

THE BEST ESP DESIGN EVER – A DATA-DRIVEN FRAMEWORK FOR EQUIPMENT SELECTION

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ABSTRACT

Determining the best Electric Submersible Pump (ESP) design ever requires analyzing a comprehensive dataset of installations. In this case, an installation set of 915 ESPs in Delaware Basin unconventional wells are utilized to identify the most effective configurations. Downhole production volumes are normalized across wells using a statistical framework that controls for confounding variables such as well productivity, casing size, and pump model. ESP designs are categorized by gas separator configuration, motor diameter, sand separation equipment, casing size, pump stage count, pump model, and gas handling equipment. Exceedance probability curves with Swanson's Mean evaluate production performance, while Kaplan-Meier survival analysis with Restricted Mean Survival Time (RMST) assesses reliability. Results highlight which configurations best accommodate the operating environment and provide actionable guidelines for ESP design selection. The answer, it turns out, is not straightforward, but this framework gets us closer.

INTRODUCTION

ESP design selection in unconventional wells involves balancing reliability, production capacity, and operating flexibility. Traditional approaches rely on individual well experience or vendor recommendations. This study takes a different approach: we analyze the full installation history of 915 ESPs to identify which equipment choices actually lead to better outcomes.

The challenge with fleet-level comparisons is that equipment choices are not random. Larger pumps go in higher-rate wells, bigger motors go in larger casing, and different configurations may correlate with various reservoir, installation period, or well completion type. To address this, we developed a normalization framework that controls for confounding variables before comparing equipment groups. Each comparison in this paper holds as many variables constant as possible to isolate the effect of a single design choice.

METHODOLOGY

Dataset

The dataset consists of 915 ESP installations with daily production data, pump intake pressure measurements downhole, and detailed equipment configuration records. Each

install includes pump model, gas handling equipment, gas separator, motor series, design, sand separation equipment configuration, casing size, stage count, and failure information.

Reliability Analysis: Kaplan-Meier and RMST

Kaplan-Meier survival curves provide a non-parametric estimate of ESP survival probability over time. Unlike simple averages, KM properly handles censoring: ESPs still running at the time of analysis are treated as censored observations rather than failures, preventing underestimation of true reliability. RMST (Restricted Mean Survival Time) summarizes the area under the survival curve up to a time horizon, tau, providing a single number for comparison. We set tau at the point where any group first drops below 10% survival, ensuring a fair comparison window across groups. Percent differences in RMST between groups quantify the relative reliability impact of each equipment choice. In this paper, the absolute reliability axis is hidden and only the relative percent differences are shown to focus attention on equipment design effects.

Production Analysis: Downhole Volume, Exceedance Curves, and Swanson's Mean

The primary production metric used in this study is the Max 30-Day Downhole Rate, defined as the maximum value of a 30-day rolling average of daily downhole total fluid volume over each install's run life. Downhole total fluid volume is calculated by converting surface production rates (oil, water, and gas) to at intake conditions using standard pressure-volume-temperature (PVT) correlations. Oil volume is converted using the Standing correlation for oil formation volume factor (B_o), which accounts for solution gas (R_s) dissolving into the oil phase at downhole pressure. Water volume is adjusted using a water formation volume factor (B_w) that accounts for thermal expansion and pressure compressibility. Free gas volume is converted using the gas formation volume factor (B_g), derived from the Hall-Yarborough Z-factor correlation for gas compressibility. The key input driving these conversions is the ESP intake pressure (PIP), measured by the downhole sensor, which determines the pressure at which fluid properties are evaluated.

Fleet-wide PVT assumptions are applied consistently across all installs: oil API gravity of 50, gas specific gravity of 0.72, water specific gravity of 1.07, and a downhole temperature of 180 degrees F. Because these are not well-specific fluid properties, the absolute magnitude of any individual downhole volume should be interpreted with caution. However, since the same assumptions are applied uniformly, the relative comparisons between equipment groups – which are the focus of this paper – remain valid.

Exceedance probability curves show the likelihood of exceeding a given production value and are used to compare the full distribution shape between groups, not just a single summary statistic. For summarizing these distributions, we use Swanson's Mean ($0.3 \times P_{10} + 0.4 \times P_{50} + 0.3 \times P_{90}$), which is the standard oil and gas industry approximation for the mean of a lognormal distribution. This weighted average gives a

more practical representation of expected production than a simple arithmetic mean, which can be skewed by outliers.

Normalization Framework

To make fair comparisons, we apply normalization bands that restrict the analysis to installs operating under similar conditions. For example, when comparing motor sizes, we may normalize by Max 30-Day Downhole Rate to ensure both groups are producing at similar volumes. The normalization band is shown as a histogram overlay so the reader can verify that both groups have adequate representation within the band. Additional categorical filters (casing size, pump BEP, gas separator size, failure type) further control for confounding variables. Each section describes its specific filtering scheme so the reader can evaluate the strength of the comparison.

Despite these controls, selection bias remains present throughout the analysis. Equipment choices are made by engineers responding to well conditions – wells with higher sand risk may receive sand separation equipment more frequently, and higher-rate wells may receive larger pumps not because of a controlled experiment but because the design called for it. This means observed performance differences between groups may partly reflect the conditions that drove the selection, not just the equipment itself. The normalization framework reduces but does not eliminate this effect.

RESULTS AND DISCUSSION

Section 1: Casing Size: The Starting Point

Before evaluating individual ESP components, we start with the wellbore itself. Casing size constrains available ESP configurations and directly affects annular space available for gas separation, which is a critical factor in ESP performance. Larger casing provides more annular area, allowing free gas to separate more effectively. To isolate the casing size effect, we held equipment configuration as constant as possible: 400-series gas separators (both HV and LV types) with 1,750 bbl/d best efficiency point (BEP) pumps. This yields 151 installs, though the split is highly uneven with 141 in 5.5 inch casing and only 10 in 7.625 inch casing. The small 7.625 count reflects that 400-series separators are rarely installed in larger casing, where 538-series equipment is preferred.

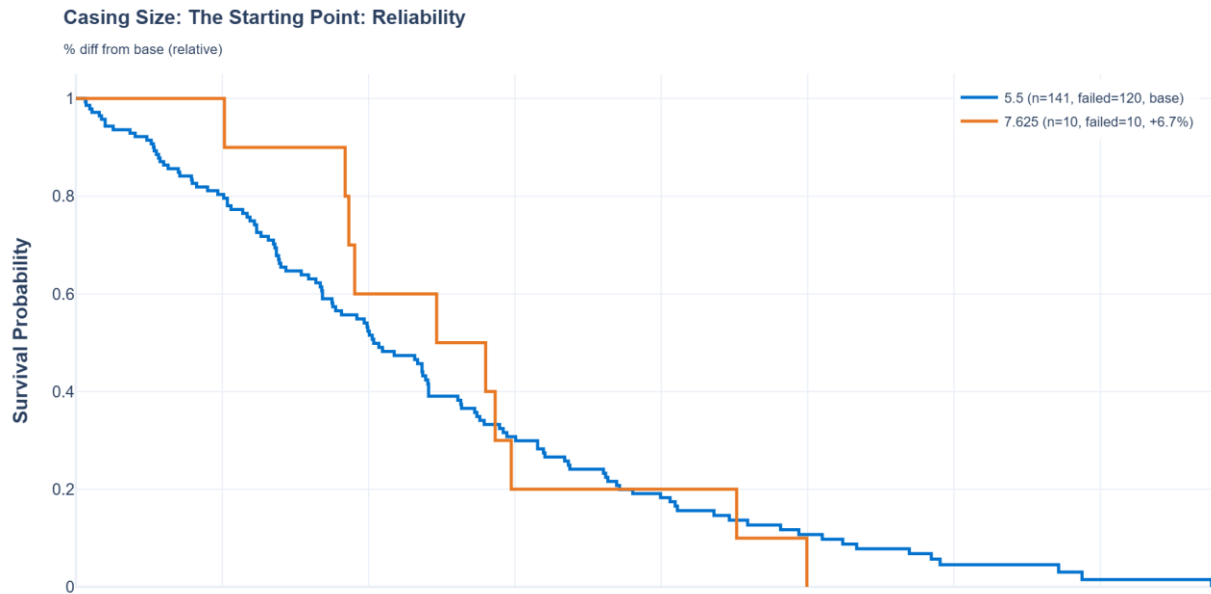


Figure 1 - Survivability between 1,750 BEP pump designs with 400-series gas separators in 5.5 inch and 7.625 inch casing

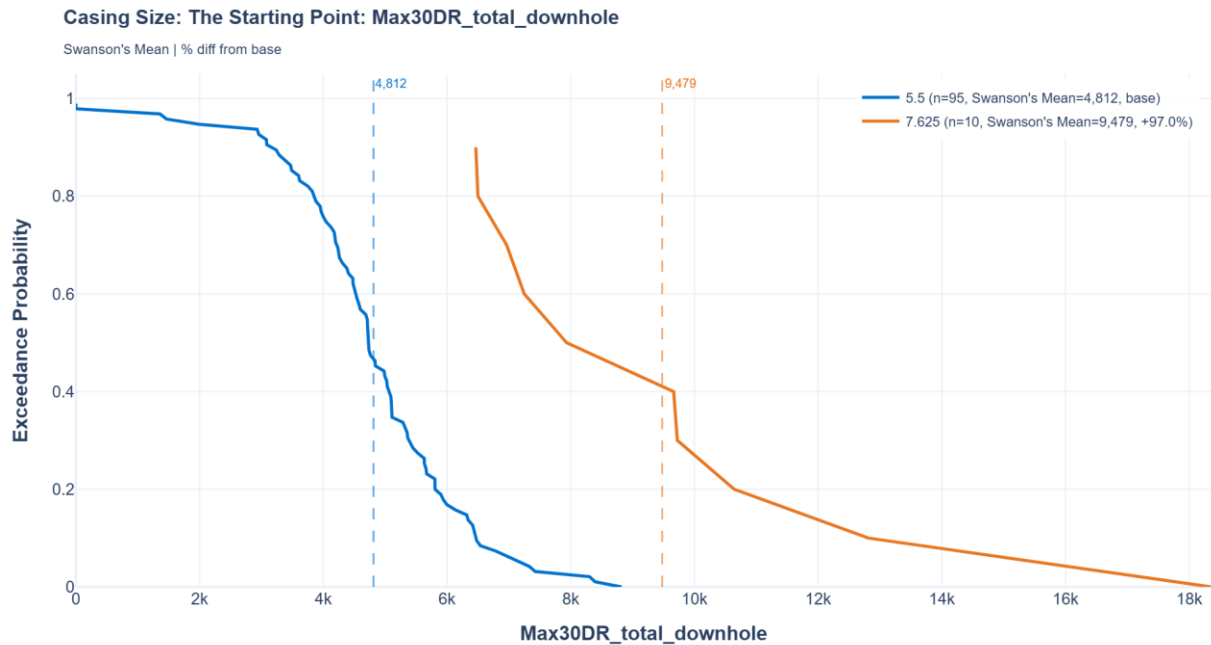


Figure 2 - Downhole produced volumes between 1,750 BEP pump designs with 400-series gas separators in 5.5 inch and 7.625 inch casing

Table 1 - Survivability and downhole volume between 1,750 BEP pump designs with 400-series gas separators in 5.5 inch and 7.625 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
5.5	141	120	base	4,812	base
7.6	10	10	6.69	9,479	+97.0%

Despite the unbalanced sample, the results are directionally clear. Reliability is comparable between casing sizes (+6.7% for 7.625 inch), but the production difference is notable: Swanson's Mean peak production nearly doubles from approximately 4,800 bbl/d in 5.5 inch casing to approximately 9,500 bbl/d in 7.625 inch casing with the same equipment. Casing size appears to be an important factor for downhole volume from this subset of 1,750 BEP pump designs. Future work should extend this comparison to other pump sizes to confirm whether this relationship holds across the fleet.

Section 2: Gas Separator Size: 400 vs 538 Series

With casing size established as the production ceiling, the next question is which ESP component has the largest influence within a given casing. We compare 400-series and 538-series gas separators in 7.625 inch casing with 1,750 bbl/d BEP pumps. ESP Cable failures and designs with older cable are excluded from this comparison to avoid masking equipment-level differences. The filtered dataset contains 44 installs (35 with 538, 9 with 400).

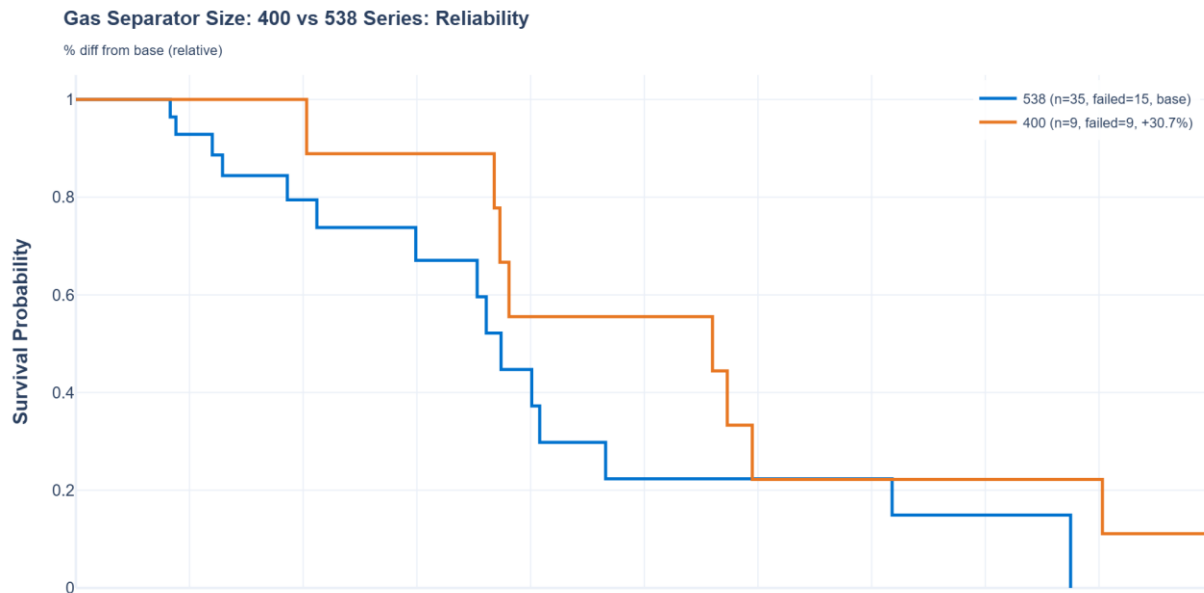


Figure 3 - Survivability between 400-series and 538-series gas separators in 7.625 inch casing with 1,750 BEP pumps, excluding cable failures

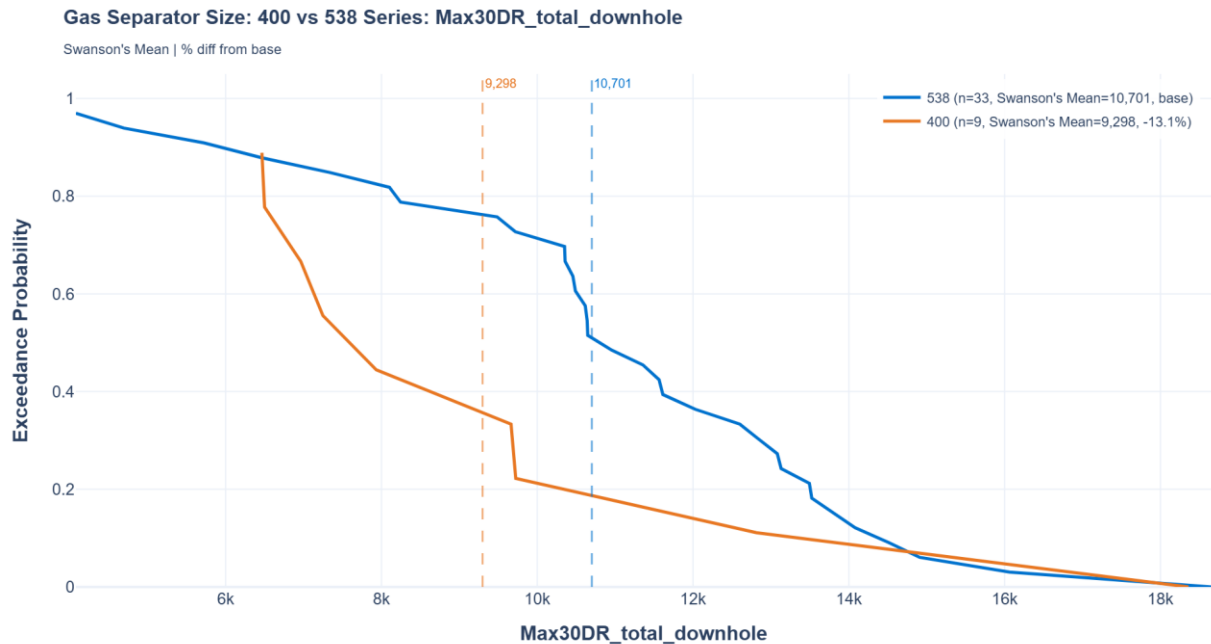


Figure 4 - Downhole produced volumes between 400-series and 538-series gas separators in 7.625 inch casing with 1,750 BEP pumps

Table 2 - Survivability and downhole volume between 400-series and 538-series gas separators in 7.625 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
538	35	15	base	10,701	base
400	9	9	+30.7%	9,298	-13.1%

After removing cable failures, the 400-series gas separators show substantially better non-cable reliability (+30.7%) compared to 538-series. However, the 538-series delivers higher peak production (Swanson's Mean of approximately 10,700 vs 9,300 bbl/d). The larger gas separator enables the system to produce at higher downhole rates, but the increased drawdown may stress other components. This trade-off between production gain and reliability cost should be evaluated on a well-by-well basis.

Section 3: Gas Separator Type in 5.5 Inch Casing

Continuing with gas handling, we focus on 5.5 inch casing where annular space is limited and gas management is especially critical. We compare gas separator types within the 400-series: High Volume (HV), Low Volume (LV), and charged gas variants (GH6000). The analysis covers three pump BEPs (1,750, 2,000, and 3,000 bbl/d) and cross-references pump BEP with gas separator type to understand how these interact.

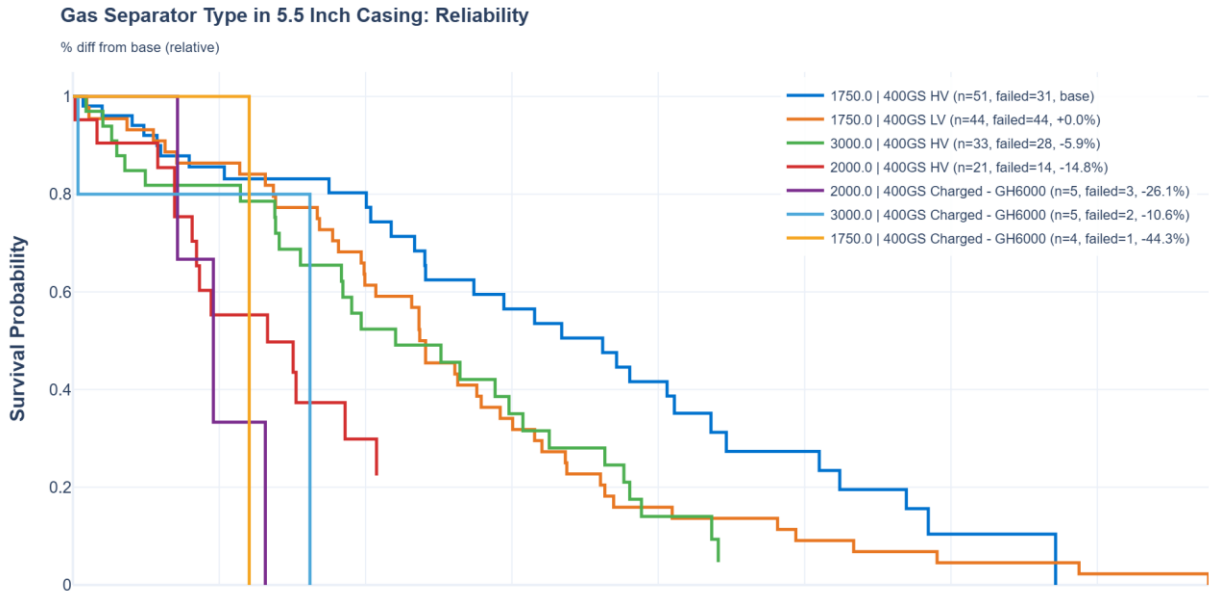


Figure 5 - Survivability across gas separator types (HV, LV, Charged) by pump BEP in 5.5 inch casing with 400-series gas separators

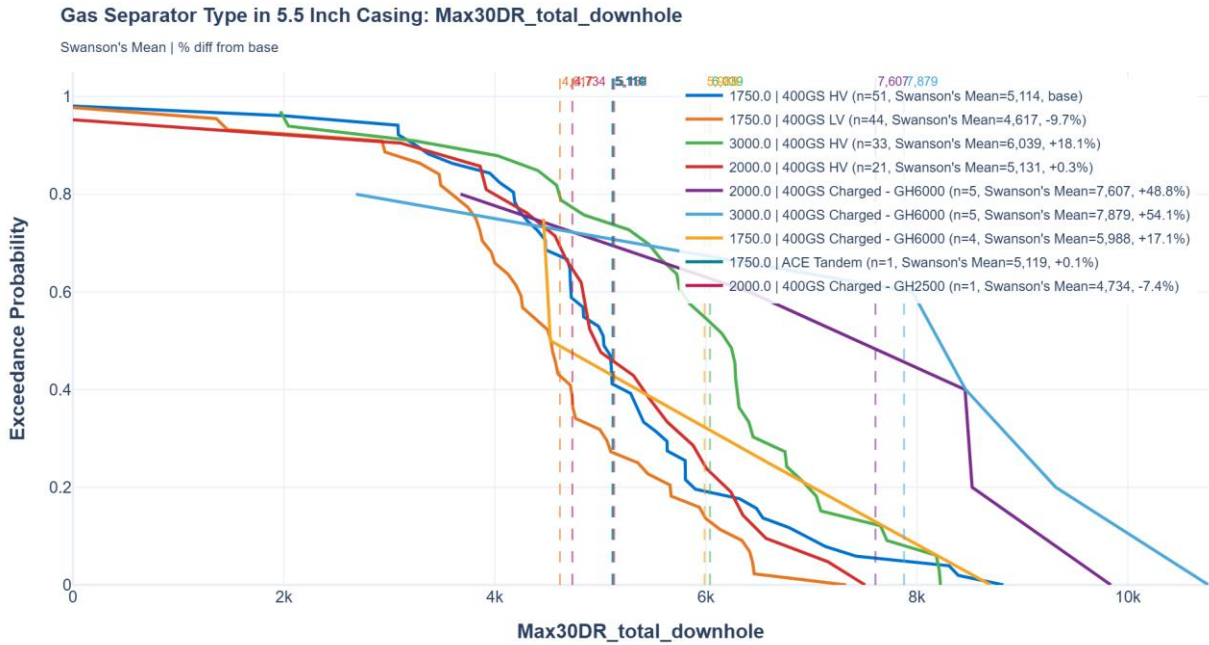


Figure 6 - Downhole produced volumes across gas separator types by pump BEP in 5.5 inch casing with 400-series gas separators

Table 3 - Survivability and downhole volume across gas separator types by pump BEP in 5.5 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
1750.0 400GS HV	51	31	base	5,114	base
1750.0 400GS LV	44	44	0.03	4,617	-9.72
3000.0 400GS HV	33	28	-5.94	6,039	+18.1%
2000.0 400GS HV	21	14	-14.8%	5,131	0.34
2000.0 400GS Charged - GH6000	5	3	-26.1%	7,607	+48.8%
3000.0 400GS Charged - GH6000	5	2	-10.6%	7,879	+54.1%
1750.0 400GS Charged - GH6000	4	1	-44.3%	5,988	+17.1%
1750.0 ACE Tandem	1	1	-	5,119	0.11
2000.0 400GS Charged - GH2500	1	0	-	4,734	-7.42

Within the 1,750 BEP group, the HV and LV gas separators show identical reliability but the HV configuration produces approximately 10% higher peak downhole volumes. For the 3,000 BEP group, HV gas seps again outperform the LV version. The charged gas separator variants (GH6000) show notably higher production (approximately 7,600-7,900 bbl/d Swanson's Mean vs 5,100-6,000 for standard configurations) but have very small sample sizes (n=4-5 each). The 2,000 BEP group with HV separators shows lower reliability (-14.8%) compared to the 1,750 HV base, which may reflect that higher-rate pumps draw the well down further in constrained casing. It is interesting to note that the 3,000 BEP group shows higher relative reliability and production than the 2,000 BEP group, which appears to contradict the drawdown hypothesis – if larger pumps stress the system by drawing the well down further, the 3,000 should perform worse, not better. This may reflect selection bias, where 3,000 BEP pumps are installed in wells better suited to handle the additional drawdown. In smaller casing, the gas separator type should be actively selected rather than defaulted.

Case Study: Design Evolution on a Single Pad

To illustrate how gas separator type, gas handling, and pump BEP interact as a complete system, we examine 5 ESP installations with pump BEP of 3,000 bbl/d or less across a single pad of wells in 5.5 inch casing. These wells share similar area, formation, and completion characteristics, making them a natural experiment for comparing 2 distinct ESP system configurations. Each install is grouped by its complete system design (pump BEP, gas separator type, and gas handling equipment) and plotted from the date of ESP installation using downhole total fluid volume.

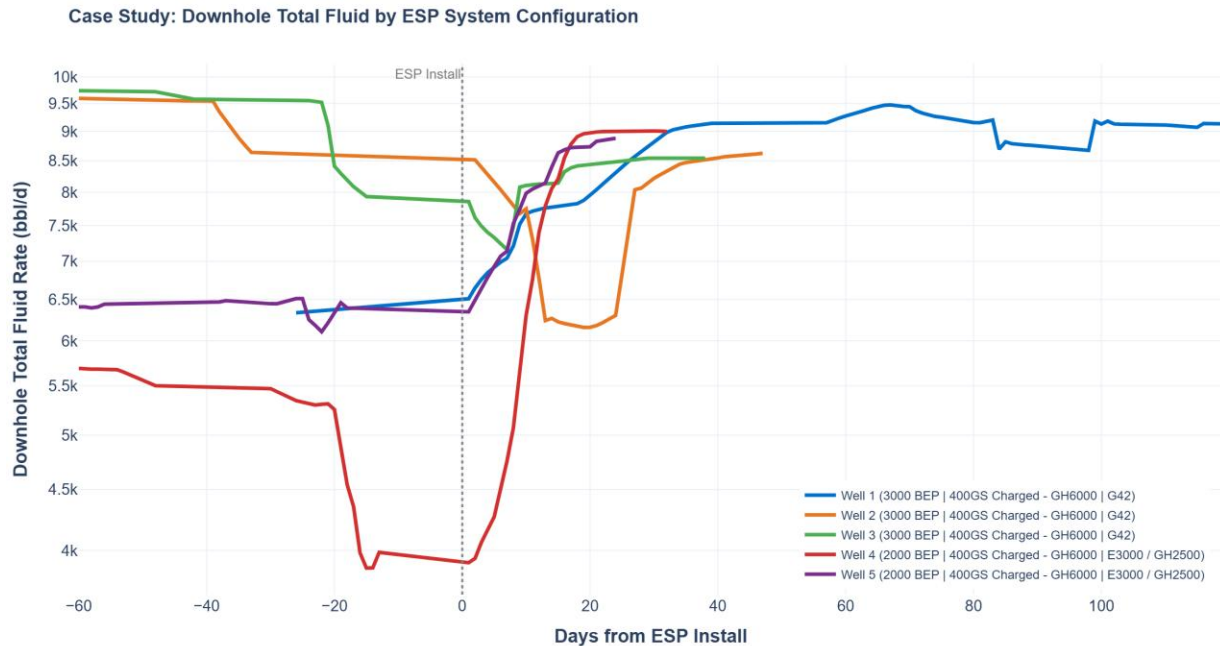


Figure 7 - Time-zero normalized downhole total fluid production for ESP installations on a single pad in 5.5 inch casing, grouped by complete system configuration (pump BEP, gas separator type, gas handling)

The time-zero normalized plot reveals interesting results. Prior to the new install (left of the dashed line), the previous ESPs on these wells – equipped with 5,600 and 6,000 BEP pumps – were producing between 6,000 to 10,000 bbl/d of downhole total fluid before being pulled. After workover, the replacement installs with significantly smaller pumps (3,000 BEP with G42 gas handling and 2,000 BEP with E3000/GH2500) ramp up to comparable downhole volumes of approximately 8,000 to 9,500 bbl/d within the first two weeks. Despite nearly halving the rated pump capacity, these downsized configurations achieve similar downhole throughput. This supports the broader finding that primary top pump oversizing does not necessarily translate to higher production and may introduce unnecessary risk of earlier failure. These installs are still early in their run life and continued monitoring will determine whether the reliability holds, but the initial production response is encouraging.

Section 3b: Pump BEP and Gas Handling in 5.5 Inch Casing

Gas handling equipment (e.g. GH2500, GH6000, G42, partial tapers 2000-3000 combinations) is a separate component from the gas separator itself and serves to further process free gas before it reaches the pump. This section examines how different gas handling equipment perform across pump BEP classes in 5.5 inch casing. Installs are filtered to 400-series gas separators with pump BEPs ranging from 1,000 to 3,000 bbl/d and grouped by the combination of pump BEP and gas handling configuration. A normalization band on early 30-day total fluid rate (513 to 2,206 bbl/d) controls for initial install rates, ensuring that groups are compared at similar design rates rather than letting higher-rate wells skew the results.

Pump BEP and Gas Handling in 5.5 Inch Casing: Reliability

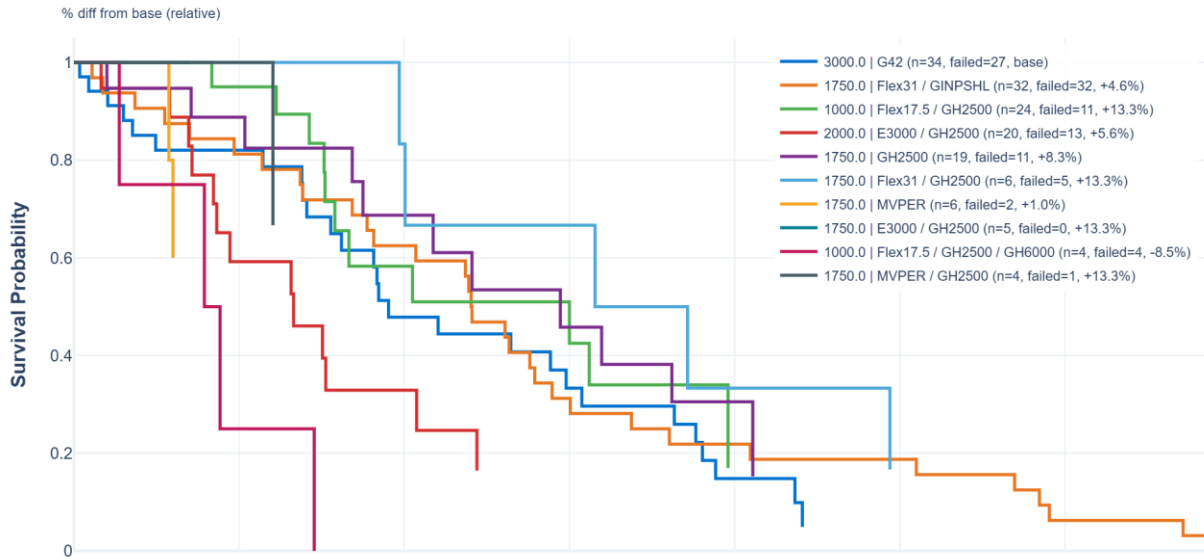


Figure 8 - Survivability by pump BEP and gas handling configuration in 5.5 inch casing with 400-series gas separators, normalized by initial production rate

Pump BEP and Gas Handling in 5.5 Inch Casing: Max30DR_total_downhole

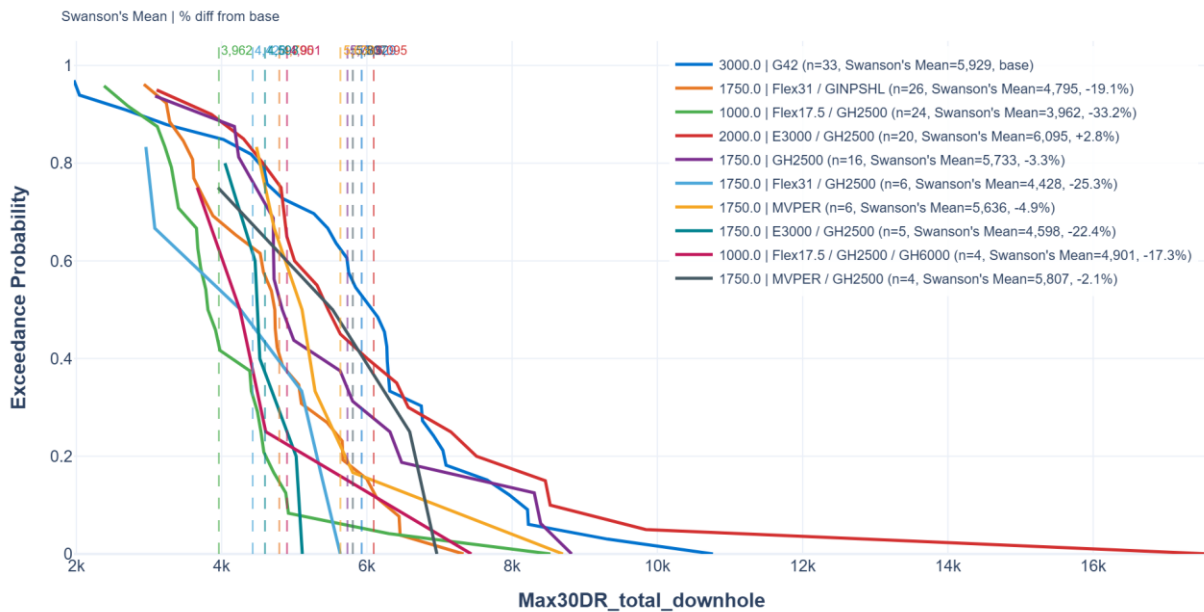


Figure 9 - Downhole produced volumes by pump BEP and gas handling configuration in 5.5 inch casing with 400-series gas separators

Table 4 - Survivability and downhole volume by pump BEP and gas handling configuration in 5.5 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
3000.0 G42	34	27	base	5,929	base
1750.0 Flex31 / GINPSHL	32	32	4.62	4,795	-19.1%
1000.0 Flex17.5 / GH2500	24	11	+13.3%	3,962	-33.2%
2000.0 E3000 / GH2500	20	13	5.61	6,095	2.80
1750.0 GH2500	19	11	8.33	5,733	-3.31
1750.0 Flex31 / GH2500	6	5	+13.3%	4,428	-25.3%
1750.0 MVPER	6	2	1.02	5,636	-4.94
1750.0 E3000 / GH2500	5	0	+13.3%	4,598	-22.4%
1000.0 Flex17.5 / GH2500 / GH6000	4	4	-8.54	4,901	-17.3%
1750.0 MVPER / GH2500	4	1	+13.3%	5,807	-2.06

Filtering by initial production rate and grouping by pump BEP and gas handling together reveals how these two design choices interact. Within the same BEP class, different gas handling configurations can produce meaningfully different reliability and production outcomes. This reinforces that pump sizing and gas handling should be selected together as a system rather than independently, and it's up to the engineer and ESP designer to select a system that balances both production and reliability for the best economic output.

Section 4: Motor Diameter: 450 vs 562 Series

With gas separator effects established, we test whether motor diameter has a similar influence. We filtered to 7.625 inch casing with pump BEPs of 1,750 and 2,000 bbl/d, comparing 450-series (n=29) and 562-series (n=85) motors across 114 installs. By holding casing size and pump BEP constant, the motor diameter is the primary variable.

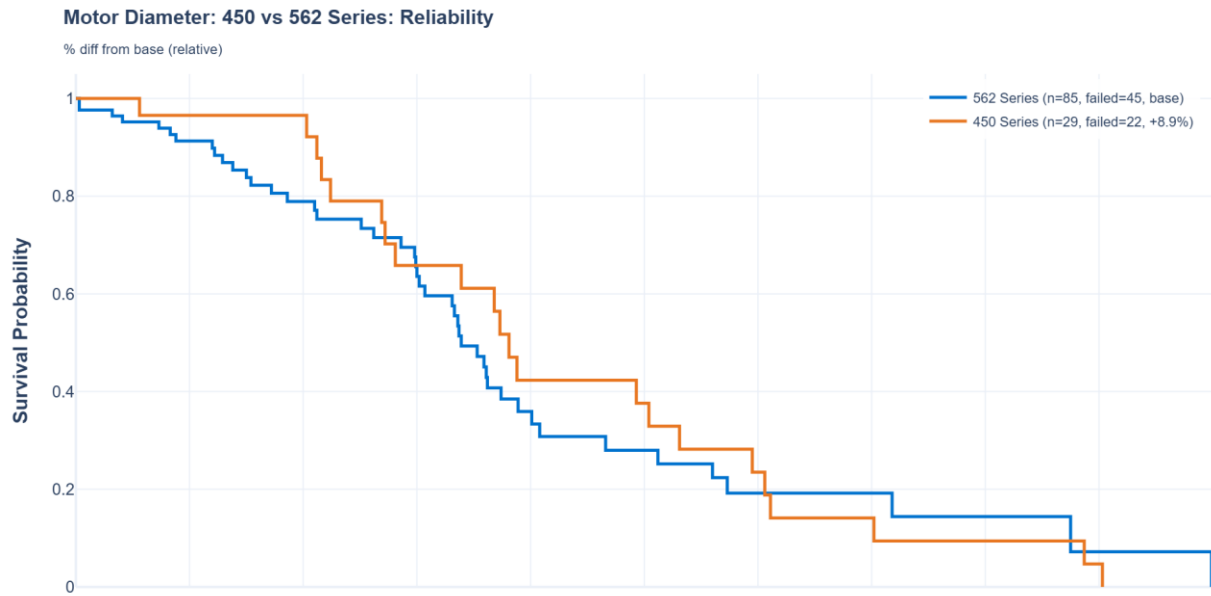


Figure 10 - Survivability between 450-series and 562-series motors in 7.625 inch casing with 1,750 and 2,000 BEP pumps



Figure 11 - Downhole produced volumes between 450-series and 562-series motors in 7.625 inch casing with 1,750 and 2,000 BEP pumps

Table 5 - Survivability and downhole volume between 450-series and 562-series motors in 7.625 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
562 Series	85	45	base	10,170	base
450 Series	29	22	8.89	10,705	5.26

The smaller 450-series motor shows a slight reliability advantage (+8.9%) and comparable peak production to the 562-series. Unlike gas separator size, motor diameter does not appear to be a strong driver of either reliability or production when other variables are controlled. This finding suggests that motor upsizing for performance gains is less effective than optimizing gas separator selection.

Section 5: Sand Separation Equipment Below the ESP

Sand separation equipment installed below the ESP is used to manage sand production and protect the pump. Two different filtering schemes provide complementary perspectives. The first view filters to 538 gas separators with Flex17.5 and E2000 pumps (73 installs). Because 538-series gas separators do not fit in 5.5 inch casing, this filter effectively restricts the analysis to 7.625 inch casing wells, holding gas separator, pump model, and casing size constant. The second view filters to 5.5 inch casing only with the same pump models (93 installs), controlling for casing geometry instead. Comparing these two schemes demonstrates how controlling for different variables changes the result. The third view uses the same 5.5 inch casing filter but groups by equipment status (open, bullplugged) to evaluate whether configuration matters.

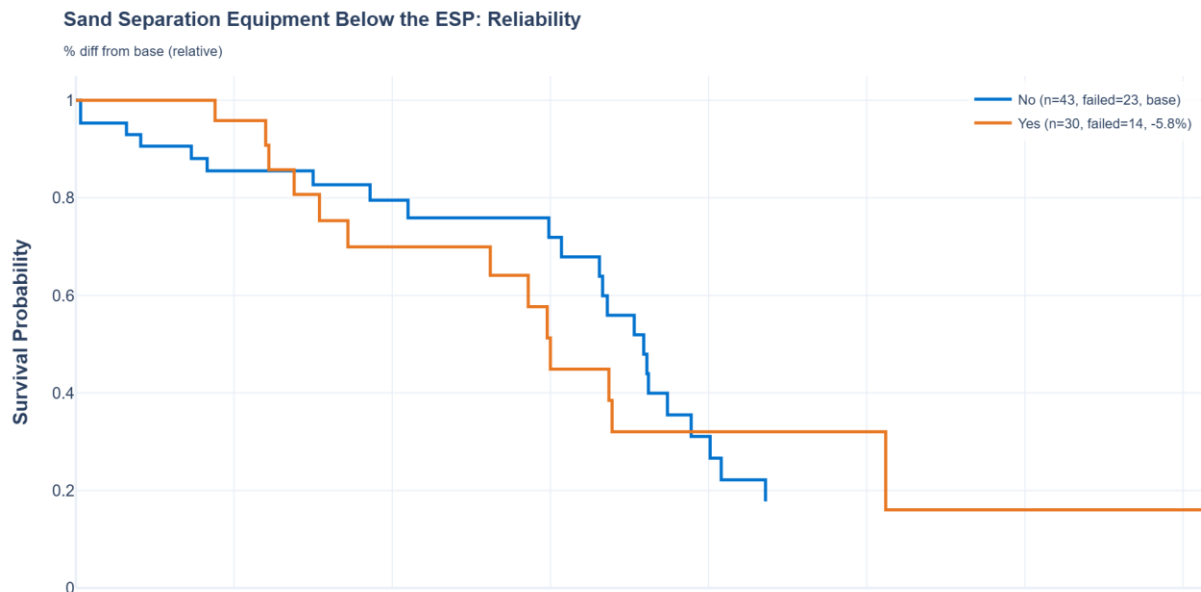


Figure 12 - Survivability with and without sand separation equipment in 7.625 inch casing with 538-series gas separators

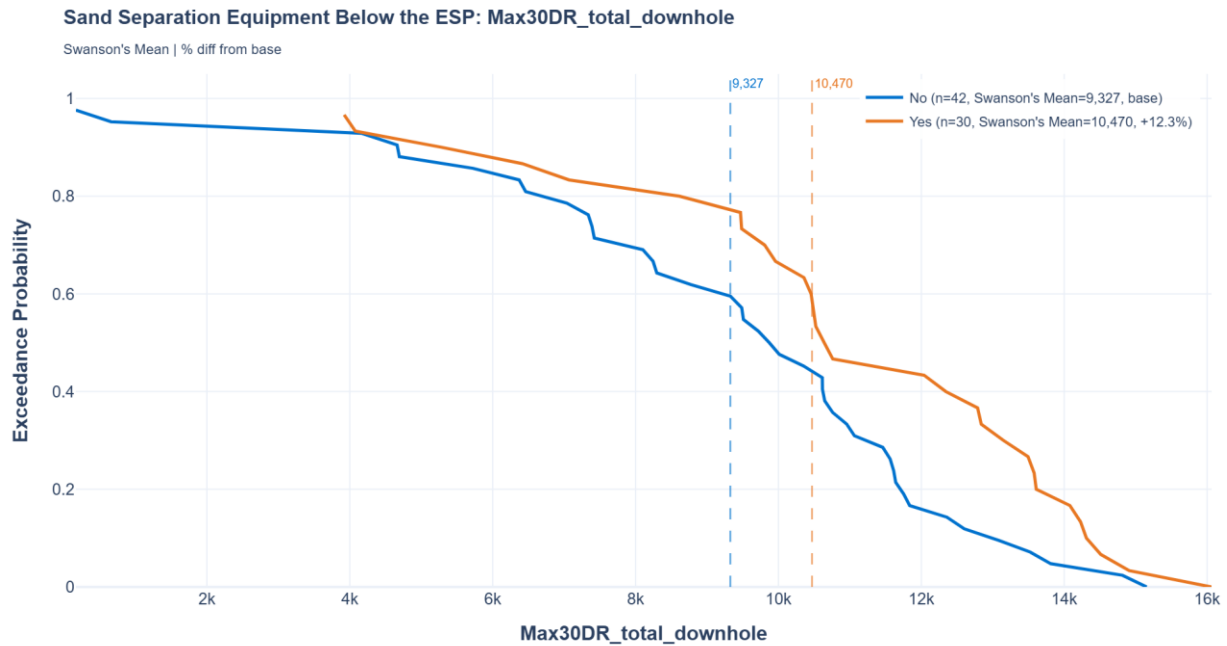


Figure 13 - Downhole produced volumes with and without sand separation equipment in 7.625 inch casing with 538-series gas separators

Table 6 - Survivability and downhole volume with and without sand separation equipment in 7.625 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
No	43	23	base	9,327	base
Yes	30	14	-5.79	10,470	+12.3%

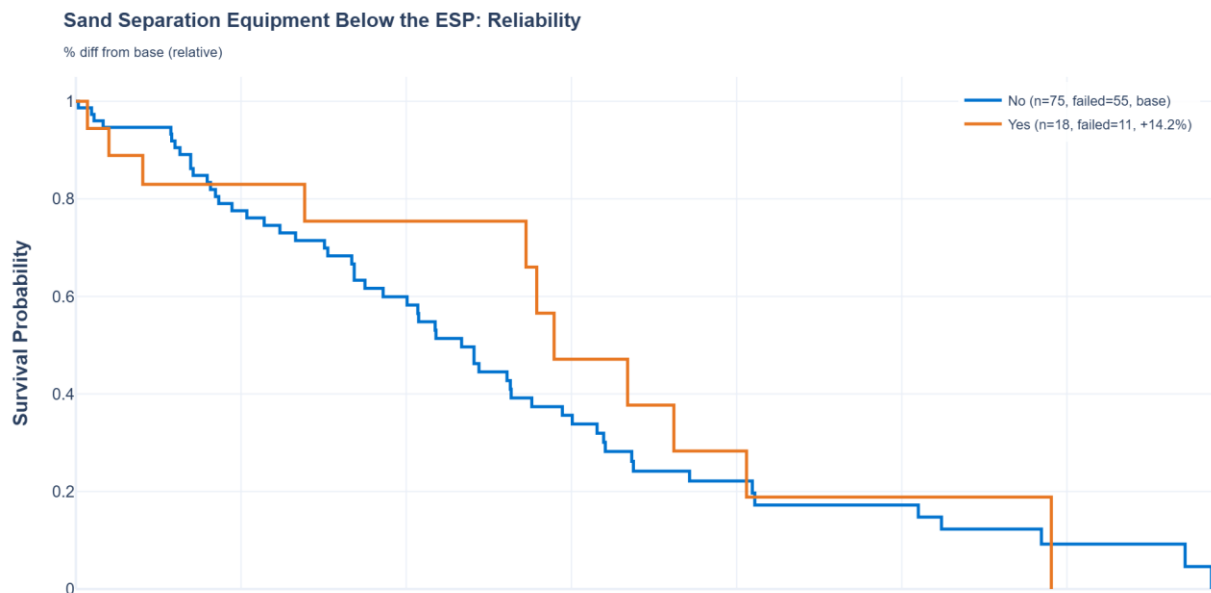


Figure 14 - Survivability with and without sand separation equipment in 5.5 inch casing

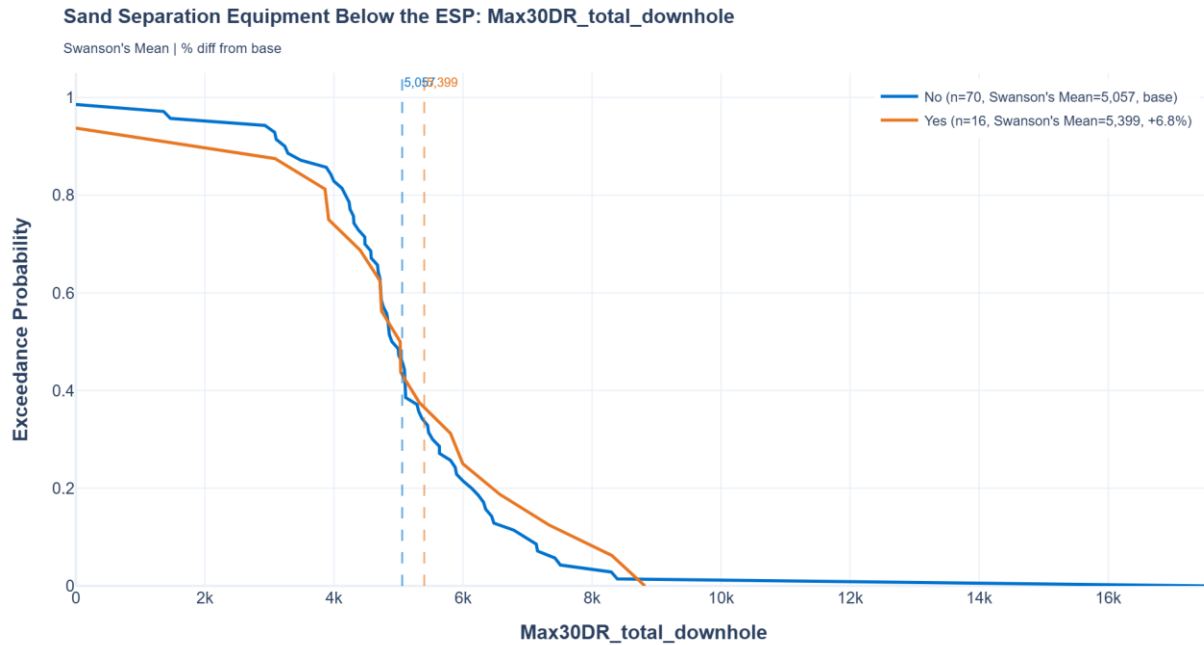


Figure 15 - Downhole produced volumes with and without sand separation equipment in 5.5 inch casing

Table 7 - Survivability and downhole volume with and without sand separation equipment in 5.5 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
No	75	55	base	5,057	base
Yes	18	11	+14.2%	5,399	6.76

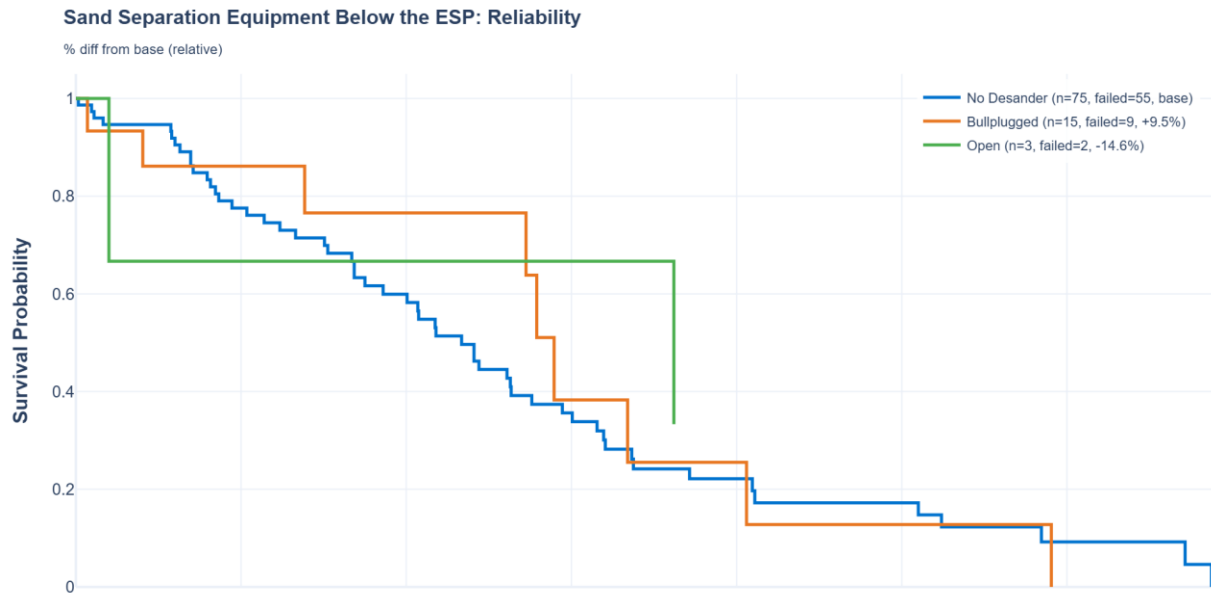


Figure 16 - Survivability by sand separation equipment status (open, bullplugged, none) in 5.5 inch casing

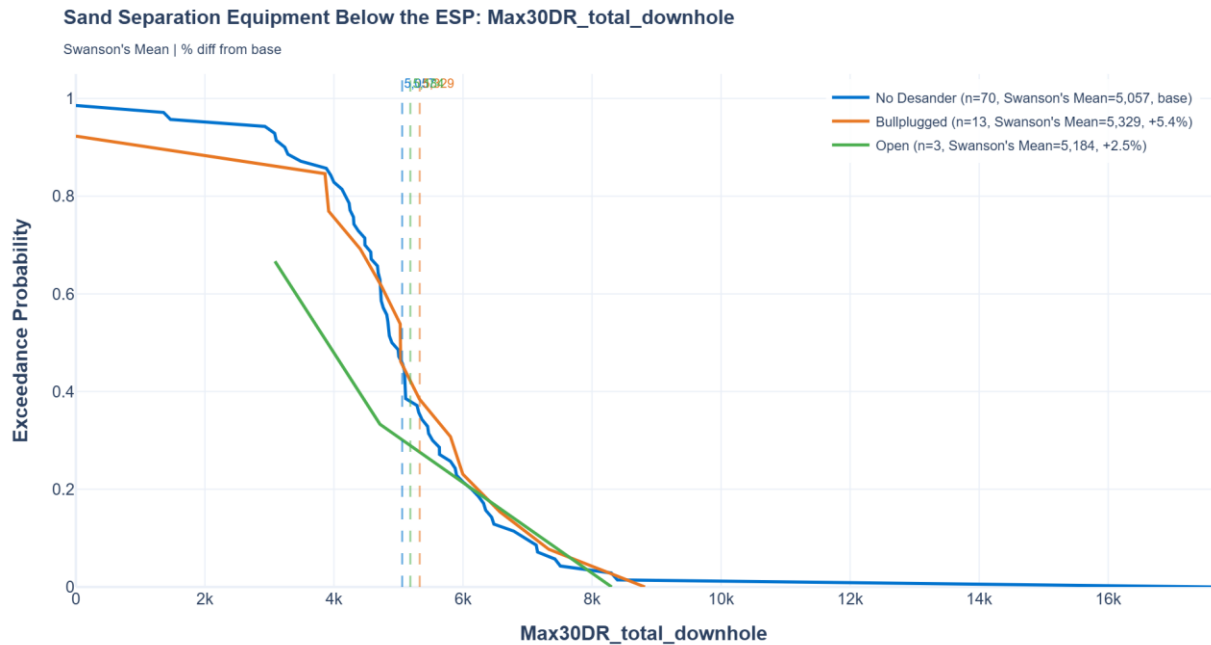


Figure 17 - Downhole produced volumes by sand separation equipment status in 5.5 inch casing

Table 8 - Survivability and downhole volume by sand separation equipment status in 5.5 inch casing

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
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No Desander	75	55	base	5,057	base
Bullplugged	15	9	9.45	5,329	5.37
Open	3	2	-14.6%	5,184	2.50

The two filtering schemes tell different stories, which highlights why normalization matters. In the 538 gas separator view (effectively 7.625 inch casing), installs with sand separation equipment show a slight reliability decrease (-5.8%) but a meaningful production increase (+12.3% Swanson's Mean peak production). In the 5.5 inch casing view, the result flips: sand separation equipment shows a +14.2% reliability advantage along with a +6.8% production gain. This difference likely reflects the confounding effect of casing size in the first view. In 5.5 inch casing specifically, where annular velocity is higher, downhole sand separators may provide more benefit. The configuration view shows that bullplugged equipment improves reliability by +9.5% over no equipment at all, while the small number of open-ended configurations (n=3) is insufficient to draw conclusions, but may be slightly worse on both metrics.

Section 6: Pump Utilization: BEP vs Actual Production

Shifting from equipment components to pump sizing, this section evaluates how well the fleet's pump selections match actual well conditions. Because pump BEP distributions differ significantly between casing sizes, we split this analysis into two separate views: 7.625 inch casing and 5.5 inch casing. Within each, we group installs by pump BEP and compare two metrics: the P95 peak total fluid rate (95th percentile of daily surface oil + water over the install, representing near-peak capacity) and the late-life total fluid rate. Late-life total fluid is calculated as the mean of the 30-day rolling average of surface oil + water production during the last 25% of each install's run life, representing the production rate the well has declined to before failure or pull. Unlike the other sections, this is a production-only analysis with no Kaplan-Meier reliability component. The BEP/Late-Life ratio indicates how many times larger the rated pump capacity is than what the well is actually producing at end of life. A versatility metric, defined as $(P95 \text{ Peak P75} - \text{Late-Life}) / \text{BEP}$, captures the operating range each pump size covers relative to its design point.

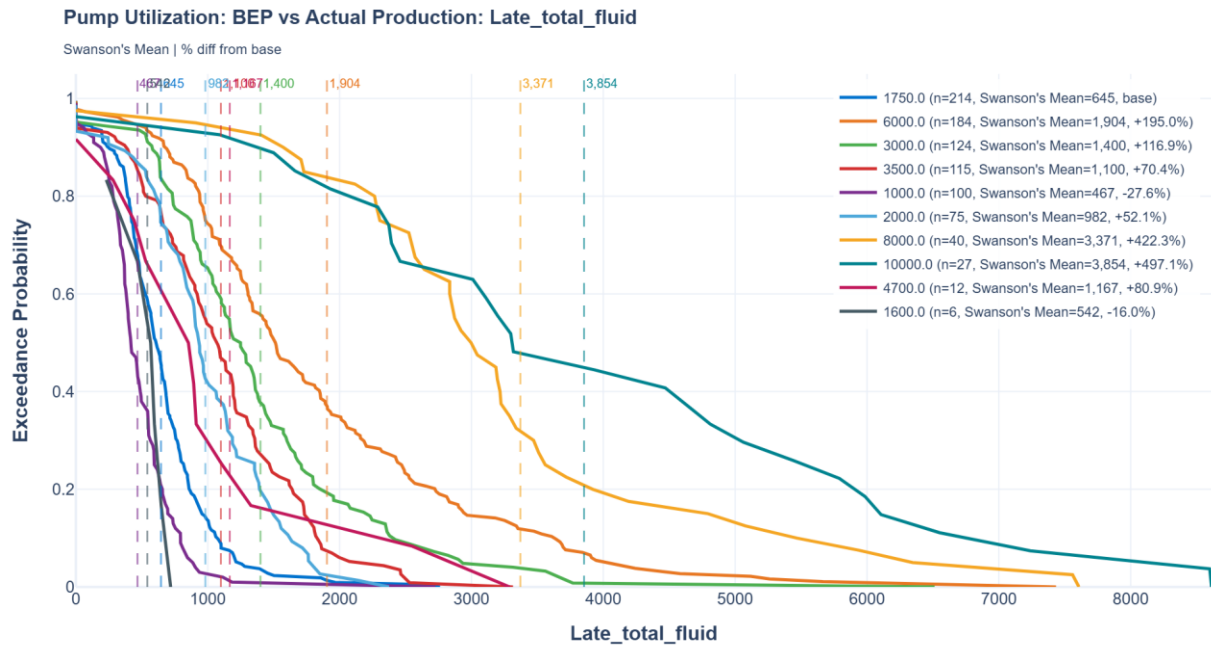


Figure 18 - Late-life total fluid rate distribution by pump BEP across the fleet

Pump Utilization in 7.625 Inch Casing

Filtering to 7.625 inch casing yields 514 installs. The following charts and table show the P95 peak total fluid and late-life total fluid distributions grouped by pump BEP for this casing size.

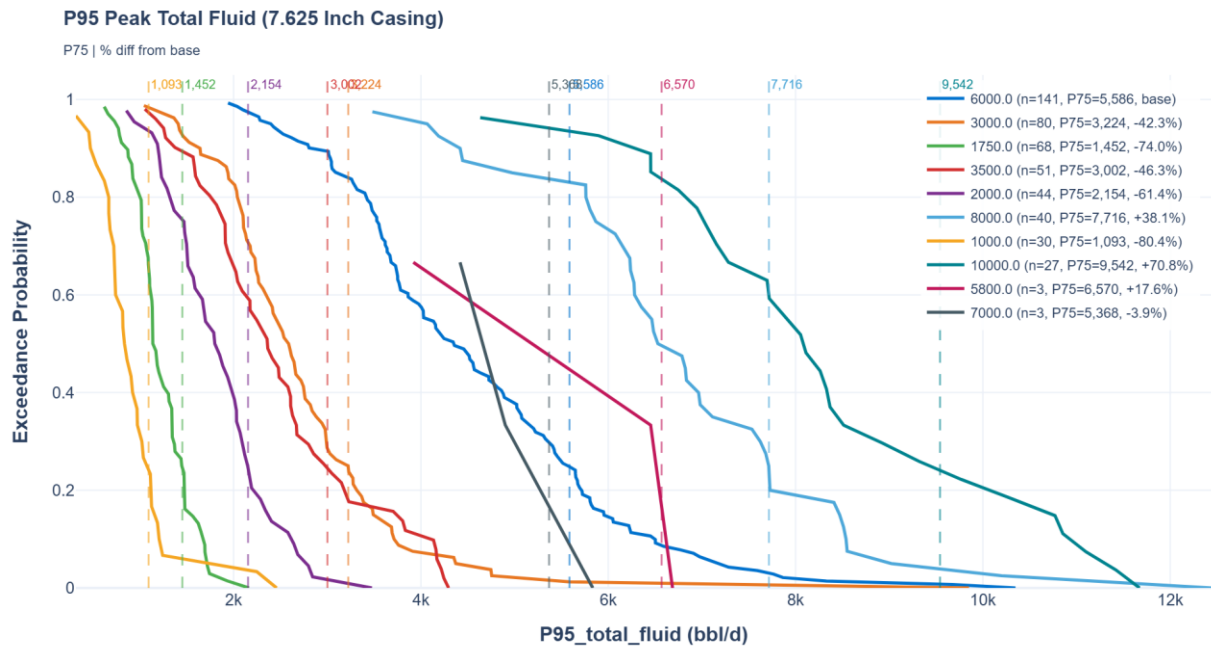


Figure 19 - P95 peak total fluid rate distribution by pump BEP in 7.625 inch casing

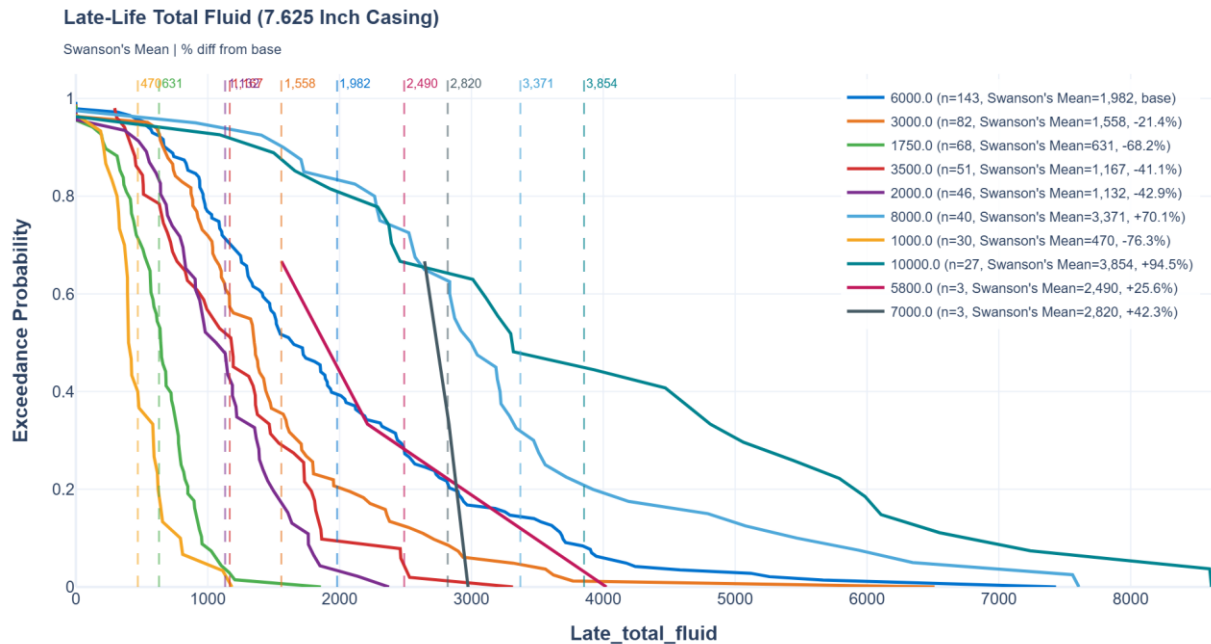


Figure 20 - Late-life total fluid rate distribution by pump BEP in 7.625 inch casing

Table 9 - Pump BEP utilization and versatility in 7.625 inch casing

Pump BEP	n	P95 Peak P75 (bbl/d)	Late-Life (bbl/d)	BEP/Late Ratio	Versatility
1,000	30.0	1,093	470	2.10	0.6
1,750	68.0	1,452	631	2.80	0.5
2,000	44.0	2,154	1,132	1.80	0.5
3,000	80.0	3,224	1,558	1.90	0.6
3,500	51.0	3,002	1,167	3.00	0.5
5,800	3.0	6,570	2,490	2.30	0.7
6,000	141	5,586	1,982	3.00	0.6
7,000	3.0	5,368	2,820	2.50	0.4
8,000	40.0	7,716	3,371	2.40	0.5
10,000	27.0	9,542	3,854	2.60	0.6

Notably, the 1,750 BEP pumps show lower peak rates than might be expected given their rated capacity. This likely reflects shaft rating limitations – when a well requires enough stages to produce above 1,750 bbl/d, the design naturally pushes toward a 2,000+ BEP pump to accommodate the higher stage count, leaving the 1,750 class with wells that were genuinely lower-rate to begin with. Selection bias is also present – higher BEP pumps are more likely to be installed in wells with higher gas rates, where

gas may naturally flow up the annulus and reduce the load on the pump, inflating their apparent production advantage.

Pump Utilization in 5.5 Inch Casing

Filtering to 5.5 inch casing yields 397 installs. The following charts and table show the P95 peak total fluid and late-life total fluid distributions grouped by pump BEP for this casing size.

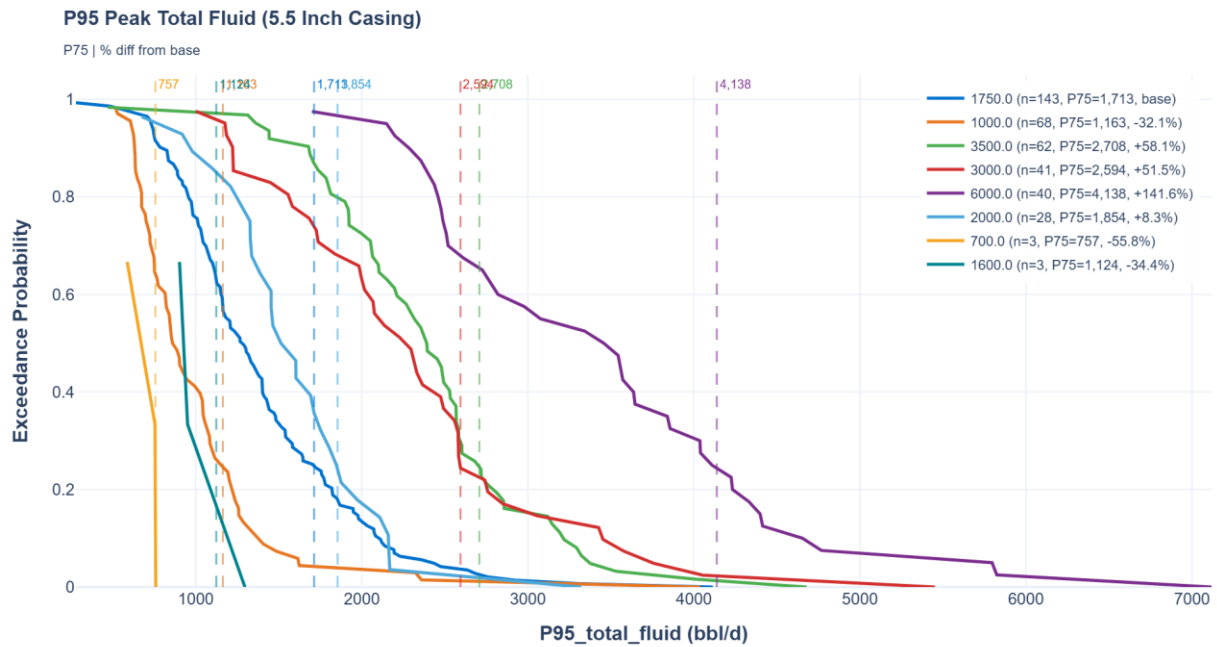


Figure 21 - P95 peak total fluid rate distribution by pump BEP in 5.5 inch casing

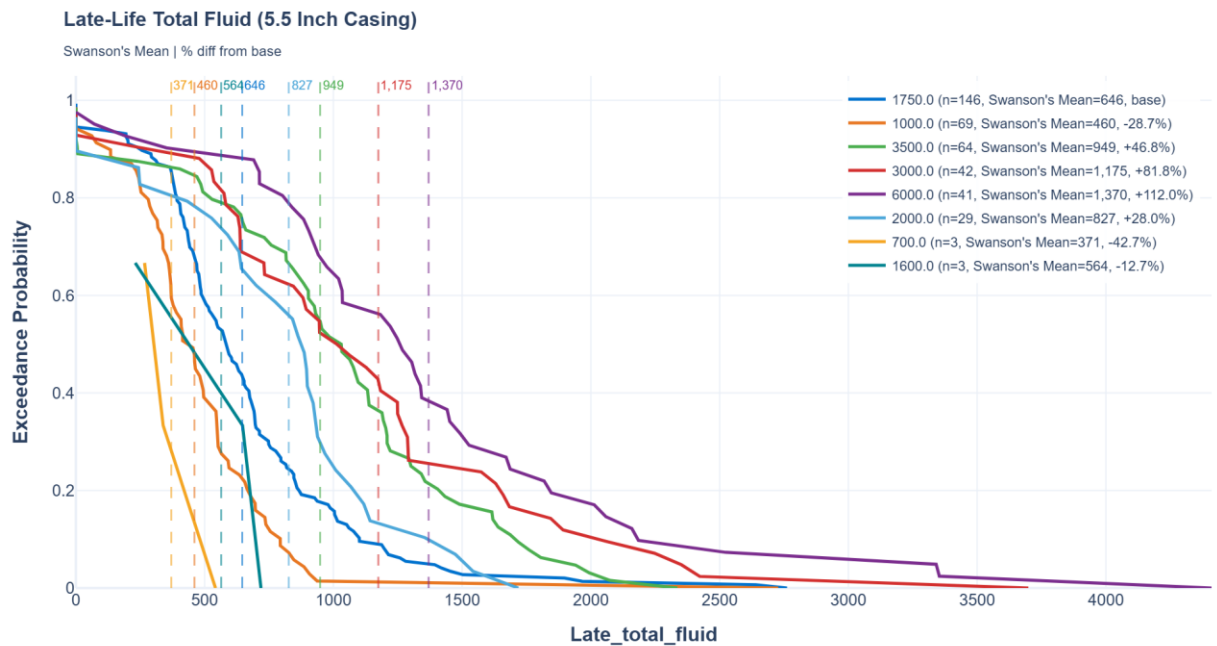


Figure 22 - Late-life total fluid rate distribution by pump BEP in 5.5 inch casing

Table 10 - Pump BEP utilization and versatility in 5.5 inch casing

Pump BEP	n	P95 Peak P75 (bbl/d)	Late-Life (bbl/d)	BEP/Late Ratio	Versatility
700	3.0	757	371	1.90	0.6
1,000	68.0	1,163	460	2.20	0.7
1,600	3.0	1,124	564	2.80	0.3
1,750	143	1,713	646	2.70	0.6
2,000	28.0	1,854	827	2.40	0.5
3,000	41.0	2,594	1,175	2.60	0.5
3,500	62.0	2,708	949	3.70	0.5
6,000	40.0	4,138	1,370	4.40	0.5

In 5.5 inch casing, the 1,750 BEP pump peaks much closer to its rated capacity (1,713 bbl/d) than in 7.625 inch casing (1,452 bbl/d). This likely reflects different selection dynamics – in larger casing, 1,750 is the smallest available option and is reserved for low-rate wells, while in 5.5 inch casing it is the standard mid-range choice and sees wells that genuinely match its capacity. This may also be related to limitations in drawdown in 5.5 inch casing, where pump intake pressures may be higher allowing for 1750 designs more often. In 5.5 inch casing, the 700 BEP pump is closest to its rated capacity at end of life (ratio 1.9x). The 1000 BEP pump shows the highest versatility (0.70), operating across the widest range of rates relative to its design point.

Across both casing sizes, late-life production rates are consistently well below rated BEP, confirming that wells decline significantly before ESP pull. It is worth noting that late-life rates may be influenced by a struggling pump – a degraded ESP may produce lower rates not solely because of reservoir decline but because the pump itself is approaching failure. The BEP/Late-Life ratios and versatility metrics reveal which pump sizes operate across the widest range relative to their design point within each casing environment.

Section 7: Pump Stage Count

Finally, we examine whether adding more pump stages improves production or comes at a reliability cost. This analysis applies the tightest normalization in the study: a single pump model (E3000, BEP 3,000 bbl/d), 538-series gas separators, and a sensor depth normalization band (8,536 to 9,767 ft) to control for well depth. ESP Cable failures are excluded to focus on equipment-driven differences. This creates a near 1-for-1 comparison where the only meaningful variable is stage count, yielding 46 installs. Stage counts are binned into groups (301-400 and 401-500 stages) based on the distribution in this filtered population.

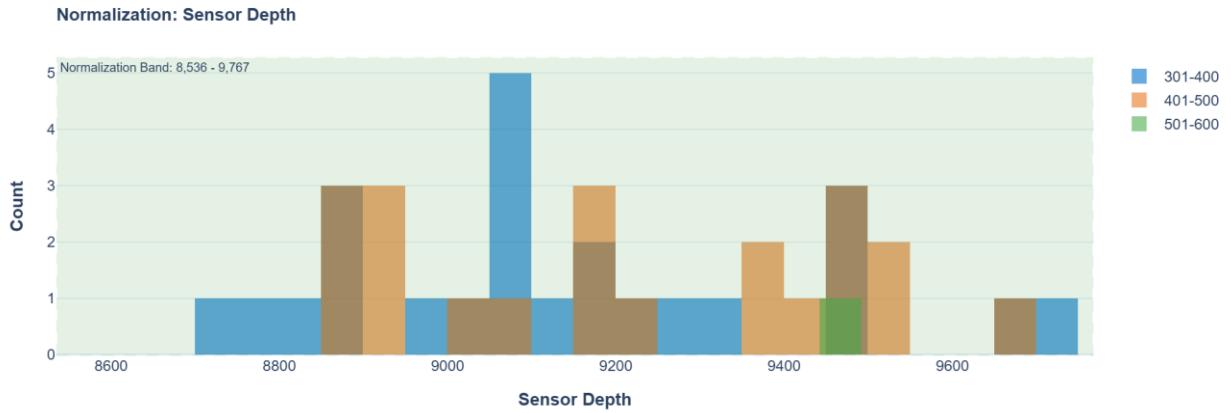


Figure 23 - Normalization band: Sensor Depth [8,536 - 9,767]

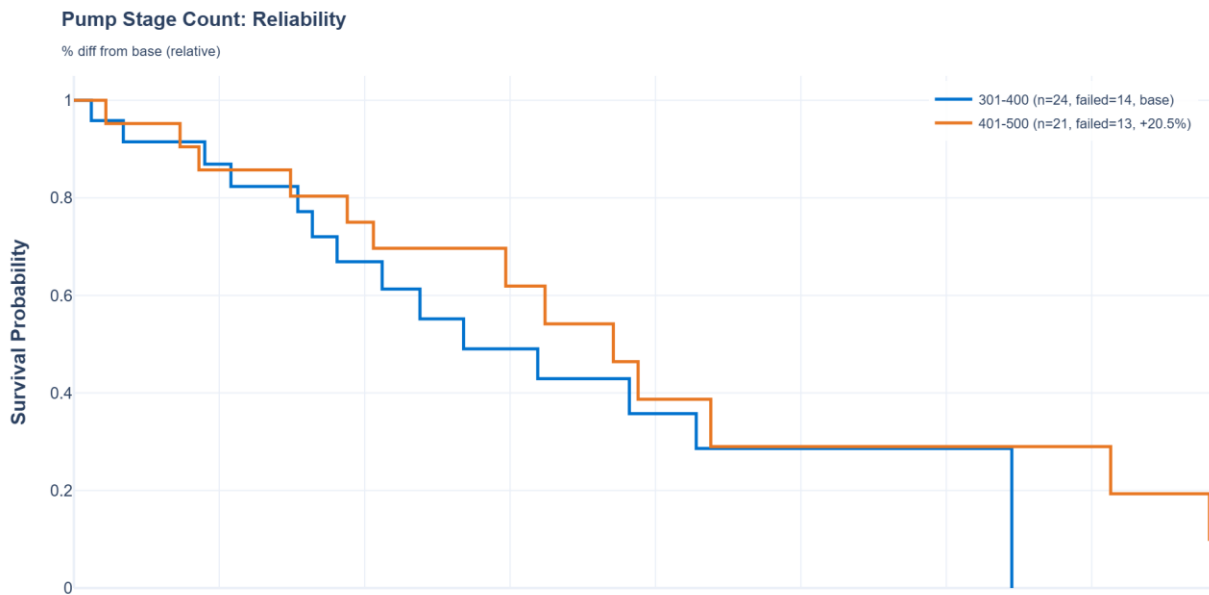


Figure 24 - Survivability between stage count groups for E3000 pumps with 538-series gas separators, excluding cable failures

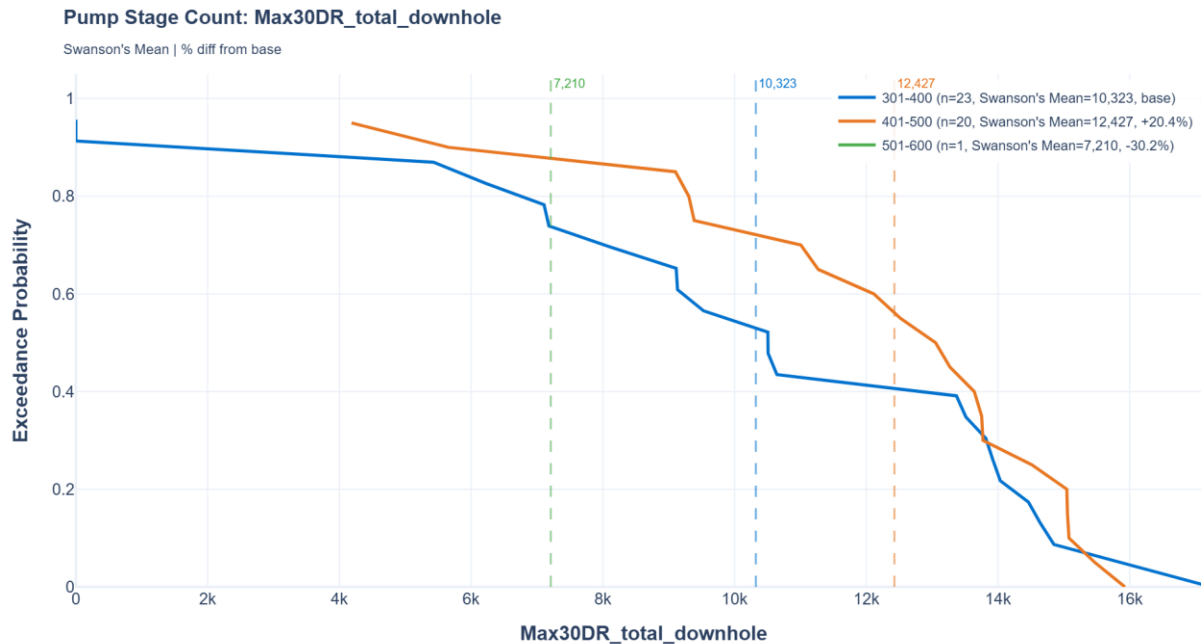


Figure 25 - Downhole produced volumes between stage count groups for E3000 pumps with 538-series gas separators

Table 11 - Survivability and downhole volume between stage count groups for E3000 pumps with 538-series gas separators

Group	n	Failed	Reliability % vs Base	Swanson's Mean (Max30DR_total_downhole)	Production % vs Base
301-400	24	14	base	10,323	base
401-500	21	13	+20.5%	12,427	+20.4%
501-600	1	1	-	7,210	-30.2%

With all other variables tightly controlled, the higher stage count group (401-500 stages, n=21) shows both better reliability (+20.5%) and substantially higher peak production (Swanson's Mean of approximately 12,430 vs 10,320 bbl/d for 301-400 stages). This is one of the cleanest comparisons in the study because the controlling variables (pump model, gas separator, well depth, cable failures removed) are tightly bounded, giving confidence that the stage count effect is real rather than a confounding artifact.

CONCLUSIONS

This study demonstrates that data-driven comparison of ESP equipment configurations, when properly controlled for confounding variables, reveals actionable patterns for design optimization. The findings are ordered by the magnitude of their influence:

1. Casing size is an important factor for downhole volume. With identical equipment, 7.625 inch casing produces approximately double the peak downhole volume of 5.5 inch casing at comparable reliability. The larger annular area for gas separation likely

contributes to this effect. Future work should extend this comparison to other pump sizes.

2. Gas separator size presents a production-reliability trade-off. The 538-series delivers higher peak production than 400-series, but the 400-series shows better reliability, likely related to drawdown differences.

3. Gas separator type matters in constrained casing. In 5.5 inch completions, HV separators consistently outperform LV on production within the same BEP class. Charged gas variants show promising results but need larger sample sizes to confirm. A case study of downsized pump designs demonstrates how these interactions play out in practice. Various gas handling equipment also generate differences in 5.5" wells, but standalone pumps with no gas handling could not be assessed since gas handlers have always been installed in the studied range.

4. Motor diameter is not a strong driver of performance. The 450 and 562 series show comparable reliability and production when casing and pump BEP are held constant. Motor upsizing is less effective than optimizing gas separator selection.

5. Sand separation equipment below the ESP shows different effects depending on which variables are controlled. In 5.5 inch casing it may improve both reliability and production. When controlling for gas separator size in 7.625 inch casing, a reliability decrease appears alongside a production increase. This demonstrates why the filtering scheme must be reported alongside results.

6. Pump utilization varies across the fleet. The BEP/Late-Life ratio and versatility metric identify which pump sizes are well matched to field conditions and which operate across the widest production range relative to their design point.

7. Pump stage count shows improvement in both reliability and production. With all other variables tightly controlled (E3000 pump, 538 gas separator, similar well depth, cable failures excluded), the higher stage count group shows meaningful gains in both reliability and peak production over the lower stage count group.

8. Normalization is not optional. Raw fleet-level statistics are misleading because equipment choices correlate with well characteristics. Cable failure exclusion and designs with older cable are essential for evaluating downhole equipment differences, as cable reliability is independent of pump, motor, or separator choice.

So what is the best ESP design ever? It depends on casing size, well productivity, and the production-reliability trade-offs each operator is willing to accept. But by controlling for confounding variables and letting the data speak, we can make better, data-driven choices.

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