ALTERNATE REALITY: WHAT IF IT HAD BEEN A PERMANENT MAGNET INSTEAD OF AN INDUCTION MOTOR?

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ABSTRACT

Electric Submersible Pump (ESP) permanent magnet motors (PMMs) have been confirmed to conserve power when compared to conventional induction motors (IMs) in various industry papers and studies. However, most production comparisons comprise a snapshot in time or the partial life of a single ESP. This analysis is useful, but it doesn't convey the full power-saving value of a PMM installation.

This paper aims to investigate the energy saving potential of a PMM in comparison to an IM for two asset types: "unconventional" shale oil and conventional waterflood. ESP power data for a selection of IM-driven shale and waterflood wells are analyzed over several years of installation(s). Power savings from theoretical PMM installations for the same wells are then calculated based on actual IM system loading. This information is used to determine the potential initial value of applying a PMM in each asset type. Theoretical and actual lifting efficiencies are compared, and the reasons for discrepancies linked to asset types are discussed.

Unconventional and conventional ESP applications were found to be more similar than dissimilar. Although PMMs conserve power usage for both asset types presented, more system installations are required to achieve the same benefit in unconventional wells than in the conventional counterparts analyzed here. It was also noted that PMMs' higher power factor over wider motor loading can provide an advantage in Variable Frequency Drive (VFD) sizing versus IMs.

MOTIVATION

Various studies have confirmed that PMMs consume less power than IMs. A few recent examples include Ararat et al. (2022), Hashar et al. (2024), Lykova and Martiushev (2021); Salah et al. (2024), and Xiao and Lastra (2018). However, most production comparisons evaluate a snapshot in time for a single or few ESPs. Some studies only focus on the first few months of an unconventional well's life where production rates and horsepower requirements are high. How would those power savings accumulate over several years? What would the total power savings benefit of a PMM "system" be?

PMMs are often marketed for unconventional assets which is understandable due to the high level of activity in the Permian and other shale oil plays. But what about legacy conventional assets? These fields have plenty of high-rate ESPs. Are PMM ESP power savings more interesting for the inconsistent, gas-ridden, rapidly dropping production of fresh unconventional wells…or the consistent, low gas, high water cut (WC) production of stately conventional wells?

WELLS SELECTION

All wells analyzed were located in the Permian basin, specifically the Texas Midland Basin and Central Basin Platform shown in *Figure 1*.

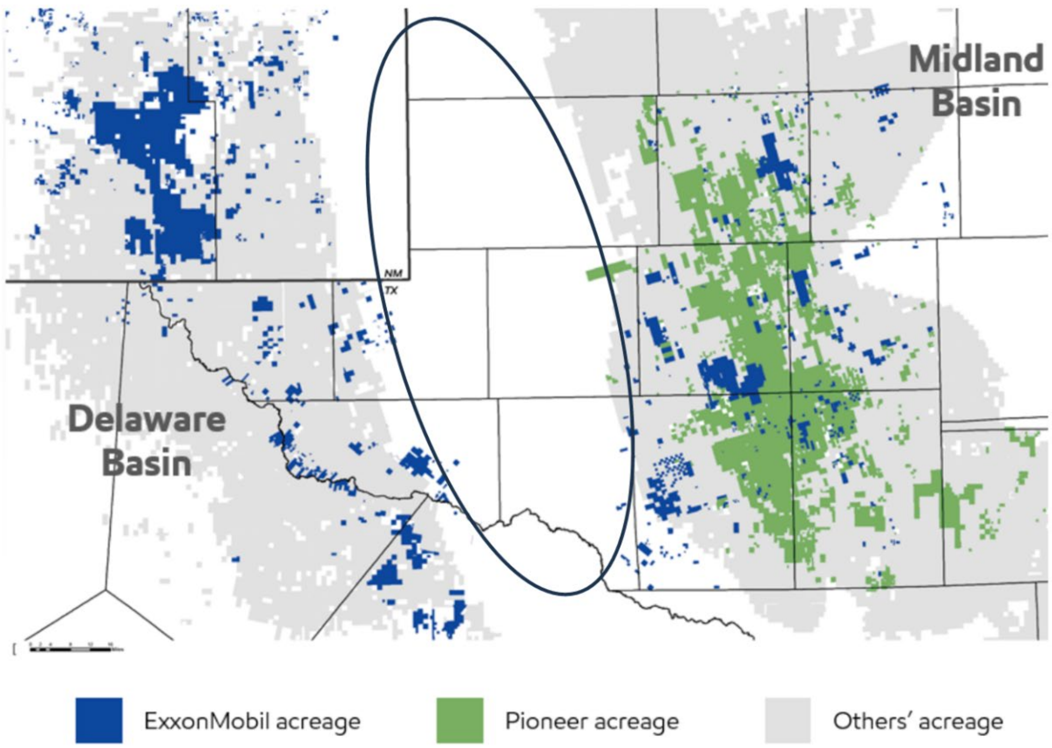

Figure 1 – ExxonMobil Permian basin acreage map (ExxonMobil 2024).

Unconventional Wells

Four unconventional shale oil wells were selected in the Midland Basin. Each had an ESP from a different provider, but all were IMs. The wells produced from various field areas and formations. Nearly three years of ESP operational and production data were available for each from 2021 to 2024, beginning when the wells were put on ESP production. Each well had three ESPs installations over the represented timeframe.

Conventional Wells

Four conventional wells were selected in the Central Basin Platform. Two ESP vendors were represented, and all motors were IMs. The wells produced from various field areas and formations, but all were waterflooded and had been producing by ESP for at least 10 years. One year (2024) of ESP operational and production data was available. Data quality and retention time are not as high for the legacy conventional assets. Each well had a single ESP installation over the represented timeframe, and ¾ of the ESPs had been installed in 2019. (The remainder was 2021.)

UNCONVENTIONAL PRODUCTION PROFILE

Figure 2 provides an example production profile from Unconventional Well #4. Note that the well initially has a rapid production decline as the energy from hydraulic fracturing wanes. Production becomes steadier and the decline flattens as production time passes. Gas production is relatively high, near 300 scf/bbl total gas-liquid-ratio in early production and approaching 1000 scf/bbl over time. WC begins around 40% and increases toward 60% in the period shown. Multiple ESPs were installed in the well, with each having a successively longer runtime (for this particular case) and reduced power (kW) requirement.

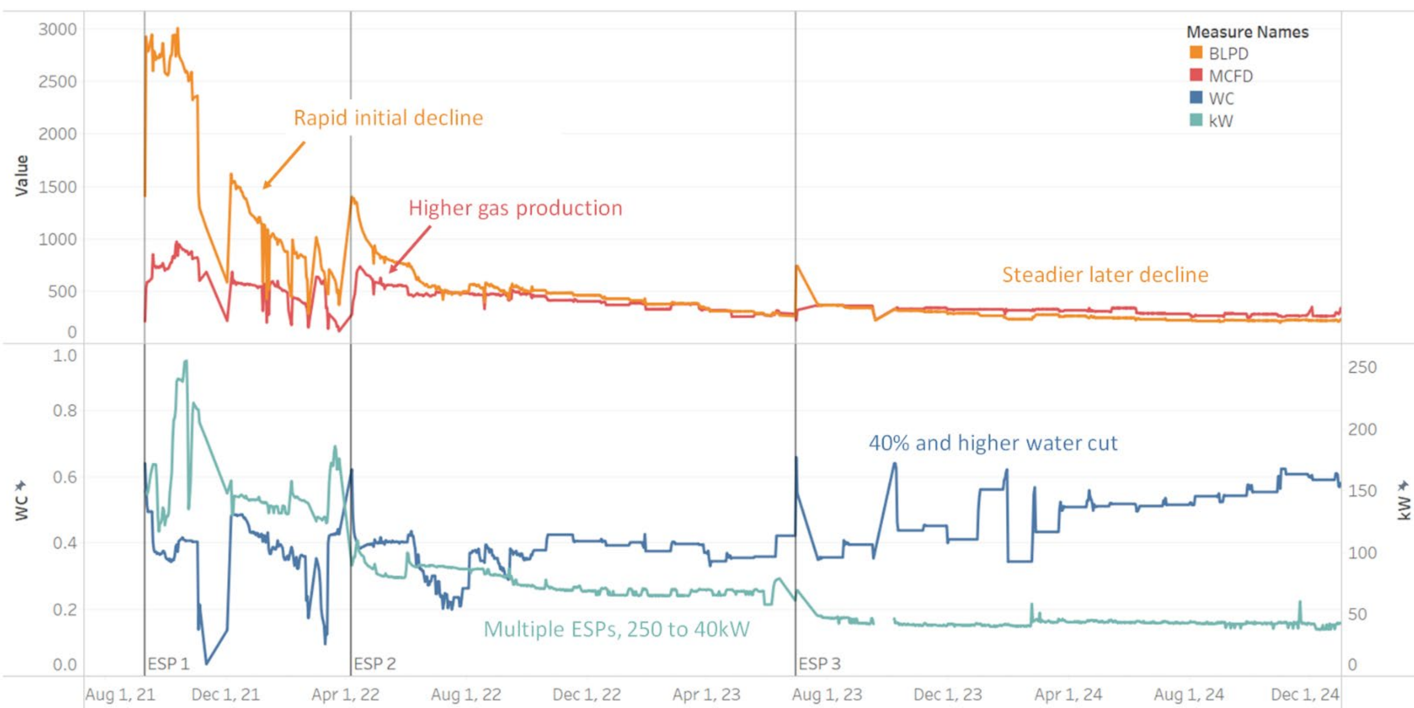

Figure 2 – Unconventional well #4 production profile example.

Figure 3 displays all four unconventional wells used in the study. Note the production profiles are similar and that each well had three ESP installations of varying run lives over the periods shown.

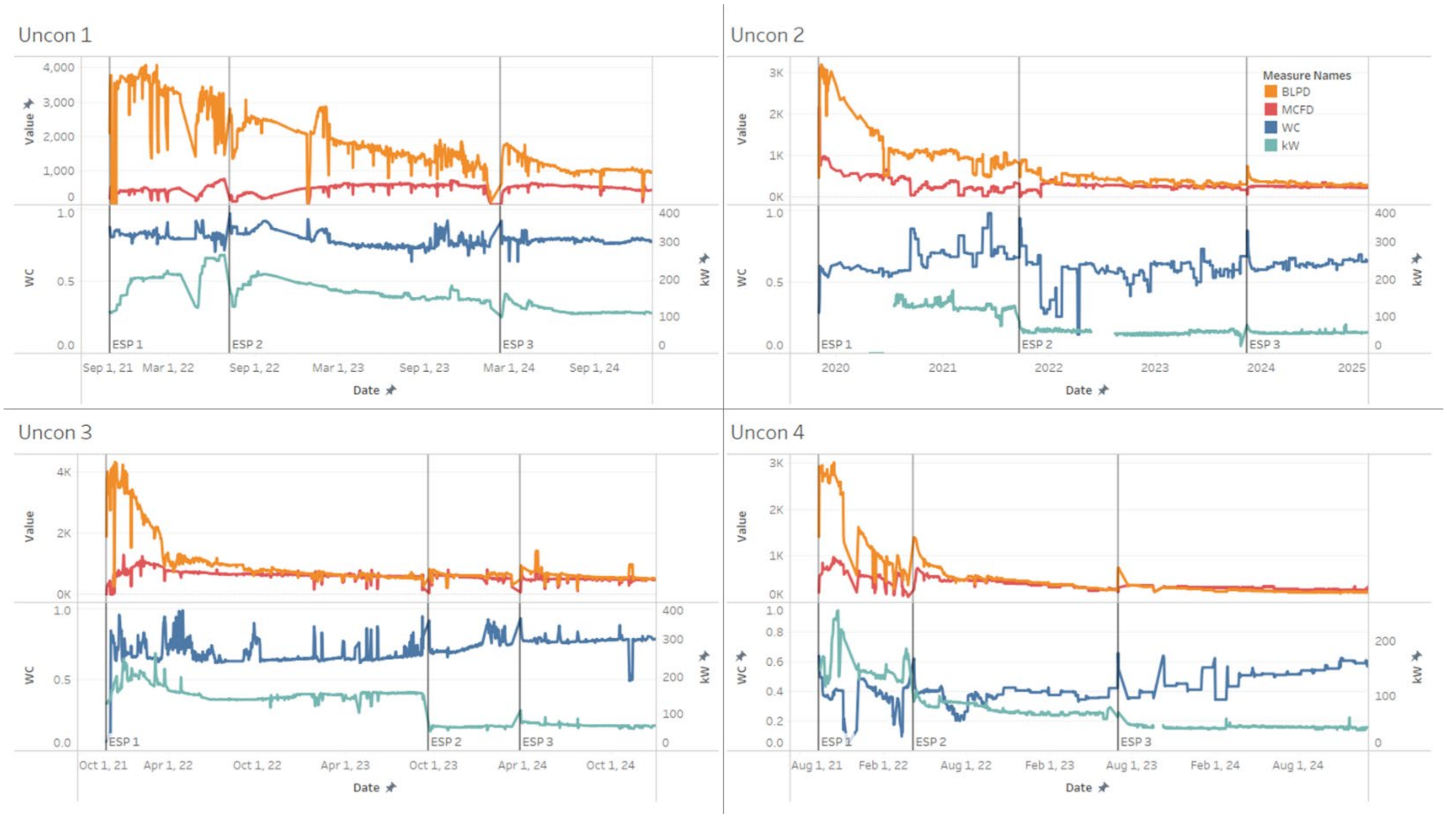

Figure 3 – Production profiles of all four unconventional wells.

The four unconventional wells were consolidated to create a single representative well for ease of analysis. This was done by synchronizing the production start dates and averaging values for each day with valid data. The averages were windowed to create a smoothing effect. The resulting unconventional consolidated profile is shown in *Figure 4*. The consolidated data was capped at 1136 days to respect the smallest of the four datasets. Note that production declined from ~3500 to 500 BLPD, gas production remained near 500 MCFD, the WC ranged roughly 50 to 70%, and the power usage of the three ESPs declined from 170 to 130 and finally to 75kW. Some minor gaps and/or odd swings do occur in the trends as the ESP replacement dates were not identical for the four wells.

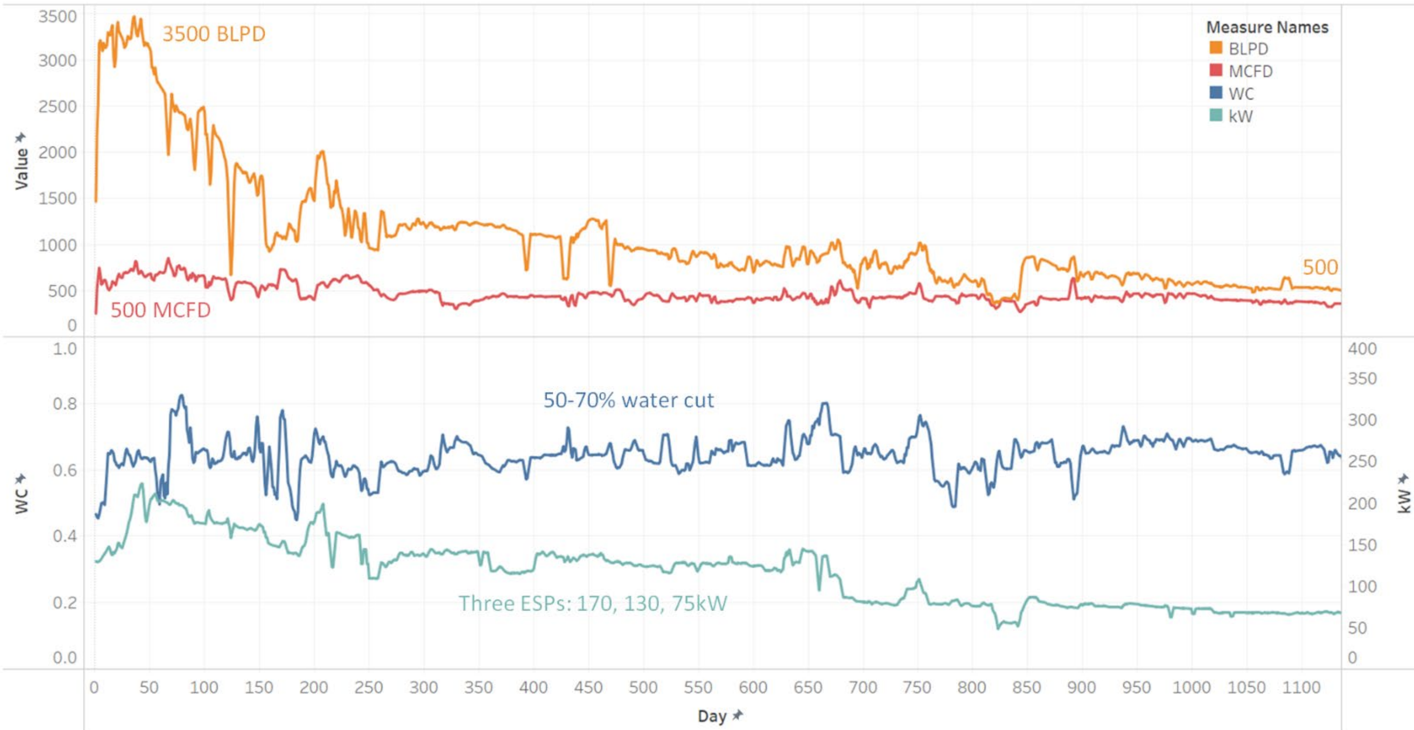

Figure 4 – Consolidated unconventional production profile for detailed analysis.

<u>CONVENTIONAL PRODUCTION PROFILE</u>

Figure 5 provides an example production profile from conventional well #3. Production is more consistent versus the unconventional wells, gas production is minimal, the WC is at least 95%, and one 45kW ESP spanned the production time shown. Production data quality is reduced, as can be evidenced by jumps in the production rates and sections of missing data (straight lines).

Figure 6 displays all four conventional wells used in the study. The production profiles are similar and each well had a single ESP installation over the period shown. The power trends indicate most of the ESPs had a considerable number of shutdowns (kW spikes toward zero).

The four conventional wells were also consolidated to create a single representative well. Production start dates were synchronized and values for each day with valid data were averaged. The averages were then windowed to create a smoothing effect. The resulting conventional consolidated profile is shown in *Figure 7*. The consolidated data was capped at 449 days to respect the smallest of the four datasets. Note that production was consistent at ~850 BLPD, 10 MCFD, and 98% WC. The power usage of the single ESP was ~95kW. Most of the data gaps and shutdowns were eliminated with the consolidation.

Figure 5 – Conventional well #3 production profile example.

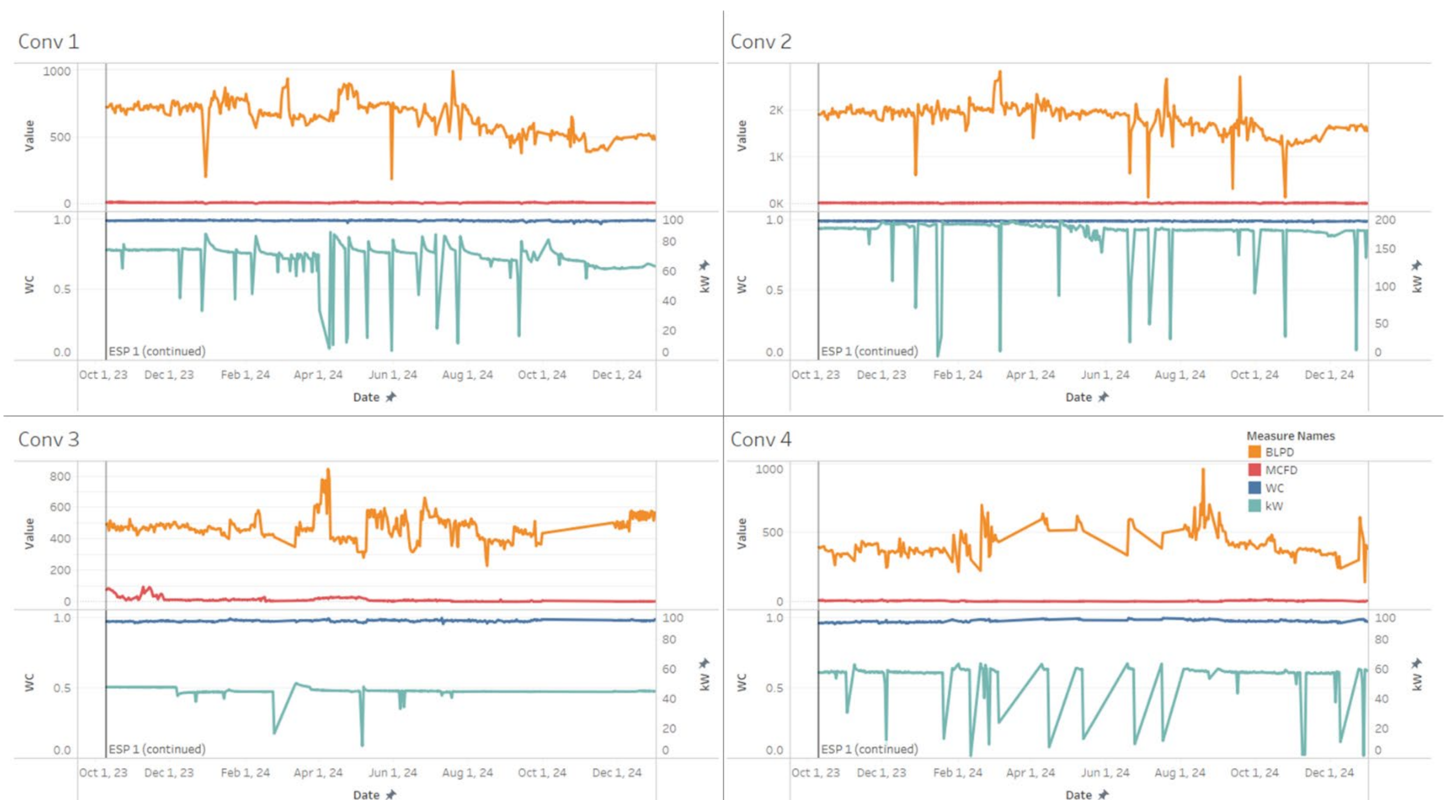

Figure 6 – Production profiles of all four conventional wells.

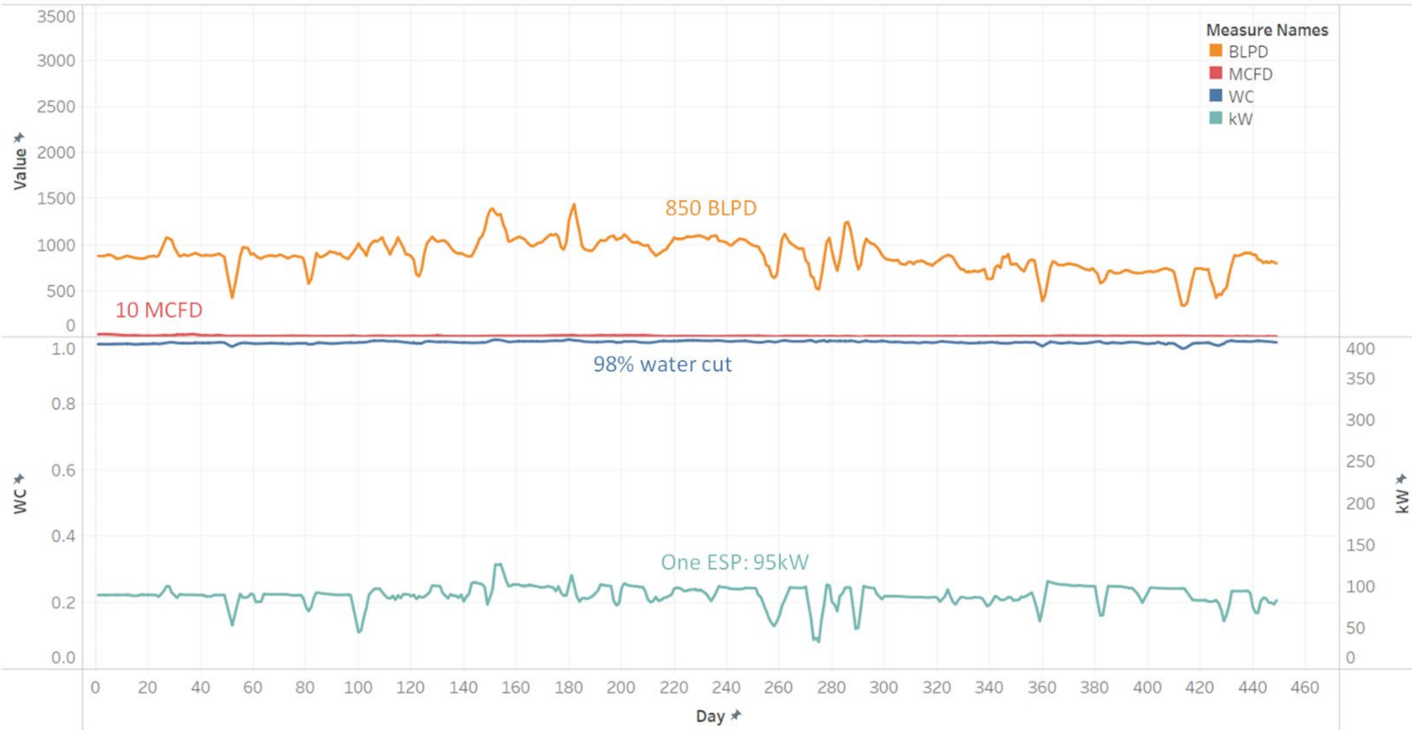

Figure 7 – Consolidated conventional production profile for detailed analysis.

CALCULATIONS AND ASSUMPTIONS

Additional data collection and ESP production data calculations and conversions were required to determine theoretical PMM power savings. This section will provide an overview of the processes used.

Additional Input Data

The unconventional and conventional ESPs selected had functioning VFDs and downhole ESP gauges. The VFDs provided ESP operational frequency and drive output current and voltage. The downhole gauges measured pump intake pressure (PIP) and pump intake temperature (PIT). Pump discharge pressure subs were not installed so measured data was not available. Post step-up transformer current (motor current) was determined from VFD data or calculated using the ESP's transformer ratio. ESP equipment details (motor nameplate horsepower and current, vertical setting depth, cable size, etc.) were pulled from installation reports. Cable voltage drops (VDrop) were calculated using standard voltage versus current sizing tables with downhole temperature correction factors (Baker Hughes 2020). All cables installed with the studied ESPs were #4 AWG flat. Surface cable lengths from the VFD to the wellhead were not considered.

Operating wellhead pressures (WHP) were extracted from SCADA for the unconventional wells, while average values were used as constants for the conventional wells. Gas, oil, and water specific gravities were taken from fieldwide formation averages.

Downhole Gas Content and Separation

Downhole gas volume fraction (GVF) prior to gas separation was calculated by converting surface gas production rates from standard to downhole conditions with PIP and PIT and comparing these volumes to surface produced liquid volumes. Liquids were assumed to be incompressible for volume calculation purposes. All ESPs studied had 400-series gas separators installed. Gas separation efficiency (η) was estimated using vendor data, commercial ESP design software, and Turpin correlation considerations for high-end limits (ChampionX 2025; Turpin, Lea, and Bearden 1986).

The gas separation chart generated and subsequently referenced for calculations is shown in *Figure 8*. Single gas separator performance was assumed although most ESPs studied had tandem separators. Note that a minimum of 20% natural separation was set even if the gas separator was deemed to be ineffective at a given liquid rate and GVF. No additional natural separation benefit was granted to the gas separator if it was considered functional (70+% η). Separated gas was assumed to exit the well via the annulus while unseparated gas was attributed to the pump.

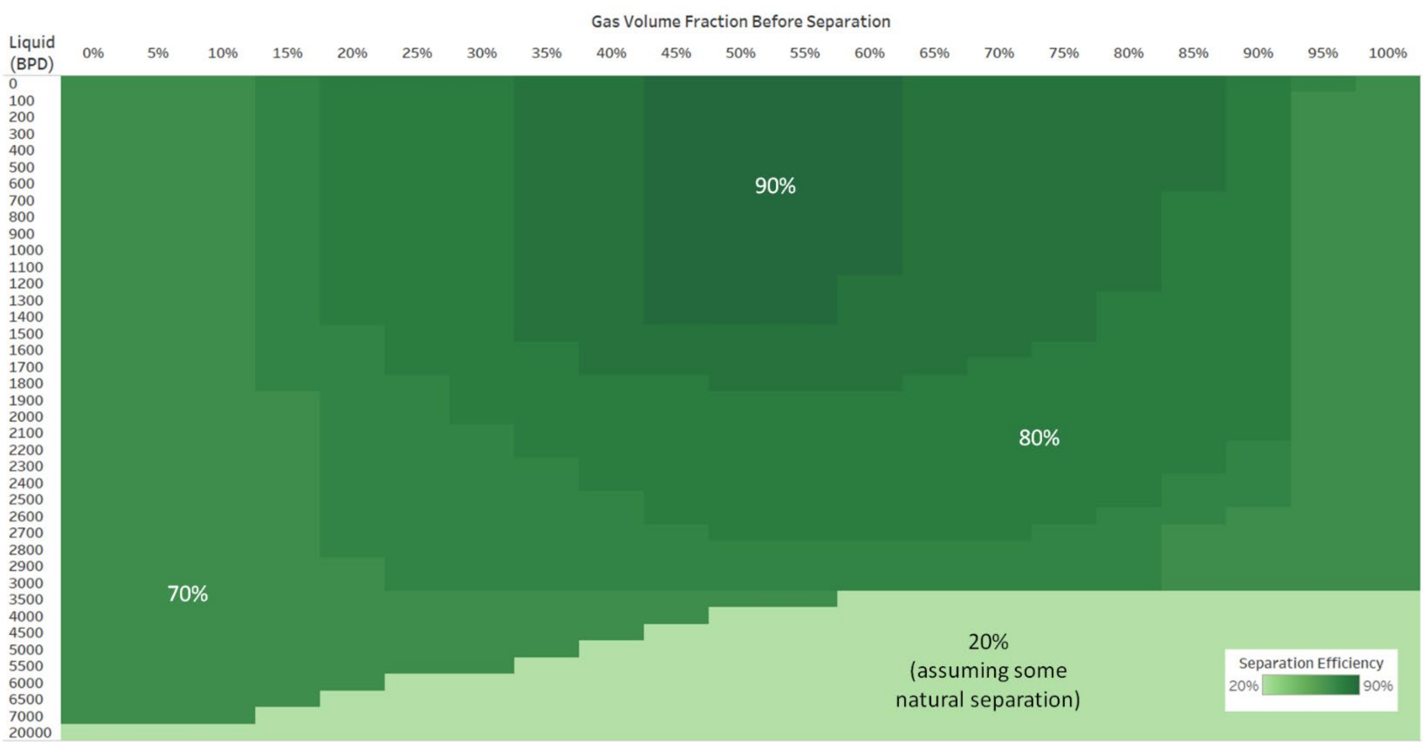

Figure 8 – Customized 400-series gas separator η map.

Pump Discharge Pressure (PDP)

PDP sensors were not installed, so PDP was calculated. The hydrostatic gradient of the produced fluids was determined from the surface liquid and downhole post-separation gas production rates. The pressure selected for the produced gas density calculation was the average of the liquid hydrostatic pressure at ESP depth and the WHP. Although liquid hydrostatic pressure is higher than what would be found at the pump discharge, its selection offsets the rapid expansion of the gas (and associated density reduction) as it accelerates to the wellhead. Temperature effects on the gas were ignored due to the relatively quick fluid transit time from the pump discharge to surface in 2-7/8” tubing.

PDP = (Combined Fluids Avg. Hydrostatic Gradient * ESP Vertical Depth) + WHP ...... (1)

Hydraulic Horsepower (HHP)

HHP calculation was necessary to evaluate system efficiencies. HHP is a function of pressure and flow through the ESP. Note that the flow rate includes all fluids processed by the pump—gas can easily make up most of the downhole flow in unconventional wells.

HHP = DP x Q / 1714, where .... (2)
DP = ESP Differential Pressure = PDP – PIP in psi, and
Q = Total flow rate in gal/min.

Efficiencies and Motors

System η was calculated as the HHP divided by the total power drawn by the ESP system. The power measurement point was at the VFD outlet, so VFD and step-down transformer power usage were not considered in the study. This means that the calculated system η will be slightly higher than actual. Step-up transformer power usage was assumed negligible for calculation purposes. This leaves the ESP cable and motor as the determinators of the System η. The motor load was assumed to be equivalent to the pump load, so the Pump η was calculated as the HHP divided by the actual motor power. Thus the Pump η calculation inherently includes the seal and gas separator loads. *Figure 9* diagrams the factors that were and were not included, as well as the linkages between System η and Pump η.

System η = HHP / Total Power .... (3)
Pump η = HHP / Actual Motor Power .... (4)
Actual Motor Power = (Total Power – Cable Power Loss) * Motor η .... (5)
Cable Power Loss = VDrop * Motor Current * 3 (phases) .... (6)

Cable losses were found to be 10-15% of the total ESP power consumed. IM and PMM η and power factor (PF) characteristics were referenced from Harris, English, and Leemasawatdigul (2017); that study’s IM and PMM η and PF versus motor loading chart is recreated in *Figure 10*. Motor loading is linear with current, so motor current was used to determine loading as a fraction of the motors’ nameplate.

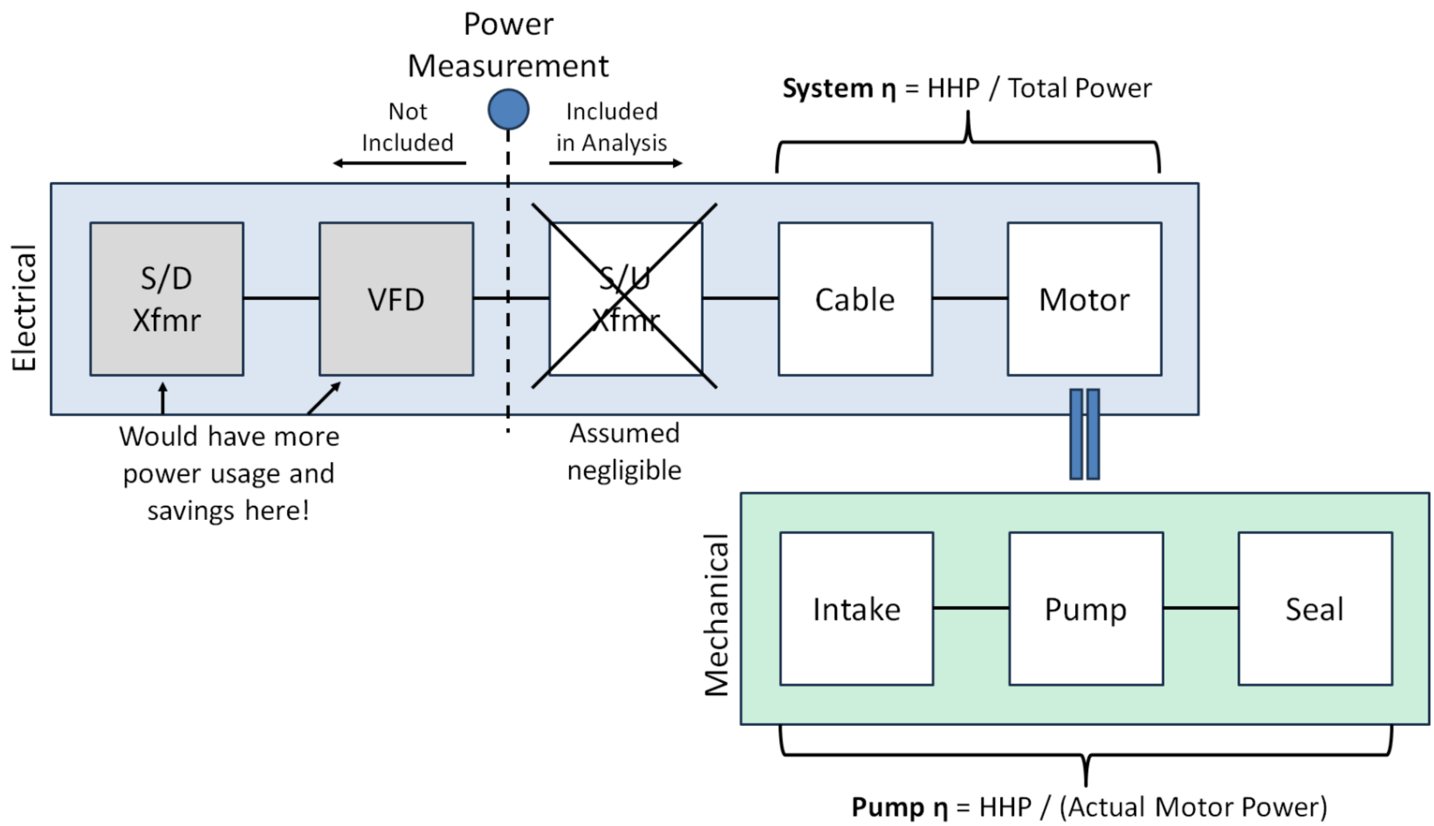

Figure 9 – ESP Electrical and Mechanical systems as configured for calculations.

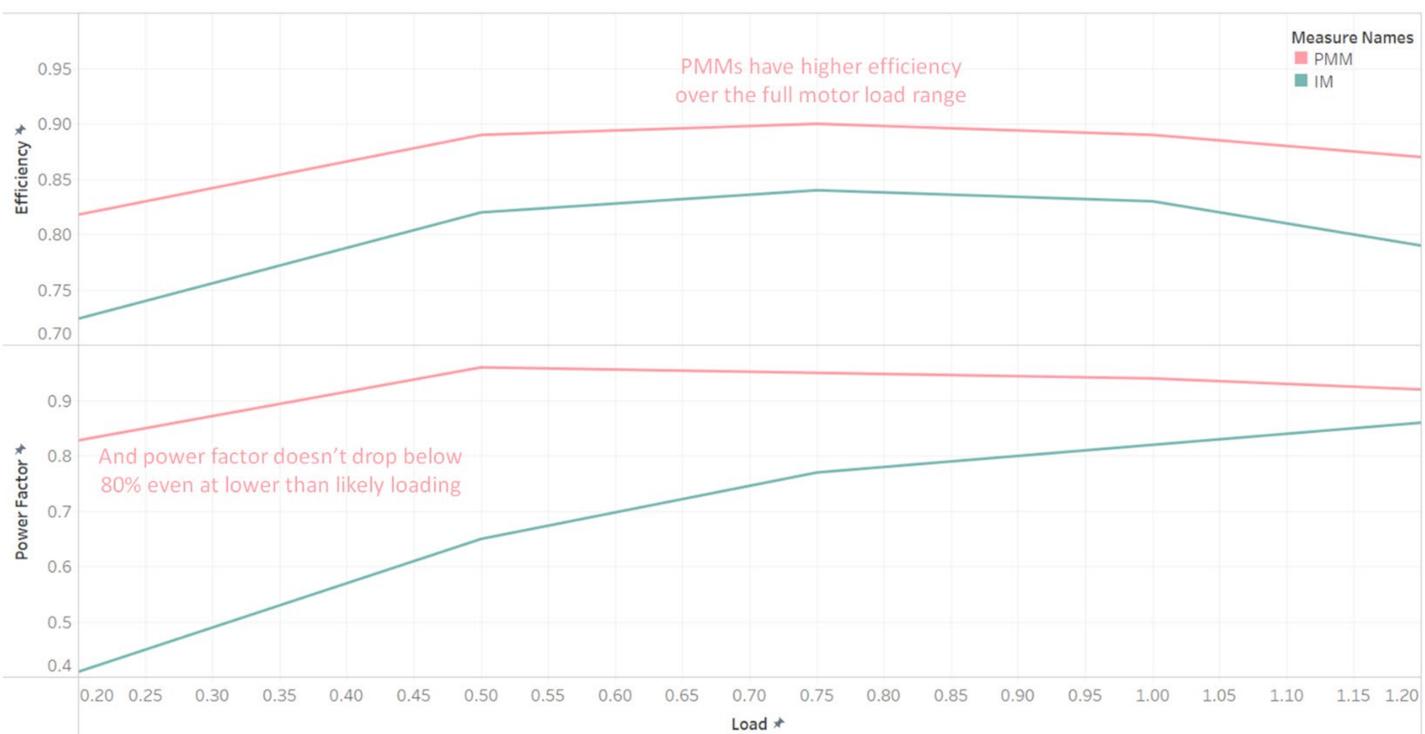

Figure 10 – IM and PMM η and PF, adapted from Harris, English, and Leemasawatdigul (2017).

The power calculations used in the study include

IM System kVA = Motor Current * (Drive Output Voltage * Transformer Ratio) * √3 ...... (7)
IM System kW = IM System kVA * IM PF .... (8)
PMM System kW = IM System kW * IM η / PMM η .... (9)
PMM System kVA = PMM System kW / PMM PF .... (10)
Daily Power Savings = (IM System kW – PMM System kW) * 24h * $0.10/kW-h........ (11)

These calculations assume that cable power losses are reduced by the same rate as motor power losses. Power savings calculations assumed uptime of 100% for days with valid ESP operating data and a fixed power cost of $0.10/kW-h.

A subset of averaged input and calculated values for all studied wells and consolidated representative wells can be found in *Table 2* at the conclusion of the paper. Note that the consolidated wells' tabulated averages will not exactly match those in the charts as that data was truncated for temporal consistency as previously described.

UNCONVENTIONAL CONSOLIDATED WELL ANALYSIS

Figure 11 shows downhole pumping conditions for the unconventional consolidated well. Note that half or more of the fluid pumped is gas. This is not due to poor gas separator efficiency; it is ~70-75% over the period examined. More than 4000 BGPD are separated before fluids entered the pump.

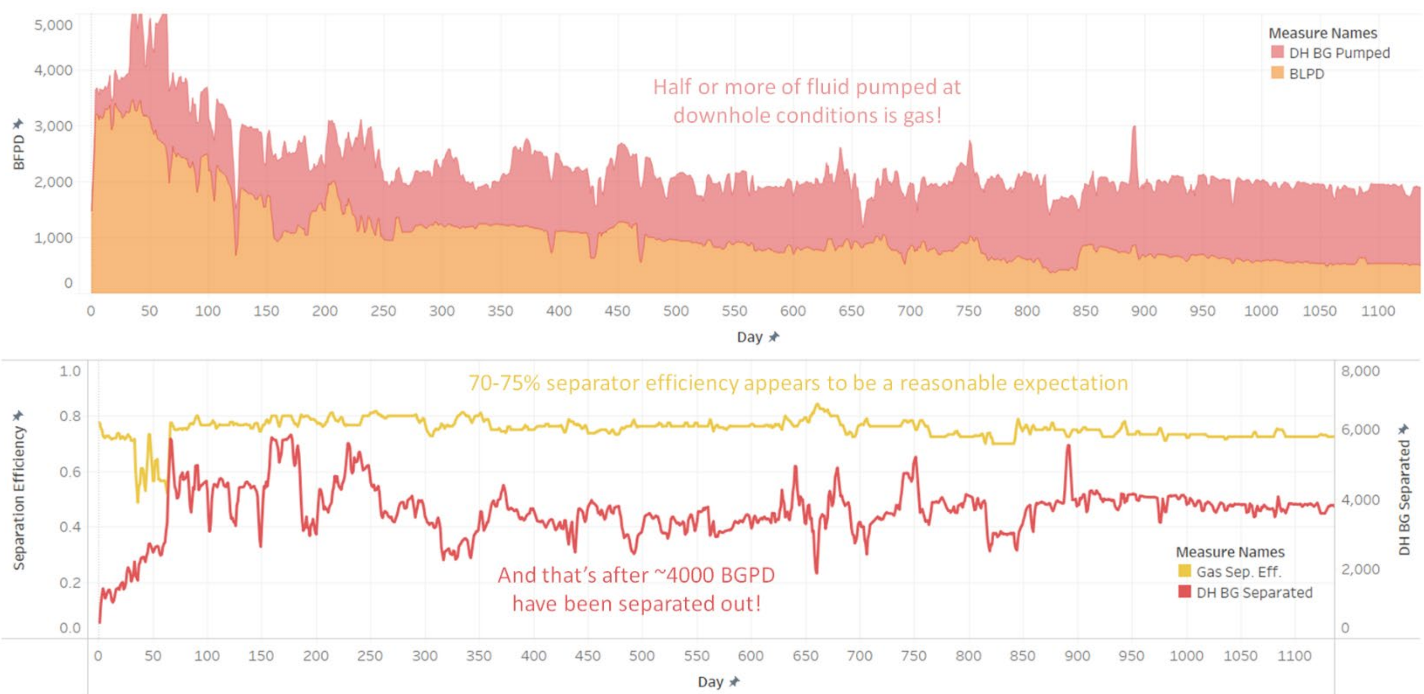

Figure 11 – Unconventional consolidated downhole pumping conditions (top) and gas separation (bottom).

Figure 12 shows power usage and various efficiencies in the unconventional system. HHP is ~1/3 of the total power drawn, so system η is only 33%. This is on the lower end of what's expected for ESPs (Woods and Lea 2017). The IM η is near 80%, so the pump η of 30-50% is the main factor driving the system η.

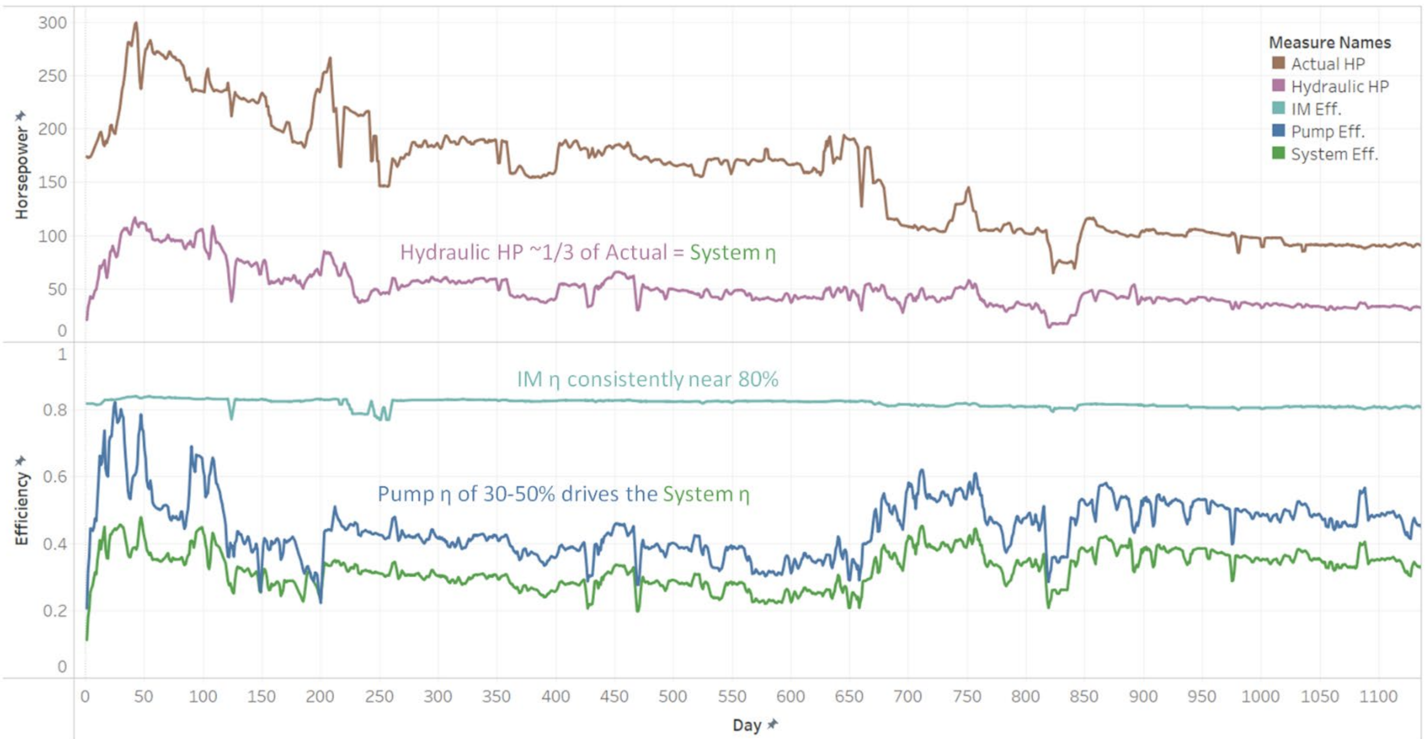

Figure 12 – Unconventional consolidated power usage and η calculations.

Figure 13 displays the motor loading over time and compares the associated PMM and IM η. The efficiencies of both motor types were consistent over the 50-75% motor loading and the PMM η was ~7% higher than the IM η. This corresponded to cumulative power savings of ~$24k. The IM-PMM difference in lifting power required was 0.0084 kW/bbl—note that this calculation is only for liquids lifted.

Figure 14 focuses on PF and kVA. The IM PF follows the motor loading, while PMM PF is mostly independent of it. The large PF difference manifests as a considerably larger kVA requirement for IMs versus PMMs, 70kVA in this example. This may be enough to reduce a VFD frame size if a PMM is initially selected for a well's high production phase.

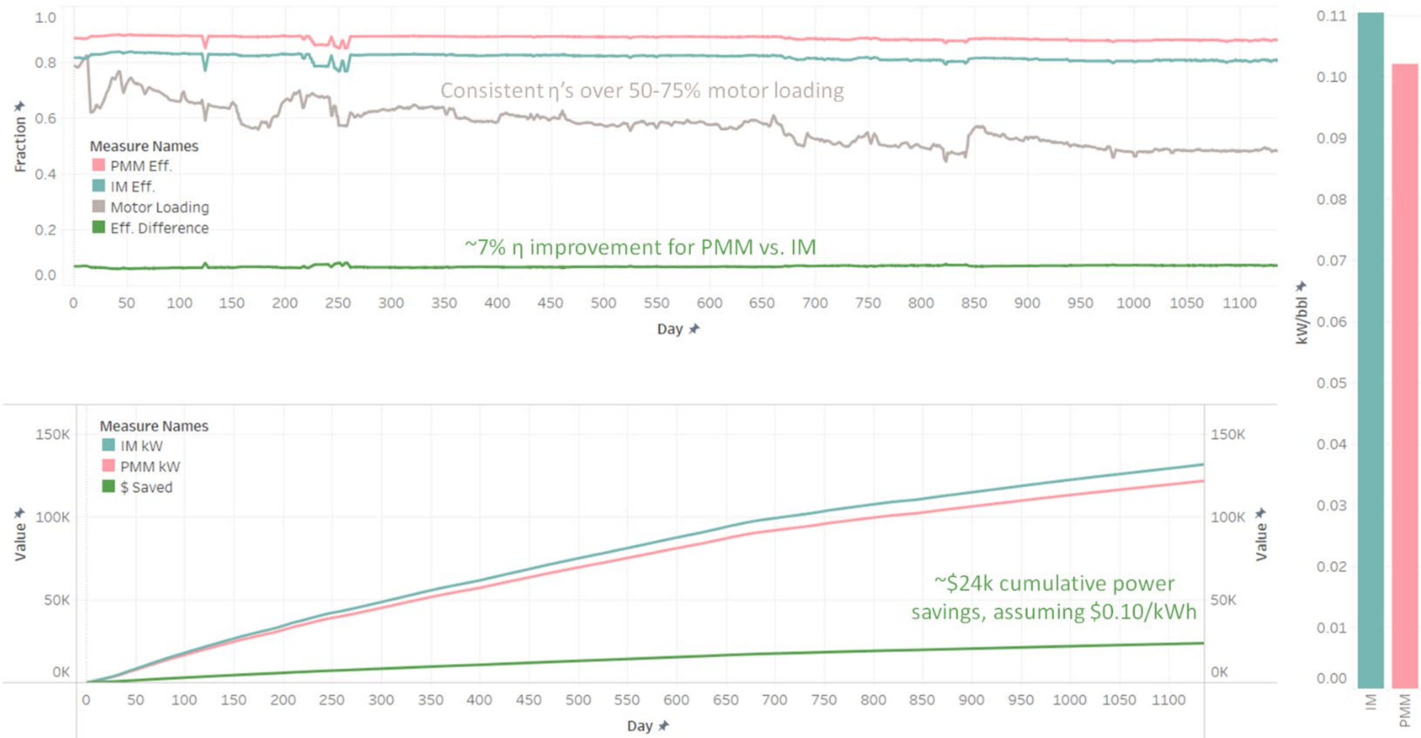

Figure 13 – Unconventional consolidated motor η and loading (top), cumulative power and savings (bottom), and calculated power per unit of liquid lifted (right).

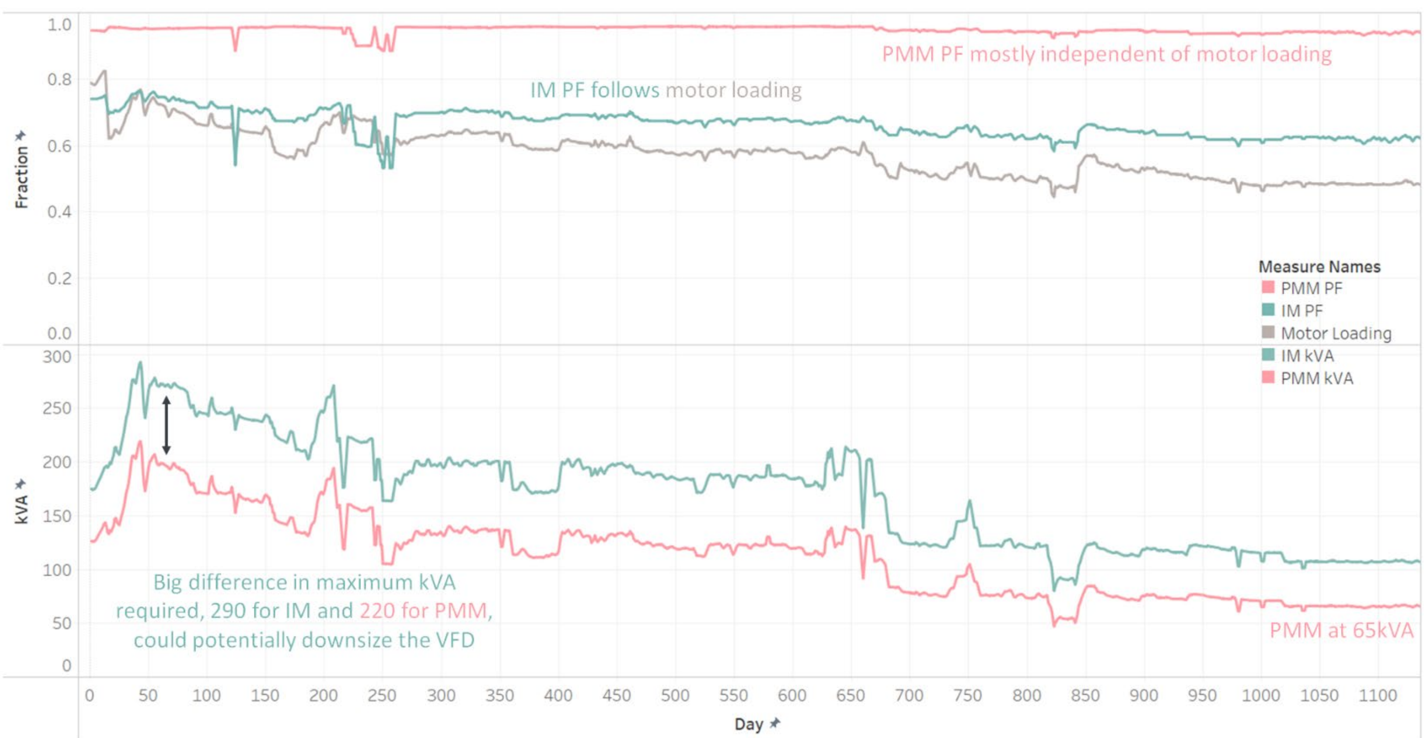

Figure 14 – Unconventional consolidated motor PF and loading (top) and kVA usage (bottom).

CONVENTIONAL CONSOLIDATED WELL ANALYSIS

Figure 15 shows downhole pumping conditions for the conventional consolidated well. Note that minimal pumped fluid is gas. Gas separator η was near 80% resulting in ~300 BGPD being separated prior to the pump intake. Separation is still necessary for the conventional well – the separated gas volume would represent ~1/3 of total liquids pumped! Surface gas production was only 10 MCFD but relatively low PIPs turn this into a downhole GVF of about 30% prior to separation.

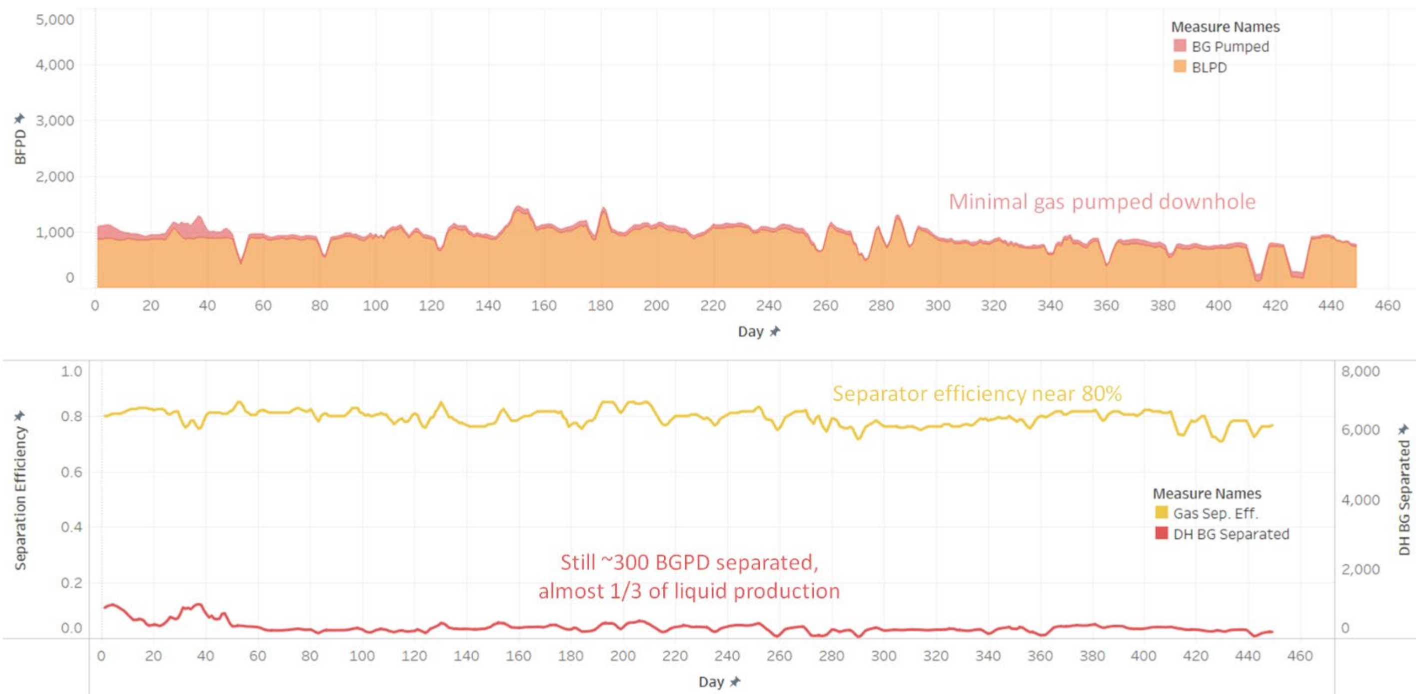

Figure 15 – Conventional consolidated downhole pumping conditions (top) and gas separation (bottom).

Figure 16 shows the power usage and various η in the conventional system. Overall power usage was lower than unconventional, but HHP is still ~1/3 of the total power drawn so the system η is about the same. This was somewhat surprising as the conventional system efficiency was expected to be higher than unconventional. The pump η was again the main driver as the IM η was 80-83%. One potential complicating factor could be that the longer ESP run lives in the conventional wells may slowly contribute to pump performance degradation. The pumps in ¾ of the conventional wells studied had been installed for ~5yr by the time of the analysis.

Figure 17 displays the motor loading and efficiencies. Both IM and PMM η were consistent over the 60-75% motor loading and the PMM η was ~7% higher than the IM η. This corresponded to cumulative power savings of ~$6.6k (although the conventional period analyzed was ~1/3 that of the unconventional wells). The IM-PMM difference in lifting power required was 0.0071 kW/bbl. The kW/bbl difference magnitude was lower for conventional than unconventional, likely because the unconventional ESP processes much more gas than the conventional ESP (more room for PMM power improvement) and this is not factored into the lifting power determination.

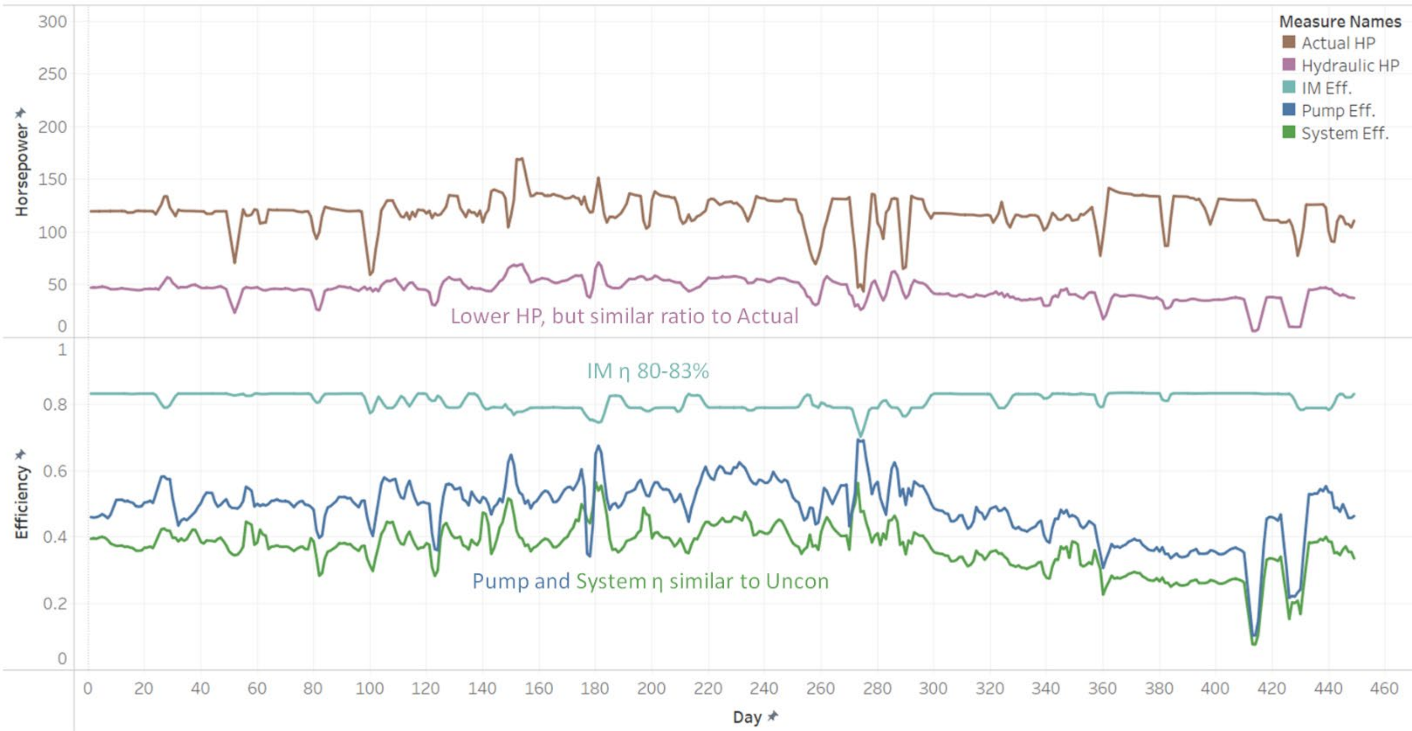

*Figure 16 – Conventional consolidated power usage and η calculations.*ك

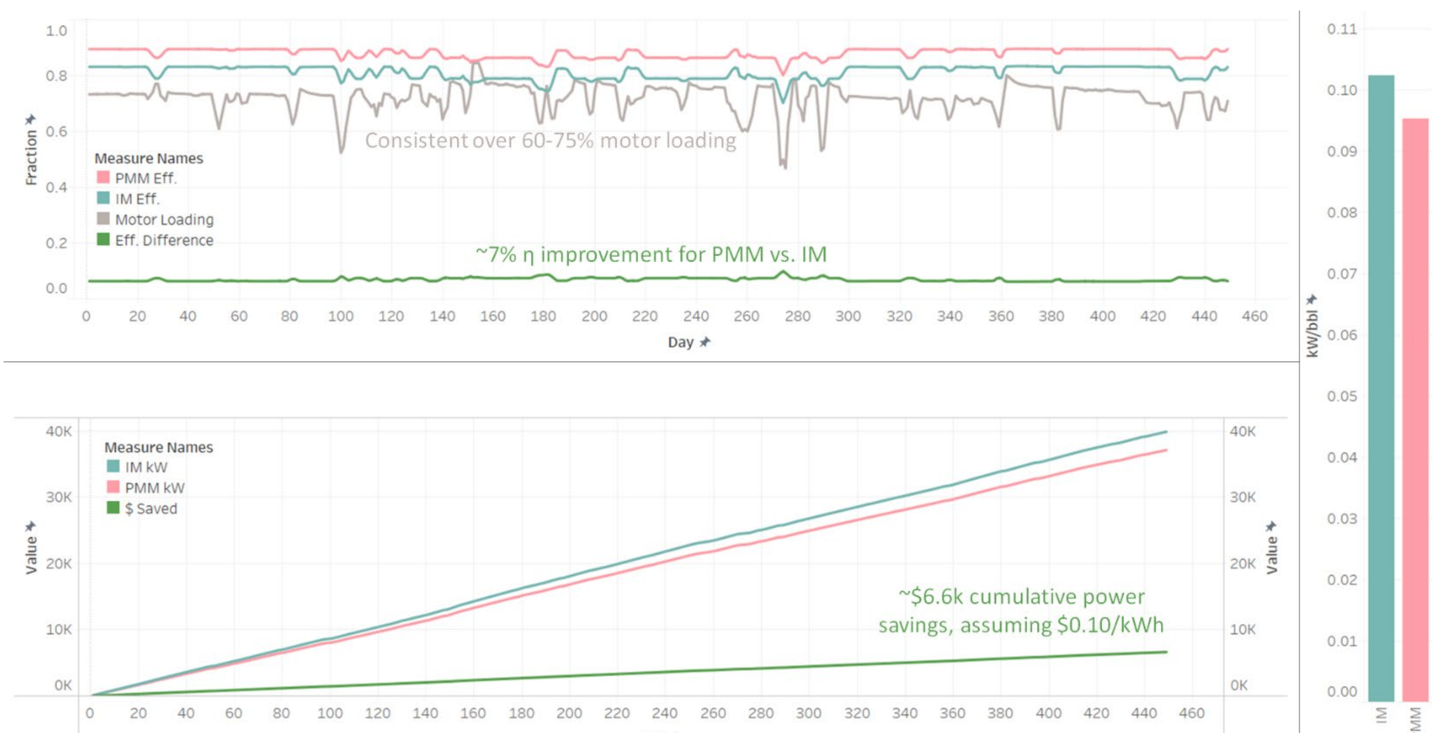

Figure 17 – Conventional consolidated motor η and loading (top), cumulative power and savings (bottom), and calculated power per unit of liquid lifted (right).

Figure 18 shows the conventional consolidated well PF and kVA. The motor loading and IM PF were in a tight band, but the PMM PF was considerably better. The PMM consistently required 30kVA less than the IM, although this difference may not be large enough to downsize a VFD frame size.

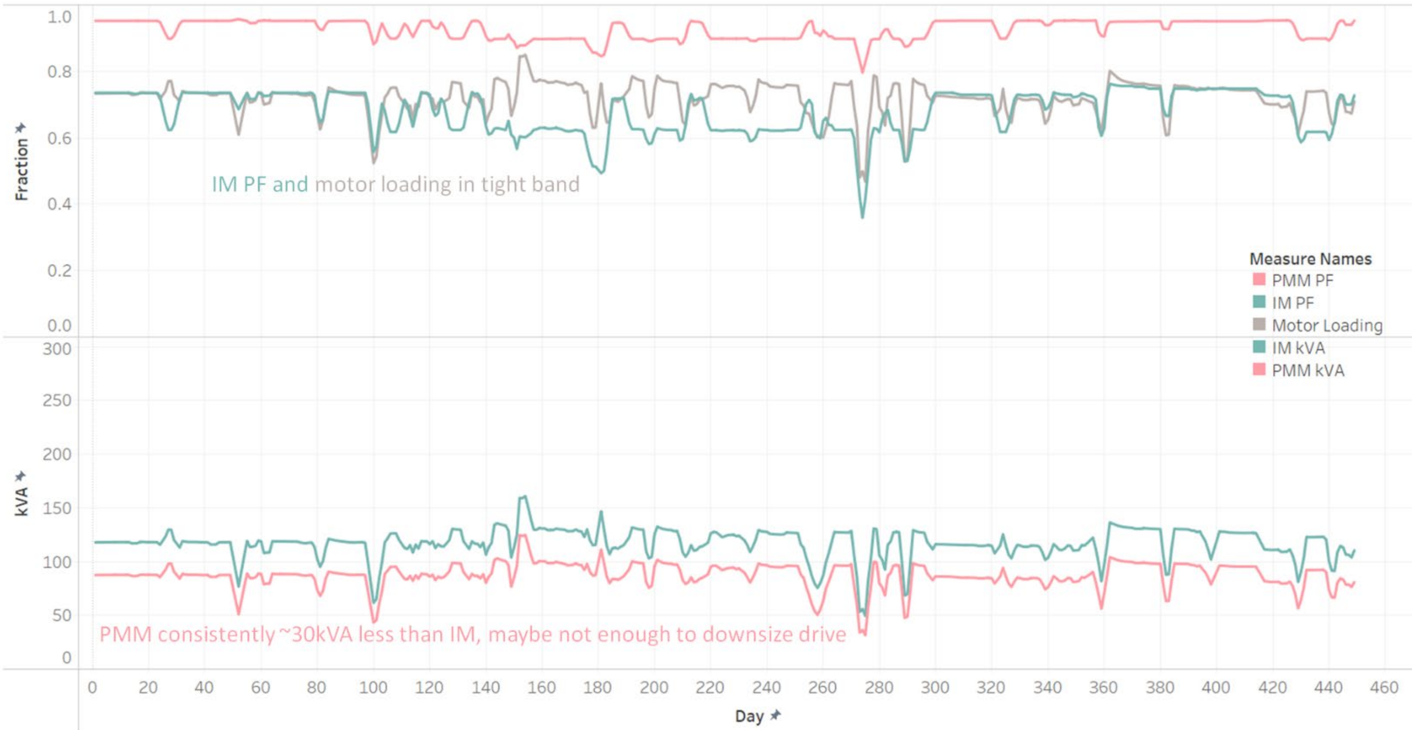

Figure 18 – Conventional consolidated motor PF and loading (top) and kVA usage (bottom).

<u>CONSOLIDATED WELLS, NORMALIZED</u>

Power savings over “system lives” were generated for the two well types for a more complete comparison of results.

The unconventional consolidated ESPs were granted 1.25yr MTTF, which is a slightly more generous estimate than actual run lives encountered. Three ESPs per unconventional well would result in a total 3.75yr or 45mo of ESP run life. More ESPs could be installed afterward, but it’s also possible that the artificial lift method may be changed as production rates drop further out of preferred ESP ranges. The production rate near the end of the 1136-day period (~500 BLPD) was extended to the end of 3.75yr (1369d) for power usage calculations.

The conventional consolidated single ESPs were capped at a 5yr MTTF. Three of four conventional ESPs studied had been installed in 2019 and were still running at the end of 2024, so this estimate is reasonable, if not conservative.

System life power savings estimates can be seen in *Table 1*. The cumulative liquid production volumes and daily rates are similar, but the unconventional wells require ~20% more power to process them due to the high volumes of downhole gas pumped. This corresponds to higher potential daily power savings (again at $0.10/kW-h) for the unconventional PMM wells versus the conventional ones. The total savings over the system lives are almost identical at $27k, but it takes three ESP system installations in the unconventional well to achieve the same amount of savings as a single PMM installation in the conventional well. Net Present Value (NPV) of the power savings calculated at 10% discount is higher for the unconventional well since the returns are generated more quickly, but both are near $21k.

Table 1 – Power savings for consolidated well types, normalized to "system lives".

			IM	PMM		
	Sys. Yrs	**Cuml. BBL**	**Daily kW**	**$ Sav/Day**	**$k Sav**	**NPV 10%**
Uncon Consol	3.75	1.34E+06	108.5	19.72	**27.0**	21.6
Conv Consol	5	1.58E+06	88.6	14.72	**26.9**	20.4

DISCUSSION

It was hypothesized that PMMs would be more beneficial in terms of power savings for conventional than unconventional wells, but it was found that this was not clearly the case. The cumulative power savings and NPV of those savings was almost the same for both well types investigated in this study.

The high natural GVF (80+%) in the unconventional wells was offset by effective gas separation (70% η). The 1000s of BGPD pumped downhole in addition to liquids increased the HHP required and improved the system η of the unconventional wells. Gas separation was also important to the conventional wells. The BGPD separated was nearly 1/3 of total liquid production.

Unconventional motor loading trended downward along with production over time. Conventional motor loading was mostly stable. The difference in IM versus PMM η was consistent versus motor loading and no significant advantage by well type was found.

System efficiencies of both well types were found to be ~1/3, which was less than expected. The pump η of 30-60% was the largest driver of system η. Low gas content (20-30% GVF before separation) in the conventional wells may improve initial pump η, but it's postulated that longer MTTF could contribute to pump performance degradation as the system ages. Meanwhile, the unconventional wells receive fresh new pumps almost annually. Improved pump η over the ESP operating life could have a greater impact on power consumption than a PMM upgrade over an IM.

It's possible that a different/larger selection of wells of both/either type may or may not have significantly affected the results described here.

CONCLUSIONS

The theoretical PMMs discussed here were shown to reduce power usage by ~7%. The power measurement point for the calculations was at the output of the VFD so step-down transformer and VFD power usage were not included in the analysis. It's expected that more power would be saved at these components with the improved electrical efficiency of PMM operation. This and ESP performance optimization would likely push total PMM electrical savings toward the 10-15% stated in the studies previously referenced.

The "system life" PMM OPEX savings case ($21k NPV) may be simpler for high-WC conventional wells where margins are tight and one ESP installation would be required instead of three for unconventional wells (plus the associated costs of PMM safety precautions). An interesting argument in favor of PMMs could be that the VFD frame size could be reduced (particularly for unconventional wells) since the PMM required 25% kVA less than the IM.

There are of course other reasons aside from power savings to choose PMMs that are discussed in detail in Harris, English, and Leemasawatdigul (2017) and other studies—low/high-speed optionality, downhole heat reduction, smaller motors and ESP systems due to higher power density, etc. This study should be considered as only one variable to be factored into a more complete decision equation.

The most surprising finding was that Permian unconventional Midland Basin and conventional Central Basin Platform wells are more similar in the eyes of their ESPs than expected!

NOMENCLATURE

AWG = American Wire Gauge, conductor sizing
BBL = Barrels
BGPD = BBL Gas Per Day
BLPD = BBL Liquid Per Day
Conv = Conventional waterflood wells
DP = Differential Pressure
η = Efficiency
ESP = Electric Submersible Pump
GVF = Gas Volume Fraction
HHP = Hydraulic Horsepower
IM = Induction Motor
MCFD = Thousand standard Cubic Feet per Day
MTTF = Mean Time To Failure
NPV = Net Present Value
PDP = Pump Discharge Pressure
PF = Power Factor

PIP = Pump Intake Pressure
PIT = Pump Intake Temperature
PMM = Permanent Magnet Motor
Q = Total fluids flow rate through the ESP
SCADA = Supervisory Control And Data Acquisition
Uncon = Unconventional shale oil (hydraulically fractured) wells
VFD = Variable Frequency Drive
VDrop = Cable voltage drop
WC = Water Cut
WHP = Wellhead Pressure

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Table 2 – Averaged input and calculated values from full dataset for individual and consolidated unconventional and conventional wells.

Well	Freq	PIP	Drive I	Drive V	WHP	Mtr I	BLPD	WC	MCFD	GVF	Sep Eff	BG Pmpd	BPD Pmpd	Oil °API	psi/ft	ESP ft-TVD	PDP	DP	HHP	kVA	Load	IM PF	Sys Eff	CLoss kW	IM Eff	IM kW	Pump Eff	PMM Eff	PMM PF	PMM kW	PMM KVA	% KVA Sav	% kW Sav
Uncon 1	57.7	893.0	139.0	453.3	261.5	37.0	1800.4	80.1%	486.6	66.5%	78%	953	2741	39.8	0.31	7285	2527.1	1650.0	76.4	220.8	64.3%	0.704	0.37	17.4	0.828	116.0	0.50	0.894	0.954	145.8	152.7	31.5%	7.3%
Uncon 2	54.6	473.3	161.3	407.9	234.4	27.3	624.3	61.6%	278.1	84.6%	75%	1201	1809	43.3	0.20	7383	1670.3	1207.9	33.7	112.3	57.1%	0.663	0.33	9.8	0.820	54.7	0.45	0.889	0.953	70.0	73.2	35.3%	7.7%
Uncon 3	58.6	630.2	247.2	422.7	188.0	34.9	938.9	71.6%	606.6	86.4%	73%	1746	2682	39.8	0.20	8139	1781.6	1152.9	51.7	181.5	53.3%	0.649	0.34	16.6	0.816	84.8	0.49	0.886	0.950	110.7	116.1	37.1%	7.9%
Uncon 4	56.8	645.1	166.7	402.5	258.7	24.2	554.4	42.7%	398.3	89.1%	72%	1134	1682	43.3	0.16	8217	1558.7	926.9	28.3	114.8	52.9%	0.638	0.28	9.3	0.809	54.2	0.38	0.881	0.939	69.8	73.8	37.7%	8.2%
Conv 1	56.8	121.3	122.3	406.1	270.0	23.1	624.6	98.6%	10.1	48.5%	87%	76	699	41.5	0.40	6394	2854.1	2746.1	33.5	89.6	74.6%	0.739	0.41	5.2	0.831	52.8	0.45	0.894	0.943	63.6	66.9	26.2%	6.9%
Conv 2	62.8	208.9	263.5	455.9	270.0	47.1	1755.4	99.2%	15.0	20.7%	75%	97	1841	41.5	0.43	6408	2998.5	2792.7	89.9	214.3	90.6%	0.781	0.38	21.4	0.829	124.8	0.52	0.891	0.939	159.5	169.0	22.0%	6.8%
Conv 3	49.7	404.9	90.6	410.8	212.0	25.0	467.5	97.9%	12.9	26.6%	78%	77	544	41.5	0.42	7428	3338.6	2934.3	26.2	66.4	58.1%	0.661	0.43	7.1	0.819	31.0	0.60	0.888	0.951	41.4	43.2	35.3%	7.7%
Conv 4	54.5	956.0	93.2	298.1	100.0	24.0	417.9	97.4%	6.7	17.7%	77%	17	430	41.5	0.43	6501	2927.4	2452.0	18.1	75.6	58.5%	0.529	0.25	5.8	0.765	39.3	0.32	0.848	0.876	48.6	50.9	34.7%	7.8%

Well Type	Freq	PIP	Drive I	Drive V	WHP	Mtr I	BLPD	WC	MCFD	GVF	Sep Eff	BG Pmpd	BPD Pmpd	Oil °API	psi/ft	ESP ft-TVD	PDP	DP	HHP	kVA	Load	IM PF	Sys Eff	CLoss kW	IM Eff	IM kW	Pump Eff	PMM Eff	PMM PF	PMM kW	PMM KVA	% KVA Sav	% kW Sav
Uncon Consolidated	56.9	660.4	178.5	421.6	235.6	30.9	979.5	64.0%	442.4	81.6%	75%	1259	2228	41.6	0.21	7756	1884.4	1234.4	47.5	157.4	56.9%	0.664	0.33	13.3	0.818	77.4	0.45	0.888	0.949	99.1	103.9	35.4%	7.8%
Conv Consolidated	55.9	422.8	142.4	392.7	213.0	29.8	816.3	98.3%	11.2	28.4%	79%	67	879	41.5	0.42	6683	3029.6	2731.3	41.9	111.5	70.4%	0.678	0.37	9.9	0.811	62.0	0.47	0.880	0.927	78.3	82.5	29.6%	7.3%