IMPROVING ESP PERFORMANCE COMBINING SAND CONTROL AND DOWNHOLE CHEMICAL TREATMENT-CASE STUDIES IN THE PERMIAN BASIN

B.N. Zapp, Lario Oil & Gas Co.
S.R. Vyas, G. Gonzalez, L.A. Guanacas, C.A. Portilla, Odessa Separator Inc.

ABSTRACT
This paper proposes a new method to deal with sand and chemical problems in the ESP. The protection system consists of 1) ESP sand separation system that works in two stages assuring the best sand separation efficiency. The first separation stage is composed of a V-wire geometry screened designed based on production. The second stage is a centrifugal system formed by a sand cutting resistance sleeve and a helix that creates a Vortex Effect. 2) Chemical treatment in downhole that microencapsulates the original components used on the surface and allows their installation and controlled dispersion at downhole below the sand separation system. The new system for sand control and downhole chemical treatment was successfully installed in 70 wells in one year. The design considered factor as the production expected, particle size distribution, mechanical well conditions and complete water analysis of the wells. This paper summarizes the most relevant cases.

INTRODUCTION
Sand control has become in one of the most important aspects of evaluation, whether a project is viable or not may be defined for the different sand control options in the market, especially in wells with high flow rate where the ESP system is currently the most used. The project evaluation become more challenging when not only sand, but also chemical problems are considered as a likely cause of failure. These two agents will short the runtime foreseen and will reduce the income in the evaluation.
A high sand production will cause many damages in the ESP system, when this enters in the pump the sand being either a formation nature or from a frac job it starts wearing the pump stages and the mechanical seal may present damage due to the vibration product of the presence of sand. The damage could create a path that will allow the fluid to flow through the seal and into the dielectric oil causing a failure in the system. The erosive nature of the sand will affect the impeller vanes affecting the hydraulic capacity of the pump this would increase the clearance on the stages triggering more recirculation and end up in a lower pump efficiency, which will increase the lifting cost. It is important to highlight that if there is a shutdown and there is sand inside the system and at the moment to restart the ESP it may cause a broken shaft, or the system is unable to start due to high motor current required. On the same way, corrosion and scale would make the ESP performance poorer. Due to the high heating effect of the motor in the fluid, the scale deposits are a very common problem in ESPs. In the short term, the massive scale tendencies will plug the pump intake and/or the flow path in the pump stages finishing with the production cycle and forcing to pull the assembly. This problem is even worse when all the agents are combined, and the erosion created by the sand trigger corrosion issues. This problem is very critical specially in the pump stages and shaft. The problem is the surface remedial treatment may not reach the pump intake because the high fluid column or when it reaches this point because mechanical degradation, this treatment would not provide the concentration needed. Regarding the sand problems, high volume of fluid and sand combined limit the use of different technologies, so the options are not widely available, and its applications could pauperize the pump operation.
This research presents a solution to high sand production and chemical problems through the use of a two-stages filtration system combined with a downhole chemical treatment, highlighting the big role that plays the right selection of slot size based on the size particle distribution acquired from the sieve analysis and the correct diagnostic and design of the chemical composition at downhole.

TWO STAGES FILTRATION TECHNOLOGY
The two-stage tool is an effective control equipment that is composed of a number Tubing screen depending on the maximum production of the well. This sand control device is made up of a screen jacket that is placed over perforated tubing with EUE thread with a different diameter option such as 2-3/8”, 2-7/8” and

3-1/2”. The screen section comprises a tubing screened in V manufactured on 304-stainless steel mesh where the fluid enters though the open area that has a specific design to prevent plugging in the screen. The tool capacity depends on the slot size, as bigger the slot size as bigger the open area. Table 1.
The second stage correspond to a Vortex separator that is in charge of separating the fine particles that can pass through the screen. The helix configuration generates a vortex effect and the radial force push the fine particles against the wall of the tool and by gravity these particles would be deposited in the mud joints below the double wall sleeve and the fluid flows upwards using a dip tube connected on top to the assembly. It is important to calculate the right amount of mud joints based on the sand rate to avoid future inconvenient. Figure 1 shows a schematic of how the assembly looks installed.

For the application of this tool there is some important data that is needed in order to analyze the whole scenario and provide the right expectations and recommendations. Table 2 shows the main information that it is required along another crucial such as deviation survey, previous interventions information, water analysis whether the well has or not possibilities of deposition of scale, etc.

DOWNHOLE CHEMICAL TREATMENT

This chemical treatment is based on the idea of taking the chemical components used in surface treatments and locating them right at the pump intake to achieve an effective inhibition of the most common problems: Corrosion, scale and organic deposits. To carry out this idea, multiple investigations were carried out that led to the development of a controlled solution pill created by the microencapsulation method. 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. After performing the encapsulation process, the final product is installed in a controlled dispersion system that is driven by the bottom temperature and the flow rate in the area adjacent to the dispersion slots. On the surface the chemical is in a solid state, but at the bottom of the well it acquires a colloidal nature that makes it combine with the production fluid. In addition to the storage and dispersion area, the containers that contain the chemical have an assembly of internal valves that allow the flow between joints when they are connected, but that close when the tool is removed from the well to avoid chemical spills. on the rig floor This mechanism guarantees the protection of both personnel and the environment (Figure 3).

FIELD BACKGROUND

The field is located mainly in Midland and Martin counties and had an aggressive drilling program during 2017 and 2018, with equivalent projections for the next 2 years. The field was developed and completed with electro-submersible pumps with initial flow rates between 4000 and 5000 bpd. In the initial stages there were many failures due to the presence of solids in the pump. As a first measure a device was installed to handle the sand above the pump, however, it did not prevent the erosion or accumulation caused by the sand in the stages and intake of the pump, therefore this first system was discarded and moved to a solution below the pump. The sand control system used was the two-stages filtration system installed under the pump sensor. The results achieved by this system were successful and the system was extended in another 10 wells. Based on the sensor data reported for these wells, increases in the motor temperature were evidenced, but due to the low volume of gas produced, a proactive evaluation of the tendency to scale in the field was carry out and based on these results, it was decided to combine the control of sand with the chemical treatment at the bottom of the well.

DESIGN OF THE COMBINED SYSTEM: SAND & CHEMICAL

The design of each well was done individually to analyze specific points such as expected production, water cut, well deviation, installation depth and the type of chemical problem affecting the well, however, at the beginning of the massive installation project, a characterization of the field was carried out to identify maximum flow rates expected, the granulometric distribution of the field and the types of chemical problems. Additionally, the scenarios were analyzed, focusing on the highest production expected and the most severe chemical conditions to define the most viable method of installing the system as a one assembly. The considerations are summarized below.

Sieve Analysis

Solid samples were collected in wells where failures had occurred and different sieve analyzes were performed to characterize particle sizes. Figure 4 shows a representative analysis of the field obtained from the Steuben 202WB well. More than 95% of the sample consisted of fine particles smaller than 381 microns. Depending on the expected production, the use of slot number 12 and 15 was initially considered for control 60 and 15% of the sand respectively. The final slot size will have to be selected after analyzing the length of the first filtration stage so that the pressure drop in the system can be analyzed

First and second stage of separation

In order to design the first stage of separation, the production volume must be considered, the sand production, the casing diameter and the slot size comparing with the pressure drop across the system. For the analysis, slot numbers 12 and 15 were considered and the results are shown in figure 5. To determine the number of Tubing Screen, the value of the calculated speed through the defined slot and diameters is compared with the speed erosion limit. The erosion speed is function of the sand production and the slot number. For this case, the sand production rate was classified as average (11-50 mg / L). After consider both scenarios it was decided to run 15 lot for two main reasons: The sieve analysis showed an average retention of 15% of the sand production on the slot 15, however, the sieve analysis are carry out after clean and dry the sample and does not consider the resorting effect and the agglutination of the particles, so we have found that in wells with apparently very fine particles, the real distribution at downhole change and become bigger. The second reason is that the screens will be combined with a second stage to optimize the separation so the particles passing through the screen are controlled by the Vortex tool that is made specially for the production rate. Now the second stage must be effective enough to control a high volume of sand. The efficiency of this tool is define for the open area in the helix where the flow will be submitted to the radial force. The perpendicular are to flow must be close enough to create enough force but wide enough to avoid erode the internal body of the sleeve. The Helix 2.9 was chose for this applications after reviewed the requirements mention before. Below this tool is necessary to calculate the right number of tail joint base of the amount of sand separated in the screen, the amount of sand separated in the Vortex, the vortex efficiency, and the run life expected (1 year). Under these scenario, 8 tail joints was the final result of the simulation.

Downhole Chemical Treatment

Based on the water analysis of the drilled wells, different simulations were performed at bottom conditions to determine what type of inorganics could be deposited and in what quantity. The simulation of the chemical species together with the production of the wells allowed to identify 2 types of zones. An area highly affected by scale deposits, mainly iron sulfide and carbonates and the other area with a greater tendency to corrosion. The simulation results are shown in figure 6 and 7. Figure 6 shows a high deposition rate for carbonates, on the other hand, figure 7 representing zone 2 shows a fairly low deposition rate so It was not considered a high impact issue. For zone 2 the problem was the high concentration of chloride and the low pH (<6.5) so the chemical treatment designed for each zone was different. Zone 1 was installed with a chemical treatment focused in scale: Scale inhibitors, acid surfactants and THPS. Zone 2 was installed with a chemical treatment focused on corrosion: Corrosion inhibitors and coco quat. Table 3 summarizes the designs.

Installation Method

The installation method was decided based on the average inclination of the wells and the depth of the perforations. In almost all the wells the final point of the installation was vertical, however the path to the point had deviated areas (figure 8). In the same way, in all the wells, the perforations were located below the pump, so it was decided to install a GV Cup packer connected to a slotted joint under the sensor. This packer is responsible for the isolation of the pump intake and forcing the fluid to enter through the Tubing Screens. The packer was installed with 2 centralizers to prevent damage to the cups during installation and excessive buckling of the pump during operation and thus protect the shaft. To confirm the weight of the assembly below the sensor will not overcome it's the capacity it was calculated the total weight of the BHA on air, considering all the tail joints below the Vortex were totally full with sand (See table 4).

The wellbore sketch of the tools designed for this scenario is showed in figure 9. From bottom up the chemical will disperse the active components in the production fluid. Then the treated fluid will flow through the Tubing Screens where the sand particles bigger than 381 microns are separated, then the mixture fluid/fine particles will flow downward to the helix that is in charge of the remaining particles. It is important to clarify that the efficiency of the Vortex Tool is function of the difference of density between the solid and liquid phase, so as greater the difference, higher the efficiency, so the sand will be separated but some fraction will be handled by the pump. After the fluid passes around the helix, the liquid will remain at the middle of the helix where the suction will take it all the way up to the to of the assembly (Packer). This inner pipe is called dip tube and is responsible for the communication between the fluid below and above the packer. After the clean fluid flow through the packer, it will exit the entire assembly by the slots of the slotted sub and then will flow to the pump.

CASE STUDIES

There are currently 86 wells installed with the combined system of sand control and downhole chemical treatment. From these wells, 53 wells are in the monthly monitoring program to monitor the performance of the chemical treatment and ensure its duration. In the monitoring, the concentrations of iron and manganese in the water are measured to identify drastic changes in the concentrations and evaluate the treatment efficiency. The concentrations of the scale and corrosion inhibitors are also measured to corroborate that the amount that is dispersed is effective and is found above the minimum limit. The Polytag is used as an indicator of the duration of the treatment, in general its value should be above 15 ppm to ensure that the duration will be optimal and the performance efficient. In some wells where there is a high presence of iron sulfide, THPS has been monitored, which is responsible for reducing iron concentrations in the water through the chelation process. The sand control system ins monitored with the sensor parameters. The relation between the current, frequency and voltages is very accurate to predict what is happening downhole. At higher presence of solid inside the pump, the motor requires more power to move the frequency for instance the current required is higher and the differential potential must increase.

Clark 402 WD

This well was installed in October of 2019, and it ran for 459 days, the well experimented few shutdowns due to gas, this well was pulled on January 2021.Figure 10 shows sensor parameters of the well. The well started at 45 Hz and basically maintained same frequency for around 6 months and then was increased up to 50 Hz, the PIP decreased from 3360 psi to final levels below 1500 psi. The well had some peaks on motor temperature which represented some shutdowns due to gas rate increased due to PIP declining. Vibration X and Y presented no significant fluctuations; “higher” values are shown after a shutdown period then it stabilized, this is due to the very fine particles flowing back into the stages and when restarting the friction between stages and fine particles can cause this effect.

The voltage was pretty much constant, and the motor was producing below 3000 RPM and it was increased to 3360 RPM until the failure. The motor temperature did not report high values so we can conclude that there is not scale deposits on the motor housing and that the chemical treatment is doing its job, peaks on motor temperature parameter are more related to gas slugs passing around the motor and avoiding a proper motor cooling.

Regarding the chemical treatment, the iron and manganese were reduced from the initial values (Figure 11). Scale and corrosion inhibitor decreased through time; however, both remain above minimum concentration levels confirming longevity of the treatment and efficiency based on ppm vs time. Iron and manganese concentrations have an increase trend and at some point, it decreases mostly when the dispersion point has released a considerably large amount of chemical overtime. THPS and Polytag decreased over time at the expected rate.

Figure 12 shows an economic evaluation showing investment vs money saved due to interventions caused by sand (based on field data and field experience), according to previous data, the initial runtime of new wells installed was around 200 days, meaning increasing the runtime by more than 100% represents a reduction of interventions evaluated in the same amount of time, the economic evaluation presented does not show cost related to damages to ESP components, but consider the deferred production, rig cost and average lifting costs. This evaluation suggests that by installing this technology the operator saved $127,528.20 only in interventions expenses and production deferred.

Clark 404 WB

The well was installed in October of 2019 and it stopped producing on June of 2021 (598 days), previous installations on this area showed multiple issues related to sand flow, scale precipitation and gas interference, normally all three issues are related or one triggers the other, which is the case of the scale precipitation around the motor due to higher temperatures causing peaks on motor temperatures causing multiple shutdowns, the sand caused multiple damages on shaft and upper stages mainly, large amounts of sand were found also on tubing string. The average runtime of "naked ESPs" near this well is around 200 days as maximum. According to figure 13 sensor parameters PIP decreased from 2,500 psi down to 1,327 psi, as the PIP decreases the ESP starts to experience gas affectation, however it remains a stable trend in terms of current and voltage, RPMs are between 2600 rpm and 3900 rpm at the end of the sensor graph, on march there was a electric failure and the sensor stopped sending data, but production remained until June 12th 2021.

The chemical treatment has resulted on reducing the iron concentration (Figure 14) from 12 ppm levels down to 6 ppm, the same case with manganese content it decreased this value below 2 ppm. Scale and corrosion inhibitor have both decreasing trends, first trend shows a rapid decreasing levels due to high initial productions, once the production stabilized the trend becomes more constant. THPS and Polytag shows a proper chemical dispersion quantity and dispersion velocity. When pulled the inspection of the sand and chemical control system was carried out, finding that the 98% of the entire chemical treatment was released, only few traces of chemicals remained on connections and mass transfer control valves. Figure 15 shows the economic evaluation for this well, considering the run time achieved with the rig expenses and the average runtime of the field, the operator saved $226,620.00 only in intervention expenses. Not ESP expenses were considered in the analysis.

Peggy 401WB

This well was installed in June 2019, and it ran for 566 days without failures, the previous runtime on the area was about 180 days, in this case the runtime was improved more than 200%. This well produced constantly gas rates above 1100 Mcfpd, causing difficulties to achieve constant conditions, as it is shown in figure 16, with small pressure dropdowns the current reacts immediately, in this case this well managed velocities between 3000 and 4200 RPM, we have a few high peaks of temperature due to gas on the motor causing shutdowns and the period after a shut down the current takes some time to clean some of the solids and gas accumulated inside the pump stages. Acid surfactant component prevents the motor to create a layer of scale, which would generate more periodic shutdown, in this case the chemical treatment is preventing a higher number of shutdowns (more downtime) and more affectation to the life of the motor. The chemical tracker shows a manganese decreased from 2.3 to levels below 1.5 ppm, on the other hand iron remain stable for the first months and it increased drastically, this information was considered when the decision was made to increase the % of corrosion inhibitor for the reinstall. The pulling report for this BHA indicated slight corrosion on some sections of the equipment and tubing string came out in good conditions. Scale and corrosion inhibitor maintain levels of concentration above minimum and THPS and polytag decrease through time with a relatively stable trend which indicates longevity target. Economic evaluation is shown on figure 18, showing savings of $208,400 in expenses rig in 566 days.

Peggy 101WA

This well was installed for the second time on 12/23/2019 achieving a runtime of 514 days coming from a previous runtime of 250 days. The application of the sand and chemical was imperative on this well due to the severe scale precipitation, by using the downhole chemical delivery method it kept the Tubing screens clean for a long period of time (Until minimum concentrations were reached). Figure 19 shows the sensor parameters with a stable trend, PIP has decreased from 2000 psi to below 1000 psi, the frequency was increased from 45 up to 65 Hz, maximum velocity is 3900 RPM. There are a few peaks on the motor temperature, but the ESP does not have any problem going back up and no major fluctuations were observed. This well was shut down for two months in 2020 due to operational conditions and turn buck up without pulling the tubing, so the runtime is 514 days, but the equipment has been downhole 576 days. The chemical dispersion velocity decreases when the well is not flowing, in this case levels of scale inhibitor and corrosion increase after these months presented a slight increase in concentration and then had a declining trend, the same concept happens with the THPS and the Polytag component. While the well was shut down the chemical monitoring continued to prevent any changes that might affect the integrity of the ESP. Economic evaluation is summarized in figure 21.

CONCLUSIONS

- The improvement in the performance of the electrical submersible pumps can be improved even in challenging conditions with combined sand and chemical problems. It is always important to perform the technical evaluation in each well and determine the feasibility of each method to reduce uncertainty

- With the installation of more than 80 with the combined system of sand control and chemical treatment, the high efficiency of this method has been demonstrated. It should be noted that this is not a standard solution and each case must be evaluated in particular. Similarly, the variables used in the monitoring should be defined based on the problems of the well

- Analyze parameters such as: motor current, voltage, frequency, motor temperature and vibration if available are keys to monitor the performance of a sand control system. Additionally, measurements of surface sand production are recommended.

- The chemical treatments are quite complex but to achieve success in this type of treatment an adequate diagnosis and identification of the specific agents that affect the well must be carried out. Thermodynamic simulations and fault reports can provide valuable information for the design.

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Table 1 Different open areas according to the slot size

Tubing Screen x 1 Unit Open area					
2-3/8"		2-7/8"		3-1/2"	
Slot	Total open Area (in2)	Slot	Total open Area (in2)	Slot	Total open Area (in2)
12	254.4	12	298.7	12	349.3
15	308.9	15	362.8	15	424.16
20	393.24	20	461.75	20	539.85
50	772.44	50	907	50	1060.4
75	983.1	75	1154.34	75	1349.63

Table 2 Well Conditions-Information required to use two stages filtration system

WELL CONDITIONS		
CASING	-	IN
CASING DRIFT	-	IN
TUBING	-	IN
AVERAGE FLUID RATE	-	BFPD
TARGET OIL PRODUCTION	-	BOPD
TARGET WATER PRODUCTION	-	BWPD
GAS FLOW	-	MCFD
WCUT	-	%
GOR	-	SCF/STB
GLR	-	SCF/STB
API	-	
SENSOR DEPTH	-	FT
BOTTOM PUMP	-	FT
LL	-	FT
TOP OF PERFS	-	FT
KOP	-	FT
THP	-	PSI
CHP	-	PSI

Table 3 Chemical design - Zone 1 & 2

Zone 1	
Screen:	**Scale Rich**
Generic Description:	Chemical formulation to address scaling tendencies downhole
Functional Applications:	Formed mixture consisting of phosphate, high molecular weight polymers, phosphonic acids, phosphoric acids, phosphonates and orthophosphates to inhibit the formation of scale in wide spectrum of 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.
Zone 2	
Screen:	Corrosion Rich
Generic Description:	Chemical formulation to address corrosive tendencies downhole
Functional Applications:	A formulated blend of amines, 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:	Hydrogen Sulfide Scavenger Compound
Generic Description:	A triazine based compound used a scavenger to remove hydrogen sulfide from crude oil. Triazine is a heterocyclic structure similar to benzene, but with three carbons replaced by nitrogen atoms.
Functional Applications:	Triazine reacts with H_2S to form dithiazine, the main byproduct. (Notice the Figure below.) The triazine based scavenger is integrated into the OSI corrosion inhibitor Compound to assist in passivation by assimilating the acid gas. This component along With the Alkyl Pyridine Coco Quat can provide comprehensive corrosion inhibition.

Table 4 Total weight of the BHA below the sensor

DESCRIPTION	Top Thread Connection	Bottom Thread Connection	Status	Max. OD (in)	Body OD (in)	Length (ft)	Top (ft)	Bottom (ft)	Weight (lb)
PUMP SENSOR		2-3/8" EUE box		3.066	N/A	3.2	7155.3	7158.5	
X - OVER 2-3/8" TO 2-7/8" (Supplier: **OSI**)	2-3/8" EUE pin	2-7/8" EUE pin		3.665	3.665	0.5	7158.5	7159	4
2-7/8" X 6' PUP JOINT (Supplier: Lario) + CENTRALIZER (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin		5.500	2.875	6	7159	7165	75
2-7/8" x 4' SLOTTED SUB (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE box	NEW	3.665	2.875	4	7165	7169	40
2-7/8" TUBBING NIPPLE (Supplier: **OSI**)	2-7/8" EUE pin	2-7/8" EUE pin	NEW	2.875	2.875	0.5	7169	7169.5	5
2-7/8" x 5-1/2" x 4' GV CUP PACKER #20 - #26 (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	5.5	2.875	4	7169.5	7173.5	30
2-7/8" X 6' PUP JOINT (Supplier: Lario) + CENTRALIZER (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin		5.500	2.875	6	7173.5	7179.5	75
2-7/8" x 4' x 75 Slot BYPASS VALVE (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.665	2.875	4	7179.5	7183.5	50
2-7/8" x 23.5' x 15 Slot TUBING SCREEN W/ DUAL FLOW (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.665	2.875	24	7183.5	7207.5	264
2-7/8" x 23.5' x 15 Slot TUBING SCREEN W/ DUAL FLOW (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.665	2.875	24	7207.5	7231.5	264
2-7/8" x 23.5' x 15 Slot TUBING SCREEN W/ DUAL FLOW (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.665	2.875	24	7231.5	7255.5	264
2-7/8" x 23.5' x 15 Slot TUBING SCREEN W/ DUAL FLOW (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.665	2.875	24	7255.5	7279.5	264
2-7/8" x 23.5' x 15 Slot TUBING SCREEN W/ DUAL FLOW (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.665	2.875	24	7279.5	7303.5	264
2-7/8" x 23.5' x 15 Slot TUBING SCREEN W/ DUAL FLOW (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.665	2.875	24	7303.5	7327.5	264
2-7/8" x 23.5' x 15 Slot TUBING SCREEN W/ DUAL FLOW (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE box	NEW	3.665	2.875	24	7327.5	7351.5	264
2-7/8" x 2' VORTEX SAND SHIELD W/ HELIX 2.9 (Supplier: **OSI**)	2-7/8" EUE pin	2-7/8" EUE pin	NEW	3.625	3.625	2	7351.5	7353.5	30
TAIL JOINT 2-7/8" x 32.5' QTY 8 (Supplier: Lario)	2-7/8" EUE box	2-7/8" EUE pin		3.665	2.875	260	7353.5	7613.5	1920
COLLAR	2-7/8" EUE box	2-7/8" EUE box	NEW	3.665	3.665	0.5	7613.5	7614	10
NO-FLOW NIPPLE (Supplier: **OSI**)	2-7/8" EUE pin	2-7/8" EUE pin	NEW	2.875	2.875	0.5	7614	7614.5	5
2-7/8" x 24' TOP CHEMICAL SCREEN W/VALVE ASSY CD8019 (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.668	2.875	24.0	7614.5	7638.5	280
2-7/8" x 24' CENTER CHEMICAL SCREEN W/VALVE ASSY CD1702 (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.668	2.875	24.0	7638.5	7662.5	280
2-7/8" x 24' CENTER CHEMICAL SCREEN W/VALVE ASSY CD8019 (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.668	2.875	24.0	7662.5	7686.5	280
2-7/8" x 24' CENTER CHEMICAL SCREEN W/VALVE ASSY CD1702 (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE pin	NEW	3.668	2.875	24.0	7686.5	7710.5	280
2-7/8" x 24' SLOW RELEASE CHEMICAL SCREEN W/VALVE ASSY CD8019 (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE box	NEW	3.668	2.875	24.0	7710.5	7734.5	280
NO-FLOW NIPPLE (Supplier: **OSI**)	2-7/8" EUE pin	2-7/8" EUE pin	NEW	2.875	2.875	0.5	7734.5	7735	5
2-7/8" x 8' QUICK RELEASE CD2003 (Supplier: **OSI**)	2-7/8" EUE box	2-7/8" EUE box	NEW	3.668	2.875	8	7735	7743	100
OSI BULL PLUG 2-7/8" (Supplier: **OSI**)	2-7/8" EUE pin	N/A	NEW	3.665	2.875	0.5	7743	7743.5	12
Weight of sand in the mud joints (filled completely)									1098
TOTAL						**588.2**			6707

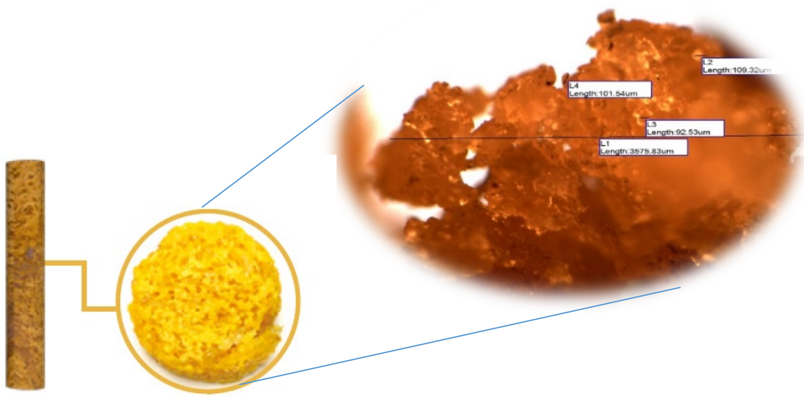


Figure 1 Inhibitors encapsulated by microencapsulation

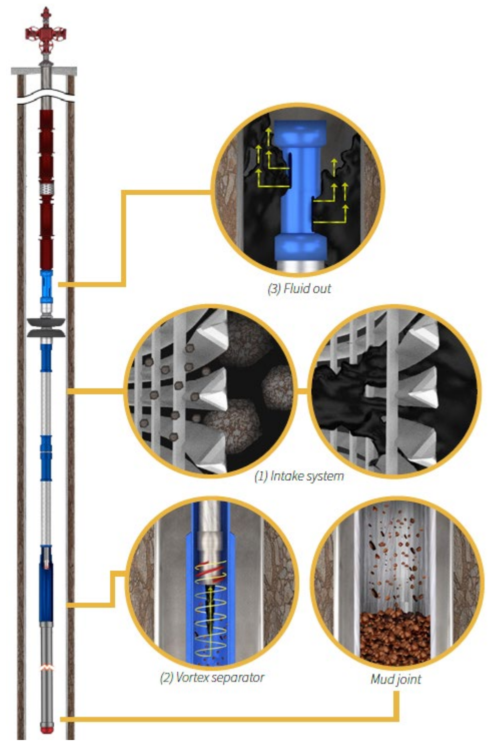


Figure 2 Wellbore Sketch-Two stages filtration system

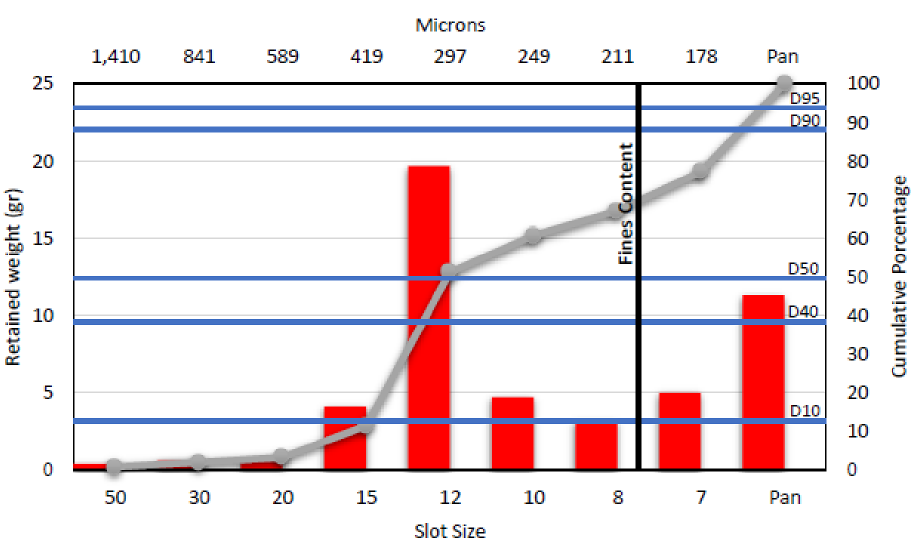


Figure 3 Sieve Analysis - Stueben 202WB

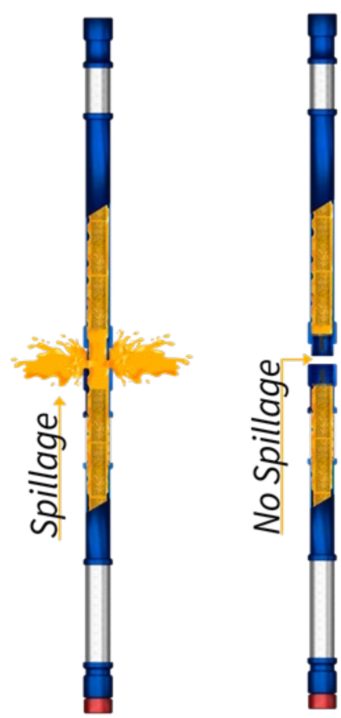
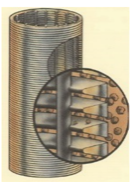


Figure 4 Chem Screen w/Shut-off Valve

TUBING SCREEN CALCULATOR		
INPUT DATA		
Production of total liquid barrel per day	4000	BFPD
Percent of run time	100%	%
Selected Tubing Screen:	*2-7/8" x 23.5'*	
Slot	*0.015*	
Well classification	*AVERAGE*	
Open area of screen (in^2)	362.8	
# Tubing screen	7	

CALCULATED RESULTS		
Size of Sand	50	Mesh
Total Open area of screen	2539.6	in^2
1440 minute per day *% of time	1440	min/day
production per minute of run	2.777777778	bbl/min
production cubic inches	26950	in^3/min
Production inch/ by screen opening	0.176865123	in/sec

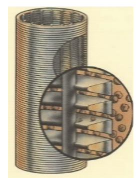


0.176865123 in/sec **Fluid velocity per second through Screen**

0.199627778 in/sec **Max. by TS.**

TUBING SCREEN CALCULATOR		
INPUT DATA		
Production of total liquid barrel per day	4000	BFPD
Percent of run time	100%	%
Selected Tubing Screen:	*2-7/8" x 23.5'*	
Slot	*0.012*	
Well classification	*AVERAGE*	
Open area of screen (in^2)	298.7	
# Tubing screen	9	

CALCULATED RESULTS		
Size of Sand	50	Mesh
Total Open area of screen	2688.3	in^2
1440 minute per day *% of time	1440	min/day
production per minute of run	2.777777778	bbl/min
production cubic inches	26950	in^3/min
Production inch/ by screen opening	0.167082047	in/sec



0.167082047 in/sec **Fluid velocity per second through Screen**

0.187155556 in/sec **Max. by TS.**

Figure 5 Tubing Screen Simulation - 15 slot & 12 slot

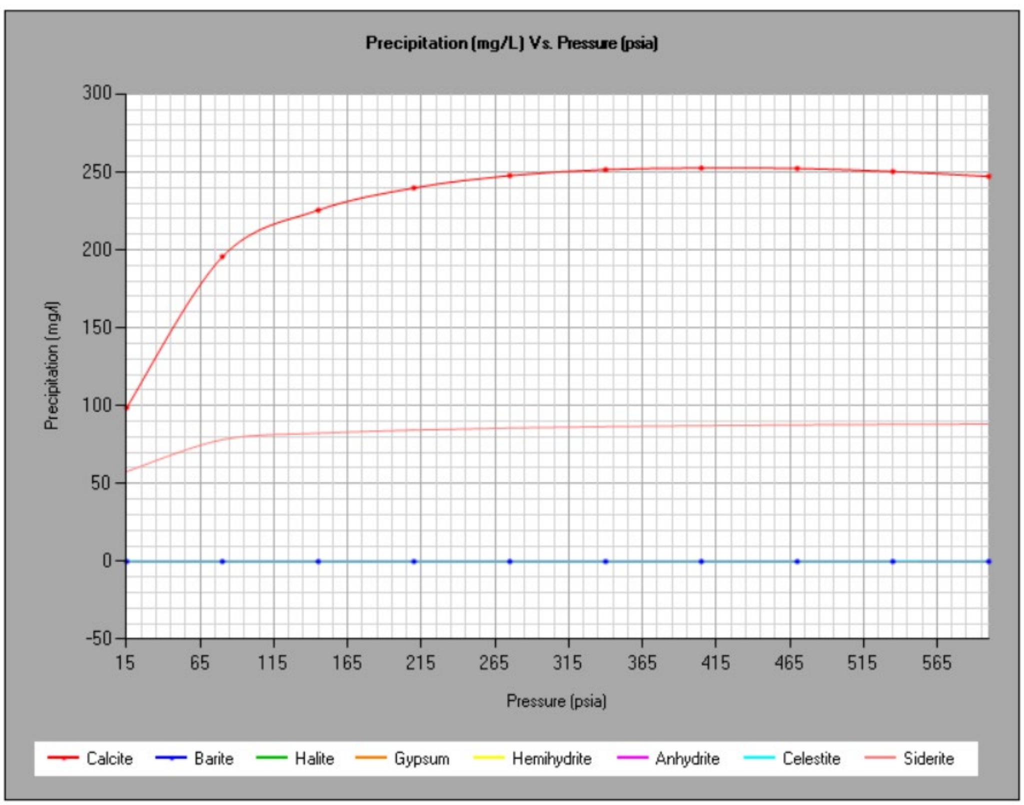


Figure 6 Deposition Rate - Zone 1

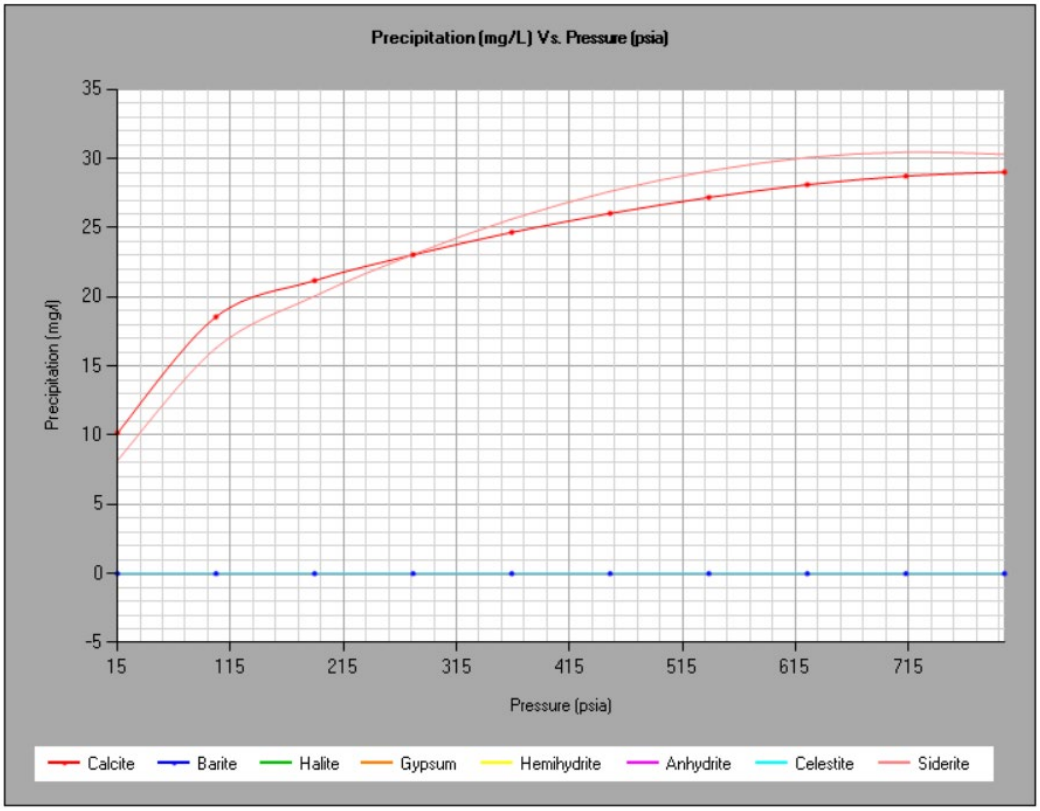


Figure 7 Deposition Rate - Zone 2

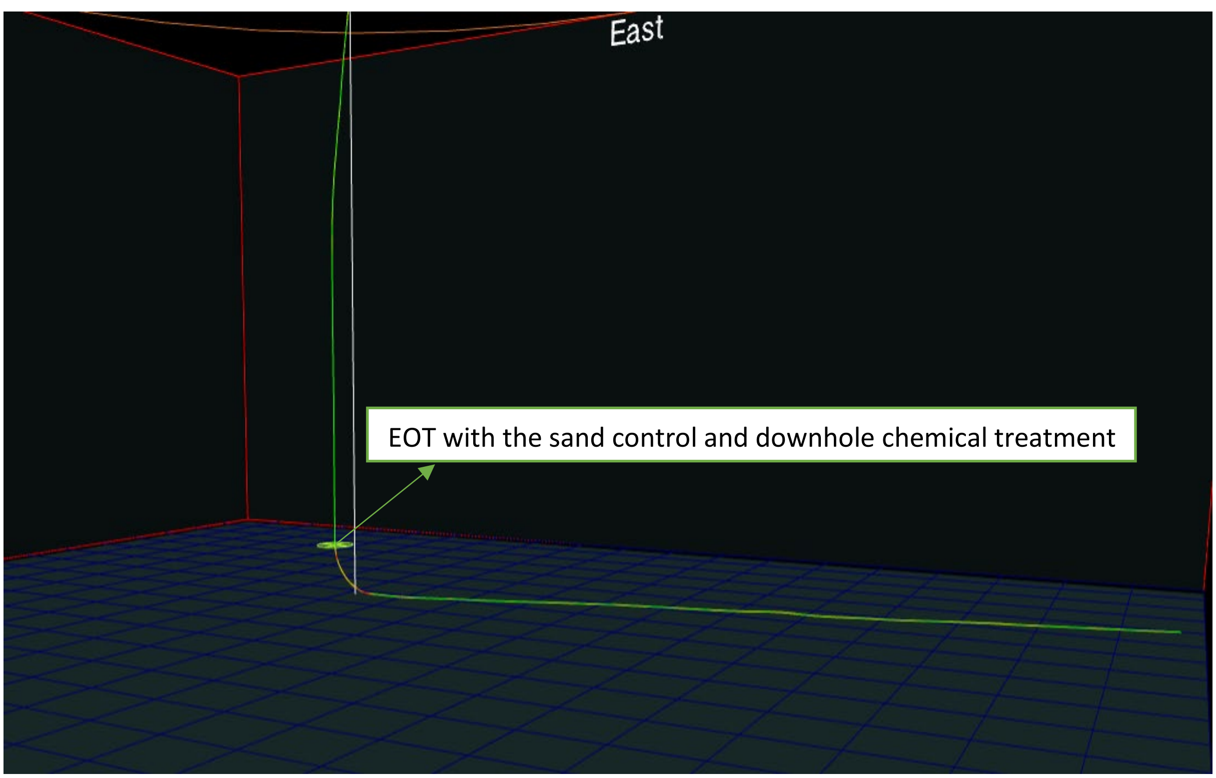


Figure 8 Typical deviation survey

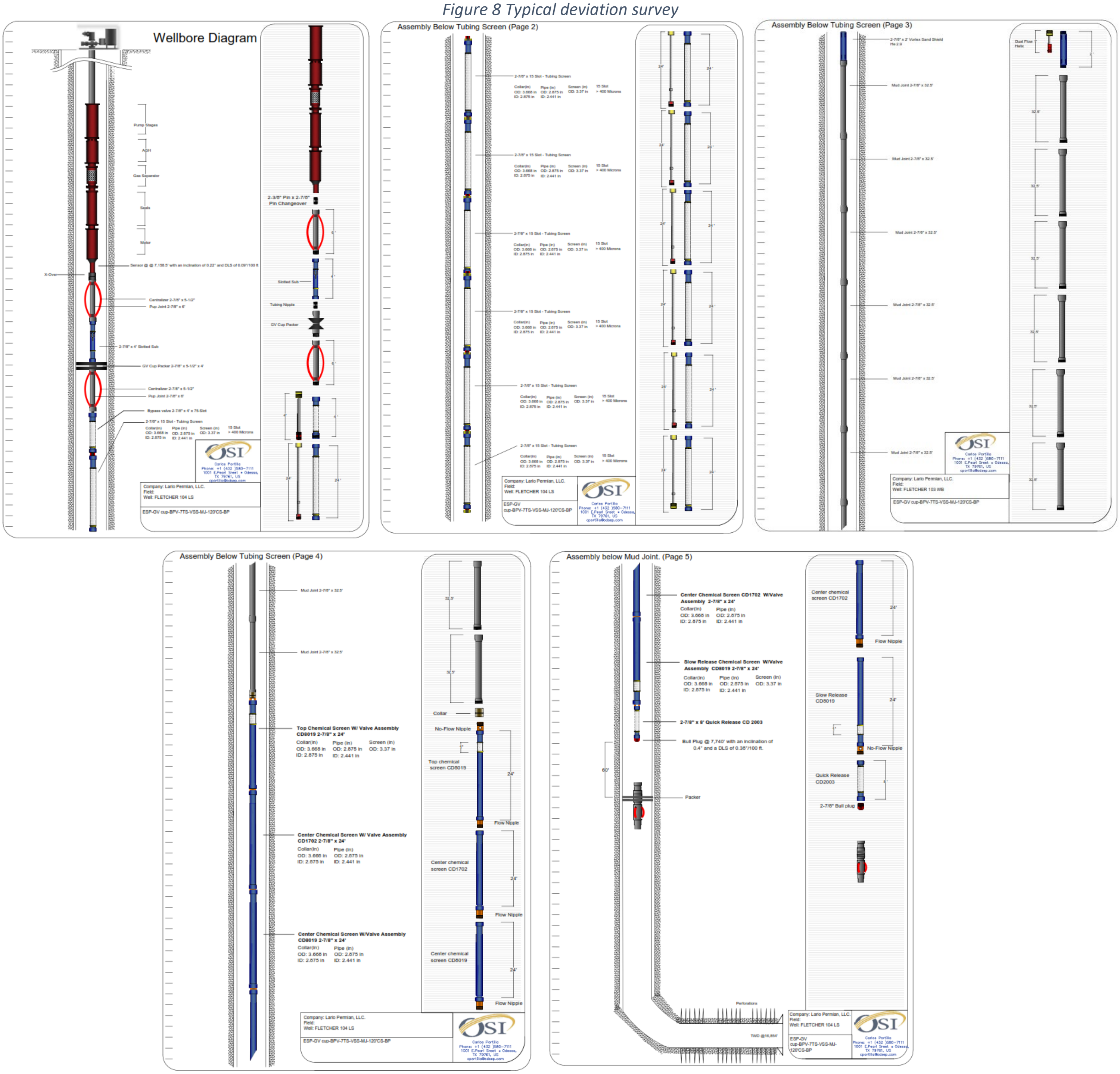
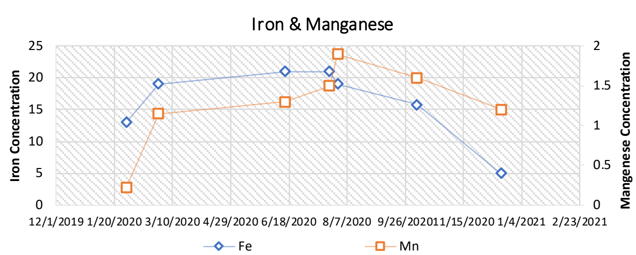
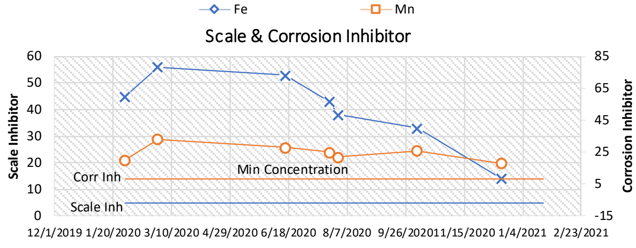
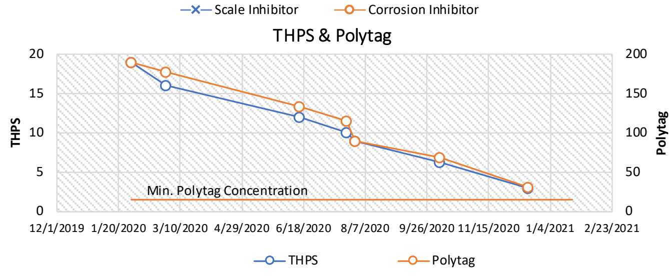


Figure 9 Complete wellbore sketch

Figure 10. Sensor parameters Well Clark 402







ECONOMIC EVALUATION FOR SAND CONTROL AND DOWNHOLE CHEMICAL APPLICATION

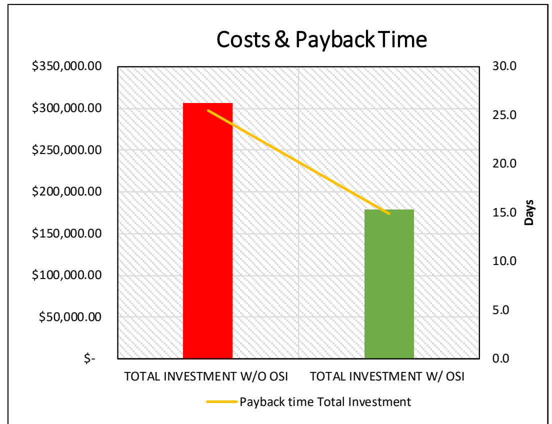
WTI	$ 55.00

Installation Results	
Average Fluid Prodution (BFPD)	1057
Average Oil Production (BOPD)	401.66
Average WC (%)	62%
Installation date	10/21/2019
Pulling Date	1/22/2021
Runtime at Pulling Date (Days) w/OSI product	459
Previous Runtime (Days)	200
Days without pumping/Failure	4.0

Costs		
Workover RIG	$	65,000.00
OSI Products	$	25,837.00
Others	$	-

Costs & Payback Time **w/Sand and Chem Products**		
Total Investment (Rig + OSI Products)	$	90,837.00
Deferred Production (BOPD)		1606.64
Deferred Production (USD)	$	88,365.20
Total Expenses (USD)	$	**179,202.20**
Lifting Cost ($/BBL)	$	25.00
Payback Time OSI investment (Days)		2.1
Payback Time total investment (Days)		14.9

Costs & Payback Time **wo/Sand and Chem Products**		
Failures without OSI products in 459 days		2
Total Investment (Rig)	$	130,000.00
Deferred Production (BOPD)		3213.28
Deferred Production (USD)	$	176,730.40
Total Expenses (USD)	$	**306,730.40**
Lifting Cost ($/BBL)	$	25.00
Payback Time total investment (Days)		25.5



OSI Application Balance for the Operator:	$	127,528.20

**No ESP costs considered in the evaluation*

***This economic evaluation simulation is made based on general rig expenses and the lifting cost of the field*

Figure 12. Economic Evaluation Well Clark 402

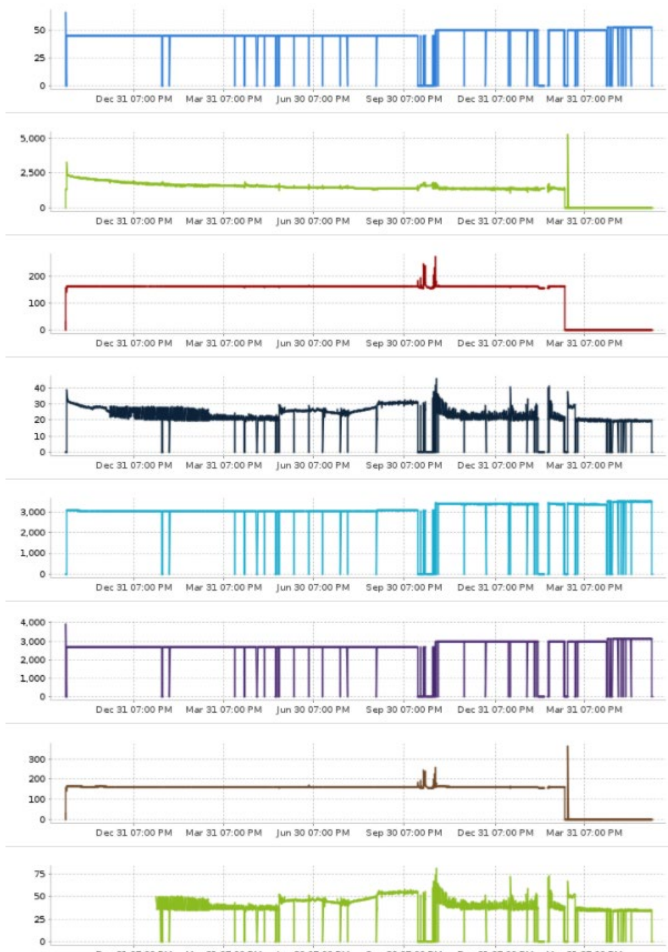


Figure 13. Sensor Parameters Well Clark 404WB

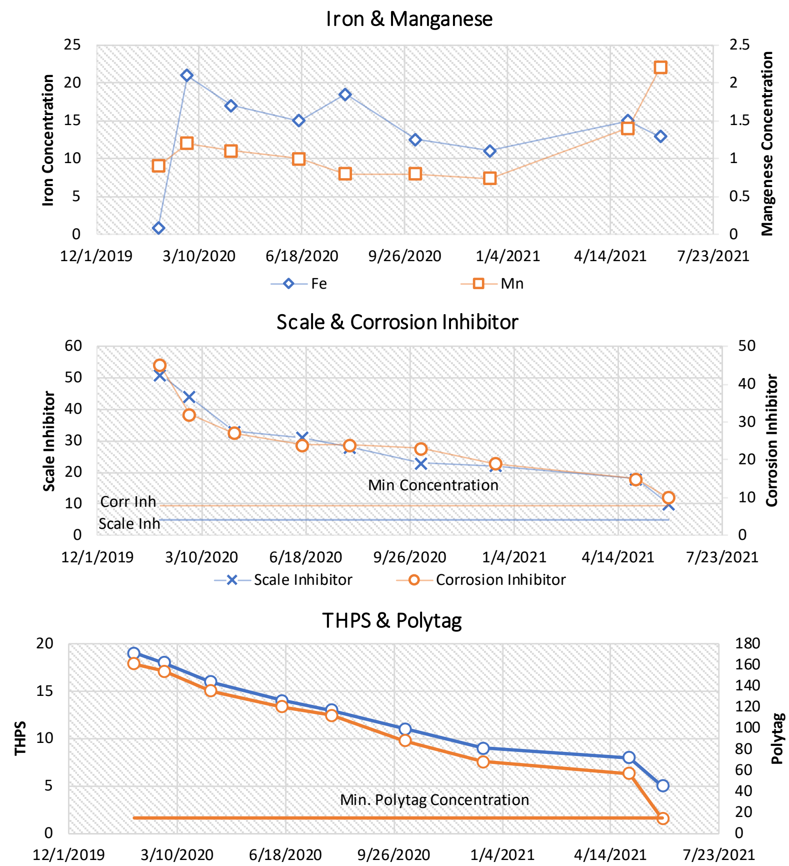


Figure 14. Chemical Tracker Well Clark 404WB

ECONOMIC EVALUATION FOR SAND CONTROL AND DOWNHOLE CHEMICAL APPLICATION

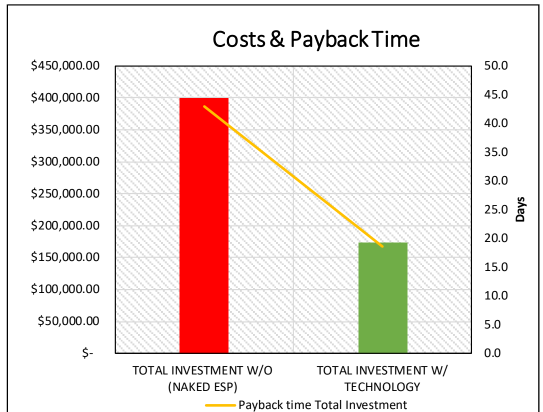
WTI	$ 55.00

Installation Results	
Average Fluid Prodution (BFPD)	1830
Average Oil Production (BOPD)	311.1
Average WC (%)	83%
Installation date	10/23/2019
Pulling Date	6/12/2021
Runtime at Pulling Date (Days) w/product	598
Previous Runtime (Days)	200
Days without pumping/Failure	4.0

Costs		
Workover RIG	$	65,000.00
OSI Products	$	40,264.00
Others	$	-

Costs & Payback Time **w/Sand & Chem Prod**		
Total Investment (Rig + Sand &Chem Products)	$	105,264.00
Deferred Production (BOPD)		1244.40
Deferred Production (USD)	$	68,442.00
Total Expenses (USD)	**$**	**173,706.00**
Lifting Cost ($/BBL)	$	25.00
Payback Time OSI investment (Days)		4.3
Payback Time total investment (Days)		18.6

Costs & Payback Time **wo/Sand & Chem Prod**		
Failures without products in 598 days		3
Total Investment (Rig)	$	195,000.00
Deferred Production (BOPD)		3733.2
Deferred Production (USD)	$	205,326.00
Total Expenses (USD)	**$**	**400,326.00**
Lifting Cost ($/BBL)	$	25.00
Payback Time total investment (Days)		42.9



OSI Application Balance for the Operator:	$	226,620.00

***No ESP costs considered in the evaluation**

****This economic evaluation simulation is made based on general rig expenses and the lifting cost of the field**

Figure 15. Economic evaluation Clark 404WB

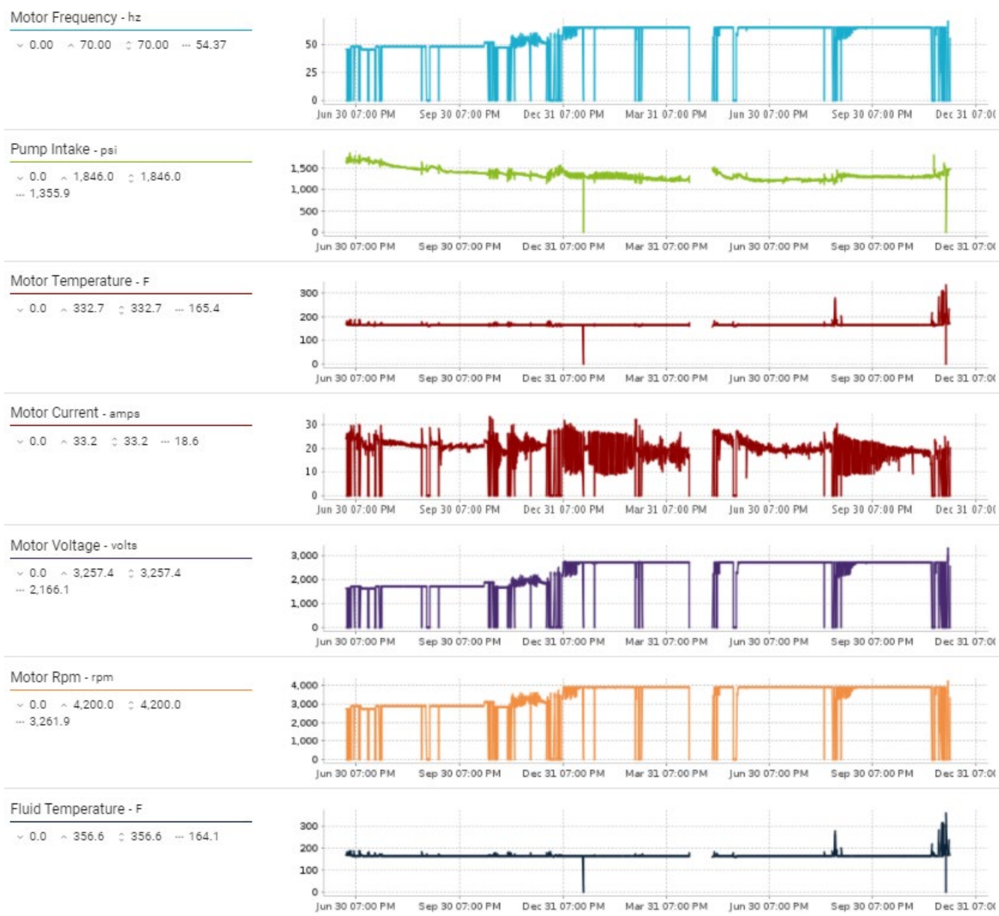


Figure 16. Sensor parameters Peggy 401WB

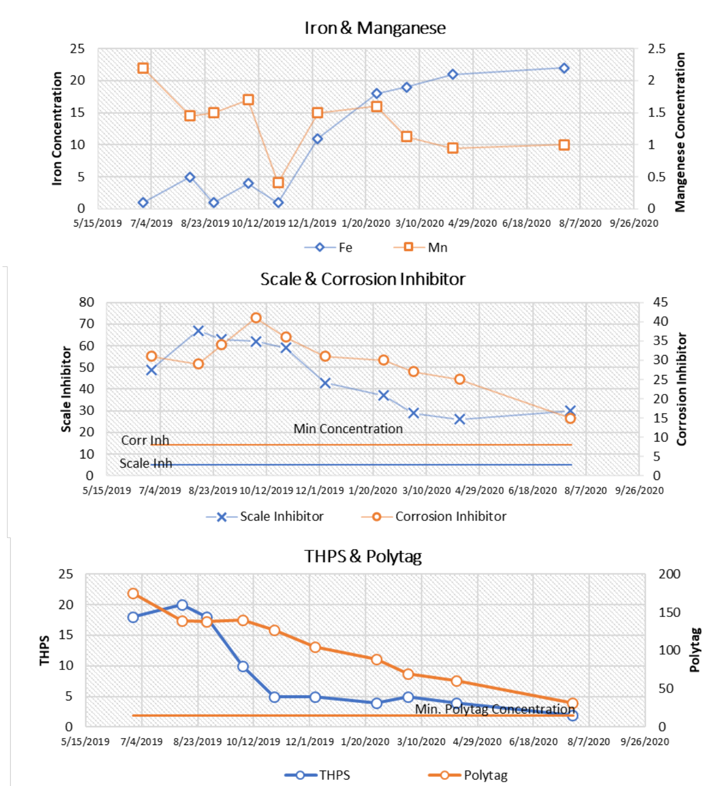


Figure 17. Chemical tracker Peggy 401WB

ECONOMIC EVALUATION FOR SAND CONTROL AND DOWNHOLE CHEMICAL APPLICATION

WTI	$ 55.00

Installation Results

Average Fluid Prodution (BFPD)	500
Average Oil Production (BOPD)	210
Average WC (%)	58%
Installation date	6/25/2019
Pulling Date	1/11/2021
Runtime at Pulling Date (Days) w/Product	566
Previous Runtime (Days)	180
Days without pumping/Failure	4

Costs

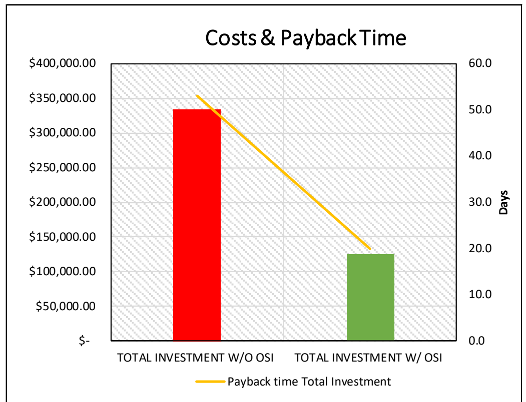
Workover RIG	$ 65,000.00
OSI Products	$ 14,000.00
Others	$ -

Costs & Payback Time **w/Sand And Chem Prod**

Total Investment (Rig + Sand & Chem Products)	$ 79,000.00
Deferred Production (BOPD)	840.00
Deferred Production (USD)	$ 46,200.00
Total Expenses (USD)	**$ 125,200.00**
Lifting Cost ($/BBL)	$ 25.00
Payback Time OSI investment (Days)	2.2
Payback Time total investment (Days)	19.9

Costs & Payback Time **wo/Sand And Chem Prod**

Failures without OSI products 566 days	3
Total Investment (Rig)	$ 195,000.00
Deferred Production (BOPD)	2520
Deferred Production (USD)	$ 138,600.00
Total Expenses (USD)	**$ 333,600.00**
Lifting Cost ($/BBL)	$ 25.00
Payback Time total investment (Days)	53.0



OSI Application Balance for the Operator:	$	208,400.00

No ESP costs considered in the evaluation

****This economic evaluation simulation is made based on general rig expenses and the lifting cost of the field***

Figure 18. Economic evaluation Peggy 401WB

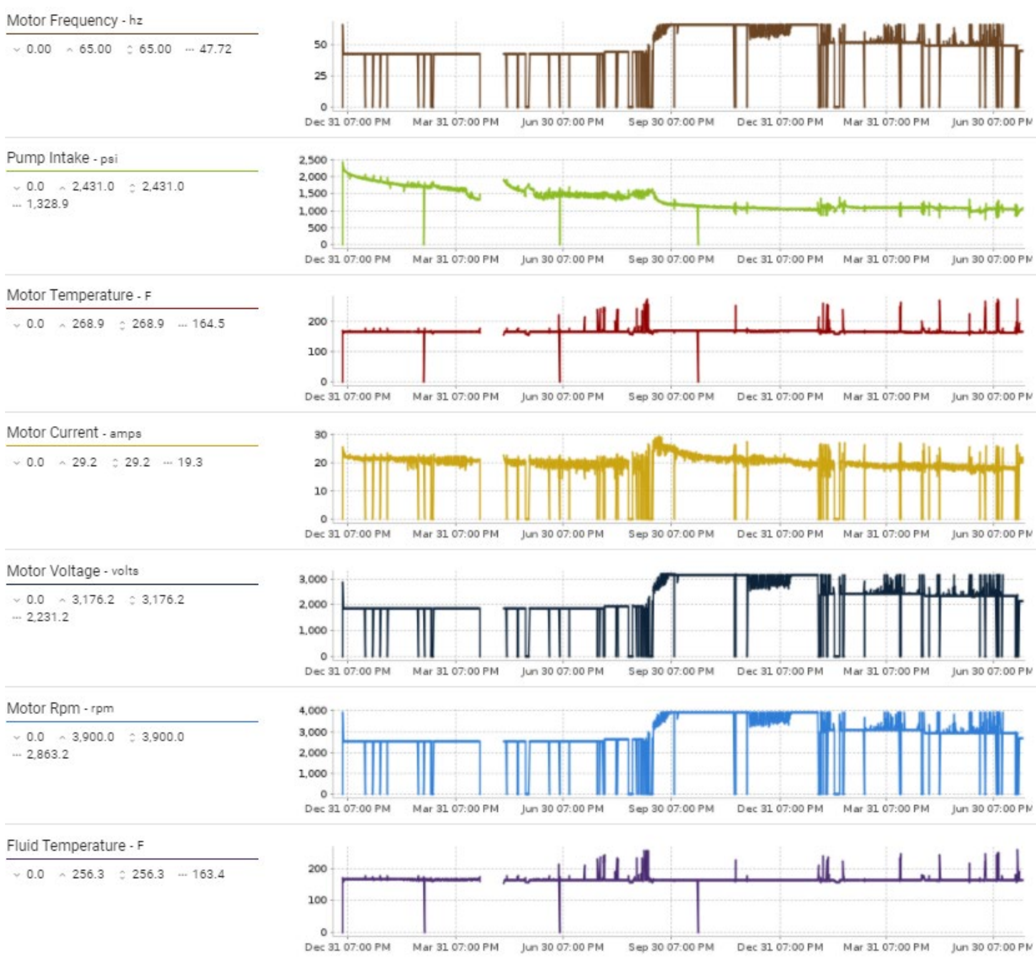


Figure 19. Sensor parameters Peggy 101WB

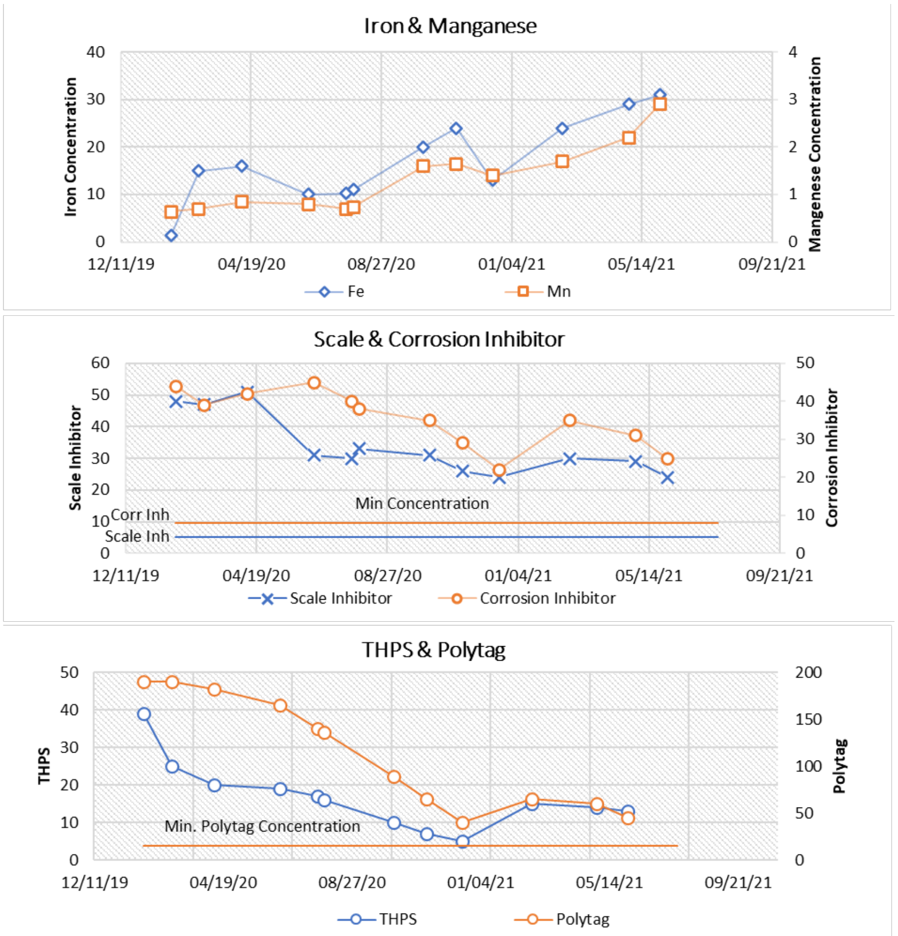


Figure 20. Chemical tracker Peggy 101WB

ECONOMIC EVALUATION FOR SAND CONTROL AND DOWNHOLE CHEMICAL APPLICATION

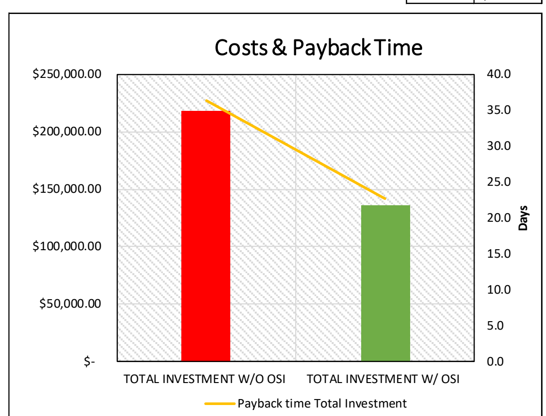
WTI	$ 55.00

Installation Results	
Average Fluid Prodution (BFPD)	1100
Average Oil Production (BOPD)	200
Average WC (%)	75%
Installation date	12/23/2019
Pulling Date	7/26/2021
Runtime at Today's Date (Days) w/product	521
Previous Runtime (Days)	250
Days without pumping/Failure	4

Costs		
Workover RIG	$	65,000.00
OSI Products	$	27,136.00
Others	$	-

Costs & Payback Time **w/Sand & Chem prod**		
Total Investment (Rig + Sand & Chem Prod)	$	92,136.00
Deferred Production (BOPD)		800.00
Deferred Production (USD)	$	44,000.00
Total Expenses (USD)	$	**136,136.00**
Lifting Cost ($/BBL)	$	25.00
Payback Time OSI investment (Days)		4.5
Payback Time total investment (Days)		22.7

Costs & Payback Time **wo/Sand & Chem prod**		
Failures without OSI products in 521 days		2
Total Investment (Rig)	$	130,000.00
Deferred Production (BOPD)		1600
Deferred Production (USD)	$	88,000.00
Total Expenses (USD)	$	**218,000.00**
Lifting Cost ($/BBL)	$	25.00
Payback Time total investment (Days)		36.3



OSI Application Balance for the Operator:	$	81,864.00

**No ESP costs considered in the evaluation*
***This economic evaluation simulation is made based on general rig expenses and the lifting cost of the field*

Figure 21 Economic Evaluation - Peggy 101WB