CONTROLLING SAND FLOW BACK IN ESPS WITHOUT LIMITING FLUSHING OPERATIONS THROUGH THE TUBING. FIELD APPLICATIONS IN THE PERMIAN BASIN

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ABSTRACT

This paper introduces a technology for handling solids above the discharge of the ESP pump that increases the run time of the well and prevents premature failure due to plugging or damage to the pump parts thus contributing to the reduction of carbon emissions and environmental impact. Additionally, the new technology was engineered to allow fluid injection through the tubing and its components can be dissembled after pulling it, providing the production engineers with valuable information about the downhole conditions.

The new device used to control the sand above the discharge of the pump was designed with the fundamental purpose of controlling the sand, allowing injection from the surface through the tubing and allowing the inspection and repair of its components after pulling it out of the well. The sand regulation system allows flow rates up to 15,000 BPD and has handled sand volumes up to 23,000 mg/L. While the internal mechanism that allows the control of solids and the injection through the tool is designed to allow up to 8 BPM of direct injection while maintaining a surface pressure of less than 600 psi.

The operational and performance advantages of this device have allowed its successful installation in several wells in the Permian Basin. After the installation, the run times have maintained high values, thus reducing the interventions to the wells and the replacement of the pumping equipment, thus reducing the carbon footprint of each one of the wells where this technology has been run. Additionally, the sensor variables have remained stable, which contributes to a higher cumulative production compared to periods where the pump was off for long periods, or the wells were under maintenance because of sand production. On top of that, each equipment pulled has been inspected and re-used to maximize the investment increasing the NPV of the projects.

This new technology is the only one with the ability to protect the ESP against solids during shutdown events, allow flushing operations, and being inspectable and repairable. The use of premium materials, along with a special assembly system make it a tool with a long useful life.

INTRODUCTION

In the past ten years, shale production has become the dominant method of oil production in the Permian basin. Shale production features long lateral wells, higher pressures than conventional production, and, due to fracturing, a large amount of erosive sand returning to the surface during production.

As the high-velocity, high-volume sand works its way back up the wellbore and into the production equipment, it causes erosion and premature wear, especially to areas with small flow paths. In artificial lift systems like the ESP, sand production will cause many damages when it enters inside the pump, either type, formation or frac sand creates wearing and plugging in pump stages, what induces large range fluctuation in motor Amp/load, high motor temperature and repeated unplanned shutdowns.

The above shortens the run life expectation on the artificial lift system, yielding in unexpected failures that can range from Low/No production to surface (broken/twisted shafts), Poor pump efficiency (stages wore out), Grounded downhole (Motor/Pothead/Cable grounded), to High Amp/No Start (Locked shaft).

In this paper we are presenting the consequences of the flowback inside the ESP pump after every planned or unplanned shutdown, which drags and builds up sand suspended in the fluid, inside the pump stages, packing off toward the discharge. Also, a hybrid device was developed to deal with this production problem, and two cases with increased runtime when this device is engaged as part of the bottom hole assembly.

FLOW BACK AND SAND FALL BACK.

Sand fallback in the context of Electric Submersible Pump (ESP) systems occurs when sand particles and other solids settle inside the ESP pump due to gravity.

During normal operation, the ESP pumps oil without hindrance. However, on every shutdown, planned or unplanned, the ESP stops pumping and the pressure due to the column of fluid inside forces to flowback inside the pump until the tubing pressure equalizes with the annular pressure.

Part of the sand and other solids suspended in the fluid will enter again in the pump stages as consequence of the flowback, but then, after both fluid columns - tubing and annular - get balanced, no more fluid will be moving, and the solids suspended in the fluid column inside the tubing will fall back – decant - inside the pump by gravity, packing off upper stages and the pump discharge.

Sand inside the pump stages may cause shaft locking, when fine grains get inserted within the radial gaps between the stages and the shaft, and stages wear out by abrasives, but can also cause plugged stages, when large amount of sand clog the flow vanes to the point where the flowing area get 100% blocked. Sand accumulation at the pump discharge creates a heavy plug, and back pressure to the pump, sometimes hard to overcome when attempting to restart the ESP pump, which become harder if gas is being produced with the fluid, because it gets trapped inside the pump by not finding any way to bleed out through the discharge.

The scenarios above described, result in a hard time restarting an ESP pump that is producing a certain amount of sand with the fluid (up to 30% of the pump capacity), after every shutdown. Therefore, temporary but repeated Low/No flow and high Motor Amp / High Motor Temperature conditions will fatigue the mechanical and/or electrical integrity of the ESP, what ultimately would yield in failure and costly workover service, usually after a short run life.

CURRENT ESP SAND FALLBACK DEVICES.

The ESP market counts with different Sand Flowback Protection devices connected to the ESP pump at or above the discharge, however, each one has its advantages and limitations, some of these tools are described as follows:

Screen with ball and seat: This device, connected at or above the pump discharge, counts with a screen/mesh that prevents the sand from entering the pump during flowback through the pump discharge, also it has a ball and seat on top, constraining the fluid to flowback only through the screen/mesh. The drawback of this tool is that because of the short length, when large amount of sand falls back, the body gets quickly filled up, and the ball and seat on top creates a hermetic seal that builds up the rest of the sand still falling back at this point and above; and leaving No room for the gas that might be trapped inside the pump to bleed out through the discharge.

Check valves: This device, connected at or above the pump discharge, connected at the discharge of the pump, creates a hermetic seal between the tubing and the pump discharge whenever the tubing column starts moving in back flow after every shutdown. The downside of this tools is that it creates a hermetic seal that builds up a heavy column of sand that falls back, at this point and above; leaving No room for the gas that might be trapped inside the pump to bleed out through the discharge.

Sand diverters: This device, connected at or above the pump discharge, consists of internal mechanisms assembled inside a tool body, which diverts the sandy/abrasive fluid column inside the tubing out to the annular section of the well, whenever the tubing column starts moving in back flow after every shutdown. The disadvantage of this tools is that, by draining the abrasive fluid from the tubing to the annular, creates early abrasives wear and lock out in its internal moving parts, leaving the drain ports permanently open and ending in low production to surface by tubing leak.

Open flow labyrinth: This device, connected at or above the pump discharge, consists of a tool body with internal zig-zag flow path constructed by pocket-shape-like components that, facing upward, create a tortuous path to the sandy/abrasive fluid column inside the tubing while flowing back inside the pump, retaining only part of the solids inside the tool (part of the solids will enter the pump), but allowing the ability to pumps fluid (fresh water, chemical, etc.) from surface through the tubing to wash the pump out. The downside of this tool is that, when producing large amount of sand, its retention capacity turns into a limitation, allowing the sand to flowback and accumulate inside the pump stages and at the discharge, resulting in hard restarts.

HYBRID ESP SAND FLOWBACK DEVICE.

A hybrid device for sand fallback control has been engineered, gathering the best characteristics of the existing tools, and overcoming their downsides (see figures 1.a and 1.b). This device consists of a longer and wider body (24ft in 350, 400 and 450 series), what allows more sand retention capacity, also longer internal screen, with patented inverted top roof shape that diverts the flow/fall back keeping the sand outside the screen and inside the device body.

Internal screen volume cleared of sand, with open flow area aligned to the pump discharge, to facilitate gas flowing from inside the pump through the tool to the tubing, pump down fluid (fresh water/chem treat) through the tubing to the ESP pump inside and allow smooth restarts. Solids jet ports fittings, to guarantee complete self-washout of the tool after restart. Threaded adapters to facilitate the complete disassemble, inspection and refurbishment of this device. In resume, this device:

- Provides the ability to pump through the tubing (see figure 2).
- Protect the pumps from sand flow/fall back, leaving the discharge clear for any up flowing gas to bleed out of the pump, through the tool and up to the tubing.
- Provides the ability to perform smooth and successful restarts.
- It is 100% refurbishable and reusable, replacing, in most of the cases, only the miscellaneous, due to the quality of materials used.

PRESENCE AND EFFECTIVENESS IN THE PERMIAN BASIN.

The Hybrid ESP Sand Fallback Device was introduced and started being installed in February 2020. The active population of these technology in Permian is 79% of the total units installed in the worldwide, and more than one third of these (34%) have been running for over one year, averaging between 776 days for devices installed first time (new ones), and 709 days for third time-installed units (after refurbishing), respectively (see table 1.a, 1.c).

Numbers on the inactive or pulled devices in the Permian show around one fifth of the population installed (21%), being able to refurbish twice: units installed three times. From the total of pulled devices in the Permian Basin, almost one third (27%) of these units ran over one year, averaging 600 days (see table 1.b, 1.c).

CASES STUDY.

The performance of the Hybrid Sand Fallback device is depicted through three case-wells selected from unconventional applications (fracked well).

Case Study Well 1.

In this case the first ESP installed ran in hole with No Sand Fallback protection device, and lasted only 244 days, having experienced 104 shutdowns with average downtime of 9 hours and eventually ended up being pulled by Broken shaft. During the pull and later DIFA, it was noticed pump stages wore out and broken shaft in more than one spot. Operational conditions can be resumed as follows: Moderate range fluctuation in motor current (9 Amps), motor temperature was not affected because of the size of the motor selected for this application, intake pressure was drawing down in smooth slope, and the speed was around 60 Hz, running in PID mode. Finally, the operational trends displayed a pattern like solids in pumps, restarts were heavy, and suddenly failed by broken shaft (see figure 3.a, 3.b).

The second ESP installed, ran with a first-time refurbished hybrid Sand Fallback device, it has been in operation for over 740 days and still active, having experienced 114 shutdowns with average downtime of 4.7 hours. Operational conditions can be resumed as follows: Moderate range fluctuation in motor current (8 Amps), motor temperature with short range fluctuation between 220 to 230 F, intake pressure was swinging 160 to 260 psi in gas purge mode, later 200 to 250 psi in PID mode, and the speed was around 46 Hz, running in PID mode. Finally, the operational trends displayed a pattern like solids and gas in pumps, and restarts are smoother (see figure 4.a, 4.b). A summary of the above description of the Case Study-Well 1 is included in table 2.

Case Study Well 2.

In this case the first ESP installed ran in hole with No Sand Fallback protection device, and lasted 429 days, having experienced 63 shutdowns with average downtime of 55 hours and eventually ended up being pulled by Low/No flow to surface – Possible hole in tubing. During the pull No evidence of hole in tubing was found and the ESP passed the pit test, therefore it ended up as a green pull. Operational conditions can be resumed as follows: Large range fluctuation in motor current (20 Amps), motor temperature stable most of the run time around 200 F, reaching peaks of up to 275 F only following restarts after shutdowns, intake pressure was stable along the run time, only fluctuating after shutdowns, and the speed was stable around 60 Hz, running in PID mode. Finally, the operational trends displayed a pattern like solids in pumps, restarts were heavy, and was pulled due to hole in tuning (see figure 5.a, 5.b).

The second ESP installed, ran with a first-time refurbished hybrid Sand Fallback device, it has been in operation for over 670 days and still active, having experienced 22 shutdowns with an average downtime of 12 hours. Operational conditions can be resumed as follows: Large range fluctuation in motor current (19 Amps), motor temperature with short range fluctuation between 200 to 220 F in periods of gas production, intake pressure stable around 200 psi, and the speed was around 59 Hz, running in PID mode. Finally, the operational trends displayed a pattern like solids and gas in pumps, and restarts are smoother (see figure 6.a, 6.b). A summary of the above description of the Case Study-Well 2 is included in table 3.

Case Study Well 3.

This well was completed in November 2018. We have no prior knowledge of the performance of the well before the hybrid device was installed. This hybrid Sand Fallback device was installed in September 2023 and is still running. The current fluid production is 2463 BFPD with a water cut of 91%. The well was producing naturally until the pump stages were forced upward and were eventually stuck in the upthrust position, due to solids or scale. To get the pumps unstuck, they underwent the following flushing procedure.

Pump 55 gallons of general surfactant.

Chase down with a full tubing volume of ~61 bbls of water.

Do not exceed pumping rate of 1.2 bbls/min to avoid damaging ESP.

Increase pumping gradually, with WHP reaching 1000, but keeping below 3000 psi.

Using this procedure, they were able to get the pump stages unstuck and the ESP was able to come back in operation, preventing from a downhole failure (motor overheating/burning, broken/twisted pump shaft, etc.) neither performing a workover operation to change the ESP string and clean out the well.

CONCLUSIONS.

- The effectiveness of the hybrid Sand Fallback device to protect the ESP system is demonstrated through the increased ESP run life in cases where the operational trends patterns are of solids inside the pump.
- Operation trends and data collected from cases study, prove the reduced number of shutdowns and the survival to every restart.
- Data from cases study demonstrated the hybrid device ability to perform smoother restarts, by allowing the system back in operation after every shutdown with lower average downtime.
- The use of this hybrid tool represents a positive impact to the environment, because, by prolonging the running life of the artificial lift systems, reduces the number of well interventions and with that, the carbon footprint.
- The acceptance of this device in the Permian Basin is evidenced in the volume of installations achieved only in the last four years after its introduction to the market, because its preferred ability to be refurbished: disassemble, inspection, reassemble and reuse up to three times, meaning four installations yet achieved in the Permian Basin market.
- This capability of refurbishment helps to reduce the BHA costs, maximizing the investment by reusing a reliable device.
- The cases study Well 3 presented, enhances the hybrid sand flowback control device capability of pumping through the tubing, in which a suggested methodology was followed, and an ESP pump that was stuck by solids was released and put back in operation, prolonging the ESP run life, reducing operational costs with less well intervention, and minimizing the impact to the environment. This ability, along with the above described, all represent operational advantages over other tools existing in the Permian Basin market.

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FIGURES, TABLES AND GRAPHS.

Table 1.a. Population Of Active Wells With Hybrid Device Installed In The Permian Basin.

Status	Runtime Intervals (days)	0-90	91-180	181-365	>365	Total
Active wells	Installation 1 #Units (Avg RL)	20% (42)	17% (138)	18% (246)	28% (776)	**83%**
	Installation 2 #Units (Avg RL)	6% (39)	2% (132)	3% (267)	4% (710)	**15%**

	Installation 3 #Units (Avg RL)	0% (N/A)	1% (135)	1% (312)	1% (709)	**2%**
	Installation 4 #Units (Avg RL)	0% (N/A)	0.3% (159)	0% (N/A)	0% (N/A)	**0.30%**

Table 1.b. Population Of Inactive/Pulled Wells With Hybrid Device Installed In The Permian Basin.

Status	Runtime Intervals (days)	0-90	91-180	181-365	>365	Total
Inactive wells	Installation 1 #Units (Avg RL)	15% (51)	22% (138)	25% (268)	24% (586)	**85%**
	Installation 2 #Units (Avg RL)	2% (80)	4% (157)	4% (295)	3% (632)	**13%**
	Installation 3 #Units (Avg RL)	1% (66)	1% (93)	0% (N/A)	0% (N/A)	**2%**
	Installation 4 #Units (Avg RL)	0% (N/A)	0% (N/A)	0% (N/A)	0% (N/A)	**0%**

Table 1.c. Population Of Active And Inactive Wells With Hybrid Device In The Permian Basin.

Active Wells With Hybrid Sand Fall Back Control Devices (since 2/27/2020):	**79%**
Inactive/Pulled Wells With Hybrid Sand Fall Back Control Devices (since 2/27/2020):	**21%**

Table 2. Performance Data Summary On Case Study Well 1.

	No hybrid flowback device installed	**With hybrid flowback device installed**
Survival to restart within 365 days:	0.67	2.03
Total Shutdowns:	104	114
RunLife (days):	244	741
ESP motor description:	300HP/3255V/57A	110HP/1550V/46A
Motor Amp operational range:	27-36	30.6 - 38.3
Motor load:	63%	83%
Average downtime (hr):	9.1	4.7
Tool reusage (times):	New	1
Types of solids collected:	Sand and Iron Sulfide Inside Pumps stages	Still Operative
ESP pump conditions:	Stages wore out. Shaft broken.	Still Operative
Comments:	**Amps:** Moderate range fluctuation (9 Amps). **Motor Temp:** not affected because of the Motor size (large). **Intake Pressure:** drawing down in smooth slope. **Speed:** around 60 Hz, running in PID mode. **Description:** Trend pattern similar to solids in pumps. **Restarts:** Heavy. **Diagnose:** Sudden SD by broken shaft.	**Amps:** Moderate range fluctuation (8 Amps). **Motor Temp:** Swinging between 220 to 230F. **Intake Pressure:** Gas Purge Mode swinging 160 to 260 psi. Overall drawdown from 250 to 180 psi. PID mode swinging 200 to 250 psi. Avg 230 psi. **Speed:** around 46 Hz, running in PID mode. **Description:** Amp fluctuations similar to Solids and Gas in pumps. **Diagnose:** Still operative. **Restarts:** Smooth.

Table 3. Performance Data Summary On Case Study Well 2.

	No hybrid flowback device installed	With hybrid flowback device installed
Survival to restart within 365 days:	1.18	1.84
Total Shutdowns:	63	22
RunLife (days):	429	670
ESP motor description:	240HP/2890V/51A	204HP/2932V/49A
Motor Amp operational range:	33 - 53	32 - 51
Motor load:	88.6%	69.2%
Average downtime (hr):	55	12
Tool reusage (times):	New	1
Types of solids collected:	Pulled by Hole in tubing. ESP Tested good. No evidence of Hole in tubing.	Still operative
ESP pump conditions:	No Teardown performed. (Green Pull)	Still operative
Comments:	**Amps:** Large range fluctuation (20 Amps). **Motor Temp:** Stable most of the runtime. Reached peaks of up to 275F in attempts to restart. **Intake Pressure:** Stable most runtime, last week fluctuating on every shutdown. **Speed:** Stable around 61 Hz, slight fluctuations in PID Mode. **Description:** Trends display presence of solids/sand inside the pumps pattern (Light). **Restarts:** Heavy. **Diagnose:** Hole in tubing.	**Amps:** Large range fluctuation (19 Amps). **Motor Temp:** Stable. Fluctuations (20F span) in periods of gas production. **Intake Pressure:** Stable around 200 psi. **Speed:** around 59 Hz, running in PID mode. **Description:** Trends display moderated gassy and solids operation pattern. **Diagnose:** Still operative. **Restarts:** Smooth.

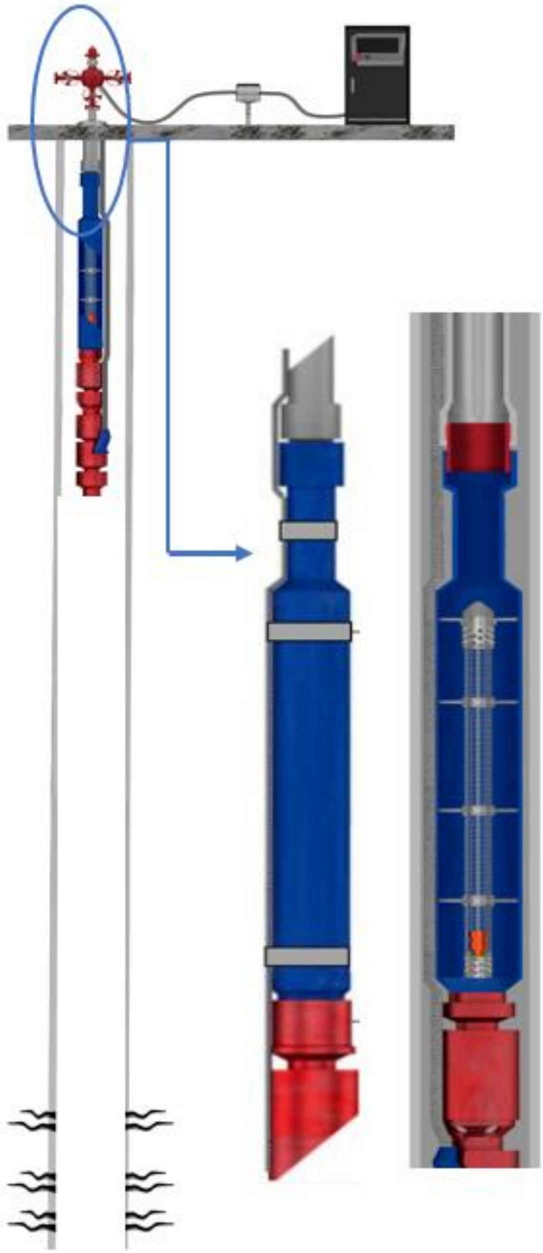

Figure 1.a - Hybrid ESP Sand Flowback Device Schematic.

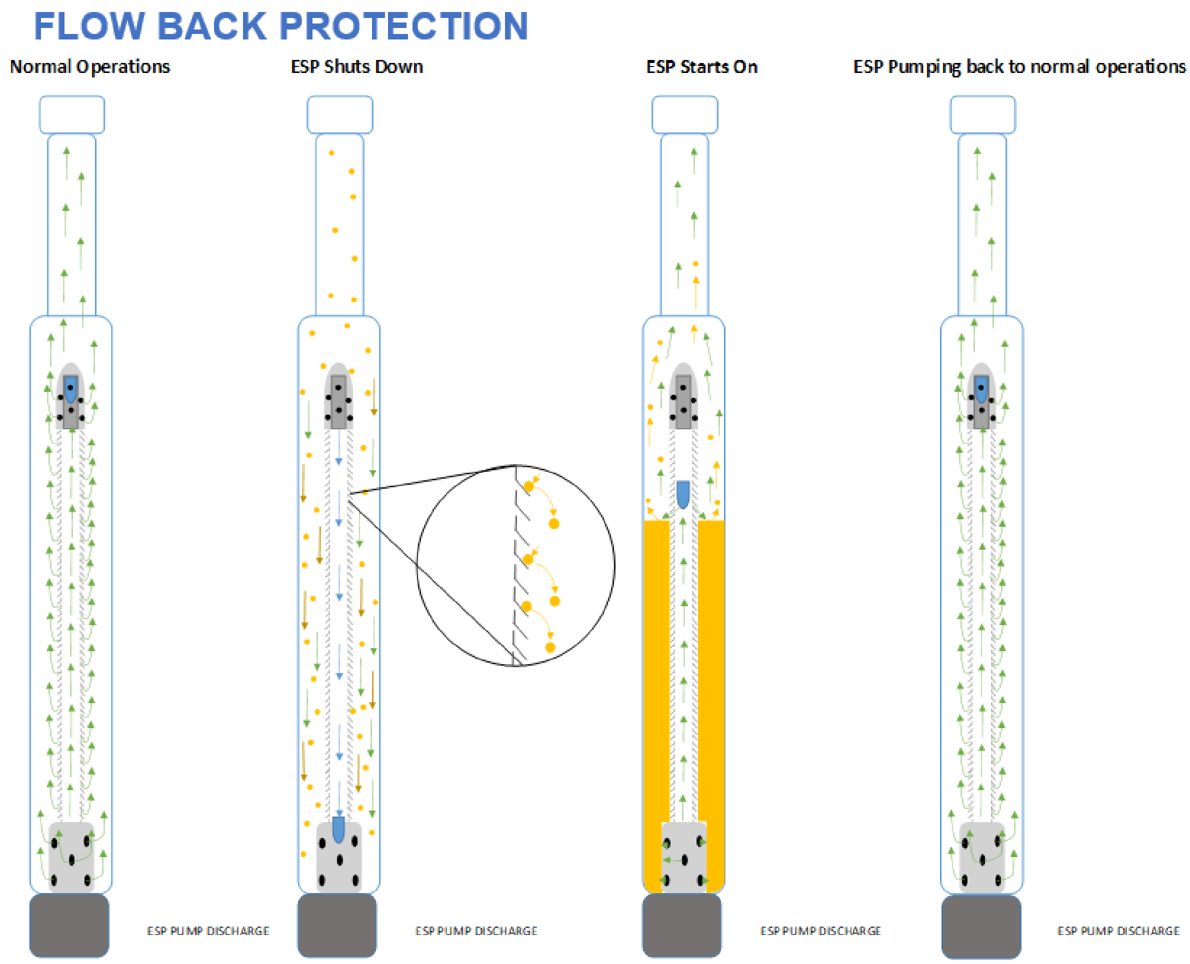

Figure 1.b - Hybrid ESP Sand Flowback Device.

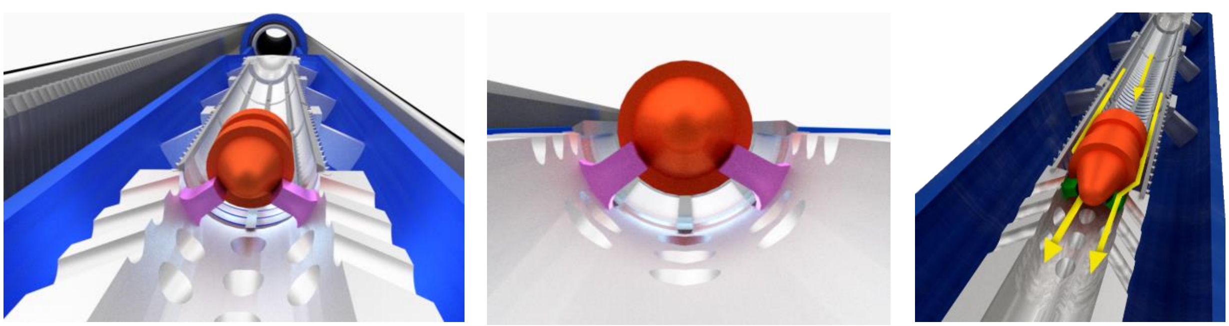

Figure 2 - Open flow area aligned to the pump discharge.

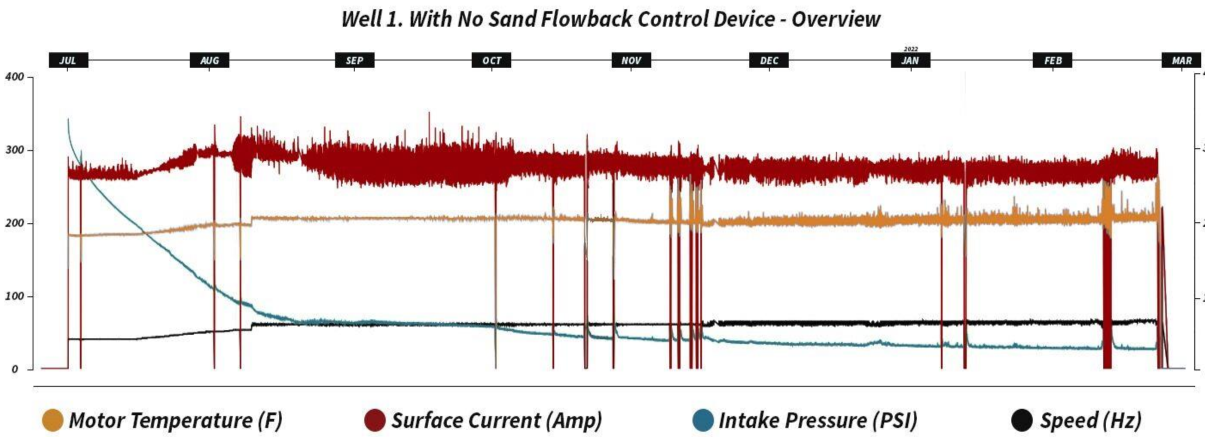

Figure 3.a - Operational trends on Case-well 1 without Hybrid device.

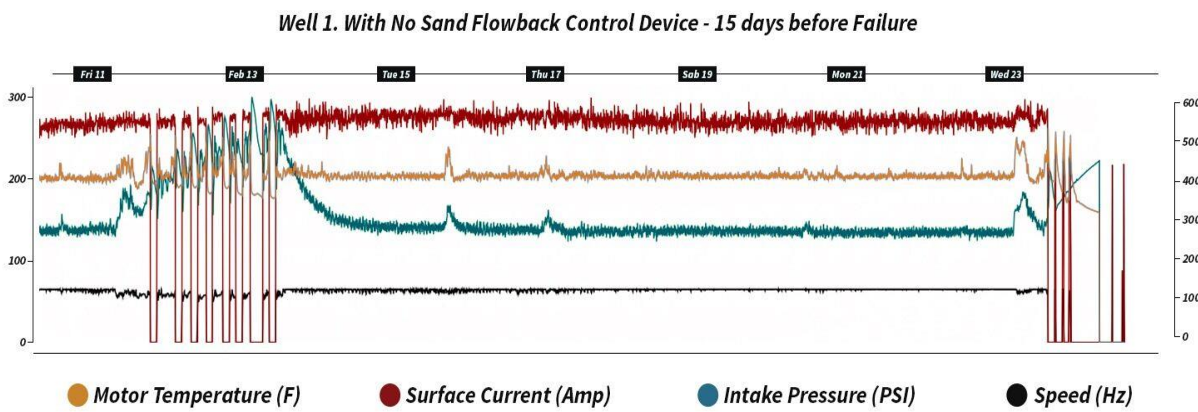

Figure 3.b - Operational trends on Case-well 1 without Hybrid device.

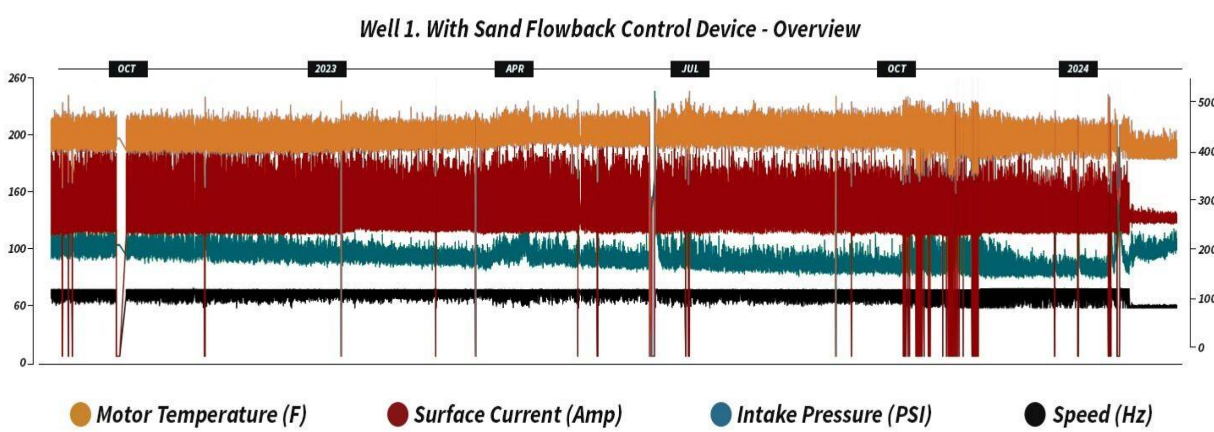

Figure 4.a - Operational trends on Case-well 1 with Hybrid device.

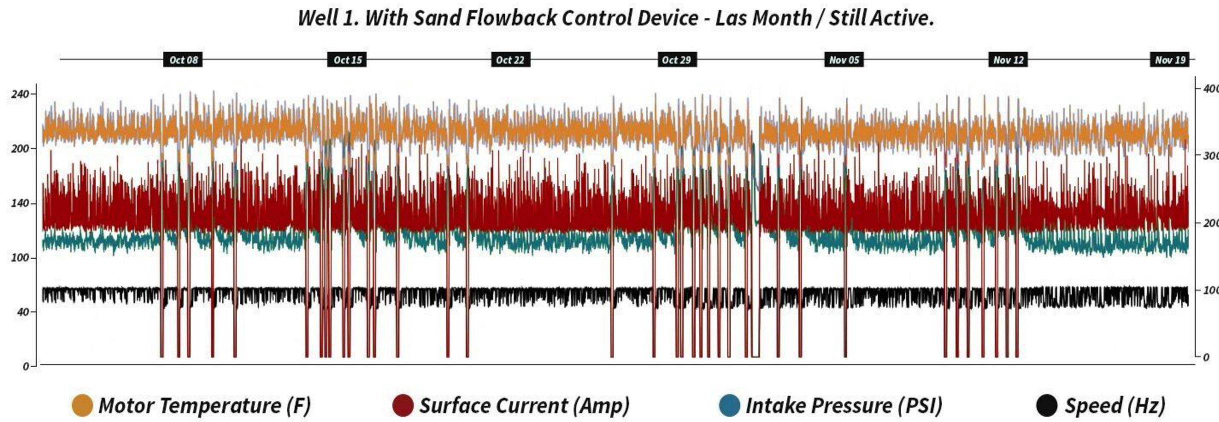

Figure 4.b - Operational trends on Case-well 1 with Hybrid device.

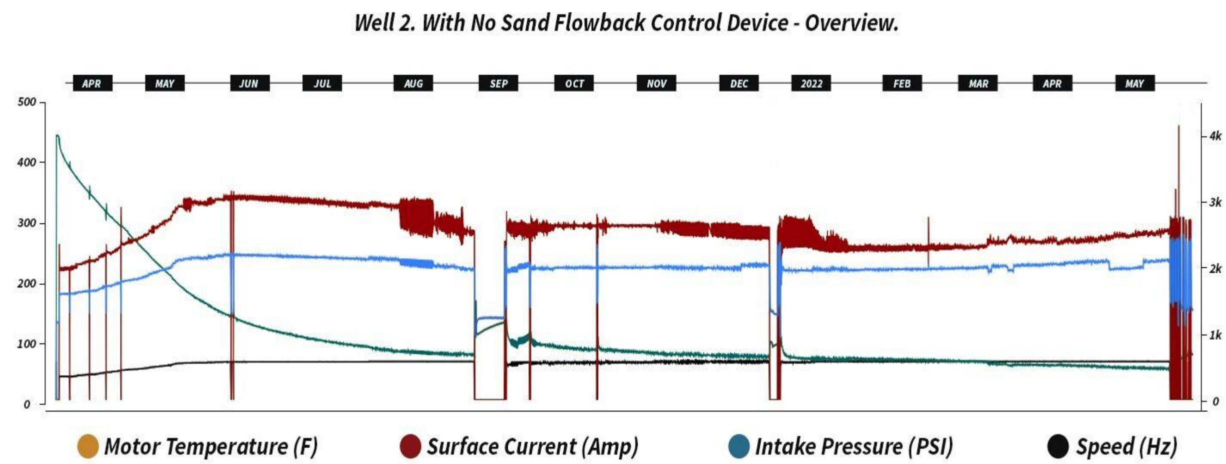

Figure 5.a - Operational trends on Case-well 2 without Hybrid device.

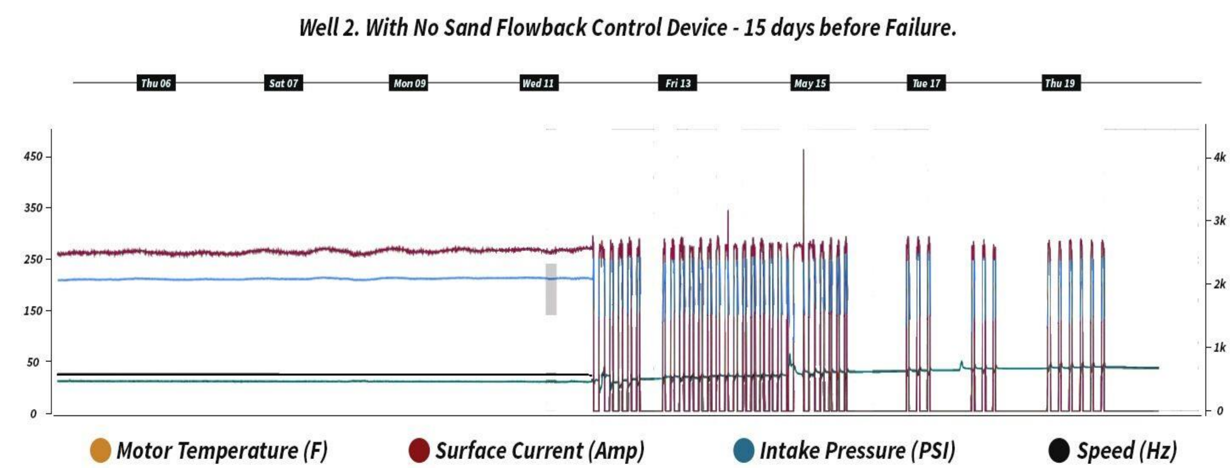

Figure 5.b - Operational trends on Case-well 2 without Hybrid device.

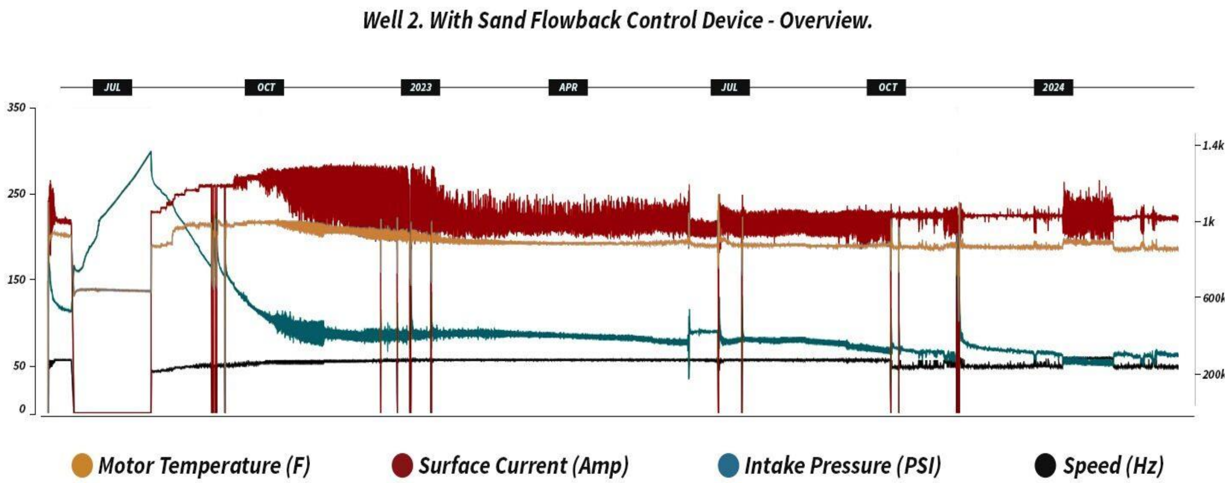

Figure 6.a - Operational trends on Case-well 2 with Hybrid device.

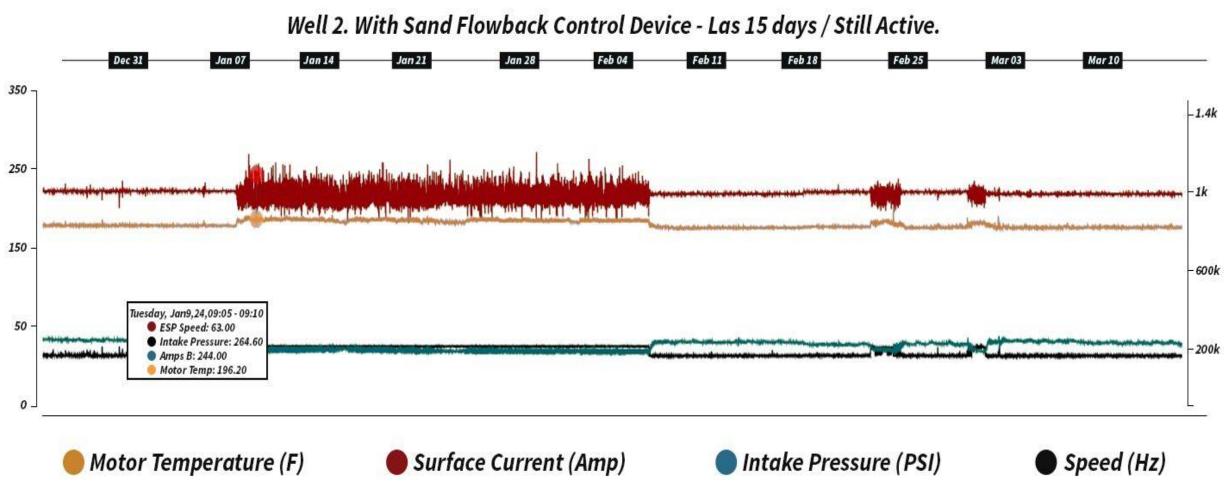

Figure 6.b - Operational trends on Case-well 2 with Hybrid device.