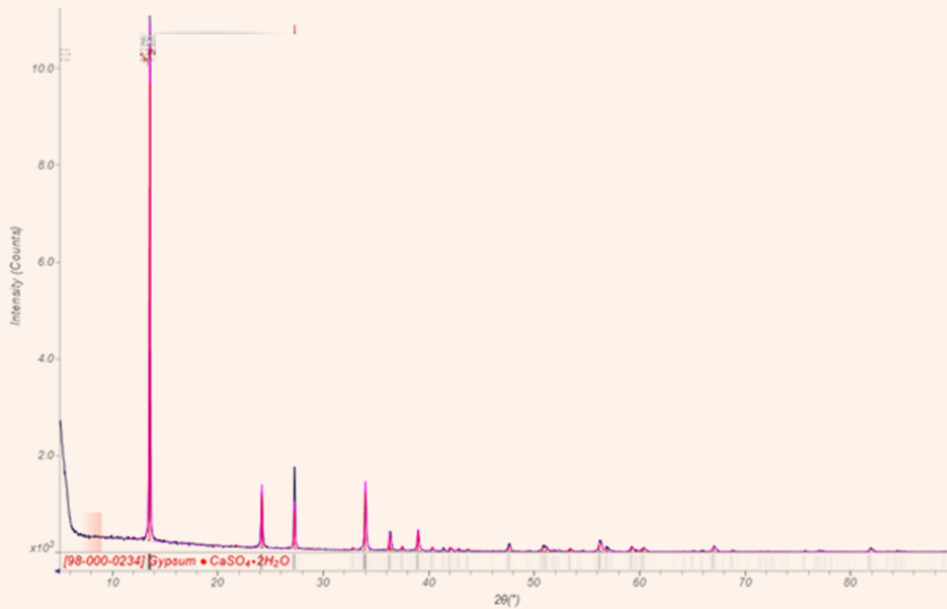
Experimental Methodologies

CaSO_4 Scale Risk Assessment

Thermodynamic prediction is carried out to assess the risk of scale formation. It provides both scaling tendency (saturation ratio) and the mass of deposition. The prediction is performed using one of the well-recognized industry standards, the ScaleSoftPitzer program, Version 2021. It should be noted that scale predictions can only be used to provide a guide to the likely nature and extent of the scaling challenge, and to investigate the impact of a process change on the likely severity of scaling.

The formula for the SR is given in Eqn. 1:

Fig. 1 The XRD diffractogram of CaSO_4 scale (gypsum) formed in an oil field at a temperature $< 100^\circ\text{C}$.



$$SR = (a_1 \times a_2) / K_{(P,T)}$$

1

where $a = \gamma \times C$. SR is the saturation ratio, and a is the activity of the scaling ions. a_1 and a_2 are the activity of scaling cation and anion in the solution, respectively. K is the solubility product, which depends on the pressure (P) and the temperature (T)⁸. C is the concentration of scaling ions in the solution, and γ is the ionic activity coefficient.

Scale can occur at any point where supersaturation is generated. A supersaturated solution is the primary cause of scale formation and the concentration of ions are above their equilibrium concentration. The degree of saturation, in terms of scaling SR, is the driving force for the precipitation reaction and implies the tendency for scale precipitation. It is applied to compare the scaling tendency and severity of scaling of scaling waters. Guideline values for the interpretation of SR values are provided in Table 1. It is the case that different programs may interpret the level of risks slightly differently.

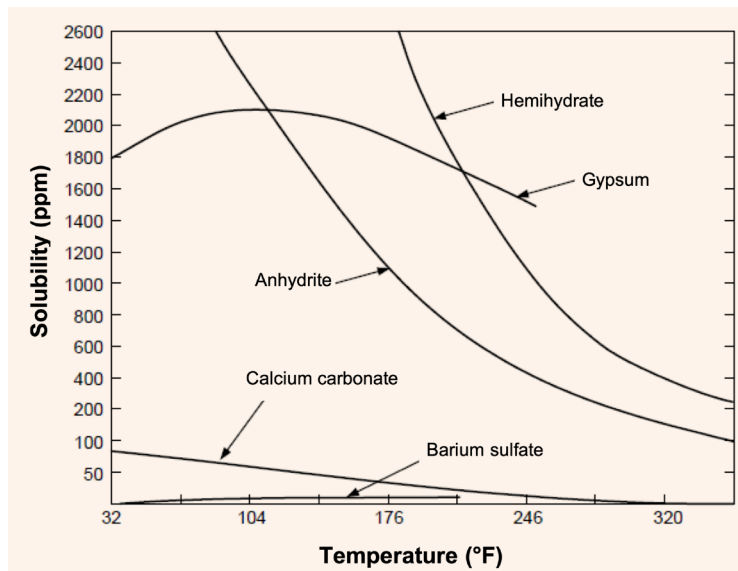
The mass deposition can also be predicted by the ScaleSoftPitzer program. It calculates the potential scale mass deposition from the initial supersaturated solution to the point where the final SR reaches 1, and the equilibrium status under the prediction conditions, given ideal conditions and infinite time.

Results and Discussion

Risk Assessment from Seawater Injection Well to Production Well

Table 2 list the water chemistries applied in this study. The assumed formation water is tuned with a SR of CaSO_4 (anhydrite) of 1 under a temperature of 105°C and pressure

Fig. 2 The solubility of common scales as a function of temperature⁷.



of 5,000 psi, which represents a calcium-rich water. The assumed seawater is a typical seawater chemistry in an oil field, representing the sulfate-rich water in this study.

CaSO_4 scale risk is assessed when formation water and seawater mix at 105°C (reservoir temperature). Figure 3 shows the results for anhydrite (CaSO_4).

The CaSO_4 (anhydrite) SR of the formation water under reservoir conditions of 105°C and 5,000 psi is

Table 1 The interpretation of scale prediction results.

SR	Interpretation
< 1	Undersaturated for the scale type. Non-scaling.
1 – 2	Slightly supersaturated. Likelihood of scale formation is low.
2 – 5	Scale formation highly likely.
5 – 10	Scale almost certain to occur. Heavy deposition likely.
> 10	Severe scaling expected. System could be blocked quickly.

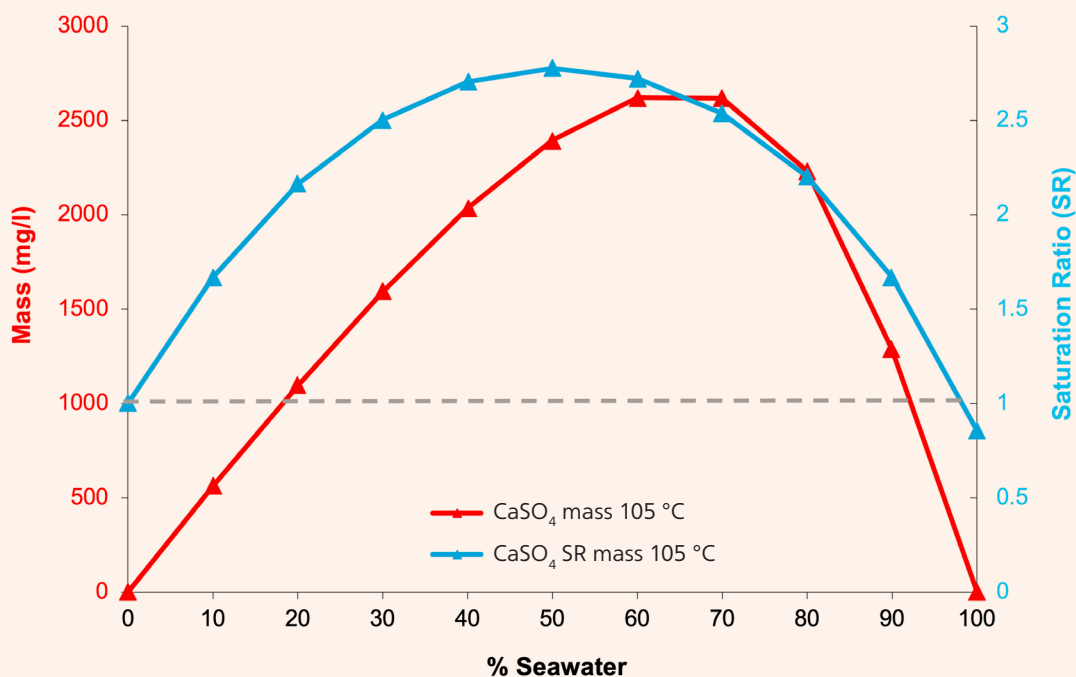
Table 2 The brine chemistry for scaling tests and prediction used in this study.

	Assumed Formation Water (mg/L)	Assumed Seawater (mg/L)
Na ⁺	64,000	22,000
Ca ²⁺	9,000	600
Mg ²⁺	4,000	2,000
K ⁺	200	600
Sr ²⁺	100	10
Cl ⁻	127,000	37,000
HCO ₃ ⁻	300	200
SO ₄ ²⁻	550	5,300

predicted as 1, where the deposition and dissolution of CaSO₄ reaches equilibrium at reservoir conditions over the long shut-in time under reservoir conditions⁹.

SR is essentially a measure of the thermodynamic driving force behind the precipitation reaction, which is used to indicate the scaling tendency and the likelihood of scale formation is described by an indication of oversaturation of a mineral in the brine. With the increase of the mixing ratio of seawater, the CaSO₄ SR increases until 50% seawater and then it starts to decrease. The worst-case scenario of CaSO₄ deposition is predicted at the point of 50:50 mixing ratio of seawater and formation water. Medium CaSO₄ supersaturation (SR = 2.78) is predicted, coupled to a high mass precipitation of 2,395 mg/l at 105 °C.

The mass of precipitate is the maximum amount of scale that could form in 1 liter of supersaturated fluid to equilibrium, given ideal conditions and infinite time. With

Fig. 3 The CaSO₄ (anhydrite) scale prediction — mixing seawater and formation water at 105 °C.

the increase of the mixing ratio of seawater, the CaSO_4 mass deposition increases until it reaches 70% seawater, and then starts to decrease. The worst-case scenario of CaSO_4 deposition is predicted at the point of a 70:30 mixing ratio of seawater and formation water, coupled to a high mass precipitation of $\sim 2,500$ mg/l at 105 °C.

CaSO_4 scale deposition is highly likely due to oversaturated SR at 105 °C and may be harsh, due to the high mass precipitation.

CaSO_4 deposition could damage the formation in the water injection wells and production wells, especially the near wellbore region^{5,10}. It could cause a significant decline of injectivity in a seawater injection well or the productivity of oil production wells. Even more, it could cause the abandonment of injection and production wells, due to a large quantity of CaSO_4 deposition in the near wellbore region, which then could cause considerable formation damage. Moreover, the CaSO_4 deposits in the deeper formation may not always cause a negative effect on the formation. When it deposits at the super-K zone between the injection and production wells, it could partially block the super-K zone and contribute to more even distribution of the seawater in the formation, which will delay the breakthrough of seawater in the production wells and improve the efficiency of seawater injection operation.

Risk Assessment from Downhole to Wellhead

CaSO_4 scale could deposit throughout the downhole to the wellhead. The temperature and pressure of the downhole and wellhead used in this study are 105 °C and 5,000 psi, and 70 °C and 500 psi, respectively. CaSO_4 scale could be more favorable to deposit at specific locations,

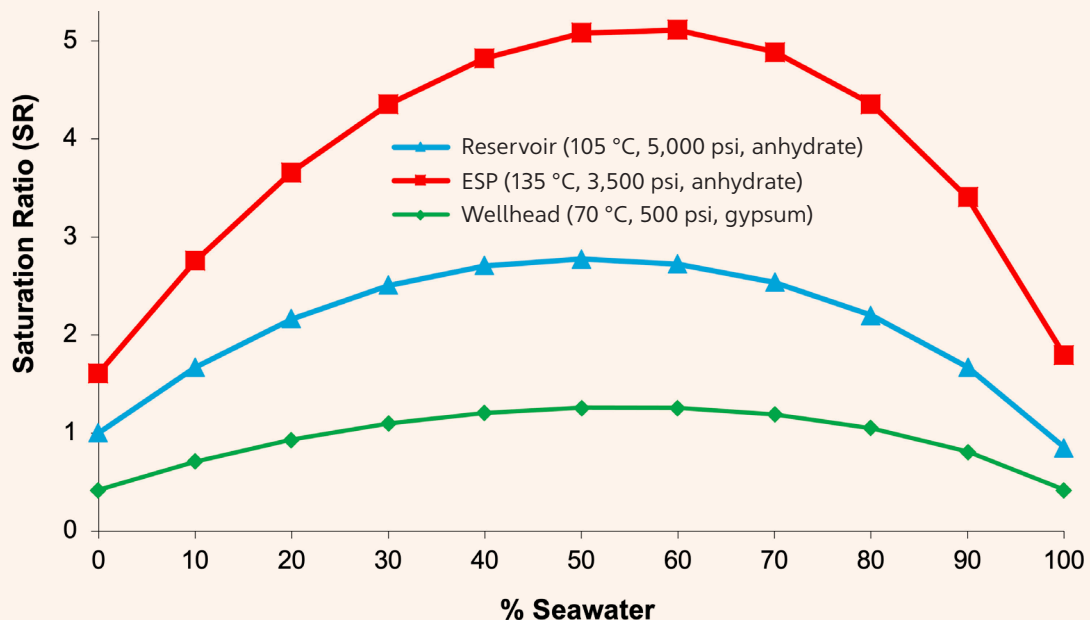
e.g., the electric submersible pump (ESP). The ESP is one of the most common artificial lift applications in the oil wells. It consists of multiple centrifugal pump stages mounted to a submersible electric motor. The motor generates heat and causes the temperature to increase on the inner surface¹¹. In this study, the applied surface temperature of the ESP was 135 °C, which is 30 °C above the reservoir temperature.

The CaSO_4 scale risk is assessed when formation water and seawater mix at 105 °C (reservoir temperature), 135 °C (temperature at ESP), and 70 °C (wellhead temperature). The results are shown in Fig. 4.

Similar to the CaSO_4 prediction previously shown in Fig. 3, the CaSO_4 SR increases until 50% seawater, and then starts to decrease with the increase of the mixing ratio of seawater, Fig. 4. The worst-case scenario of CaSO_4 deposition is predicted at the point of 50:50 mixing seawater and formation water, where the CaSO_4 SR (SR = 2.78) was predicted. The likelihood of CaSO_4 scale deposition is marginal at 105 °C in the reservoir.

The similar trends of the CaSO_4 SR are predicted at the wellhead temperature (70 °C) and ESP surface temperature (135 °C). The CaSO_4 SR increases until 50% seawater, and then starts to decrease with the increase of the mixing ratio of seawater. Consequently, the SR of the CaSO_4 (gypsum) SR at wellhead temperature of 70 °C is lower than the CaSO_4 (anhydrite) predicted at the bottom-hole temperature of 105 °C. It indicates that the CaSO_4 scaling tendency decreases from the bottom-hole to the wellhead with the gradient reduction of temperature and pressure. The SR of the CaSO_4 (anhydrite) SR at the ESP with a surface temperature 135

Fig. 4 The CaSO_4 scale prediction — mixing seawater and formation water at 105 °C, 135 °C, and 70 °C.



°C is much higher than the CaSO_4 (anhydrite) predicted in the bottom-hole at a temperature of 105 °C.

The worst-case scenario of the CaSO_4 deposition predicted at 135 °C is at the point of 50:50 mixing seawater and formation water, where the CaSO_4 supersaturation (SR = 5.08) is predicted. The likelihood of the CaSO_4 scale deposition is more likely at the ESP with a surface temperature of 135 °C, than at the bottom-hole with a temperature of 105 °C. The temperature is a major driving force for CaSO_4 scale formation. CaSO_4 scale is more likely to form in the ESP due to the increase of surface temperature inside the ESP.

Risk Assessment from Surface Flow Line to Production Water Re-Injection Unit

Another scenario of potential CaSO_4 deposition from the surface flow lines to a water re-injection unit is to mix two types of water produced in the same field from different formations at the surface facilities, like flow lines, and a gas-oil separation plant (GOSP).

Table 3 lists the examples of these waters produced in a field from different formations. The composition of Water-A is calculated of a 10:90 mixing formation water and seawater (Table 2), which represents a sulfate-rich water after mixing formation water and seawater, previously shown in Table 2. Water-B represents a calcium-rich water produced in another formation.

Once comingled in the surface flow lines or in the GOSP, the mixed water becomes supersaturated with respect to CaSO_4 and leads to the formation of gypsum scale.

Figure 5 shows the prediction results for gypsum scale under conditions of 70 °C and 500 psi. It can be seen that Water-A or Water-B is undersaturated (SR < 1) to

gypsum; the mixed water can be more than two times supersaturated (at Water-B = 30% to 50%), coupled to a significant amount of gypsum mass precipitation of ~2,000 mg/l. These results indicate that the CaSO_4 scale can be deposited in the surface facilities, such as flow lines and separation units.

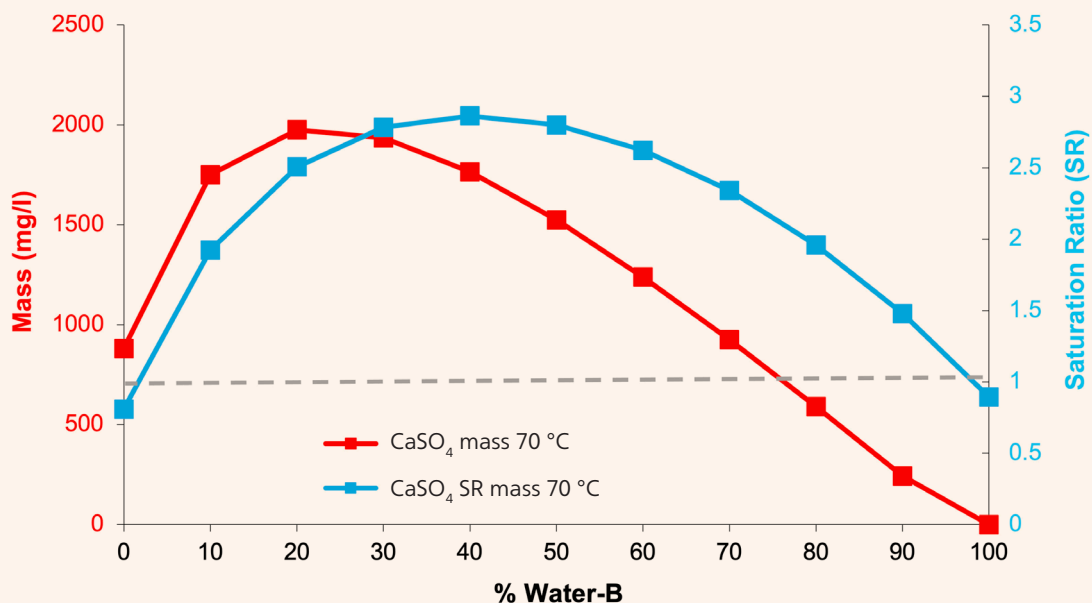
Risk Assessment in Production Water Re-Injection Wells

A large quantity of water is produced during oil and gas productions. The produced water is often injected underground or subsea for disposal through disposal wells, after being separated from the produced hydrocarbons. The water temperature at the surface facilities

Table 3 Calcium- and sulfate-rich waters produced from two formations.

(mg/L)	Water-A (Formation Water:Seawater (10:90) in Table 2)	Water-B
Na^+	27,520	32,000
Ca^{2+}	1,476	32,000
Mg^{2+}	2,320	5,700
K^+	596	2,000
Sr^{2+}	20	1,000
Cl^-	48,220	126,000
HCO_3^-	222	300
SO_4^{2-}	5,143	550

Fig. 5 The CaSO_4 scale prediction — mixing Water-A and Water-B at 70 °C and at 500 psi.



and injection wellhead is usually lower than injection well reservoir temperature. When the water travels down to the injection well, its temperature and pressure increase. If the water is saturated or nearly saturated at surface conditions, CaSO_4 scale may form along the production string and injection reservoirs⁶.

The CaSO_4 scale risk was assessed when Water-A and Water-B mixed at 105 °C — downhole temperature — and 70 °C — wellhead temperature — in the injection well.

Figure 6 shows the prediction results of the CaSO_4 (anhydrite) scaling under injection well conditions of 105 °C and 5,000 psi. Water-A or Water-B are slightly saturated with a SR between 1 and 2 to anhydrite. The SR of the mixed waters can approach ~6, about three times supersaturated at the waters, with mixing ratios of Water-A and Water-B between 30% and 50%.

Compared to the gypsum SR predicted at wellhead conditions of 70 °C and 500 psi, Fig. 6, anhydrite is more likely to deposit in the downhole of the water injection well. If the produced water can form inorganic scale precipitates under the disposal well conditions, these precipitates could cause a significant decline of injectivity, and in the worst-cases, the abandonment of disposal wells. Unlike other types of scale, CaSO_4 can be formed in a large quantity within a short period of time; and once formed, it is difficult to remove.

This article gives a comprehensive study of the potential CaSO_4 scaling risk evaluation from a seawater injection unit to a produced water disposal well. Table 4 summarizes the risk and driving force of the CaSO_4 formation. It contributes to the understanding of the CaSO_4 formation and inhibition in the whole production system

and recommends effective scale mitigation strategies.

Summary and Conclusions

The results obtained from this study can be summarized as:

- The CaSO_4 scale is predicted when formation water and seawater mix at 105 °C (reservoir temperature) in the seawater injection well and production well. The worst-case condition for CaSO_4 is predicted at the mixing of 50% formation water and 50% seawater.
- The harsher CaSO_4 is predicted at the ESP under 135 °C, than under downhole conditions at 105 °C. The CaSO_4 scale deposition is almost certain to occur in the ESP with the water and conditions applied in this study.
- The reduced CaSO_4 scaling potential is predicted at the wellhead with a low temperature of 70 °C.
- CaSO_4 is predicted to potentially deposit from the surface flow lines to the water re-injection unit when mixing two types of waters produced in the same field from different formations at the surface facilities, i.e., flow line and GOSP.
- CaSO_4 is predicted to deposit in the near wellbore of the produced water re-injection well under conditions of 105 °C and 5,000 psi. It could cause significant decline of injectivity, and in the worst-cases, the abandonment of disposal wells.

Fig. 6 The CaSO_4 (anhydrite) scale prediction — mixing Water-A and Water-B at the wellhead (70 °C, 500 psi) and downhole (105 °C, 5,000 psi) in a water injection well.

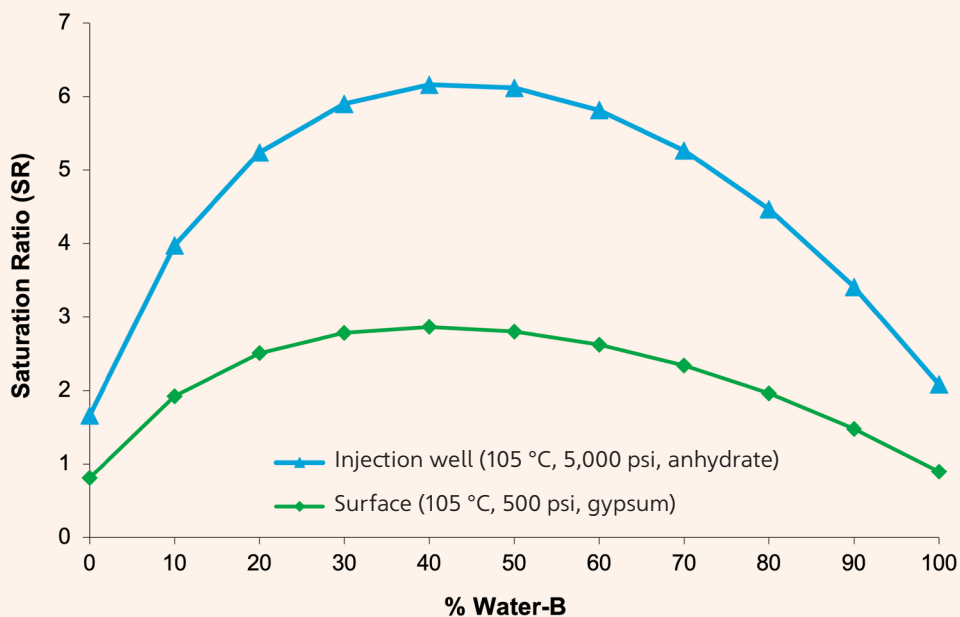


Table 4 A summary of the CaSO₄ scaling risk and driving force under conditions predicted in this study.

Location	Temperature (°C)	Pressure (psi)	Driving Force	CaSO ₄ Type	Severity
Near wellbore of seawater injection well	105	5,000	Incompatible waters	Anhydrite	Medium
Deeper formation from injection well to production well	105	5,000	Incompatible waters	Anhydrite	Medium
Near wellbore of production well	105	5,000	Incompatible waters	Anhydrite	Medium
ESP	135	3,500	Incompatible waters and High temperature	Anhydrite	High
Wellhead	70	500	Incompatible waters	Gypsum	Low
Surface facilities	70	500	Incompatible waters	Gypsum	Low to medium
Produced water re-injection well	105	5,000	Incompatible waters and High temperature	Anhydrite	Medium to high

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