CASE STUDY RESULTS ON OVERCOMING MASSIVE GAS INTERFERENCE FROM SRP WELL DRAWDOWN IN PERMIAN BASIN

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ABSTRACT

As operators draw down a well, massive quantities of gas are released into the wellbore which results in shut-downs and lost production. Using appropriate bottom hole assembly (BHA) best practices can help the operator pump through these gas slugs to maximize production and return on investment. Additionally, solid separation is an ongoing issue. Using a gas separator minimizes abrasion and corrosion related failures, keeping operating expenses lower.

The problem is twofold: Gas interference can lead to poor pump efficiency and severe sand issues can lead to sticking and excessive wear and tear on the pump. Both problems lead to unnecessary and costly operational expenses due to well failures and overall poor system efficiencies.

Maintaining proper gas and solid separation widens operator options in regard to optimization and improved well control. This paper focuses on an all-in-one system that effectively allows operation through gas rates as high as 1900 MCF, as shown in case studies presented in this paper.

By maximizing separation area and minimizing downward fluid velocity, higher production rates are achieved in high gas-to-liquid ratio (GLR) environments. Installing this type of equipment reduces gas and sand interference, which in turn increases pump efficiency and extends the life of all downhole equipment.

This paper presents the technology behind this combination gas and sand separation system and offers case study results that prove the positive impact of this tool on overall operating expenses.

INTRODUCTION & BACKGROUND

When producing unconventional wells, gas and solid separation can be the difference between a successful, proactive high revenue installation and an inefficient, reactive pit of lost production. During the fracking process, hundreds of perforations are made across the lateral, creating many zones with different permeability, porosity and reservoir conditions.

As the operator draws down the well, lateral zones unload due to the decrease in hydrostatic pressure. As those zones unload, the wellbore is overrun with gas and solids.

Gas interference causes premature shutdowns and lost production. Correct procedure by industry standards would call to pump through the gas as opposed to stopping the pump, which could allow gas and solids to accumulate in both the annulus and the pump.

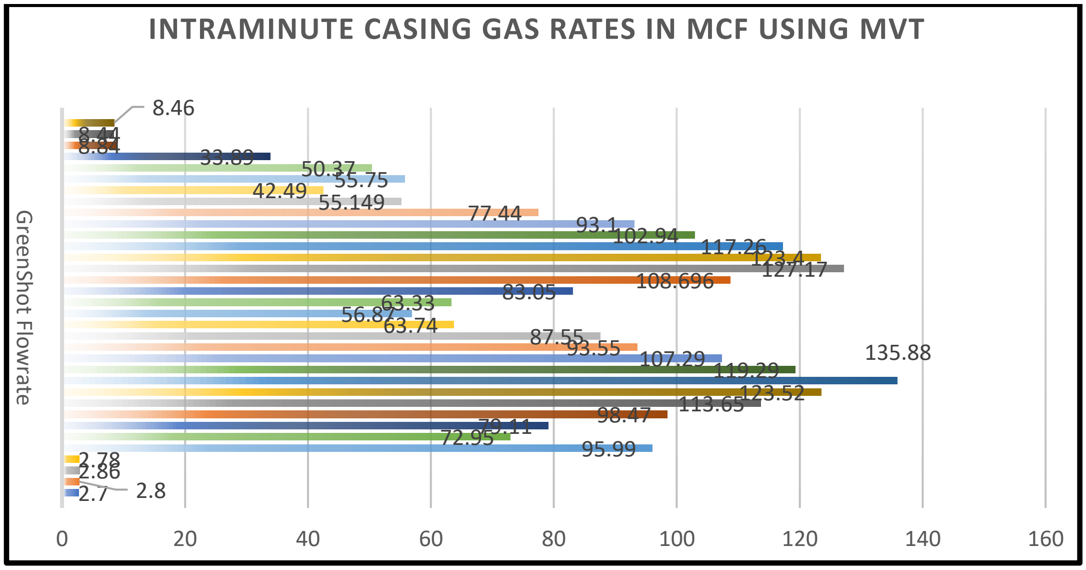


Figure 1: Casing Gas Rates in MCF using a multivariable transmitter.

Figure 1 shows the erratic gas behavior that occurs on a well, often without operator knowledge. A single daily average of gas production is typically recorded but doesn’t show the whole picture.

A well might average 50 MCF per day, but the quantity might fluctuate wildly throughout the day. Figure 1 shows how a casing gas rate can fluctuate from 8 MCF all the way up to 135.88 MCF and back down to 2.7 MCF in as little as 30 minutes. If the BHA was not designed in anticipation of this phenomenon, gas will overrun the separator and produce gas interference, which in turn causes a premature controller shutdown based on low fillage. This can cost the operator missed production and revenue.

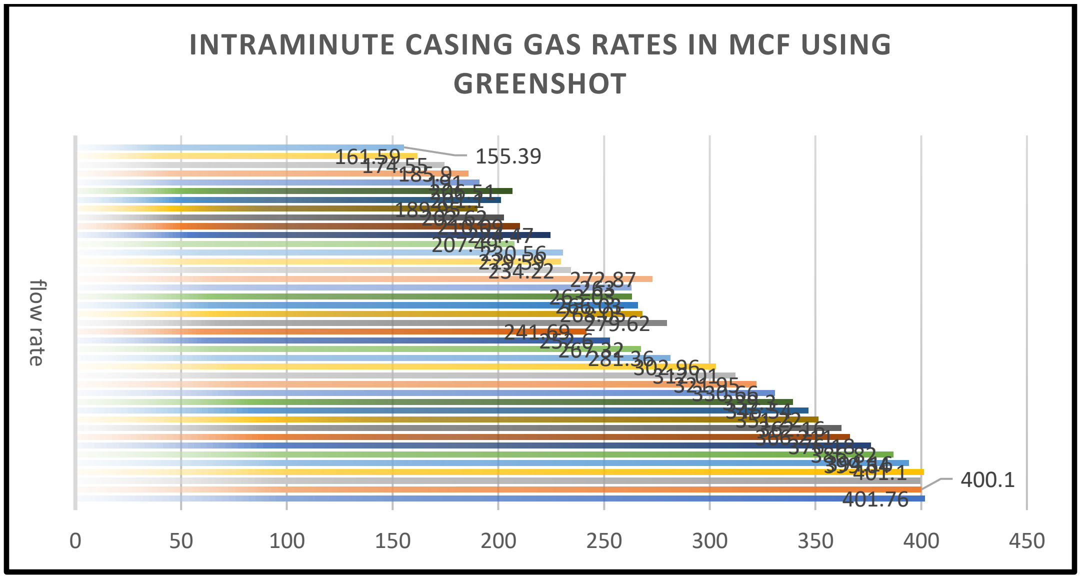


Figure 2: Casing Gas Rates in MCF using a multivariable transmitter.

Figure 2 shows another example where the extraordinary behavior of casing gas rates can be observed. In this instance, casing gas rates balloon up to 400 MCF from 155 MCF in just a little more than 30 minutes; an increase of 250 MCF. This data was collected using a permanently installed fluid level device.

Gas and solid separators are commonly used to improve efficiency on installations dealing with gas interference and solids. Two main types of gas separator exist: Poor Boy and packer style, cf. [2,4].

Solids passing through the pump can lead to erosion failures, which incurs costly repairs. [1] Two main types of solid separation exist: Mesh or vortex style, cf. [5].

A downhole tool called the Super MAX was designed specifically to mitigate gas and solids by utilizing the cross-sectional area between the inside diameter (ID) of the casing and the outside diameter (OD) of the separator body. Details on the procedure to design a properly fitted BHA are shared as are the concepts of total fluid rate and downhole fluid velocity.

Results are presented to show stabilization of pump fillage, increase in production and runtime as well as decreased gas-to-liquid ratio. Case studies showing before and after data and downhole cards are also presented.

BHA DESIGN REQUIREMENTS

Downward fluid velocity (DVF), also known as bubble rise velocity, represents the rate gas bubbles rise in inches per second. Since bubble rise occurs at 0.5 feet per second in fresh water but faster in an oil and gas environment, bubble rise velocity is a critical data point. [1]

Based on many field experiments as well as additional field tests, an industry standard has been set for DFV of 0.4 feet per second. This standard rate is a guideline for proper separation. If DFV stays under the standard rate of 0.4 feet per second, it is assumed the gas in solution stays in solution. However, if the DFV exceeds the standard rate, gas will break out of solution and eventually overpower the gas separator.

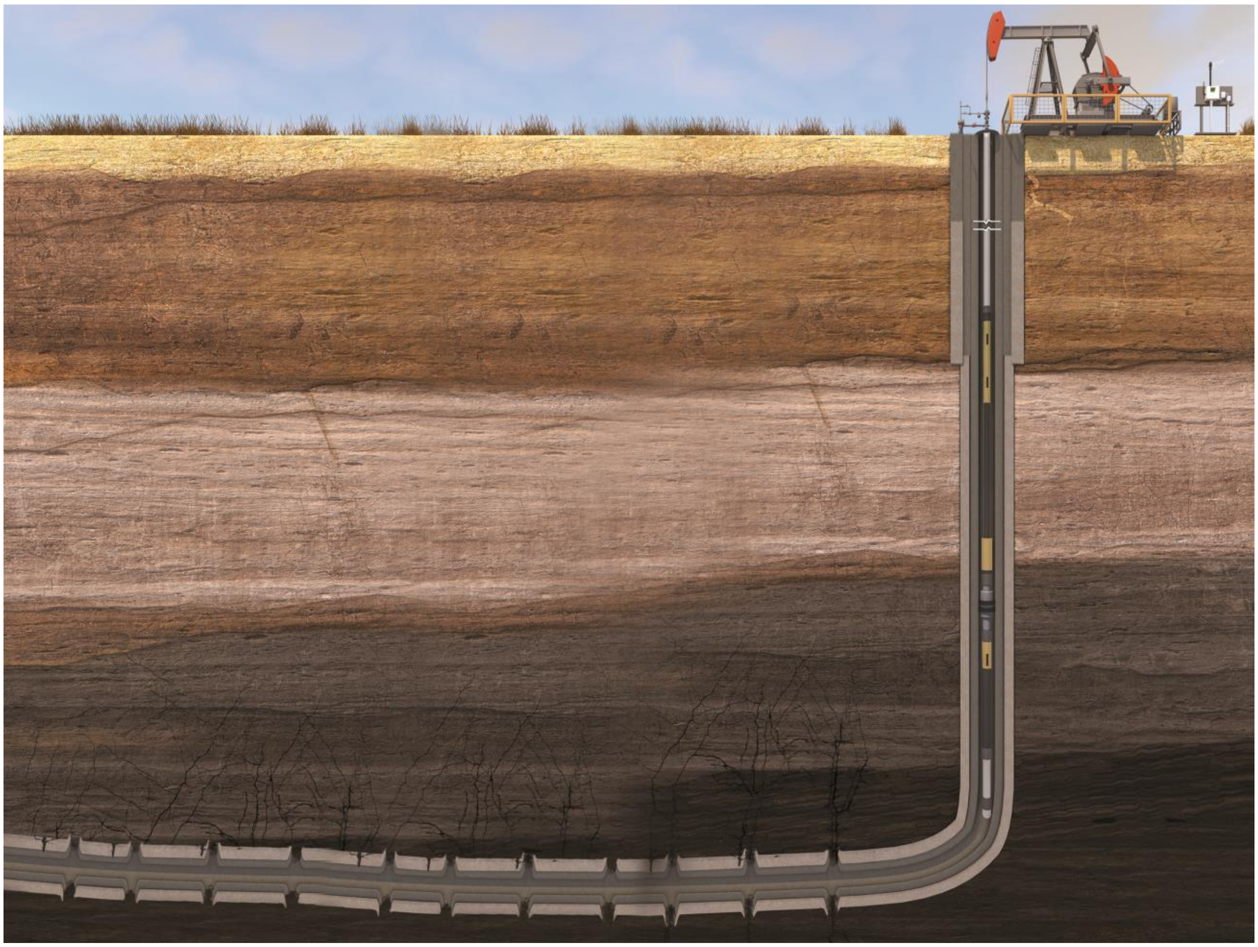


Figure 3: Wellbore showing multiple frac zones and placement of the tool.

Equation 1 shows the calculation of DFV and is a very important step in BHA designs. This equation takes into account the total barrel of fluid, the inner diameter of the casing as well as the outer diameter of the separator.

$$\frac{Q * 0.0119}{{ID_{CSG}}^2 - {OD_{SEP}}^2} = DFV = Downward\ Fluid\ Velocity \quad [1]$$

Mother Hubbard Separator		Recommended Packer Style Separator	
Constant	0.0119	Constant	0.0119
ID of Poor Boy (in)	3	ID of 5.5" Casing (in)	4.778
OD of Dip Tube (in)	1.05	OD of Separator (in)	1.9
Downward Fluid Velocity (ft/sec)	0.4	Downward Fluid Velocity (ft/sec)	0.4
SEPARATION AREA (in^2)	**6.20**	**SEPARATION AREA (in^2)**	**15.09**
PRODUCTION LIMITS (BFPD)	**265**	**PRODUCTION LIMITS (BFPD)**	**646**

Figure 4: Comparison of a Mother Hubbard (Poor Boy) searator versus the design of the updated packer style separator.

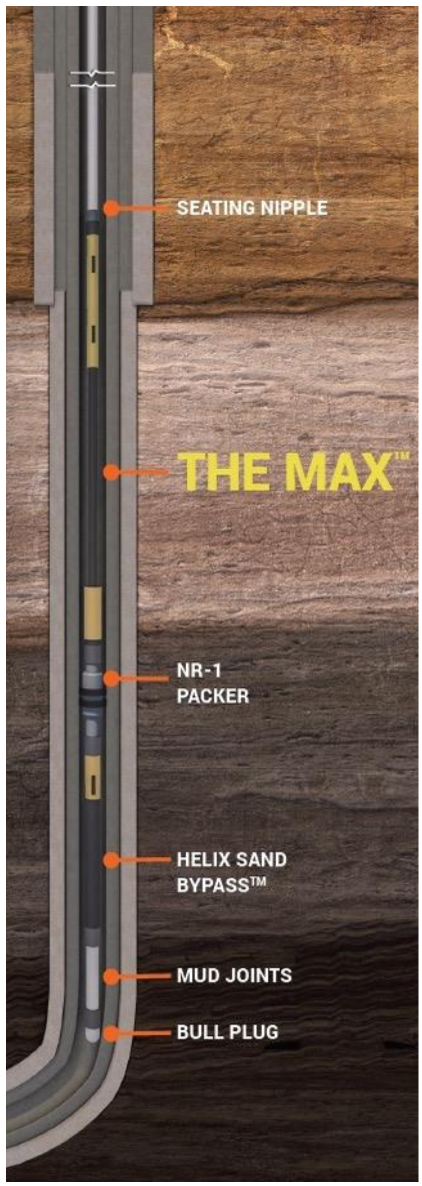


Figure 5: Schematic of the packer style separator, marketed as the Super MAX.

DESIGN OF THE SEPARATOR

The separator design utilizes a solids separation portion marketed as the HELIX Sand Separator. The design of the solids separator includes a dual-channel, centrifugal vortex with a solids bypass tube. The outer tube is nine feet in length with a 3.75-inch OD and a 3-inch ID. The inner tube has a 2.375-inch OD with a 1.99-inch ID. The centrifuge is one foot long and consists of two flow channels of different pitches. The solids bypass tube is three feet long with a .675-inch OD and an ID of 0.493 inches.

Figure 6: Structure of the dual-channel spiral.

As shown above, the dual-channel spiral encourages heavier solids particles to fall into the lower channel while lighter fluids are retained in the higher channel. Solids are then funneled into the drain and eventually fall into the solids bypass tube, where they are then deposited into the mud joints. Fluid exits the bottom of the centrifuge and enters the pump suction. [3]

The separator design also utilizes a gas separation portion marketed as the MAX Gas Separator. The design utilizes a dual hydrogenated nitrile butadiene rubber (HNBR) cup technology (NR-1) that effectively sumps the pump while reducing the risk of a stuck packer. By utilizing two inverted cups to seal the wellbore and eliminating any setting and unsetting mechanisms, the risk of ‘sticking’ the packer is eliminated. The weight of the fluid level above the top cup pushes down on the cup and creates the top seal. The inflow from the reservoir pushes up on the bottom cup, creating the bottom seal. The separator uses HNBR because of the material’s resistance to abrasion, which is an important factor when running the packer in and out of the hole. To ensure the best seal possible, a casing scraper run is recommended prior to running the separator. This practice is especially important in older wells that have already been producing for several years. Also, to prevent damage to the packer cups, it is recommended for the rig operator to run in the hole at a speed slower than 60 feet per minute. As an added safety factor, the separator features a four-by-20-foot shroud. This shroud on the OD of the tool protects the tool's intake from any gas that does manage to leak by a damaged or improperly set packer.

The separator is designed to create the greatest tool OD to casing ID ratio possible, allowing for a maximized cross sectional separation area in the annulus of the given wellbore. The separator is composed of a 1.9-inch tool OD for a full 40-foot length.

By utilizing the ID of the casing and the OD of the tool housing, this tool allows for maximum cross-sectional separation area and therefore decreases the downward velocity of the fluid prior to pump entry. As a result, gas can escape naturally through the casing. The DFV must be slower than the bubble rise velocity for gas separation to occur. Assuming a maximum gas bubble rise velocity of 0.4 feet per second, the DFV equation can be used to calculate total pump displacement or barrels of fluid per day that can be effectively separated before overrunning the separator. Surpassing that number would cause the downward fluid velocity to exceed the bubble rise velocity and separation efficiencies would be limited.

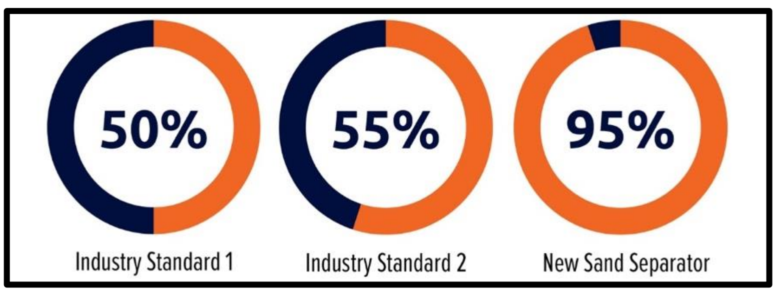


Figure 4: Two industry-standard solids separators compared to the new separator.

S VORTEX SAND SEPARATOR CASE STUDY RESULTS

Two industry-standard vortex solids separators as well as the newly developed solids separator component were tested in a well simulator. Solids with different mesh sizes and production rates were also tested. Screen-type separators were excluded from the test because of their propensity to plug off. [2]

The desander component of the new tool operated with an efficiency of 95 percent, 40 percent higher than the next closest industry standard separator, as shown in Figure 4. These findings are consistent with earlier research which indicates pumping unit speed and separator design likely causes efficiency to drop below 50 percent.

The various types of gas separators may be simply evaluated through the use of straightforward calculations. The relationship between the cross-sectional separation area and fluid volume shows how crucial it is to maximize the separation area for higher gas separation efficiency. [3] By taking full advantage of the casing-tubing annulus rather than the tool's dimensional variations, packer-style separators unquestionably produce the largest cross-sectional separation area.

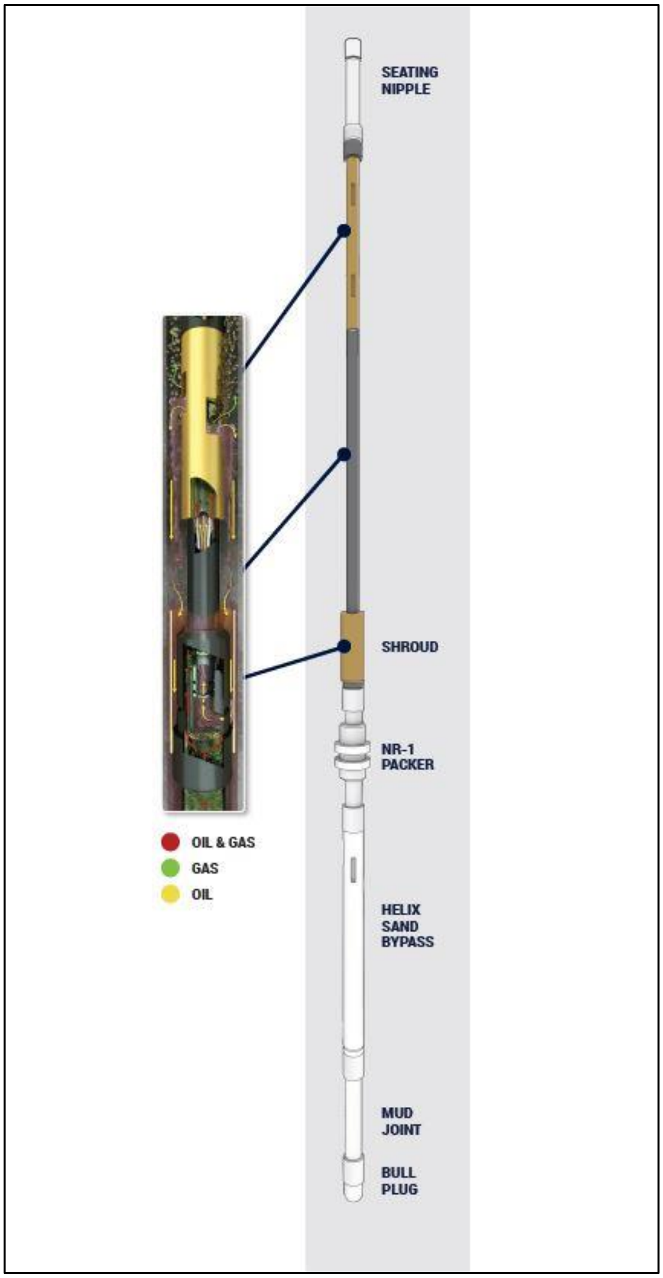


Figure 7: The 40-foot by1.9-inch gas separator, dual cup HNBR packer and 9-foot solids separator that form the Super Max System.

As shown in Figure 7, fluids first enter the solids separator portion of the system, located below the NR-1 cup-type packer. Solids are then deposited into the mud joints, while fluid enters the ID of the packer and travels upwards inside the system for a full 40 feet. Fluids are then expelled into the casing-tubing annulus where gas continues to rise up the casing annulus and fluids fall 40 feet back down to catch in the shroud. Once in the shroud, gas-free fluid enters the dip tube and rises back up, eventually entering the pump intake.

RESULTS & DISCUSSION

Well A results showcase production rates and downtime. The history of the well is showcased in Figure 8 and listed as follows:

- Two-year DT ESP failure.
- Return to production as ESP.
- ESP failure.
- Converted to sucker rod pump (SRP).
- Super MAX system installed.
- Sucker rod failure due to chemical (tubing not pulled).

The key takeaways are that minimal production loss was incurred from ESP conversion, Well A still has the original Super MAX system installed since the conversion took place and that the well has produced up to 1900 MCF with an average of 1500 MCF.

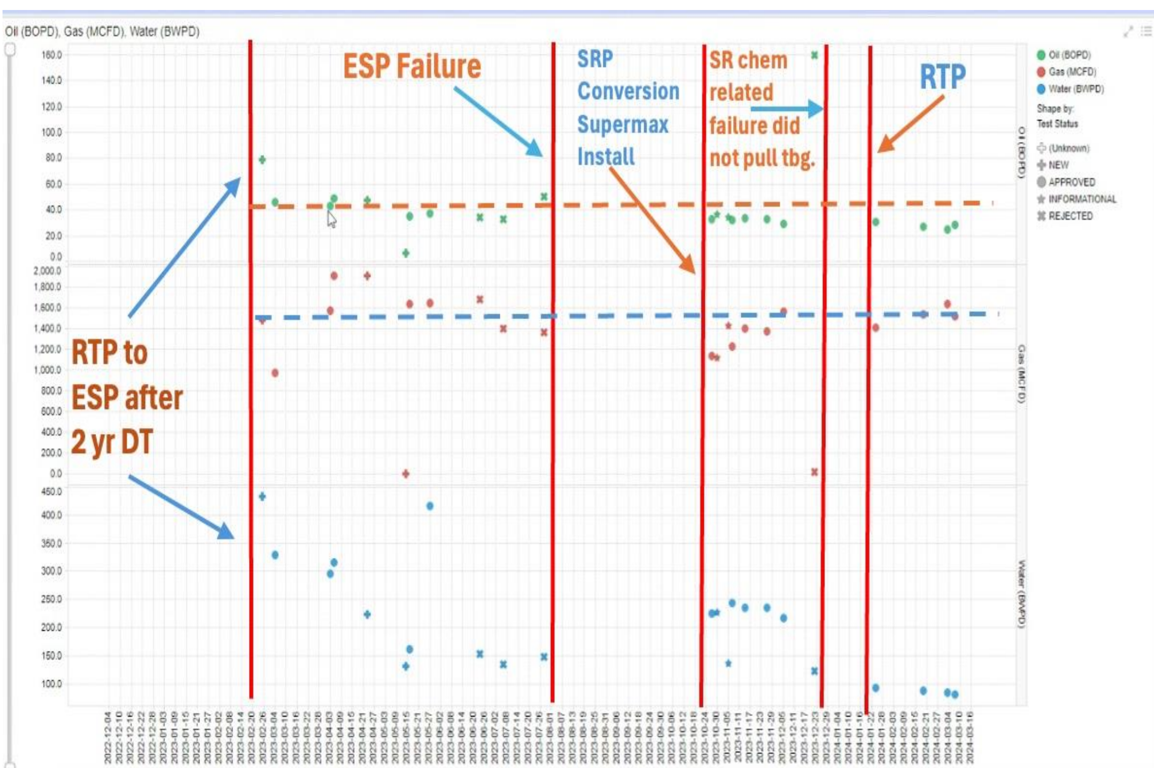


Figure 8: Well A Results; ESP Conversion to SRP.

Well A is exhibiting steady operational trends with consistent run times, strokes per minute, peak and minimum loads, and closely matched inferred and actual production. The well has also been operated conservatively while maintaining production targets. It could be argued that the well has the potential to operate slightly more aggressive with increased max strokes per minute and lowering pump fillage set points to further draw the well down.

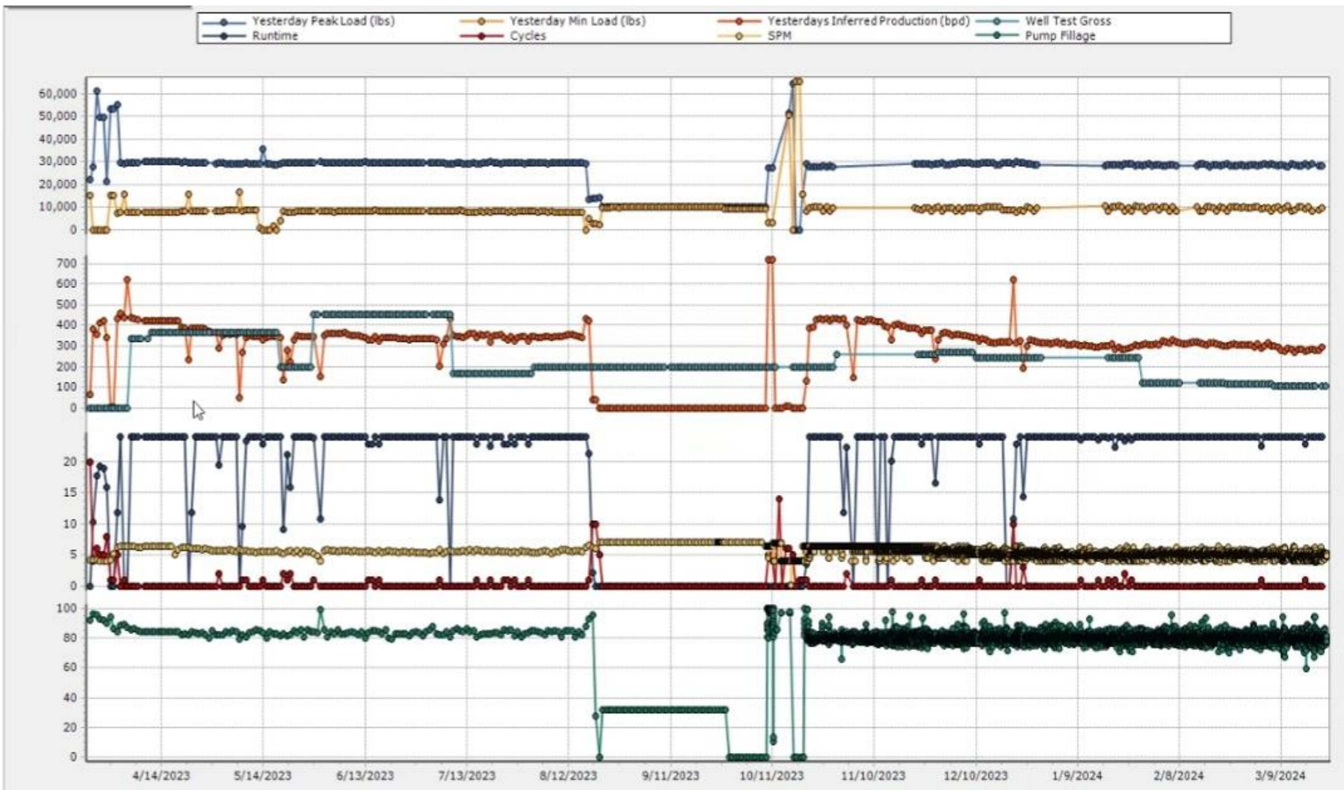


Figure 9: Well A displaying operational trends.

Well B results showcase production rates and downtime. The history of the well is showcased in Figure 10 and listed as follows:

- 872-day run with a Mother Hubbard (Poor Boy) separator in place until failure.
- Production returned with Super MAX system installation
- 784-day run until failure.
- Return to production with no design changes.

The key takeaways are that total fluid production was increased, gas rates were increased while maintaining production targets and that the overall run life exceeded predicted estimates.

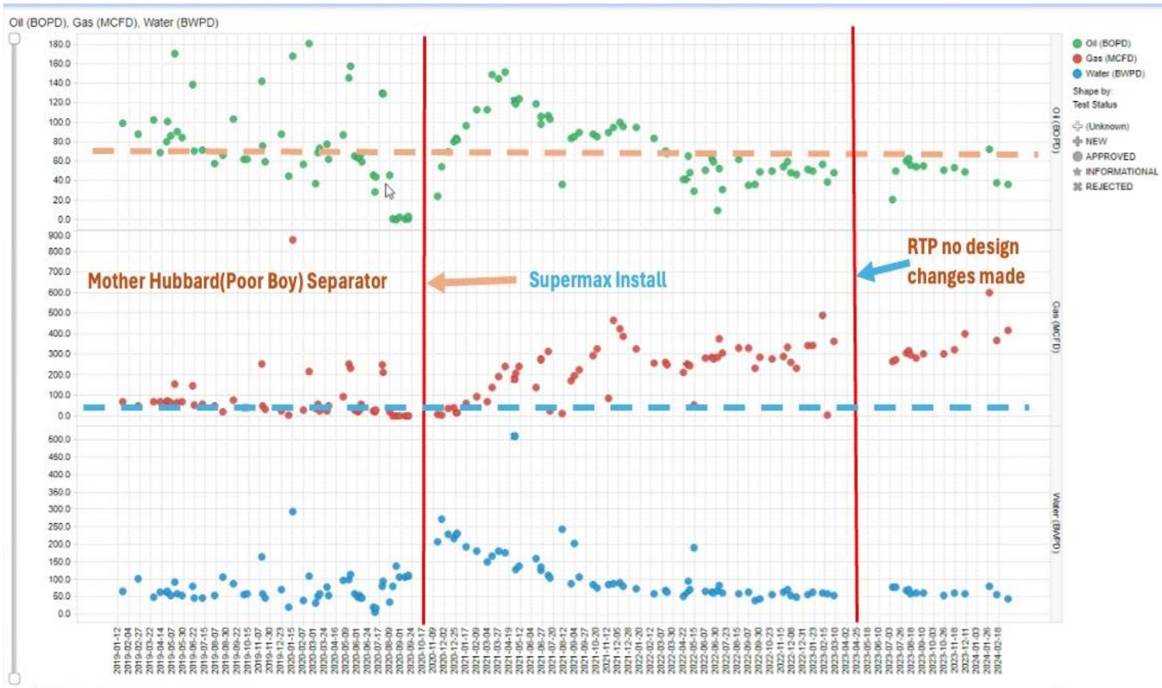
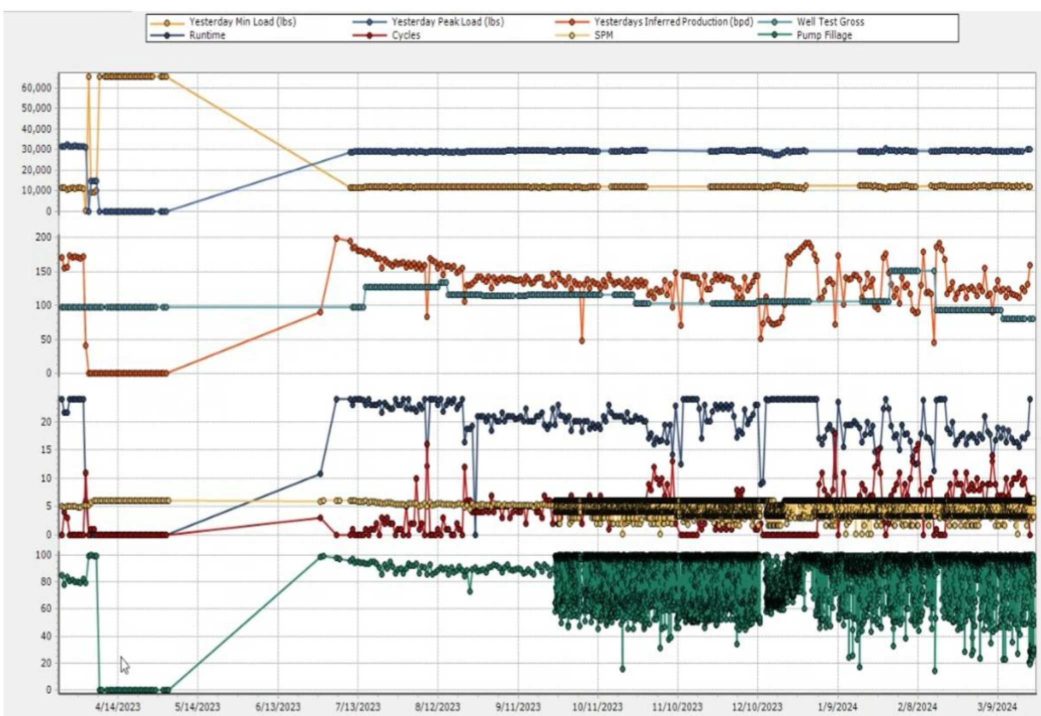
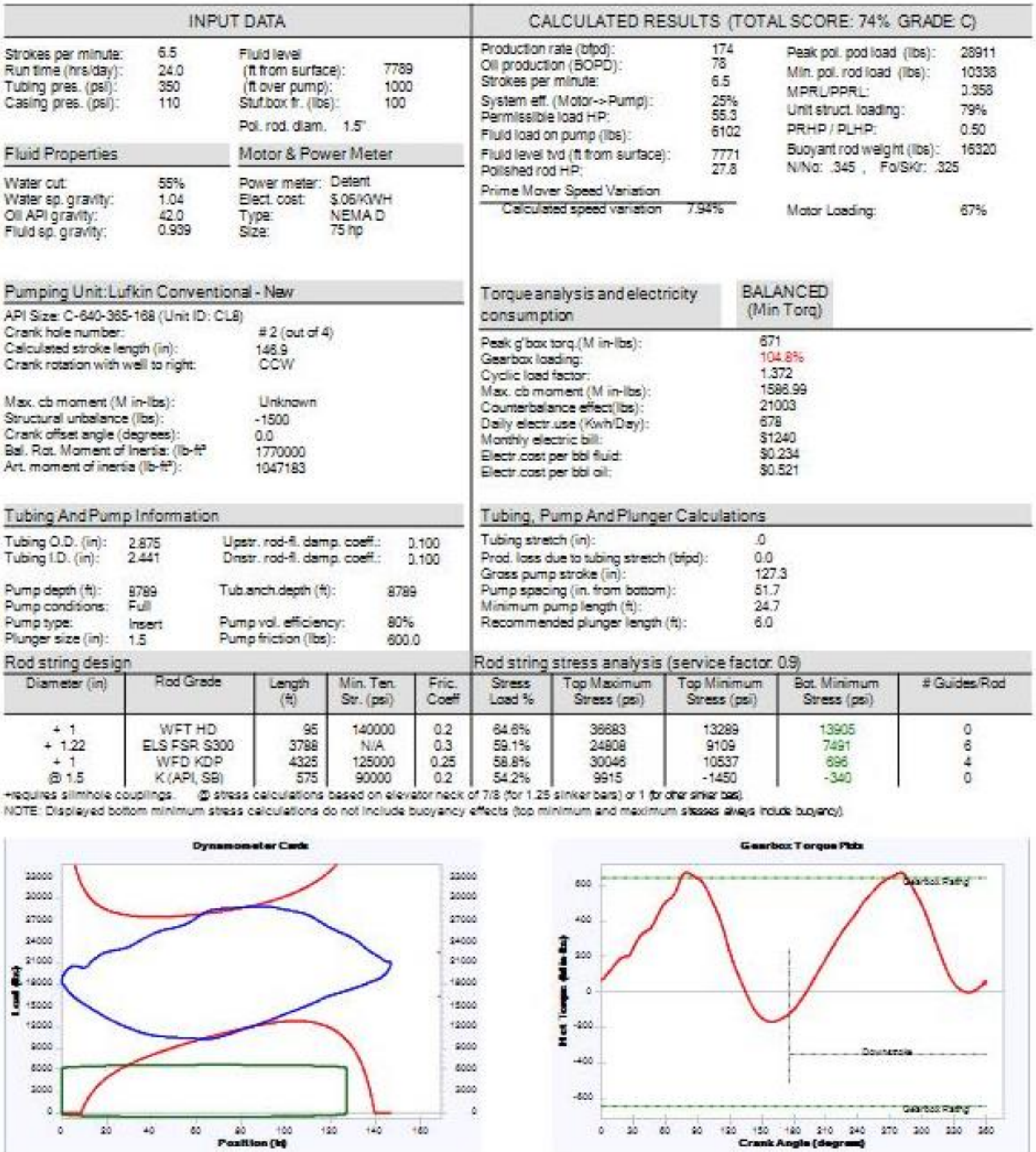


Figure 10: Well B production trends from separator change.

Well B, recent operational trends are displaying pump fillage inconsistencies due to increased gas rates represented in Figure 11. Well B is operating conservatively with potential to increase peak strokes per minute and adjust the minimum and maximum speed should the operator choose to do so.





INPUT DATA

Strokes per minute: 6.5
Run time (hrs/day): 24.0
Tubing pres. (psi): 350
Casing pres. (psi): 110

Fluid level
(ft from surface): 7789
(ft over pump): 1000
Stuf.box fr. (lbs): 100
Pol. rod. diam. 1.5"

Fluid Properties

Water cut: 55%
Water sp. gravity: 1.04
Oil API gravity: 42.0
Fluid sp. gravity: 0.939

Motor & Power Meter

Power meter: Detent
Elect. cost: $.06/KWH
Type: NEMA D
Size: 75 hp

Pumping Unit: Lufkin Conventional - New

API Size: C-640-365-168 (Unit ID: CL8)
Crank hole number: # 2 (out of 4)
Calculated stroke length (in): 146.9
Crank rotation with well to right: CCW

Max. cb moment (M in-lbs): Unknown
Structural unbalance (lbs): -1500
Crank offset angle (degrees): 0.0
Bal. Rot. Moment of Inertia: (lb-ft^2 1770000
Art. moment of inertia (lb-ft^2): 1047183

Tubing And Pump Information

Tubing O.D. (in): 2.875
Tubing I.D. (in): 2.441
Upstr. rod-fl. damp. coeff.: 0.100
Dnstr. rod-fl. damp. coeff.: 0.100

Pump depth (ft): 8789
Pump conditions: Full
Pump type: Insert
Plunger size (in): 1.5
Tub.anch.depth (ft): 8789
Pump vol. efficiency: 80%
Pump friction (lbs): 600.0

CALCULATED RESULTS (TOTAL SCORE: 74% GRADE: C)

Production rate (bfpd): 174
Oil production (BOPD): 78
Strokes per minute: 6.5
System eff. (Motor->Pump): 25%
Permissible load HP: 55.3
Fluid load on pump (lbs): 6102
Fluid level tvd (ft from surface): 7771
Polished rod HP: 27.8
Prime Mover Speed Variation
Calculated speed variation 7.94%

Peak pol. pod load (lbs): 28911
Min. pol. rod load (lbs): 10338
MPRL/PPRL: 0.358
Unit struct. loading: 79%
PRHP / PLHP: 0.50
Buoyant rod weight (lbs): 16320
N/No: .345 , Fo/SKr: .325
Motor Loading: 67%

Torque analysis and electricity consumption — BALANCED (Min Torq)

Peak g'box torq.(M in-lbs): 671
Gearbox loading: 104.8%
Cyclic load factor: 1.372
Max. cb moment (M in-lbs): 1586.99
Counterbalance effect(lbs): 21003
Daily electr.use (Kwh/Day): 678
Monthly electric bill: $1240
Electr.cost per bbl fluid: $0.234
Electr.cost per bbl oil: $0.521

Tubing, Pump And Plunger Calculations

Tubing stretch (in): .0
Prod. loss due to tubing stretch (bfpd): 0.0
Gross pump stroke (in): 127.3
Pump spacing (in. from bottom): 51.7
Minimum pump length (ft): 24.7
Recommended plunger length (ft): 6.0

Rod string design / Rod string stress analysis (service factor: 0.9)

Diameter (in)	Rod Grade	Length (ft)	Min. Ten. Str. (psi)	Fric. Coeff	Stress Load %	Top Maximum Stress (psi)	Top Minimum Stress (psi)	Bot. Minimum Stress (psi)	# Guides/Rod
+ 1	WFT HD	95	140000	0.2	64.6%	36683	13289	13905	0
+ 1.22	ELS FSR S300	3788	N/A	0.3	59.1%	24808	9109	7491	6
+ 1	WFD KDP	4325	125000	0.25	58.8%	30046	10537	696	4
@ 1.5	K (API, SB)	575	90000	0.2	54.2%	9915	-1450	-340	0

+requires slimhole couplings. @ stress calculations based on elevator neck of 7/8 (for 1.25 sinker bars) or 1 for other sinker bars).
NOTE: Displayed bottom minimum stress calculations do not include buoyancy effects (top minimum and maximum stresses always include buoyancy).

Figure 11: Well B operational design.

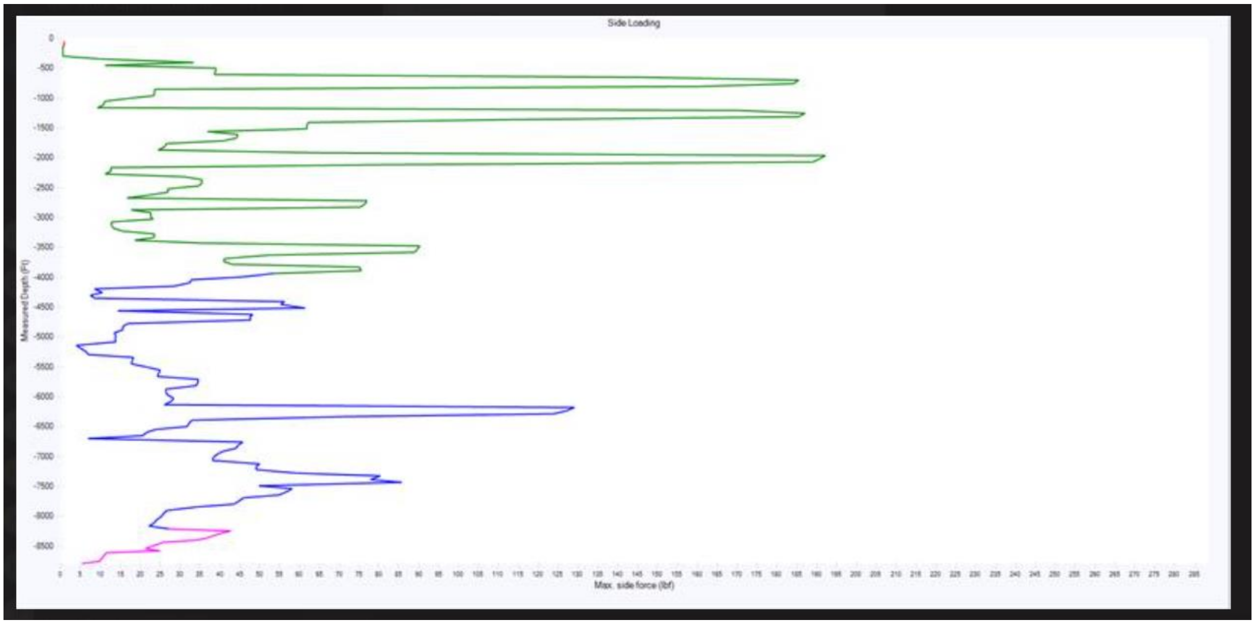


Figure 12: Well B side loading presenting operational challenges.

CONCLUSION

The data presented in this paper shows that with proper gas and solid separation, well drawdown and production targets, extended run life is possible. If reducing sporadic SPM and pump fillage behavior as well as avoiding frequent premature shutdowns is the goal, this separator is an ideal candidate that allows maximum gas separation by utilizing casing ID and tool housing OD. Optimal production is capable with a carefully thought-out BHA design and optimization practices.

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