MICRO-ENCAPSULATED TECHNOLOGY: NEW CHEMICAL TREATMENT FOR DOWNHOLE APPLICATIONS

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ABSTRACT
The common surface chemical applications cannot reach the bottom of the well or have low efficiency due to high fluid levels. This paper introduces a new chemical technology for all types of artificial lift systems that guarantees an efficient downhole treatment at the entry point and summarizes the applications of this revolutionary method established to deliver chemical combinations by microencapsulating the compounds and packaging the completed formulation in a chemical screen that is placed at the base of the tubing column below any type of artificial lift systems. The new downhole treatment technology was designed and successfully applied in 6 wells in the Permian Basin to control scale and corrosion. The installation of the chemical tool is easily made up below the pump intake and no additional equipment is needed in the pump or in the surface facilities.

INTRODUCTION

Chemical problems occur in almost every stage of production. Several methods have been presented to offer solutions to these problems and deliver chemical inhibitors into the produced fluids from oil wells. Nevertheless, some of these applications are not the best solution or represent a challenge for the oil industry due to high cost and uncertainty in the efficiency of the application.

The concept of encapsulation has been considered and practiced by a wide range of industries over many years. The pharmaceutical industry has pioneered this field by developing large gelatin capsules to provide a distinct dosage. The microencapsulating technology aims to protect and avoid deterioration of a special material due to high volatility and interaction with other components. In order to do that; the solid, liquid or gas that would be encapsulated, needs a matrix or membrane coating it but, also it has to be an agent or force that will release by breaking, melting, dissolving or crushing the thin wall that is covering it, so the fluid can act whenever is necessary which is the case of the New Technology applied to downhole treatments for oil wells. The chemical treatment needs to be dispersed at the bottom of the well so all the chemistry flows from the bottom to the top acting in the whole system.

A New Downhole Chemical Treatment has been developed for an optimal solution for chemical problems occurring downhole. This new technology includes chemical microencapsulation, a concept that has been present for many years, and that represents advantages such as control of the release rate of chemicals, easy installation, and protection of the encapsulated active agent against degradation.

This paper Introduces a new technology that guarantees an optimal downhole treatment at the entry point where usually, the common surface chemical applications cannot reach. The new downhole treatment technology was designed and successfully applied in 6 wells in the Permian basin to control scale and corrosion. These applications included a combination with a solid control system installed below a packer with the purpose of offering chemical protection of the downhole equipment (Pump + solid control tools).

MICROENCAPSULATION

Over the years many industries such as pharmaceutic, food, cosmetic among others have developed many processes that allowy to create a membrane that stop(stops) a substance to be released until is necessary for some specific function. These processes have varied and are based on scientific principles that deal with polymerization, surface energetic and reaction kinetics. The microencapsulation process contains physical and chemical considerations, for example, there are three forms of physical encapsulation, a slurry, a wet cake, and dry powder. The slurry form is a suspension of microcapsules in water containing preservatives. The wet cake is a slurry that has been filtered to approximately 50% to 70% capsule solids, with the remainder weight being water containing preservatives. The dry powder form of microcapsules contains less than 5 wt% moisture. This Form is typically provided only for capsules that are about 500 microns or less in size and is also dependent upon the type of capsule required membrane-type used to prepare the coating. Figure 1 shows the Microencapsulation Techniques, each technique depends on the nature of the fluid that would be encapsulated, the physicochemical properties, compatibility, and the application.

Another important factor is how the fluid inside the microcapsule would be released. In this case there is a variety of mechanical rupture mechanism where the most common are; (1) melting the shell material, internal rupture of the shell material activated by temperature; a certain increase of temperature will trigger the reaction within the system, (2) Biological degradation of the shell material involving the consumption of the capsule by microbial action and (3) solubility of shell material; the shell material will tend to change from insoluble to soluble due to changes in the pH and this would produce the release of the substance inside of the shell.

MICROENCAPSULATION TECHNOLOGY APPLIED IN CHEMICAL TREATMENT

From the great number of Microencapsulated Techniques, polymerization is the process used to create the shell matrix that will cover the chemical treatment. There are a variety of polymerization processes (Figure 1) including Interfacial polymerization, In-situ polymerization, and matrix polymerization.

The Interfacial Polymerization:
Creates the capsule shell at or on the surface of the droplet or particle by polymerization of the reactive monomers. The multifunctional monomer dissolved in the liquid core material and it will be dispersed in an aqueous phase containing a dispersing agent. At this point, a co-reactant amine is added accelerating the polymerization process creating the shell capsule around the core liquid or substance.

In situ Polymerization:
The capsule shell formation occurs because of polymerization monomers added to the encapsulation reactor. In this process, no reactive agents are added to the core material. Initially a low molecular weight prepolymer will be formed and as time goes on the prepolymer grows in size and deposits on the surface of the dispersed core material there by generating a solid capsule shell (e.g. encapsulation of various water-immiscible liquids with shells formed by the reaction at acidic pH of urea with formaldehyde in aqueous media (Cakhshaee et al.1985). Wang et al.

The polymerization process applied to this New Microencapsulation Technology process is an exothermic reaction that occurs readily at room temperature between the Polymeric ingredients, the solid additive and the Active ingredients creating a network cross linking of mainly covalent bonds. Initially, the polymeric ingredients are added to our blend and then the created polymer has the capacity to encapsulate and to absorb higher amounts of active ingredients such as Scale, corrosion, Paraffin, Asphaltene inhibitors, etc. without affecting their chemical properties. That encapsulation capacity can be increased by adding a solid additive to the final blend, creating a more stable and solid stick with enhanced capacity to encapsulate more active ingredients. Normally the process occurs almost immediately or until all the polymeric ingredients have reacted completely or the temperature has reached room temperature. The final solid mix is then mixed for a short period of time to ensure all the actives ingredients have been encapsulated completely into the final mix.

The microencapsulation process is performed by blending inhibitor compounds with a water-soluble matrix (Figure 2.) and extruding it under pressure to form condensed chemical sticks that are stored and cured for placement into a screen that will after, be sealed and prepared for delivery to the field.
The combination of compounds used depends on the chemical treatments that plans to be installed downhole. Different blends and concentrations have been developed taking into consideration the degree of chemical issues happening in the well. They include treatment for corrosion, paraffin and scale deposition.

DELIVERY METHOD

For this specific application, there must be a control method to release the treatment. The New Chemical Treatment for Downhole Applications Tool is designed to control downhole corrosive and scale deposition environments and organic deposits (paraffin and asphaltene). Depending on the well conditions, a short-term treatment combined with a long-term treatment is the best option to extend the run life of problematic wells. However, if the chemical is released all at once, the long-term treatment would disappear that is why it is so important to simulate and estimate the quantity of internal phase that will go through the capsule shell. There are several factors that affect the release control such as Solubility of the internal phase, type of polymer, Molecular Weight of the coating polymer, the capsuled particle size and the environment temperature. All these factors are studied carefully in order to simulate the well conditions and make sure that the chemistry would be applied at the moment and depth that was planned.

The encapsulated compound is encased in a screen-jacket metal tube. The tools are designed with 24 feet J-55 joint pipe base that contains a 2 feet perforated pipe section along with 304 stainless steel v-wire screen that offers an optimal dispersion area for the chemical (Figure 3). This downhole assembly containing the chemical matrix, slowly delivers chemical treatment at the level of production perforations, releasing all the chemical compounds and offering a solution for chemical problems occurring downhole.

CASE STUDIES AND RESULTS

Corrosion rate measurements in coupons, the concentration of iron and manganese ions, scale inhibitor and corrosion were performed for one year (Top) to determine the success of the applications. During this period, the corrosion rate was measured and maintained below 1.0 MPY in the wells with a SEVERE corrosion problem, as well as the iron and manganese content was always reported in the control range. Additionally, the longer run life without corrosion or scale problems was reported for the 6 wells analyzed and all are still operating efficiently.

These wells are located in the Permian basin and for each one, the amount of chemical treatment of a year was calculated. The chemical components for corrosion and scale were installed and after 14 months of installation in the 2 first wells, low concentrations of Iron and Manganese compounds and high Amine and Phosphate residuals were found in the residual tests carried out to track the amount of chemical treatment remained in the well.

The success of this delivery system for downhole chemical remediation can be measured in several ways. Ultimately, the customer and the oil company that has invested time, resources and capital to extract fluids for profit, determine the success rate. Fiscal concerns and price of chemical per barrel of hydrocarbon produced is a ratio frequently referred to by engineers in this phase of oilfield production.
The cost of providing this type of chemical applications is substantially less than surface chemical treatment applications that can be designed for specific period lengths based on the necessities of the operator and the characteristics of the well.
Several results have been gotten, showing improvements in well conditions. Furthermore, after a good period of time, chemical testing has been done to measure the concentrations of a chemical found downhole finding high concentrations and good results.

WELL A

Well, A was producing with an ESP PMP 400 H3000 W 109S 15AR with a tubing 2-7/8”. The well conditions are summarized in table 1 and according to the operator, the well reported several failures due to scale deposits and sand particles.
Based on the information and to control the sand production and the chemical depostis it was proposed a design with a double stage of separation with screens and Vortex Desander and tail joints. Below the tail joints, the chemical assembly was installed. The length of the tool was decided based on the expected production that was 3500 BFPD, and taking into consideration the Bottom Hole Temperature to calculate the amount of chemical to control the downhole conditions sucessfully. The whole assembly was installed below a mechanical packer to protect the pump shaft due to the inclination in the section. See table 2 with a complete design. Figure 4 shows the wellbore diagram with the positions of the tools in the well.
The Bull Plug was landed @7201’ which is the bottom of the 96’ Chemical Screen (7105 – 7201’) with an inclination of 54.49° and DLS 1°/100. Figure 5 shows the wellbore sketch with the inclination in the

installations sections. The high inclination was one of the main concern but because the use of the mechanical packer it was overcome.
The Chemical treatment installed consisted of a combination of Scale-Corrosion that would be in charge of stabalizing the iron and manganese ions in order to avoid corrosion and sequestrate the cations to prevent the formation of scale deposits. For controlling the iron deposits of scale, an acid surfactant treatment was installed as well. More details of the chemical components are showed in table 4.

After the installation of OSI's Tools, the concentration of Iron and Manganese have been fluctuating throughout, remaining in the optimal range of concentration for the tools to keep being effective. (Figure 6) The same monitoring was performed for corrosion and scale inhibitors, with good results found, the concentration rates for corrosion remained above the minimal corrosion inhibitor range. (Figure 7) For scale, we can see some period where the concentrations are below the minimal concentration, but this is because of a decrease in production. (Figure 8). To ensure the effective control of the scale deposits downhole, it was tracked a specific component in charge of capture the cations: THPS. Residual concentrations needed to be present so the system could be protected. Results are shown in figure 9, where it is illustrated that along the residual tests, this component was always detected. Finally, to determine the longevity of the treatment it was tracking the residual component of the Chemical treatment called Polytag. This component is unique and there is no natural source of it in the well, so all the concentrations reported must come from the chemical treatment in downhole. Figure 10 summarizes the tracking of the Polytag and how the component was in high values until December 2018. The aim is always to maintain the Polytag over the minimum value of 15 ppm so no additional treatment is required.

In general, the chemical treatment designed for this well had initial longevity of 1 year. The tool was installed in August 2017 and it was determined final longevity of 16 months after the evaluation of the performance. When the Polytag was not recorded in the residual tests, the operator company began a surface treatment to protect the bottom equipment until they had to do an intervention and re-run the downhole chemical treatment.

WELL B

The well B is located and the same cluster in the same field as Well A. This well was using an ESP PMP 400 H3000 CW 109S 15AR. The well conditions and problems reported by the operator were very similar to well A, so it was decided to run the same design as the well A and monitor its performance with the parameters tracked for well A. Well conditions are summarized in table 3. The technical design and wellbore schematic are shown in table 2 and figure 4 respectively.

The Bull Plug was landed @ 7655' which is the bottom of the 96' Chemical Screen (7558– 7655'). With an inclination of 59.64° and DLS 8.98°/100. Figure 11 shows the wellbore sketch with the inclination in the installations sections. The high inclination was one of the main concern but because the use of the mechanical packer it was overcome.

On this well, the corrosion rate was measured to determine the efficiency of the corrosion treatment (figure 12). The corrosion rate was reduced drastically and maintained below 1 which was the target in this application. The concentrations of Iron and Manganese for this well were also in the established range of acceptable data. (Figure 13) And it's possible to predict a similar behavior as the Well A with corrosion inhibitor concentrations above the minimal range accepted (Figure 14) and variation for the Scale inhibitor because of a decrease in production rates (Figure 15).

In the same way as Well A, THPS residual concentrations needed to be present so the system could be protected. Results are shown in figure 16, where it is illustrated that along the residual tests, these components were always detected. Finally, to determine the longevity of the treatment it was tracking the residual component of the Chemical treatment called Polytag. This component is unique and there is not a natural source of it in the well, so all the concentrations reported must come from the chemical treatment in downhole. Figure 17 summarizes the tracking of the Polytag and how the component was in high values until December 2018. The aim is to always maintain the Polytag over the minimum value of 15 ppm so no additional treatment is required.

In general, the chemical treatment designed for this well had initial longevity of 1 year. The tool was installed in August 2017 and it was determined final longevity of 16 months after the evaluation of the performance. When the Polytag was not recorded in the residual tests, the operator company began a surface treatment to protect the bottom equipment until they had to do an intervention and re-run the downhole chemical treatment.

WELL C

The well C was producing with an ESP H4300. with a maximum production of 6000 BFPD. Other well conditions are summarized in table 5. A complete water analysis (CWA) provided from the well was used to determine the chemical problems. The water analysis sample showed the presence of iron and dissolved H_2S and CO_2 along with the high amount of chloride presence and the pH is 6.4, it leads us to believe the possibility of corrosion in the well. Using a thermodynamic model and the CWA, the interaction of the ions was simulated, and it was found there was high deposition of calcite at higher temperatures and also siderite at lower temperatures and also a few proportions of barite at low temperatures (figure 18).

Due to a higher production rate in this well 120' Chemical treatment tool was installed for treating scale and corrosion, including acid surfactant concentrations. The combination of the chemical treatment was decided based on the simulation carried out and it is shown in table 6. The mechanism of inhibition is the same illustrated in table 3, however, the percentage of each component shows the effort to control mainly scale problems in the well. The wellbore schematic for this application is in figure 19. In this case, the hole chemical assembly was installed below the sensor since the weight of the assembly allowed to make it possible and would not represent any risk for the shaft of the pump.

In this case, the Iron and Manganese concentrations are optimal as well (Figure 20) while corrosion inhibitor and scale inhibitor keep the same behavior as the other wells. (Figure 21 & 22). In the same way as Well A and B, THPS residual concentrations needed to be present so the system could be protected. Results are showed in figure 23, where it is showed that along the residual tests, this component has been always detected. The treatment was installed in March 2018 and the polytag component used to detect the concentration of the chemical treatment in the well, is still above the minimal value (15 ppm). Figure 24.

In general, the treatment was designed for 1 year and still, the values obtained in the residual tests are above the threshold. Additionally, the well was treated with one acid job every month before the installation. In 2017 for five months, the well was treated 4 times. By contrast in 2018 after the installation of the downhole chemical treatment no acid job has been needed so and after analyzing the costs of the well, they presented a reduction of 40% on the investment to control the scale deposition based on the concept that the 120 Chem treatment has longer longevity. The scenario analyzed for these two treatments in 12 months is showed in figure 25.

WELL D

The well D is currently producing with an ESP system, with a maximum production of 5000 BFPD and WC of 93%. The well is producing from the same formation as Well C and according to the operator, the problems could be homologized with the analysis of the well C. The only additional condition considered was an unusually high bottom hole temperature generated by gas problems that were overheating the ESP motor. To avoid a rapid dispersion of the chemical treatment due to the high temperature, it was decided to space the Chemical tool 3 joints from the pump sensor. Additional information is showed in table 7.

After analyzing the well production and the CWA from well C, 120 feet of chemical treatment was installed for treating scale and corrosion, including acid surfactant concentrations. The total chemical combination is shown in table 6. The installation of the tool required special consideration due to the extra joints between the chemical tool and the pump. Figure 26 illustrates the wellbore schematic and how the tool is set up to avoid the heat coming from the motor.

As we can see in figure 27 the iron concentration has maintained low values except for one episode caused by a production anomaly, and the manganese content presents a stabilize trend without surpassing the 1.3 mg/L. The Corrosion and Scale inhibitors (Figure 28 and 29) proved a good chemical dispersion always maintaining values above the minimum. THPS have kept high values while the polytag is considerably above the threshold according to the last test. See figure 30 and 31.

As in well C, before the Installation of the New Chemical treatment the operator was using acid jobs to clean the wellbore and prevent future failures due to scale deposition. This change on the chemical treatment method obtained a decrease on the solution cost, in five (5) months a total of 7 acid jobs were needed to control the scale deposition, installing a 120’ Chemical treatment the well presented a reduction of 58% on the investment to control the scale deposition based on the concept that the 120 Chem treatment has a longer longevity, the average acid job rate was 1.4 job/month but the New Microencapsulated Technology will achieve approximately 12 consecutive months. By the moment of publishing this paper, the well has been operating by 7 months without failures.

WELL E

Well E was using an ESP 400PM HVSSD, the well was experiencing a poor motor cooling, so a water analysis test was run, and it was found, presence of iron and dissolved H2S and CO2 along with high amount of chloride presence and the pH is 6.4, it leads us to believe the possibility of corrosion in the well. Due to the poor motor cooling, the downhole temperature is going to rise, this will facilitate the Scale deposition. After analyzing the information provided, the Scale – Corrosion configuration was chosen as the best treatment for this specific scenario, a 120’ Extended Chem Screen was run, there is a Quick release (it would be released within one week) at the bottom of the assembly in charge of stabilizing the ph. Other well conditions are summarized in table 9. The design was chosen with the same combination as well C and D (table 6) and the method of installation is in figure 26 to prevent the overheating from the motor.

The iron concentration declines since the chemical tool were installed starting with values of 24 mg/L (Figure 32) and in the last 3 months, the concentration is between 0 and 5 which is great control of the corrosion environment. And the manganese maintains a stable trend with picks caused by production events. Figure 33 and 34 prove that the Scale and corrosion inhibitor are dispersing properly controlling the downhole conditions always maintaining more than the minimum concentration. THPS have kept normal values while the polytag is considerably above the threshold according to the lab tests. See figure 35 and 36.

WELL F

This well is currently producing with an ESP. The conditions of operation according to the operator were similar to wells A and B so the technical design was selected by the same considerations of these wells. Based on this, it was designed a 96’ length for maximum production of 1000 - 1100 BFPD with WC 70-72%. The bottom of the tool was landed above the perforations which are recommended.

According to Figure 37. the OSI Chem tool proved to have a clear effect on the prevention of failures due to corrosion and scale deposition. A clear decrease from 154 mg/L to 18 mg/L on the iron concentration proves the control provided by the Chem screen, and the Corrosion and Scale inhibitors concentration (Figure 38 and 39) proves that the tool has continuous dispersion maintaining the best conditions. THPS have kept normal values while the polytag is considerably above the threshold according to the last tests. See figure 40 and 41. Finally, the corrosion rate has been tracked showing value below 1 MPY which is the target for the treatment (figure 42).

CONCLUSIONS

- The creation of the micro-encapsulated chemical matrix offers an economical and optimal solution for chemical problems occurring when producing fluids.

- The New Chemical Treatment for Downhole application proved to be a successful tool to control challenging environments (Corrosion and Scale deposition), maintaining the downhole conditions stable and extended the run life of the well. All 6 wells are still producing.

- The variation of production can affect the results nevertheless; we can see how they go back to normal once the production is stabilized.

- In general, the New chemical microencapsulation process represents an excellent solution to treat chemical issues happening in wells. Nevertheless, it is important to evaluate all the parameters to make sure the treatment is more appropriate for each specific well.

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Table 1 Well conditions - Well A

WELL CONDITIONS		
PRODUCTION CASING	5-1/2	IN
CASING DRIFT	4.767	IN
TUBING	2-7/8	IN
MAX PUMP PROD	3500	BFPD
PUMP INTAKE	6986	FT
SENSOR DEPTH	7048	FT
KOP	7137	FT
ZONE (MD)	7510	FT
ZONE (TVD)	7413	FT
FRAC SAND	100 30/50 40/70	

Table 2 Technical Design-Well A & Well B & Well F

QTY	DESCRIPTION
1	**2-7/8” x 5-1/2” x 9’ Mechanical Packer**
1	**2-7/8” x 4’ x 75 Slot Bypass Valve**
5	**2-7/8” x 24’ x 20 Slot Tubing Screens**
1	**2-7/8” Vortex Sand Shield w/ 2.9 HE + 120’ Dip Tube**
10	**2-7/8” x 31’ Mud Joints (Supplied by Operator)**
1	**2-7/8” x 96’ Chemical Screen** ▪ **Bottom Section CD8019 (90%Scale 10% Acid Surfactant)** ▪ **Middle CD1252 (50%Scale 50% Corr w/quat+scavenger Surfactant)** ▪ **Middle Section CD8019 (90%Scale 10% Acid Surfactant)** ▪ **Top CD1252 (50%Scale 50% Corr w/quat+scavenger Surfactant)**
1	**2-7/8” OSI Bull Plug**

Table 3 Chemical screen components

Screen:	**Corrosion Rich**
Generic Description:	Chemical formulation to address corrosive tendencies downhole
Functional Applications:	A formulated blend of amines, amides, high molecular weight Imidazolines and surfactants to passivate corrosion issues. It provides film persistency and protection in turbulent environments and protection in the presence of acid gases. This formulation has also been modified with the addition of an alkyl pyridine coco quat and a triazine based scavenger combination for high acid gas (CO_2, H_2S) environments.
Screen:	**Scale Rich**
Generic Description:	Chemical formulation to address scale tendencies in downhole
Functional Applications:	A formulated blend of phosphonate, high molecular weight polymers, phosphoric acid, phosphonic acid, phosphonates and orthophosphates to inhibit scale formation in wide spectrum temperature and pressure environments. Iron chelators (THPC— Tetrakis hydroxyl methyl phosphonium chloride + THPS-- Tetrakis hydroxyl methyl phosphonium sulfate) have also been added to sequester metal compounds and promote film persistency for the active corrosion inhibitors.
Screen:	**Acid Surfactant Compound**
Generic Description:	A acid-based surface active agent to assist with wellbore cleanup when a presence of iron-sulfide or calcium carbonate scale is detected. The droppable sticks are used during the workover operation. The four sticks are dropped separately in the open hole to solubilize the scale components and promote suspension so that the flushing phase of the cleanup can discharge the residue.
Functional Applications:	Phosphoric acid surfactants solubilize scale components and promote metal integrity by leaving a residual protective layer on all exposed metal.

Table 5 Well conditions - Well B

WELL CONDITIONS		
PRODUCTION CASING	5-1/2	IN
CASING DRIFT	4.767	IN
TUBING	2-7/8	IN
MAX PUMP PROD	3500	BFPD
PUMP INTAKE	6986	FT
SENSOR DEPTH	7048	FT
KOP	7137	FT
ZONE (MD)	7510	FT
ZONE (TVD)	7413	FT
FRAC SAND	100 30/50 40/70	

Table 4 Well conditions - Well C

WELL CONDITIONS		
CASING 20#	5-1/2	IN
DRIFT	4.653	IN
TUBING	2-7/8	IN
MAX. FLUID RATE	6000	BFPD
OIL PRODUCTION	420	BOPD
WATER PRODUCTION	5580	BWPD
GAS FLOW	200	MCFD
WCUT	93	%
GOR	600	SCF/STB
API	42	°
PUMP INTAKE	6475	FT
KOP	6635	FT
LANDING POINT	7451	FT
TOTAL WELL DEPTH	16769	MD FT
TOTAL VERTICAL DEPTH	7151	TVD FT

Table 7 Technical design-well C, D and E

QTY	DESCRIPTION
1	**2-7/8" x 120' Extended Chem. Screen** **Top Section CD1250 (50% Scale 50% Corrosion)** **Middle Section CD8019 (75% Scale 25% Acid Surfactant)** **Middle Section CD8019 (75% Scale 25% Acid Surfactant)** **Middle Section CD1250 (50% Scale 50% Corrosion)** **Bottom Section CD8019 (75% Scale 25% Acid Surfactant)**
1	**2-7/8" x 8' Quick Release CD1000 (100% Scale)**
1	**2-7/8" Bull Plug**

Table 6 Well conditions well C

WELL CONDITIONS		
CASING 20#	5-1/2	IN
DRIFT	4.653	IN
TUBING	2-7/8	IN
MAX. FLUID RATE	5000	BFPD
OIL PRODUCTION	350	BOPD
WATER PRODUCTION	4650	BWPD
GAS FLOW	350	MCFD
WCUT	93	%
GOR	1000	SCF/STB
API	42	°
PUMP INTAKE (ASSUMED)	6475	FT
TOTAL WELL DEPTH	16765	MD FT
TOTAL VERTICAL DEPTH	7138.12	TVD FT

Table 8 Well conditions welll E

WELL CONDITIONS		
CASING 20#	5-1/2	IN
CASING DRIFT	4.653	IN
TUBING	2-7/8	IN
MAX. FLUID RATE	5356	BFPD
EXPECTED PRODUCTION	3500	BFPD
OIL PRODUCTION	770	BOPD
WATER PRODUCTION	2730	BWPD
GAS FLOW	748	MCFD
70API GRAVITY	42	º
WCUT	78	%
GOR	314	SCF/STB
GLR	69	SCF/STB
PUMP INTAKE	6753	FT
PUMP SENSOR	6801.2	FT

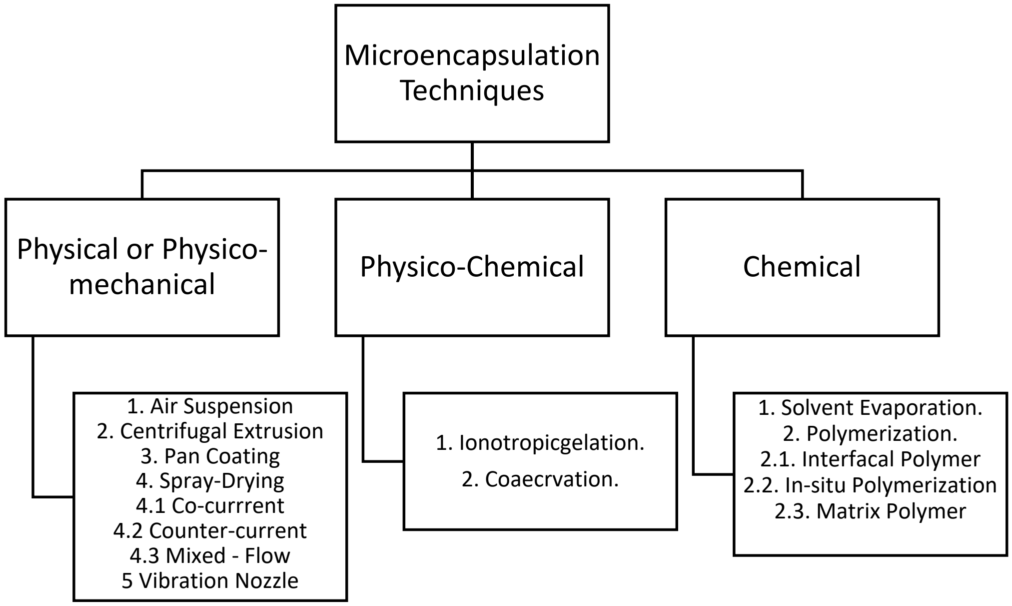

Figure 1. Different microencapsulation Techniques.

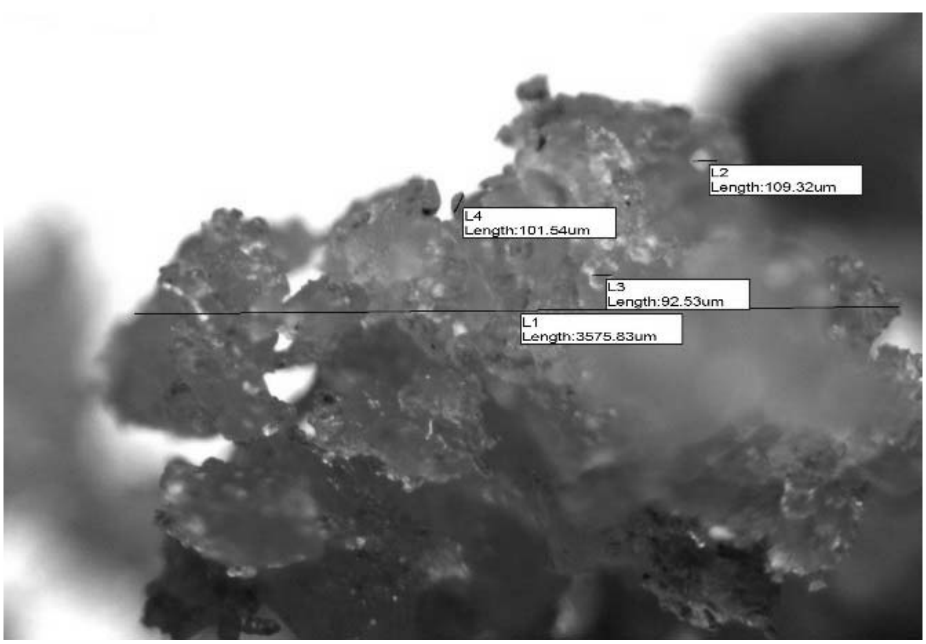

Figure 2. Inhibitors encapsulated in water soluble matrix.

Figure 3. Chemical Tools

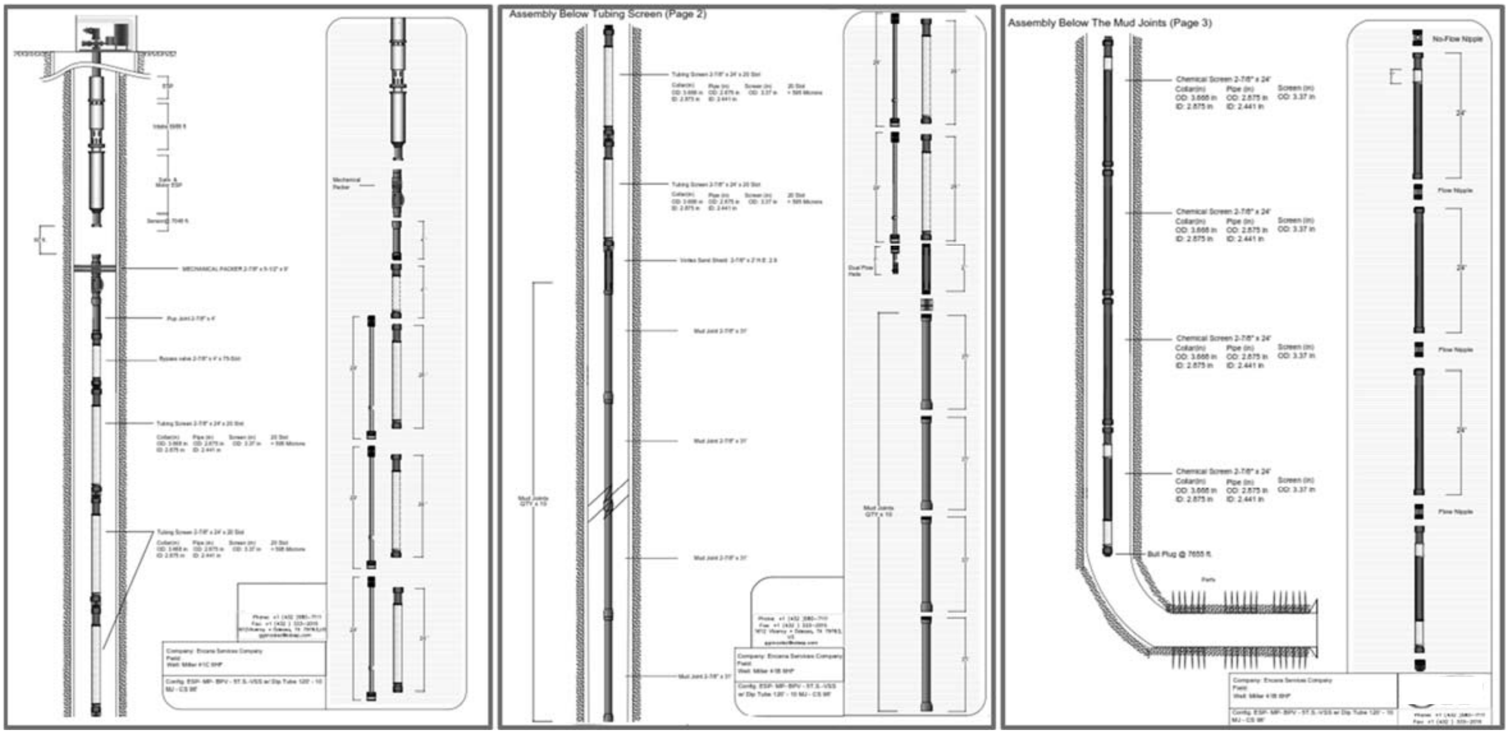

Figure 4. Wellbore Diagram-Well A & Well B

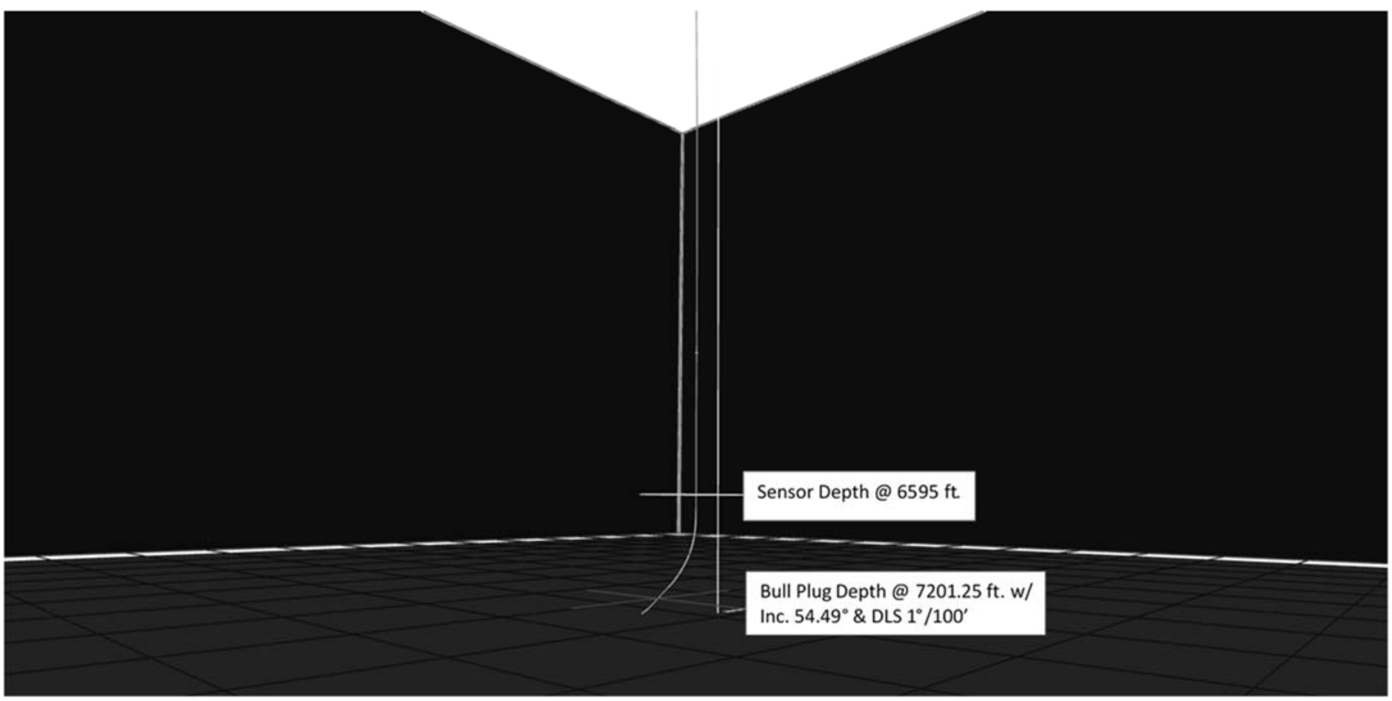

Figure 5. Deviational survey-Well A

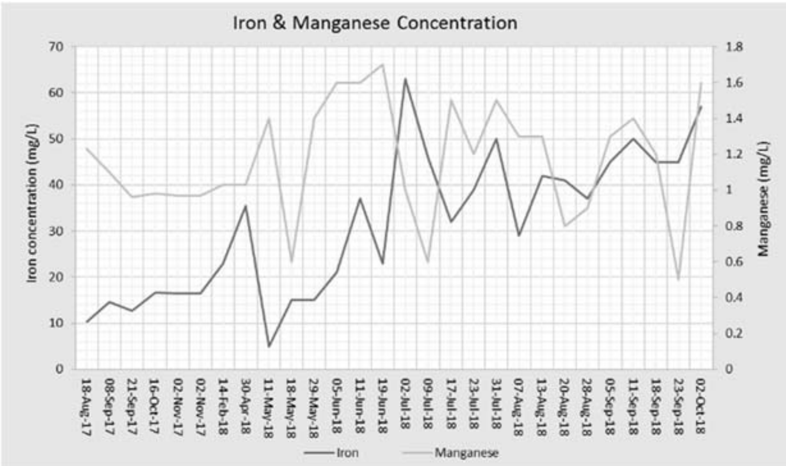

Figure 6. Iron and Manganese-Well A

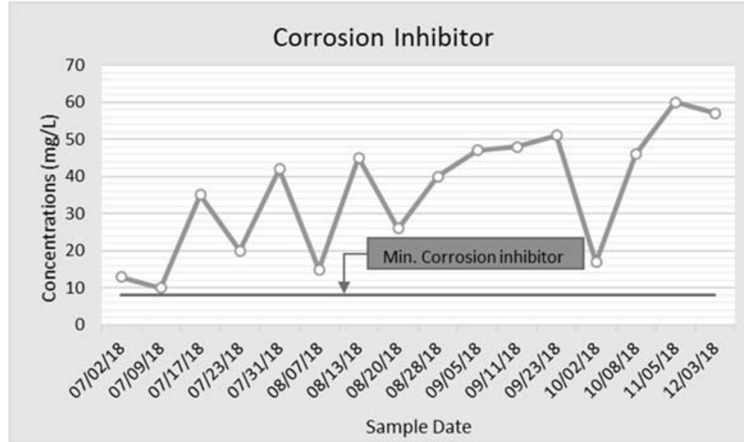

Figure 7. Corrosion Inhibitor-Well A

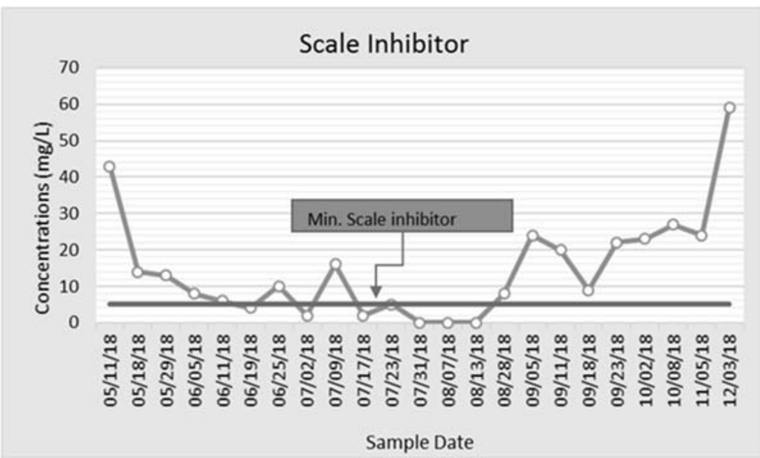

Figure 8. Scale Inhibitor Well A

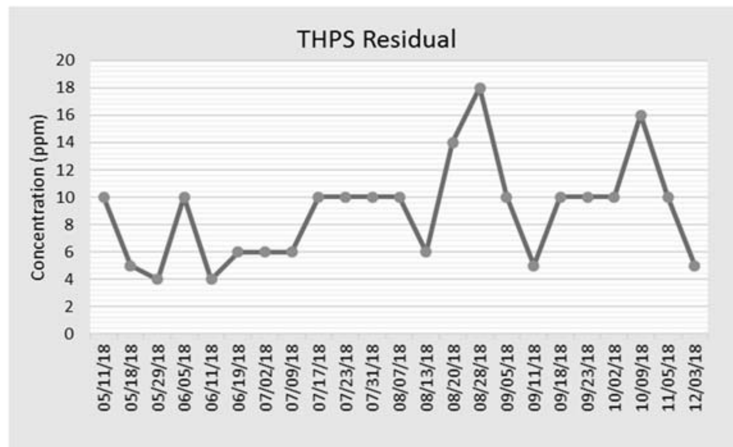

Figure 9. THPS Well A

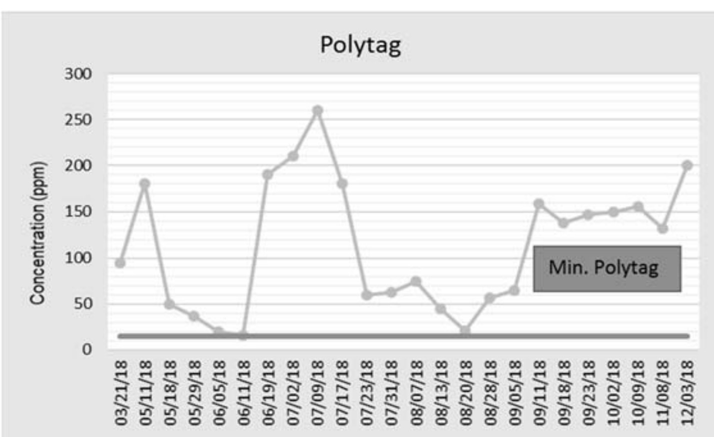

Figure 10. Polytag Well A

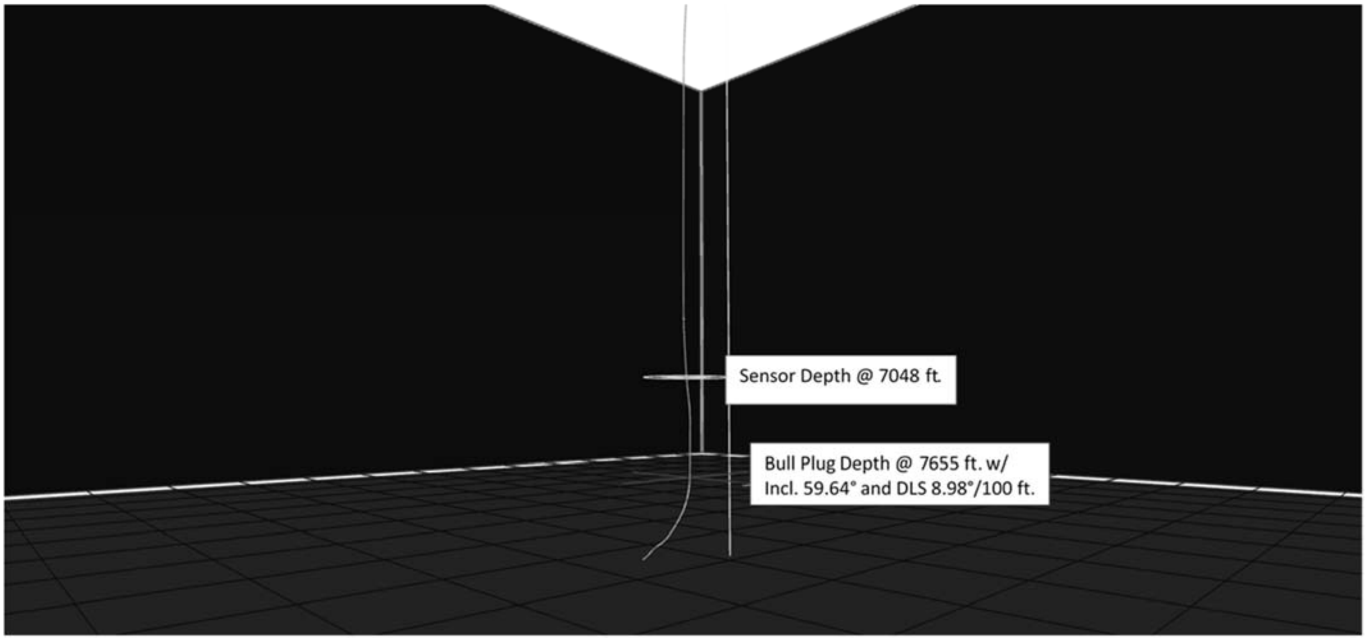

Figure 11. Deviational survey-Well B

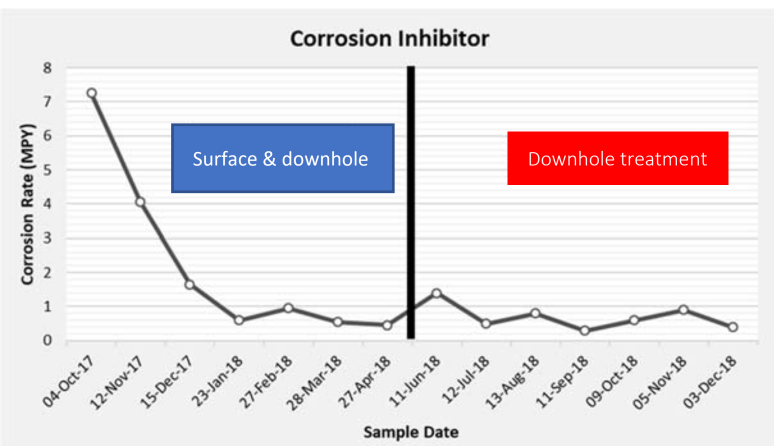

Figure 12. Corrosion rate well B

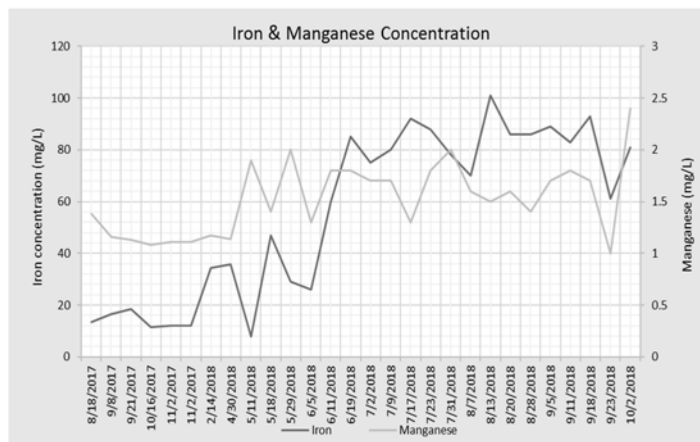

Figure 13. Iron and Manganese well B

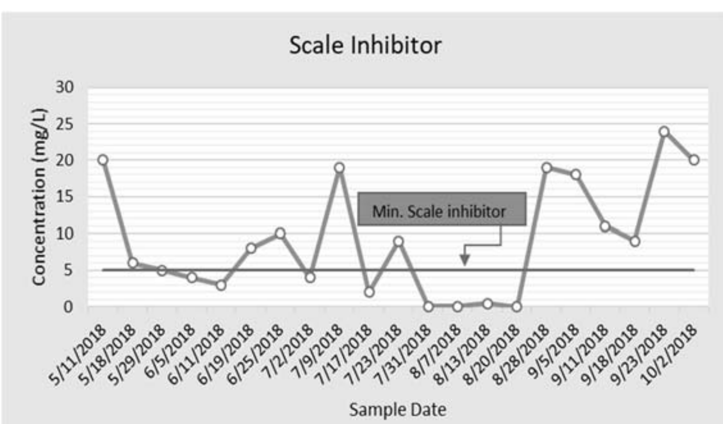

Figure 14. Scale Inhibitor well B

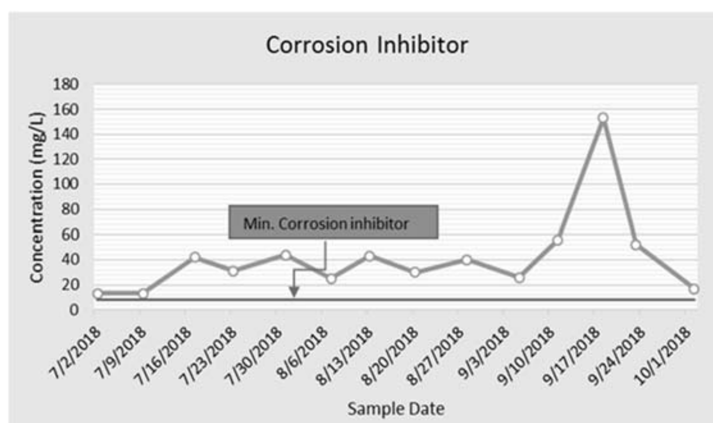

Figure 15. Corrosion Inhibitor well B

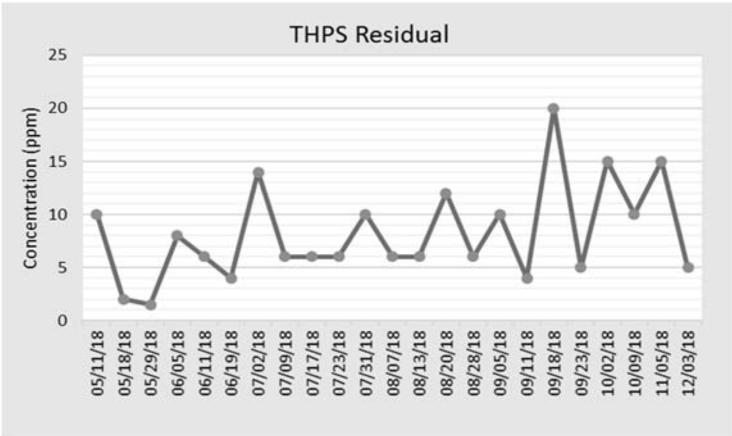

Figure 16. TPHS well B

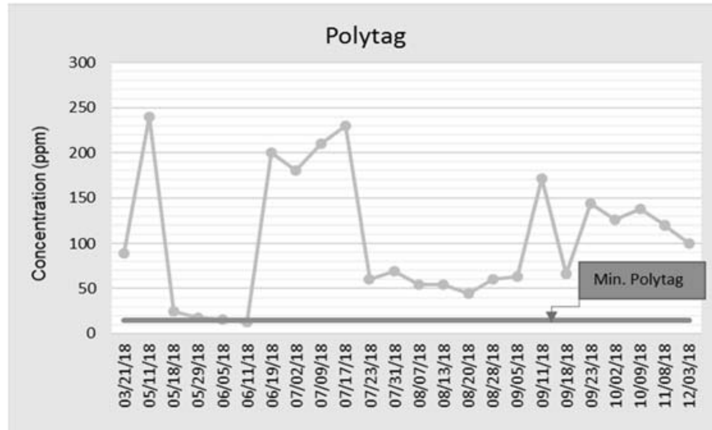

Figure 17. Polytag well B

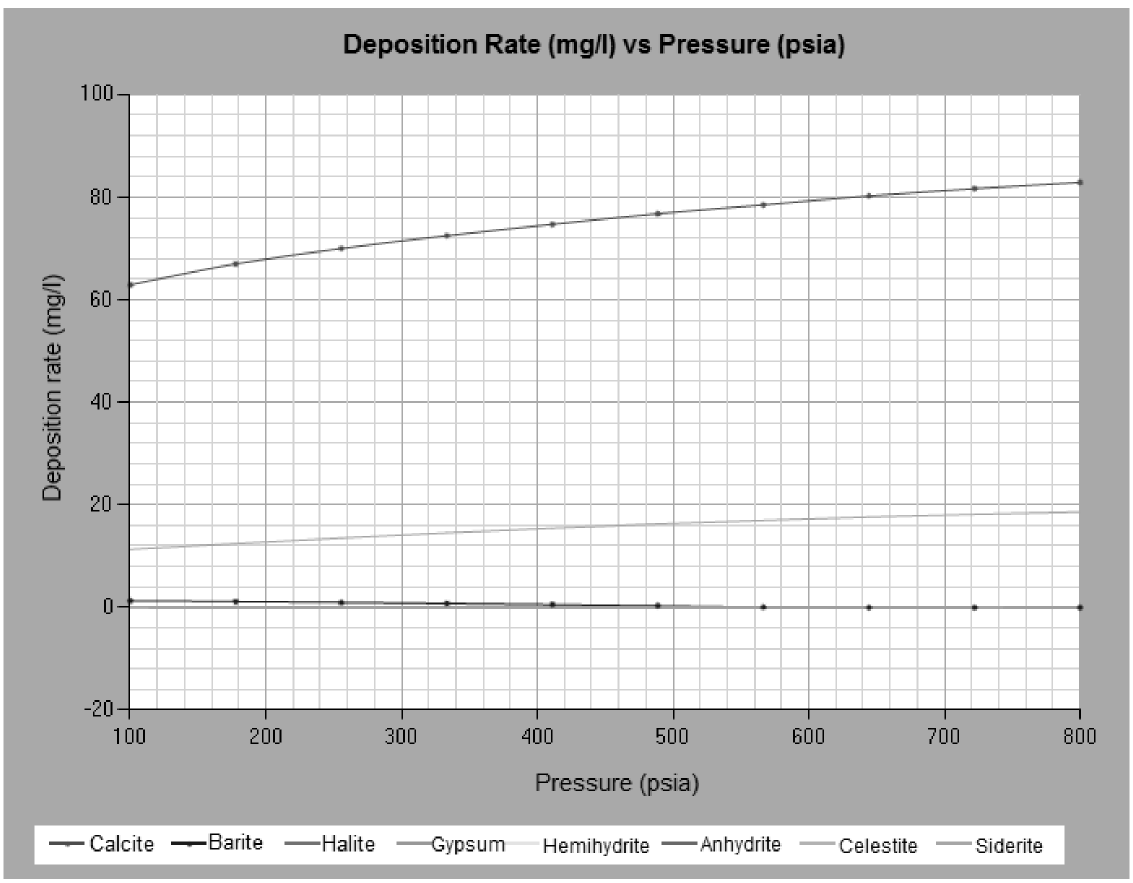

Figure 18. Thermodynamic simulation well C

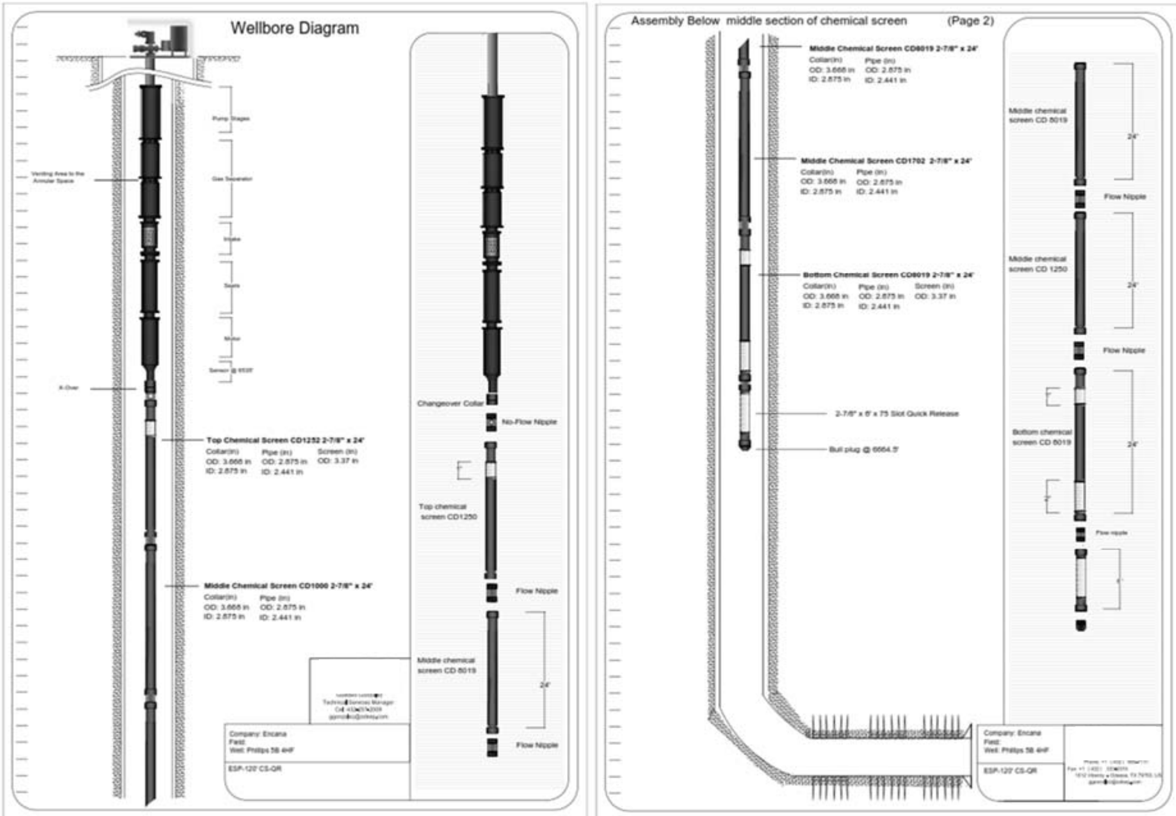

Figure 19. Wellbore schematic well C

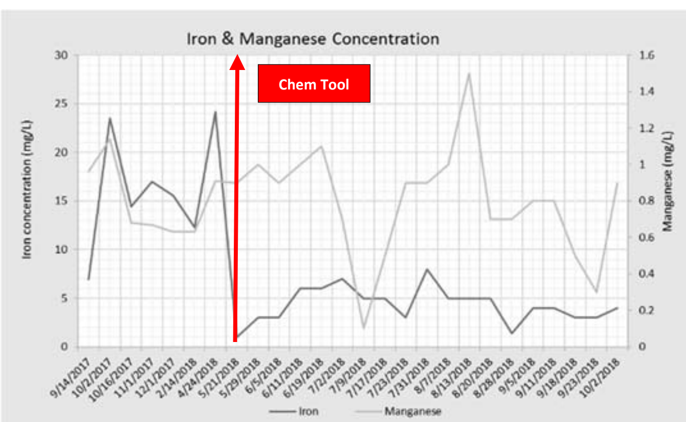

Figure 20. Iron and Manganese well C

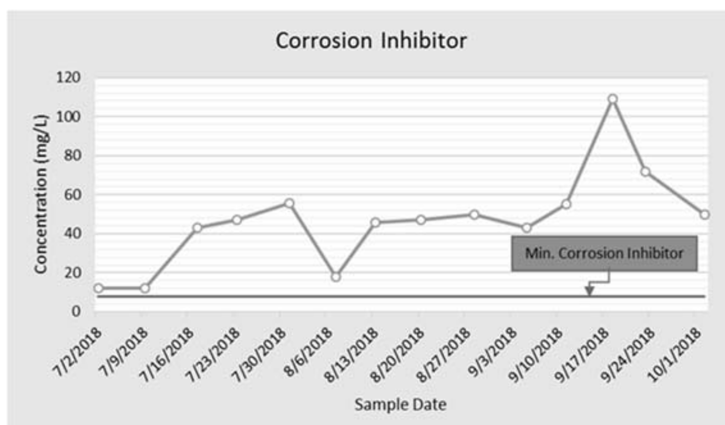

Figure 21. Corrosion Inhibitor Well C

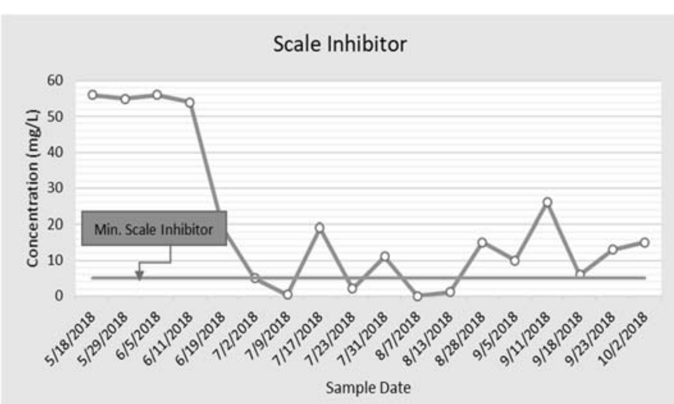

Figure 22. Scale Inhibitor well C

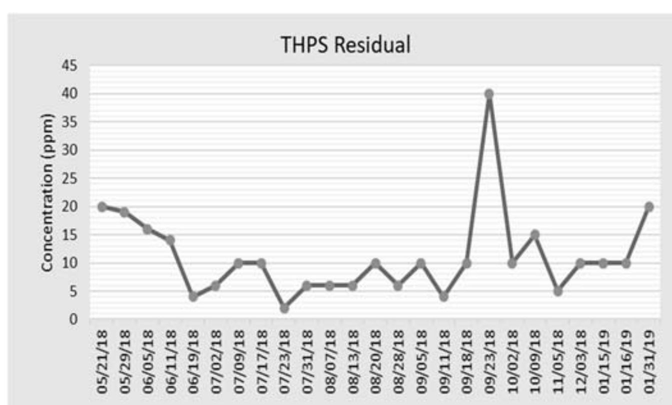

Figure 23. THPS well C

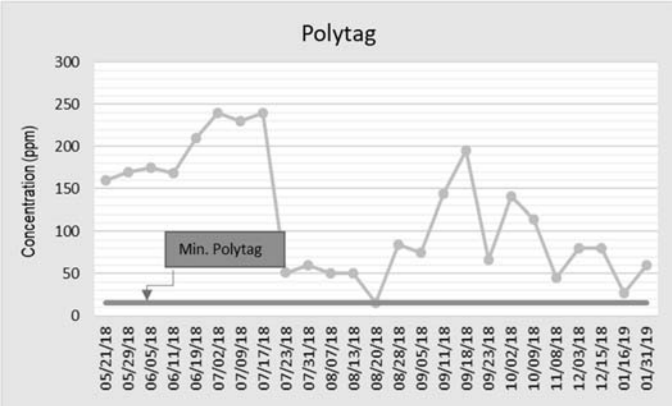

Figure 24. Polytag well C

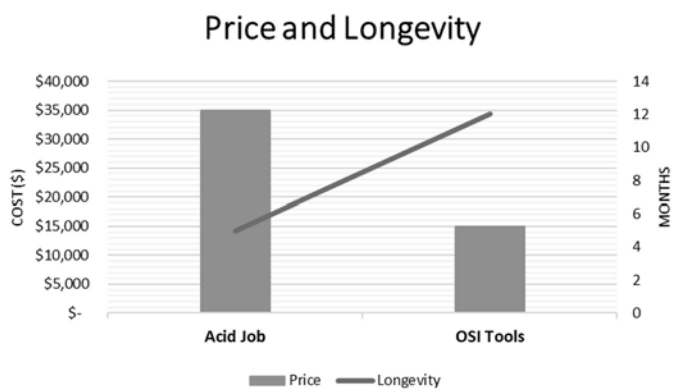

Figure 25. Price and longevity well C and well D

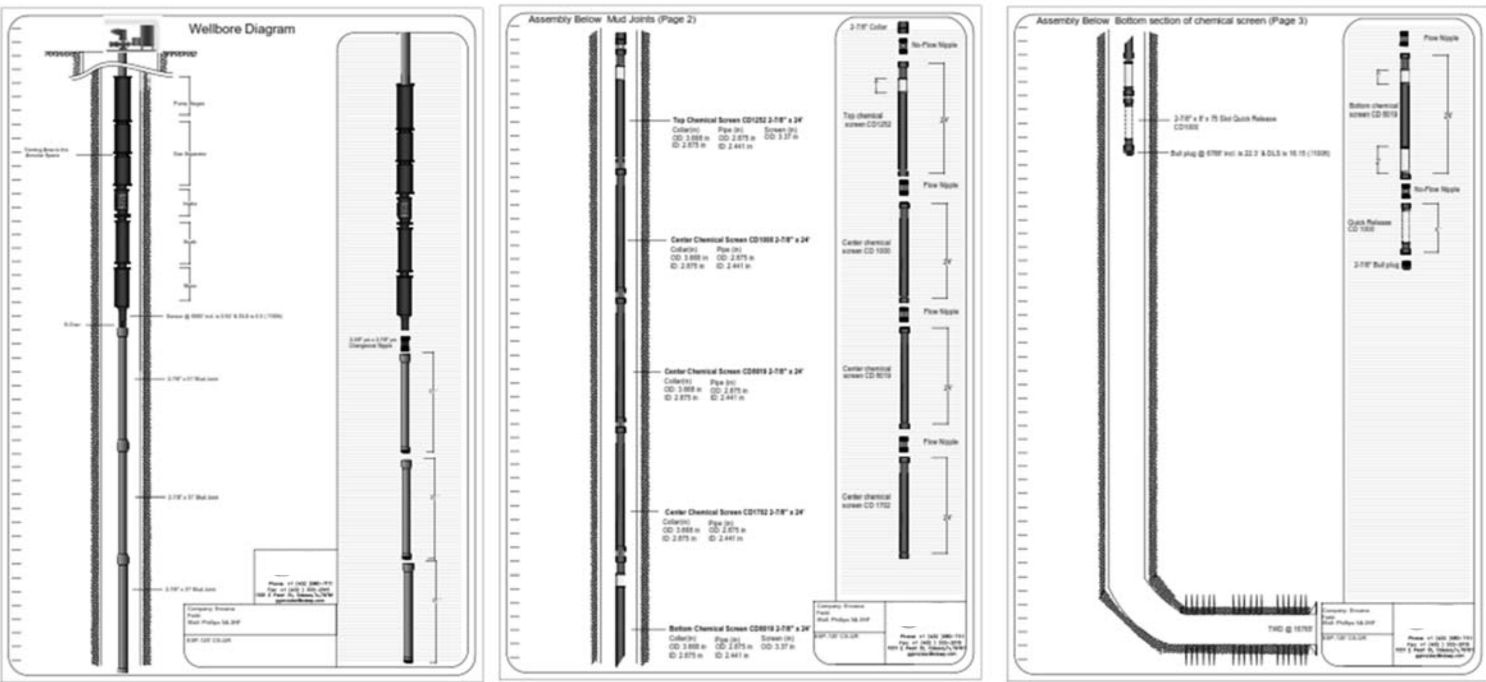

Figure 26. Wellbore diagram well D

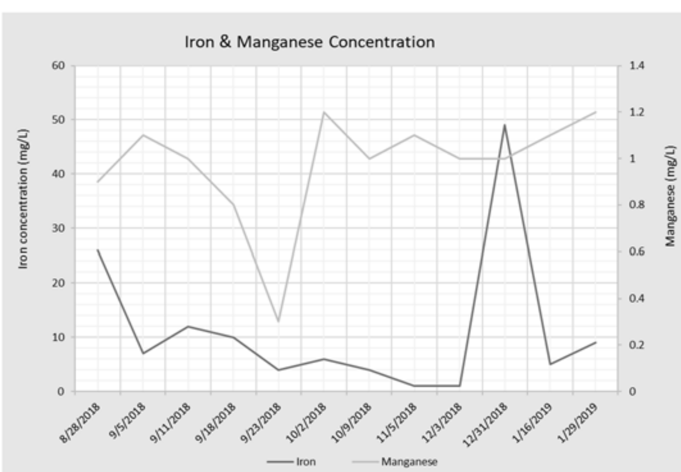

Figure 27. Iron and Manganese well D

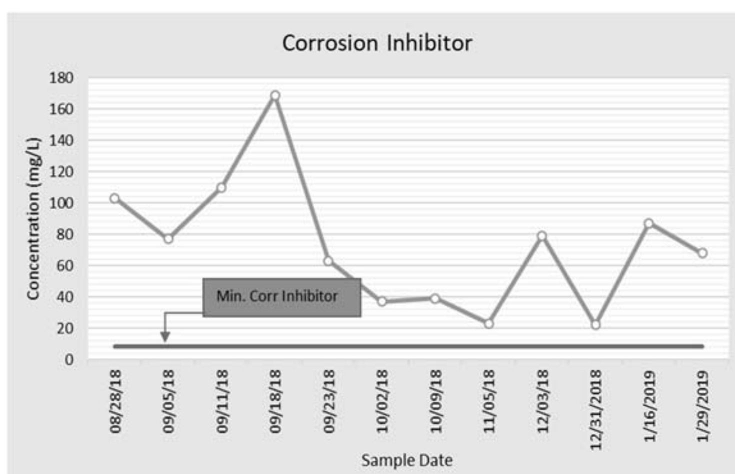

Figure 28. Corrosion Inhibitor Well D

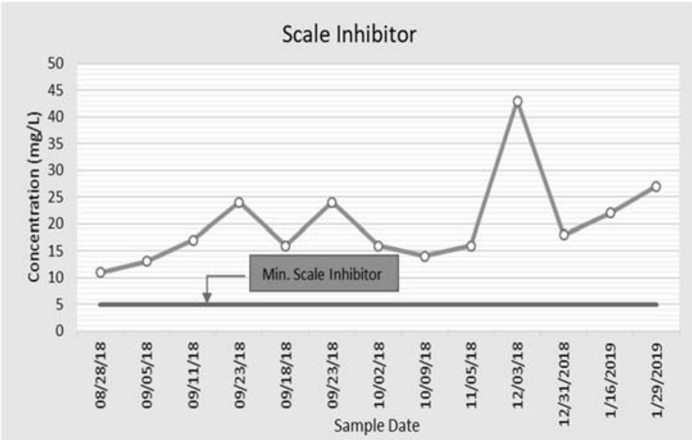

Figure 29. Scale Inhibitor well D

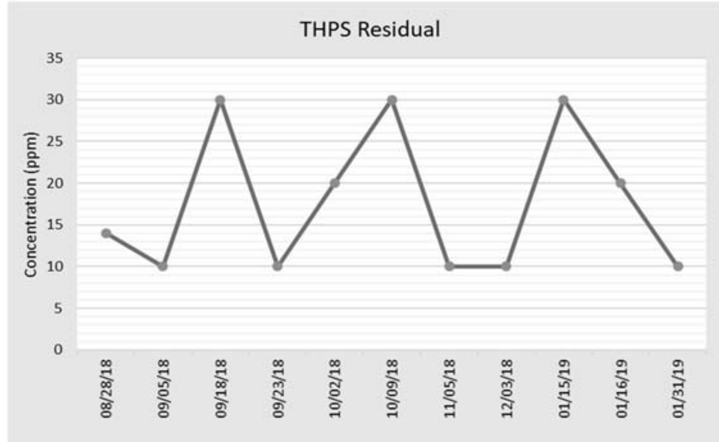

Figure 30. THPS well D

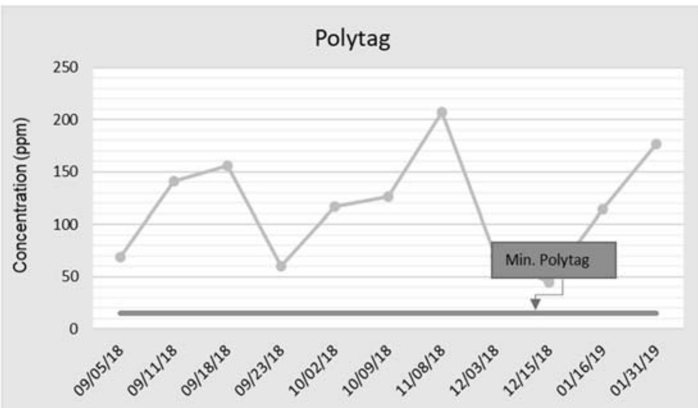

Figure 31. Polytag well D

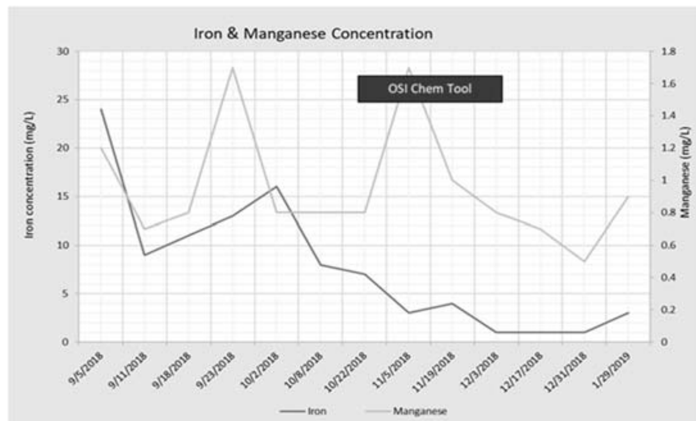

Figure 32. Iron and Manganese well E

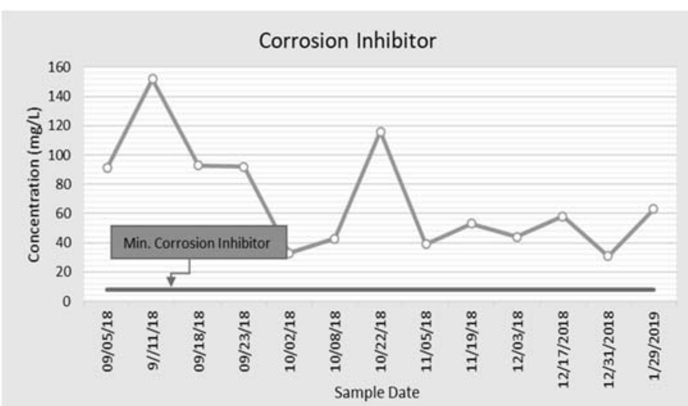

Figure 33. Corrosion Inhibitor well E

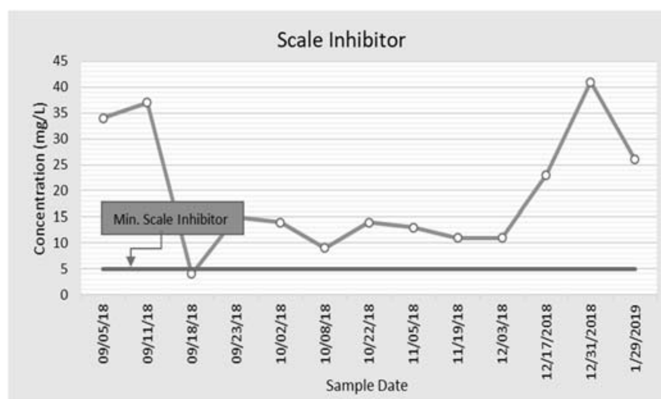

Figure 34. Scale Inhibitor well E

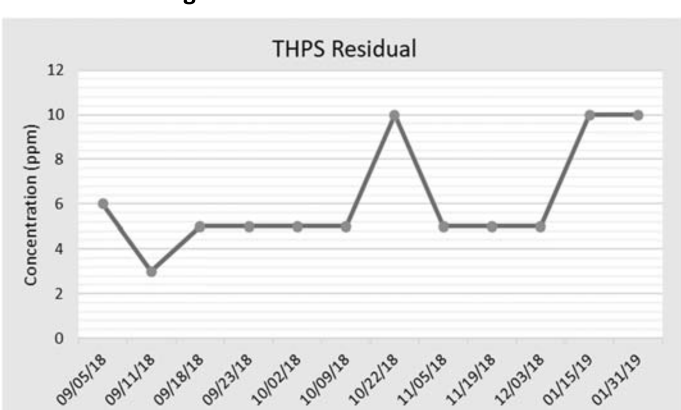

Figure 35. THPS well E

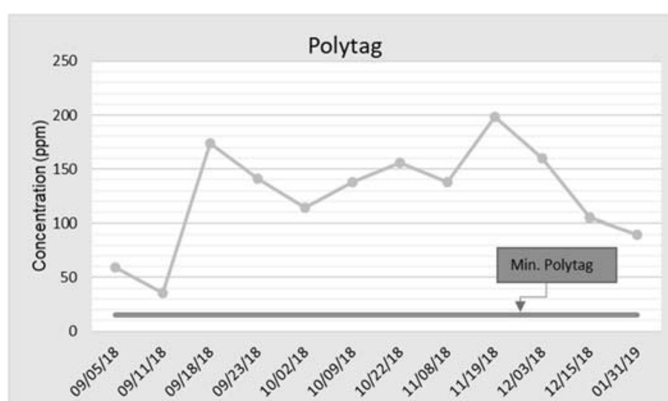

Figure 36. Polytag well E

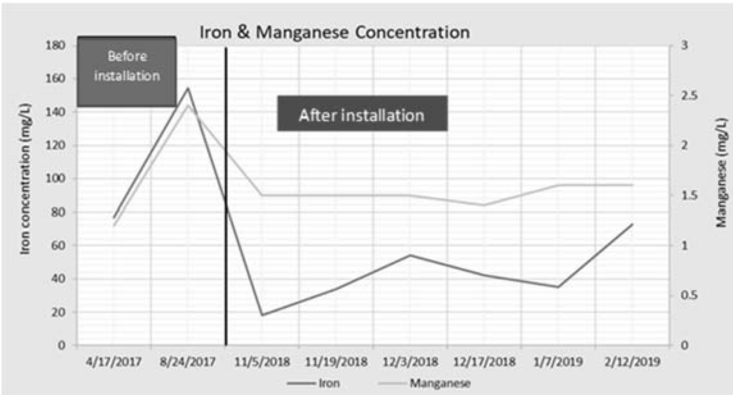

Figure 37. Iron and Manganese well F

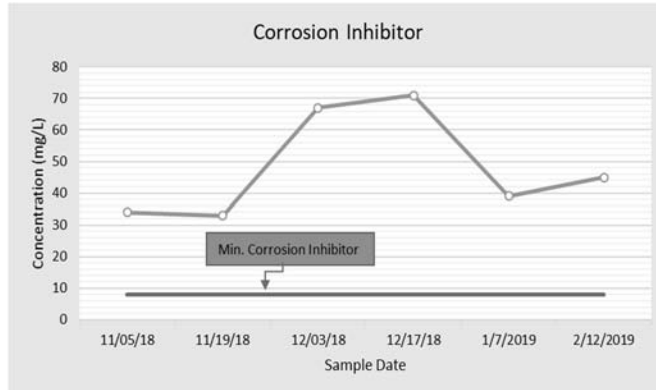

Figure 38. Corrosion Inhibitor well F

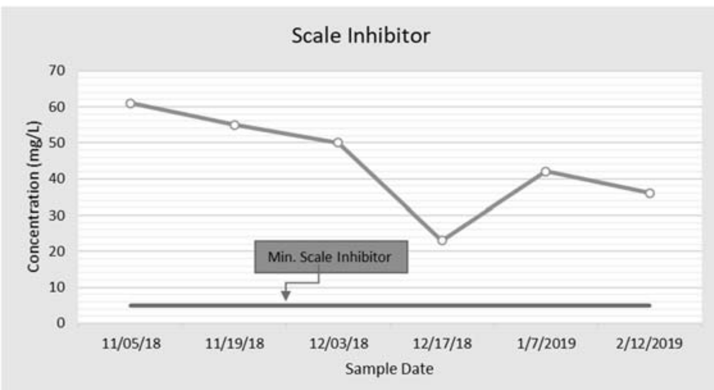

Figure 39. Scale Inhibitor well F

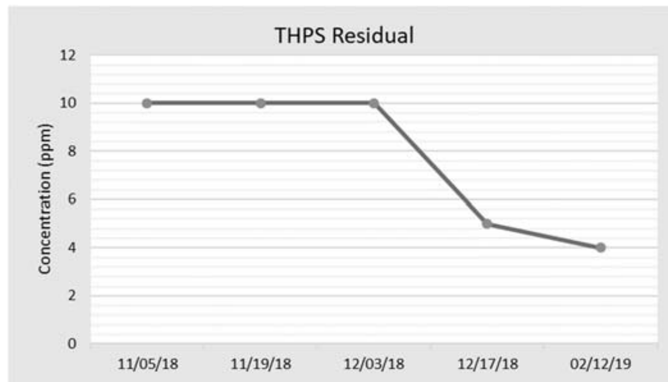

Figure 40. THPS well F

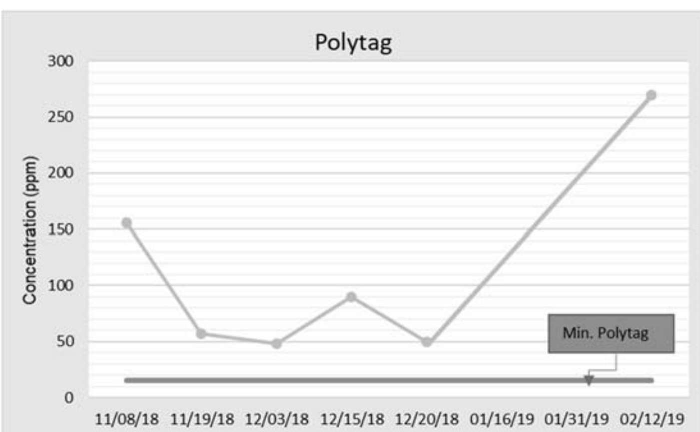

Figure 41. Polytag well F

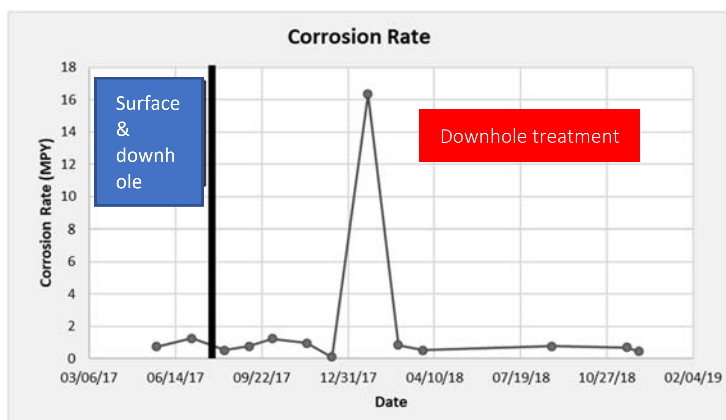

Figure 42. Corrosion rate well F