De-risking dissolver treatments in low pressure wells by data manipulation and modelling.

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The North Everest Field is a gas condensate field produced by natural depletion from the Forties and Lista/Andrew/Maureen (LAM) reservoirs. Historically, several production wells have been mechanically treated to remove $BaSO_4$ and $CaCO_3$ scale. Recent Environmental Scanning Electron Microscopy (ESEM) data have confirmed the presence of $BaSO_4$ particles in the produced water from several wells, and recent topsides interventions have identified the presence of scale.

Given the evidence for a potential ongoing scale risk, a scale management review was instigated. The objectives were to better understand the current scale risks and to plan future mitigation and treatment requirements. To aid this review, a scale risk prediction study was required to confirm current scale risks, but it was first necessary to estimate the produced formation water compositions and rates as all produced waters from the field are mixtures of formation water and condensation water.

Interpretation of the produced water analyses allowed five compositionally distinct formation waters to be identified; three in the Lista/Andrew/Maureen (LAM) Formations and two (one with subtle variations) in the Forties Formation. Also, good estimates of produced formation water compositions and rates have been obtained for most wells on North Everest using the produced water analyses and PVT calculations.

Scale risk predictions demonstrated that the current primary risk at North Everest is $CaCO_3$ deposition deeper in several of the wells. This was contrary to expectations based on recent scale observations, and historic predictions and well treatment strategies (i.e. that the primary risk would be $BaSO_4$). Only one well was predicted to be susceptible to $BaSO_4$ deposition at bottomhole and this is a minor risk. Minor topsides $BaSO_4$ scale risks were also identified from two wells. The predictions are consistent with recent 'scale observations' from the producing wells and topsides.

This work has allowed North Everest scale management planning to be undertaken with greater confidence. Topsides inhibitor injection has been introduced and a few wells have been identified for carbonate dissolved treatment. It has also allowed those wells that do not require treatment to be identified meaning a reduction in unnecessary formation damage risks, lift issues, corrosion exposure, and HSE exposure. This will raise the treatment success rate and reduce the risk of a poor spend/reward ratio.

Introduction

North Everest Field

North Everest is a gas condensate field located in the Central North Sea (blocks 22/9, 22/10a and 22/14a). The field lies 217km east of Scotland and 14km from the UK/Norway median line (Figure 1) in a water depth of approximately 90m. First production from the field was in 1993.

The platform processes gas and condensate from platform (ET) wells and from subsea wells drilled into two nearby accumulations: South Everest (wells SA, SJ), located 7km south of the North Everest production platform and Everest East Expansion (EEE) (wells LAA, LAF) located 7km north-east of the platform (see Figure 2).

The producing wells considered in this study are shown in Table 1. Some have been completed in the Forties Formation whilst others have been completed in the underlying Lista, Andrews and Maureen (LAM) Formations.

Figure 1 North Everest Installation location and map of nearby fields.

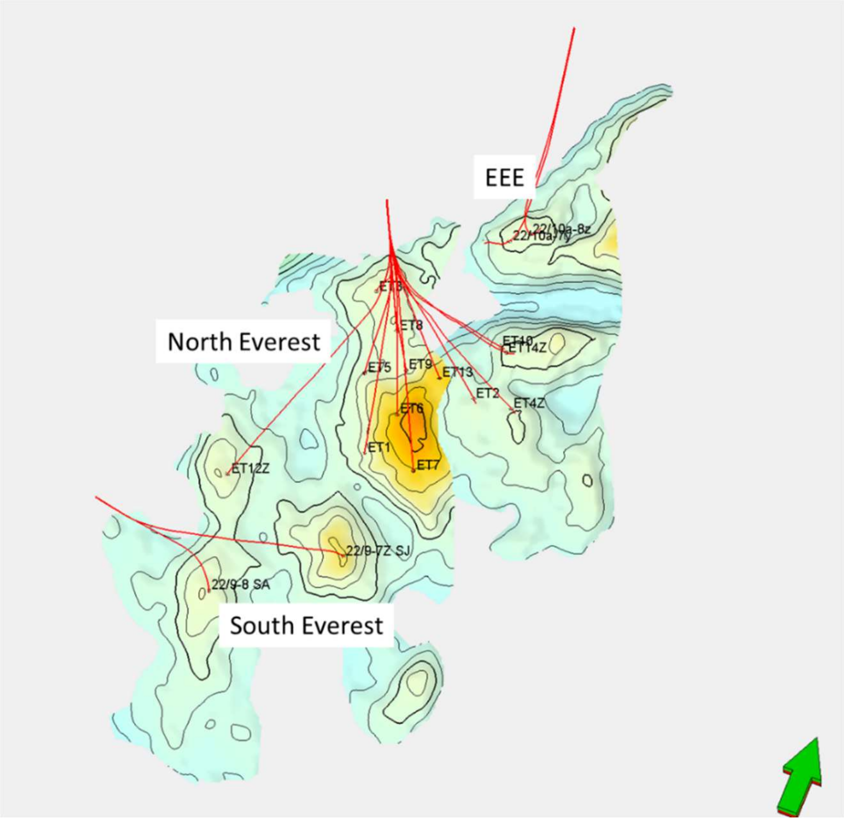

Figure 2 North Everest field map.

Table 1 North Everest producing wells considered in this study.

Well	Reservoir
ET-03	Forties
ET-08	Forties
ET-12z	Forties
ET-14z	Lista; Andrew; Maureen
LAA	Andrew; Maureen
LAF	Andrew; Maureen
ET-04z	Lista; Andrew; Maureen
SA	Forties

North Everest produced fluids are separated via the topside process system (see Figure 3 and Table 2 for process conditions). Demulsifier is added upstream of the high pressure (HP) separator, where separation of gas occurs. After the fluids leave the high pressure separator, de-oiler is injected. Corrosion inhibitor is added upstream of the intermediate pressure (IP) separator. Water is removed from the IP separator, with some water also being removed from the low pressure (LP) separator and combined prior to flowing to the tilted plate separator (TPS) and subsequent routing overboard. Produced water samples can be obtained from individual wells routed to the test separator or mixed samples can be obtained from the TPS.

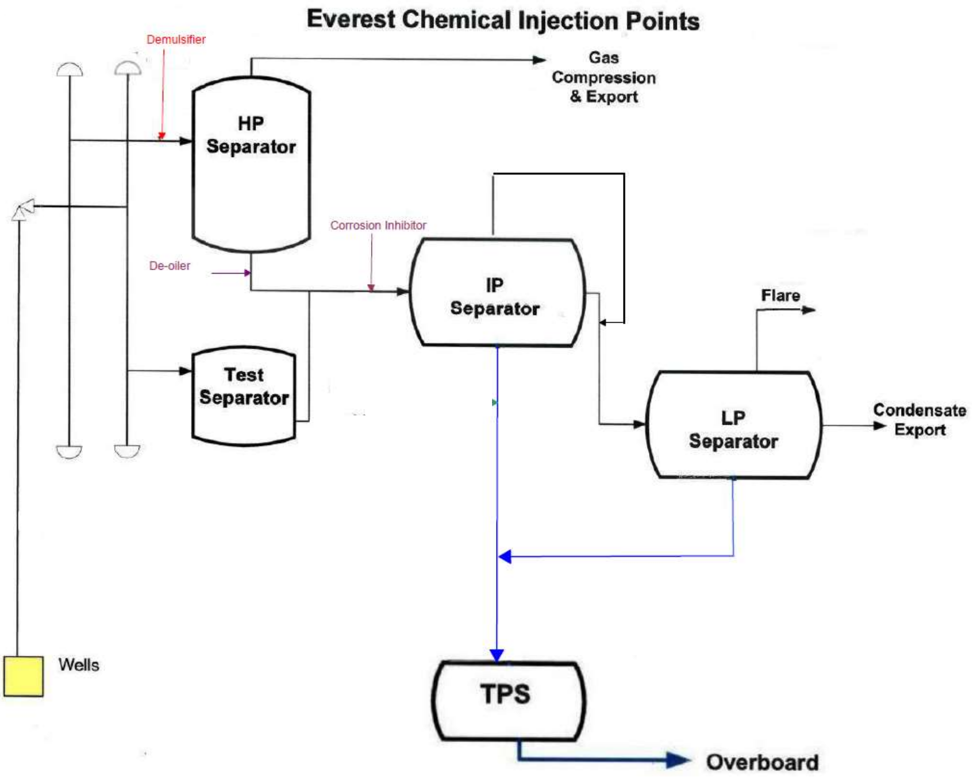

Figure 3 North Everest Process Schematic

Table 2 North Everest Process Conditions

Vessel	Temperature (ºC)	Pressure (Bar)
HP separator	50-55	14-16
IP separator	30-35	8
LP separator	30	6
Tilted plate separator (TPS)	30	1.5

The separation conditions are challenging, given the varying compositions of fluids from platform and subsea wells, the cool fluid temperatures, and the cyclic nature of some of the wells. In addition, sand in produced fluids stabilises emulsions, and build-up of sand in the separators reduces residence times.

Occurrence of scale

Historic interventions (including mechanical removal of scale), and solids sampling and analysis via ESEM, indicate that the wells have previously operated in $CaCO_3$ and $BaSO_4$ scaling regimes. Recent ESEM data have confirmed that produced water contains inactive $BaSO_4$ particles (Table 3), supporting the past precipitation of $BaSO_4$ in these wells. But modified $BaSO_4$ particles are also being produced suggesting that active precipitation of $BaSO_4$ is still occurring in some wells. Also, during recent maintenance, a scale rim (unidentified) was present in the pipework either side of the liquid control valve (LCV) downstream of the high pressure separator (Figure 4) and in a previous TPS entry, $BaSO_4$ solids were identified amongst flocculent and sand in the vessel.

Table 3 ESEM analysis of solids in North Everest Wells and Process

Sample ID	Sample Date	Total Filter Coverage %	Scale Coverage of Total (%)	Sand Coverage of Total (%)	Scale coverage filter (%)	Comments
IP Sep Outlet	27/09/2017	15	30	70	4.5	Inactive Ba/SrSO4 appeared sparse amongst sand.
TPS Outlet	27/09/2017	2	20	80	0.4	Inactive Ba/SrSO4 appeared very sparse amongst sand.
Well ET-14	16/05/2017	5	10	90	0.5	Inactive BaSO4 & FeCO3 appeared sparse.
Well 5A	20/05/2017	10	60	40	6	Inactive BaSO4 & FeCO3 appeared sparse.
Well LAF	12/06/2017	30	10	90	3	Inactive BaSO4 appeared sparse amongst sand.
ET-07	07/05/2017	2	40	60	0.8	Inactive BaSO4, appeared very sparse (some modified)
ET-12	13/05/2017	2	30	70	0.6	Modified BaSO4, appeared very sparse
ET-03	14/05/2017	5	10	90	0.5	Inactive Ba/SrSO4, appeared very sparse.
ET-08	14/05/2017	1	10	90	0.1	Modified BaSO4. Appeared very sparse. Inactive BaSO4 & FeCO3

Figure 4 Scale rim in the liquid control valve pipework.

Scale management review

Some wells have, in the past, been mechanically cleaned to remove $BaSO_4$ and $CaCO_3$ scale, but at present there is no active scale mitigation (no routine scale squeezes or remedial dissolver treatments and no downhole injection) Given the evidence for a potential ongoing scale risk, a scale management review was instigated. The objectives were to better understand the current scale risks and to plan future mitigation and treatment requirements.

To aid this review, a scale risk prediction study was required to confirm current scale risks. Produced formation water compositions and rates were necessary inputs to these calculations. This information was however not available because although produced water samples/analyses and rates had been acquired from the wells since 1997, the wells were producing a mixture of formation water and condensation water. Also, although a water sample was collected from the Forties Formation of appraisal well 22/9-4, it was not known whether this was representative of the reservoir formation water.

In the remainder of this paper, we describe how the produced formation water compositions and rates were determined, summarise the scale risk prediction results and show how these are being utilised in the scale management review for the field.

Characterising the formation water compositions

To undertake scaling risk predictions, it was first necessary to evaluate available produced water analyses to estimate the likely formation water compositions for the wells. All available past produced water analysis (since 1997) were compiled for this study and anomalous data were removed before the ‘cleaned-up’ data set was used for this purpose. The remaining produced water sample compositions were the result of mixtures of formation water and condensation water.

Based on X/Cl ratios (i.e. X=Na, Ca, Ba, etc), five compositionally distinct formation waters were identified in the field; three in the Lista/Andrew/Maureen (LAM) Formations and two in the Forties Formation (see Figures 5 and 6):

- LAM FW 1: Produced from ET-14z only.
- LAM FW 2 (Ba-depleted): Produced from ET-04z, ET-06 (potentially), ET-13.
- LAM FW 2 (Ba-rich): Produced from ET-02, ET-06 (potentially), LAA, LAF.
- Forties FW A: Produced from ET-01z, ET-03, ET-05, ET-07, ET-08, ET-09, ET-12z, SJ.
- Forties FW A (SA): Produced from SA only.

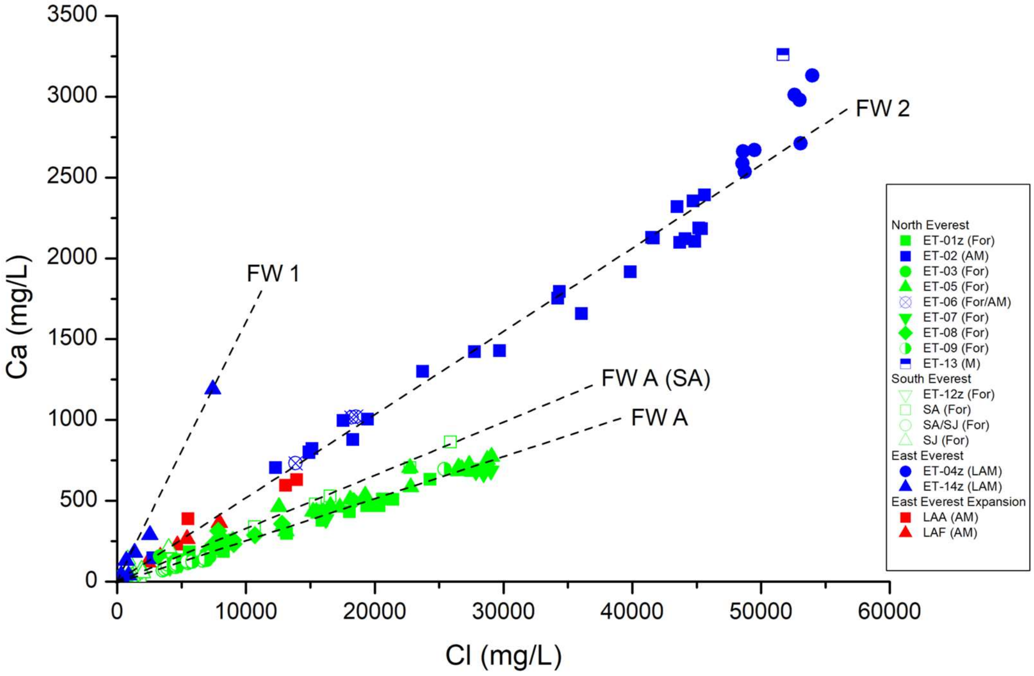

Figure 5 Variation of Cl and Ca in water produced from the Forties and Lista/Andrew/Maureen Formations.

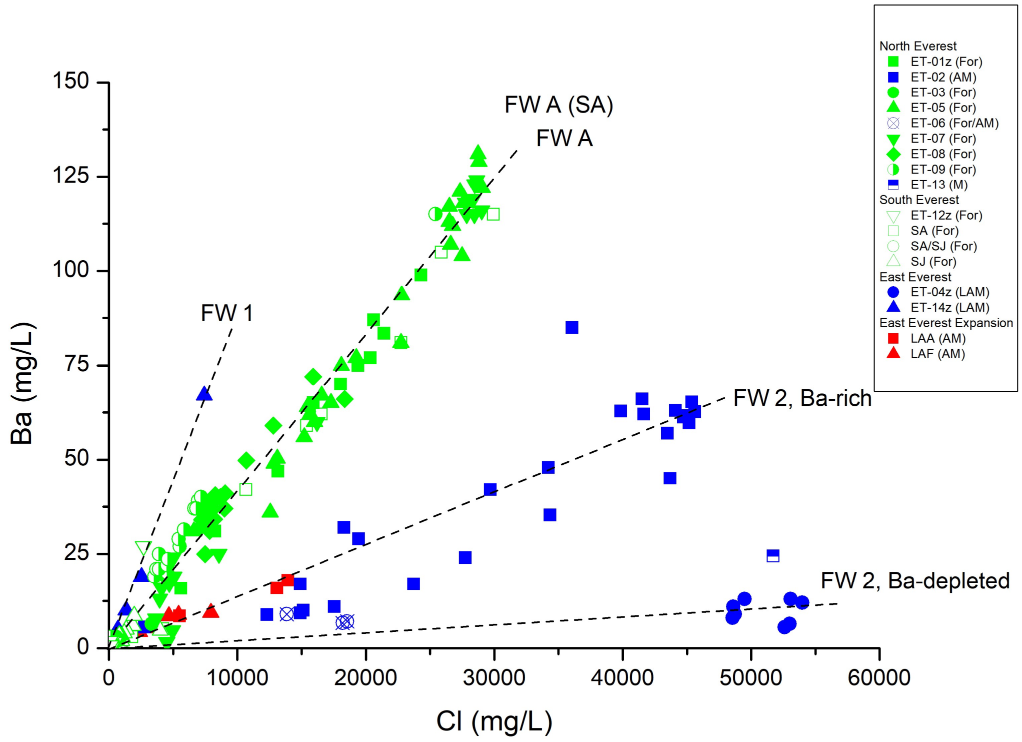

Figure 6 Variation of Cl and Ba in water produced from the Forties and Lista/Andrew/Maureen Formations.

For each of these formation waters, the X/Cl ratios are constant, but there is some variability about them. This variability may be the result of sampling/analytical uncertainties but equally could be due to mixing of formation waters with slightly different compositions. The potential effect on scaling risks of this latter possibility has been investigated (see below).

LAM FW 2 is present across the field (except at the location of ET-14z) but has two variants: Ba-rich and Ba-depleted. LAM FW 2 has probably originated in underlying formations, but the Ba-depleted variant has probably contacted anhydrite in the Zechstein Formation under the area occupied by ET-04z and ET-13 (and possibly ET-06).

LAM FW 1 is only produced from ET-14z and has relatively high Ca/Cl (Figure 5) which suggests it may have much higher salinity than other formation waters for the field (>80,000 mg/L Cl). Again, this has probably originated from underlying formations and may have contacted halite in the Zechstein Formation below this well area.

The wide distribution of FW 2 in the LAM Formations of the field implies that there is generally good communication across the area where most of the LAM production wells are located. The presence of both FW 1 and Ba-depleted FW 2 in close proximity, and the lack of spread of these formation waters more widely however suggests that the lateral connectivity is poor in those areas between where these formations waters have been identified.

Forties FW A is Ba-rich and is widely distributed indicating that there is good communication across the area where the Forties production wells are located. There are subtle variations in FW A composition which are most apparent at the location of well SA. FW A (SA) appears to be a local variant of FW A (e.g. Ca-Cl; Figure 5). It is common to see variations such as this in Forties reservoirs (i.e. Forties, Nelson, Pierce Fields) (Coleman 1992, Gill et al. 2010, McCartney et al. 2013) but because these variations are subtle, this is consistent with the Forties Formation having good lateral connectivity.

Estimating the formation water compositions

As noted above, the produced water compositions are the result of mixing of condensation water and formation water. The formation water Cl concentration of each formation water was therefore estimated using PVT calculations. These were used to calculate the condensation water rate from well test data and then this was subtracted from the measured produced water rate to provide an estimate of the formation water rate. This allowed the formation water Cl concentration to be estimated from the produced water Cl concentration using Eq. 1 (where FW = formation water; PW = produced water; Cl = chloride, mg/L; WR = water rate, m^3/day).

$$Cl_{FW} = \frac{Cl_{PW}.WR_{PW}}{WR_{FW}} \qquad \text{Eq. 1}$$

Table 4 summarises the results obtained for each formation water from the various wells. There was insufficient data to obtain an estimate of the formation water Cl concentration for ET-14z (FW 1).

Table 4 Summary of estimated formation water Cl concentrations.

Well (Formation water)	Period	No. Well Tests Utilised	Average ± Standard deviation (mg/L)
ET-02 (FW 2)	Oct-04 to Jun-08	18	50575 ± 1757
ET-04z (FW 2)	Aug-09 to Jan-20	4	52896 ± 2653
ET-02 + ET-04z (FW 2)	Oct-04 to Jan-20	22	50997 ± 2085
ET-05 (FW A)	Jul-04 to Nov-08	9	33358 ± 420
ET-08 (FW A)	Dec-12 to Nov-16	4	34021 ± 6178
ET-05 + ET-08 (FW A)	Jul-04 to Nov-16	13	33562 ± 3124
SA (FW A, SA)	Oct-18 to Feb-20	3	30352 ± 2852

The concentrations of other ions were estimated from the Cl concentration and X/Cl ratios obtained from regression of the produced water analyses. The compositions of the different formation waters are given in Tables 5-7.

Table 5 Estimated LAM FW 2 composition.

Constituent	Concentration (mg/L)	Uncertainty (± mg/L)
Cl	50997	4170
Na	29699	4216
K	323	98
Ca	2688	509
Mg	255	48
Ba (Ba-rich)	69	22
Ba (Ba-depleted)	13	12
Sr	280	55
B	72	10

To obtain an estimate of FW 1 Cl concentration, regression lines through ET-14z produced water Cl, Na and Ca analyses were compared with North Sea formation water compositions (e.g. Figure 7). These showed that FW 1 has Na/Cl and Ca/Cl ratios which are more typical of higher salinity formation waters (i.e. with >80,000 mg/L Cl). So, for this formation water it was assumed that the Cl concentration is approximately 80,000 mg/L. Again, the concentrations of other ions were estimated from the Cl concentration and X/Cl ratios obtained from regression of the produced water analyses. Evidently uncertainty remains over the composition of FW 1.

Table 6 Estimated Forties FW A composition.

Constituent	Concentration (mg/L)	Uncertainty (± mg/L)
Cl	33358	840
Na	20839	988
K	260	33
Ca	860	83
Mg	127	11
Ba	138	14
Sr	119	16
B	68	7

Table 7 Estimated Forties FW A (SA) composition.

Constituent	Concentration (mg/L)	Uncertainty (± mg/L)
Cl	34110	480
Na	21309	763
K	266	30
Ca	879	74
Mg	155	8
Ba	142	12
Sr	201	11
B	76	3

Table 8 Estimated LAM FW 1 composition.

Constituent	Concentration (mg/L)	Uncertainty (± mg/L)
Cl	80000	4000
Na	33569	2990
K	1362	201
Ca	12034	1660
Mg	1366	193
Ba	714	88
Sr	1198	153
B	301	104

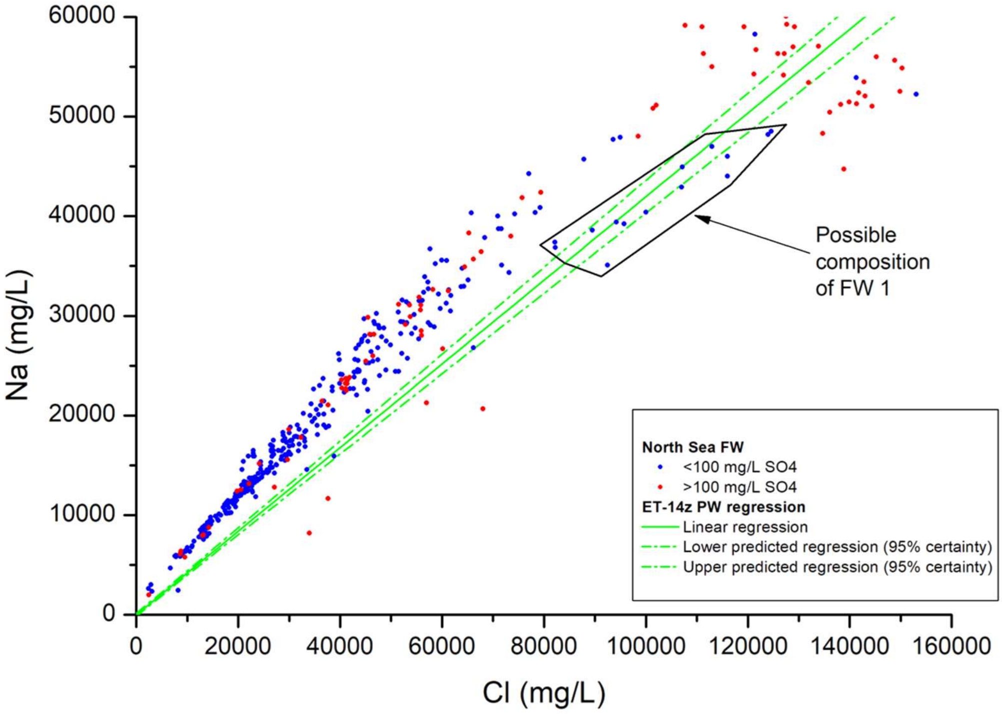

Figure 7 Cl-Na: Comparison of regression lines through ET-14z produced water (FW 1) and North Sea formation water compositions. The marked area shows the Cl concentrations at which North Sea formation waters start to regularly have lower Na/Cl and higher Ca/Cl ratios similar to those of FW 1.

Figures 8 and 9 compare the estimated formation water compositions with those of North Sea formation waters. The larger solid blue symbols on this plot are formation waters from the Forties Field and the open symbols are from other fields producing from the Forties formation. There is good agreement between the composition of FW A and those of formation waters from the Forties Field and other Forties reservoirs. There is also good agreement between the composition of the 22/9-4 water samples and FW A (SA). These wells are close to each other and this suggests that the estimate of FW A is good and that reasonable quality formation water samples were collected from 22/9-4.

The solid olive-green symbols in these figures are formation waters from the Cyrus and Donan Fields which also produce from LAM reservoirs. Na, Ca and Cl concentrations of FW2 are similar to these formation waters but this might be fortuitous because Donan and Cyrus are some distance away (Cyrus, ~50km; Donan, ~100km). The anomalous composition of FW1 from ET-14z relative to other North Everest formation waters is evident, but there are other high salinity North Sea formation waters with similar Na/Cl and Ca/Cl ratios as shown in these figures.

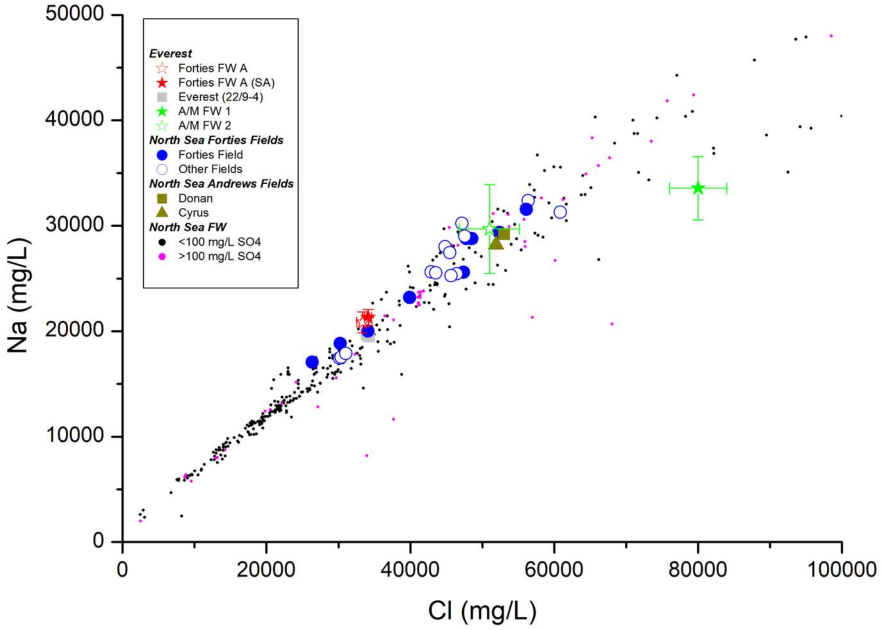

Figure 8 Cl-Na: Comparison of estimated North Everest formation water compositions, 22/9-4 formation water compositions and North Sea formation water compositions.

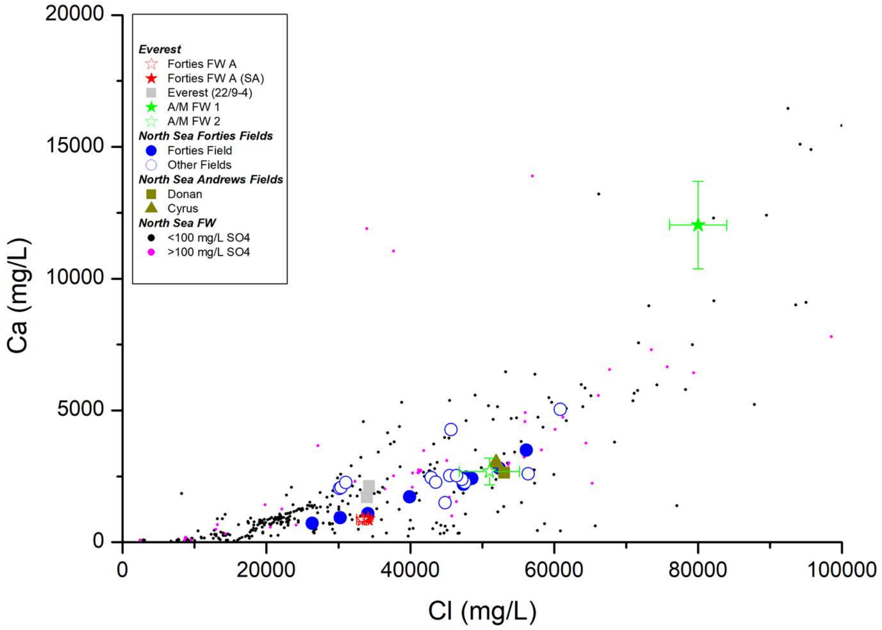

Figure 9 Cl-Ca: Comparison of estimated North Everest formation water compositions, 22/9-4 formation water compositions and North Sea formation water compositions.

Scale risk predictions

Scaling risks were predicted using MultiScale 7.1 (Petrotech 2006). The scenarios simulated were identified as those which might potentially explain the presence of active $BaSO_4$ precipitates in the produced water samples:

1. Production from the eight wells studied; four producing from the Forties Formation (ET-03, ET-08, ET-12z, SA) and four producing from the LAM Formations (ET-04, ET-14, LAA and LAF). The objective was to determine whether production conditions might cause $BaSO_4$ precipitation between the near-field of each well and the separator.
2. Mixing of fluids produced from LAA and LAF in the subsea flowline. The objective was to determine whether mixing may cause $BaSO_4$ precipitation in the flow line.
3. Production of mixed formation waters from five wells (ET-04z, LAA, ET-14z, ET-03 and SA). The objective was to determine whether production of mixed formation waters may increase the risk of $BaSO_4$ precipitation between the near-field and the separator in these cases.

For the production simulations, sensitivity calculations were undertaken using the potential range of formation water compositions for each well. A range of formation water rates were also used. These were adjusted to provide a match with recent separator produced water Cl concentrations. Recent well test pressure, temperature, and flow rate data and gas compositions were also used in these simulations.

For the simulations involving production of mixed formation waters, lower and higher salinity formation water compositions were calculated based on the compositions in Tables 5-8 and their associated uncertainties (i.e. composition plus uncertainty and composition minus uncertainty respectively). It was then assumed that these were mixing with each other in the well.

Results

Scale risks predicted via the simulations have been evaluated using calculated produced water saturation ratios (SR) and predicted precipitated masses (SM, mg/L produced water) for common scaling minerals. These have been compared against typical industry values to assess whether the scaling risks are operationally significant (see Tables 9 and 10). That is, possible $BaSO_4$ scale risks have been identified where $1 < SR_{BaSO4} < SR_{critical}$ and probable scale risks have been identified where $SR_{BaSO4} > SR_{critical}$. The scaling risk is only deemed operationally significant where $SR_{BaSO4} > SR_{critical}$ and $SM_{BaSO4} > SM_{critical}$. Of the common scaling minerals, only $CaCO_3$ and $BaSO_4$ were identified as being scale risks at North Everest.

Table 9 Industry 'rules of thumb' for critical values of SR and SM.

Scale	$SR_{critical}$	$SM_{critical}$ (mg/L)
$CaCO_3$ > 100 °C	1.2	50-75
$CaCO_3$ < 100 °C	2-3	50-75
$BaSO_4$	3	50-75

Table 10 Severity of scale: Typical industry values.

SR	SM (mg/L)	Severity
<1	0	Non-scaling.
< $SR_{critical}$	< $SM_{critical}$	Very low. Scale possible but unlikely to be operationally significant.
$SR_{critical}$ – 9	50 - 250	Low (mild). Scale likely but should not be severe.
9 – 100	250 - 500	Moderate. Scale almost certain to occur. Expected to be strongly scaling.
> 100	> 500	High. Severe scaling likely.

Factors controlling $BaSO_4$ scale risk

$BaSO_4$ scaling risks in the wells are influenced by changes in temperature and pressure during production. This affects the solubility of $BaSO_4$ but also determines whether formation water is evaporated or diluted by condensation water at different locations downstream of the reservoir. Formation water rates are important because these determine how much influence evaporation/condensation have on the produced water composition and scale risk. Uncertainties in the composition of formation waters for each well appear to be of minor importance.

The influence of these factors varies from well to well but the most important factor for low formation water rate (i.e. <~2 m^3/day) wells (LAA, ET-03, ET-08, ET-12z, ET-14z) is pressure reduction close to the well and bottomhole. This causes evaporation at these localities which increases the $BaSO_4$ scaling risk[1]. For higher formation water rate wells (SA, ET-04z), cooling is the most important factor (pressure decline less so) which increases the $BaSO_4$ scaling risk higher in the well, at the wellhead and in the separator.

Formation/bottomhole $BaSO_4$ scaling risks

Figure 10 shows SR and SM results for $BaSO_4$ at bottomhole conditions for all the production wells considered in this study. For most wells producing with low rates (i.e. LAA, ET-03, ET-08, ET-12z), there is a possible scaling risk, whilst for ET-14z there is a probable scaling risk. This is due to formation water evaporation, the effects of which are most significant at low formation water rates. Other than LAA, this condition is also present adjacent to these wells in the formation, so scaling is possible here too for them.

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[1] LAF is also a low formation water rate well but is affected by condensation conditions at bottomhole and in the adjacent formation so it has no $BaSO_4$ scaling risk at these locations.

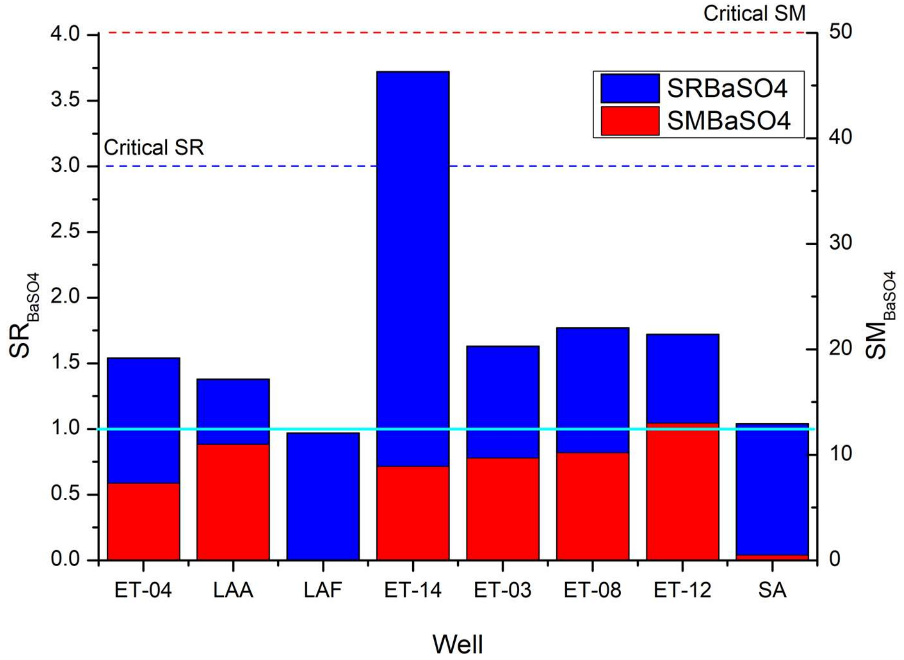

Figure 10 Variation of SR_{BaSO4} and SM_{BaSO4} at bottomhole conditions for North Everest wells.

At higher formation water rates, even when evaporating conditions are present, they have less effect, so SR_{BaSO4} tends to be lower than at lower formation water rates. This is the case with SA (negligible bottomhole $BaSO_4$ scaling risk).

Bottomhole conditions for LAF and ET-04z favour condensation. This particularly reduces SR_{BaSO4} in LAF due to its low formation water rate (negligible bottomhole scaling risk). SR_{BaSO4} is less reduced in ET-04z due to its higher formation water rate but also due to its relatively low bottomhole temperature so for this well, a $BaSO_4$ scaling risk is possibly still present. But, for all these wells, SM_{BaSO4} is below critical values so the scaling risk is not operationally significant.

Wellhead and separator

Produced water from all wells is affected by condensation at the wellhead and separator. The effects of condensation are greatest on the low formation water rate wells (i.e. LAA, LAF, ET-03, ET-08, ET-12z) so there is no $BaSO_4$ scaling risk at these locations (Figures 11 and 12).

Despite its low formation water rate, there is a possible risk for ET-14z due to the relatively minor amount of condensation occurring at the wellhead and separator for this well.

For the higher rate wells there is a possible $BaSO_4$ scaling risk at the wellhead for SA and a probable risk for ET-04z, whilst there is a probable risk for both wells at the separator. For these wells/locations, however, SM_{BaSO4} is below critical values so the scaling risk is not operationally significant.

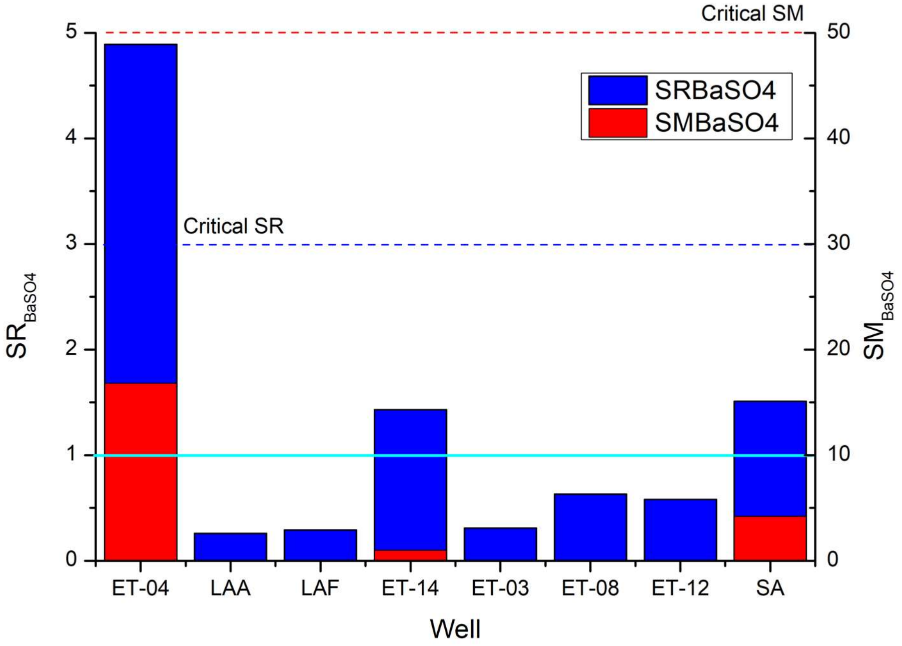

Figure 11 Variation of SR_{BaSO4} and SM_{BaSO4} at wellhead conditions for North Everest wells.

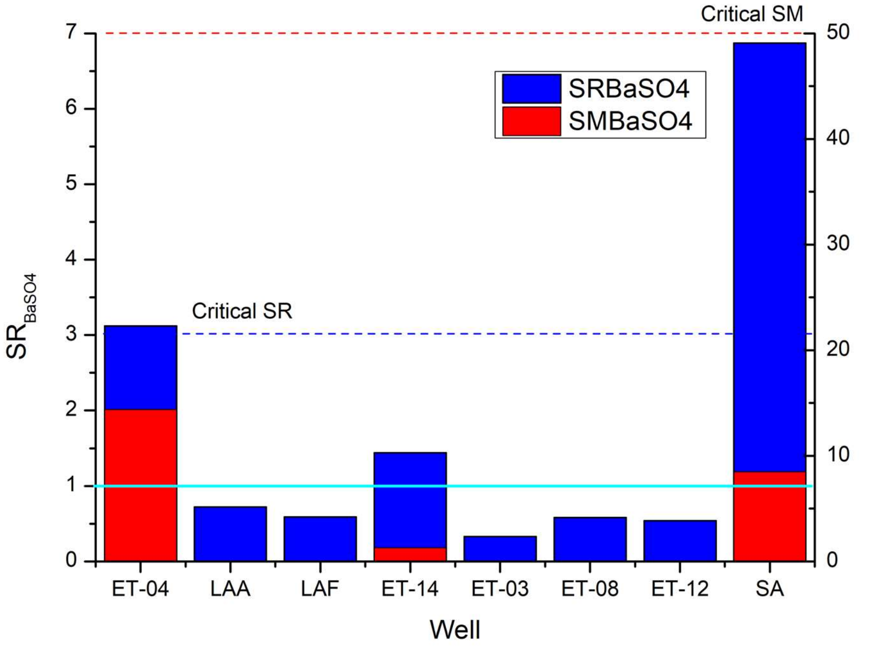

Figure 12 Variation of SR_{BaSO4} and SM_{BaSO4} at separator conditions for North Everest wells.

Mixed formation water

$BaSO_4$ scaling risks are only significantly changed for ET-04z if mixed formation water is produced. This is because it produces Ba-depleted (and hence relatively SO_4-rich) formation water. For this well, production of mixed formation waters causes a probable $BaSO_4$ scaling risk at formation/bottomhole, wellhead and separator. Despite this, because the Ba concentration in the mixed formation water is low, SM_{BaSO4} is also low ($<SM_{critical}$) and so the scaling risk is not operationally significant.

Mixing in the subsea flowline

There is no $BaSO_4$ scaling risk associated with mixing of LAF and LAA produced fluids in the subsea flowline.

Correlation with ESEM data

ESEM has sporadically been used to monitor $BaSO_4$ scaling risks in most of the producing wells considered in this study (except LAA). There are however only two recent ESEM samples from these wells (ET-04z and ET-12z; 2019), which likely experienced similar conditions to those simulated in this study:

1. ET-04z. 8% filter scale coverage with both active and inactive $BaSO_4$.
2. ET-12z. 1.5% filter scale coverage with both active and inactive $BaSO_4$.

In both cases, these data are consistent with, and hence verify, the results of this study. For example, active $BaSO_4$ particles for ET-04z can be explained by precipitation occurring higher up the well near the wellhead or separator. For this well, it is possible that precipitation might also be occurring at bottomhole. For ET-12z, it is feasible that active $BaSO_4$ is precipitating under bottomhole conditions. It is also notable that SM_{BaSO4} (up to 29 mg/L for ET-04z; up to 13 mg/L for ET-12z) appears to be correlated with filter scale coverage in these cases and is consistent with the sparse scale coverage.

These results suggest that the active $BaSO_4$ particles present in ESEM samples could be caused by the mechanisms, and at the locations, discussed above. The ESEM sample data are not indicative of an operationally significant $BaSO_4$ scaling risk to these wells which is also the conclusion drawn from the scaling risk predictions.

The presence of inactive $BaSO_4$ in the ET-04z and ET-12z ESEM samples may indicate that some $BaSO_4$ deposition has occurred downhole previously via similar mechanisms however the possibility of other mechanisms being active in the past cannot be discounted.

$CaCO_3$ scaling risks

Low/mild $CaCO_3$ scaling risks are predicted bottomhole for ET-14z, ET-03, ET-08, and ET-12z. These are low formation water rate wells and so this risk is directly influenced by evaporation. For this reason, these risks may extend into the adjacent formation.

Of the producing wells considered in this study, only ET-08 has had scale-related well interventions. Scale was identified in the tailpipe/packer area and this was subsequently milled out (2005). The type of scale is not known with certainty, but it tested negative for

NORM so was likely $CaCO_3$. This is plausible given the above results and confirms that $CaCO_3$ scale can occur in North Everest wells.

Minor (operationally not significant) $CaCO_3$ scaling risks were also predicted for LAA (bottomhole), SA (bottomhole) and ET-04z (separator at higher formation water rates where the ‘mid’ or ‘high’ formation water is being produced).

Use of the results in the scale management review

The above results are summarised in Tables 11 and 12. These display the predicted severity of the $BaSO_4$ and $CaCO_3$ scale risks in each well and at bottomhole, wellhead and separator locations. These tables were used to assess current scale risks to producing wells. An evaluation was also made using produced water rates on scale deposition in kg/day, year and over 5 years, to determine potential levels of scale which had historically formed to ensure that slower forming scale was not overlooked.

Table 11 Predicted severity of $BaSO_4$ scale risk for producing wells

(SR_{BaSO4}: Green = no risk; Yellow = possible risk, Orange = probable risk;

SM_{BaSO4}: Green = no risk; Yellow = very low severity).

	Downhole		Wellhead		Separator	
Well	SR_{BaSO4}	SM_{BaSO4}	SR_{BaSO4}	SM_{BaSO4}	SR_{BaSO4}	SM_{BaSO4}
ET-03	🟨	🟨	🟩	🟩	🟩	🟩
ET-08	🟨	🟨	🟩	🟩	🟩	🟩
ET-12z	🟨	🟨	🟩	🟩	🟩	🟩
SA	🟨	🟨	🟨	🟨	🟧	🟨
ET-14z	🟧	🟨	🟨	🟨	🟨	🟨
LAA	🟨	🟨	🟩	🟩	🟩	🟩
LAF	🟩	🟩	🟩	🟩	🟩	🟩
ET-04z	🟨	🟨	🟧	🟨	🟧	🟨

From these results it was possible to identify the wells most likely to have significant scale build up and target these as the most likely to give a better cost:value ratio. This was then combined with information from previous well intervention findings to identify the best candidate wells for scale mitigation treatment. This led to a short list of 3 wells, which would most benefit from intervention.

These wells were operating under a similar scaling regime with the main issue being long term build-up of carbonate scale in the lower sections of the well. These candidates were evaluated from a production perspective and the lowest production risk well (that which would impact production the least should we encounter issues) was selected for treatment with a carbonate dissolver. If this treatment is successful, then treatment will be carried out on a further 2 wells (which have similar scaling regime and estimated deposition volume). Bull headed chemical treatment of the wells is preferential, where feasible, due to the comparative cheapness versus application via coiled tubing and or milling as the platform does not have any permanent workover facilities.

Table 12 Predicted severity of $CaCO_3$ scale risk for producing wells

(SR_{CaCO3}: Green = no risk; Yellow = possible risk, Orange = probable risk;

SM_{CaCO3}: Green = no risk; Yellow = very low severity; Orange = low/mild severity).

	Downhole		**Wellhead**		**Separator**	
Well	SR_{CaCO3}	SM_{CaCO3}	SR_{CaCO3}	SM_{CaCO3}	SR_{CaCO3}	SM_{CaCO3}
ET-03	🟧	🟧	🟩	🟩	🟩	🟩
ET-08	🟧	🟧	🟩	🟩	🟩	🟩
ET-12z	🟧	🟧	🟩	🟩	🟩	🟩
SA	🟨	🟨	🟩	🟩	🟩	🟩
ET-14z	🟧	🟧	🟩	🟩	🟩	🟩
LAA	🟧	🟨	🟩	🟩	🟩	🟩
LAF	🟩	🟩	🟩	🟩	🟩	🟩
ET-04z	🟩	🟩	🟩	🟩	🟨	🟨

Although sulphate scale was originally suspected to be the major contributor to scaling issues in the Everest wells, from this study only one well is predicted to be susceptible to $BaSO_4$ deposition at bottomhole and this is a minor risk. This is significant as sulphate scale dissolvers are slower working than acid-based carbonate treatments, and therefore require a greater shut-in time and hence greater deferment. More significantly, the sulphate dissolver is heavier than carbonate dissolver and would have placed a greater lifting requirement on these low pressure wells than the lighter carbonate dissolvers. Had we not carried out the review and gone with preconceptions, and historic predictions and well treatment strategies (i.e. that there is a $BaSO_4$ scale risk to mitigate), we would have placed the well under unnecessarily high static head and caused potential lift issues without benefit.

The wellhead/separator ET-04 and SA separator $BaSO_4$ scale risks identified during the review are consistent with the occurrence of scale in the LCV pipework discussed earlier. Injection of scale inhibitor had already commenced, prior to the intervention, to try to reduce the topside scaling risk from the recommencement of ET-04 production earlier in the year. Scale inhibitor is injected into the ET-04 flow line and is injected at a level sufficient to protect both the individual well and the topsides process on mixing with other fluids. Following the review and field results, injection had been made permanent.

Benefits of review

The work undertaken as part of the scale management review has been beneficial:

- The formation water compositions and rates for the field and the associated uncertainties are now fully understood.
- The factors influencing the produced water compositions and rates have been identified.
- This has aided our ability to QC produced water samples and identify outliers from real and historic trends.
- It is now possible to undertake scale risk predictions to determine the associated scale risk to each well.
- This has allowed the wells that should be targeted for scale mitigation treatments to be identified and prioritised, allowing staged planning of interventions.
- It has also allowed those wells that do not require treatment to be identified meaning a reduction in unnecessary formation damage risks, lift issues, corrosion exposure, and HSE exposure.
- Similarly, this will raise the treatment success rate and reduce the risk of a poor spend/reward ratio.

Further work

A characteristic of several of the North Everest wells is their low formation water production rates. With their declining gas production rates, total produced water rates are also declining. Due to the presence of retained water in the test separator from previous tests, this is making it challenging to obtain good quality produced water samples within a sensible time frame during well testing. This has particularly been the case with samples from ET-14z where contamination free sampling currently requires exceptionally long well tests Therefore, a new method has been developed to allow produced water compositions to be determined under normal well test conditions. This will be trialled soon, and if successful, will be rolled out to other wells and fields as required.

Conclusions

1. A scale management review has been undertaken on the North Everest Field to better understand the current scale risks and to plan future mitigation and treatment requirements.
2. To aid this review, produced water analyses from the field have been interpreted allowing five compositionally distinct formation waters to be identified; three in the Lista/Andrew/Maureen (LAM) Formations and one (with subtle variations) in the Forties Formation.
3. Good estimates of produced formation water compositions and rates have been obtained for most wells on North Everest using the produced water analyses and PVT calculations.
4. These compositions and rates were used in scaling risk predictions which demonstrated that the current primary risk to North Everest wells is $CaCO_3$ deposition (and not $BaSO_4$ precipitation, as was previously thought).

5. The predicted scale risks are consistent with other ‘scale observations’ in the producing wells and topsides.
6. This work has allowed North Everest scale management planning to be undertaken with greater confidence and only a few wells have been found to require treatment meaning lower risks to field production.

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