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# Fit-For-Purpose Non-Aqueous Drilling Fluids: A Data-Driven Review of Electrical Stability

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## Abstract

Fluid specifications and key performance indicators (KPIs) can be very costly if not properly designed and justified. For invert emulsion non-aqueous drilling fluids (NADFs), electrical stability (ES) is a legacy metric for emulsion quality. Unfortunately, these fluids are often over-treated with surfactants to achieve unnecessarily high ES values. While high ES can sometimes correlate with improved emulsion stability and oil wettability, this isn't always the case. Relying solely on absolute ES values to gauge fluid quality can prove detrimental to the NADF and lead to costly resource misallocation.

This paper reviews the fundamental chemistry of drilling fluid emulsions and analyzes over 400,000 data points from over a decade of field operations. It explains how ES is measured and its relationship to emulsion strength and base fluid type. An analysis of both wellsite and laboratory data shows that while ES is valuable, its usefulness as a single diagnostic tool is limited and can be misleading. The data reveals high ES values don't always correlate with the NADF's ability to resist contamination, maintain performance, or demonstrate overall stability. The review also shows how fluids with low ES values can still provide strong, robust emulsions.

By placing ES within a broader context of other fluid properties and operational conditions, the paper presents a more accurate framework for evaluating an emulsion's state. These findings provide a better understanding of how to properly assess an emulsion, including ES data, which leads to more confident and effective fluid management decisions.

## Introduction

The relationship between electrical stability and emulsion stability remains an area of confusion. Despite broad industry literature and supporting data, operators regularly demand specific and elevated ES values, introducing unnecessary cost for little to no benefit. In some cases, excess treatment results in elevated rheology and may fail to address another fluid-related issue.

The perception that “higher is better” for ES seems intuitive in that less conductivity could indicate that the aqueous phase requires more current to break down, but this is not entirely correct. ES values, regardless of stability, will vary by the surfactants used, the amount of oil and water in the system, the solids, and many other factors that will be discussed in this paper. Field data sets confirm that arbitrarily high ES values are not pertinent to emulsion stability.

## Review of Emulsion Principles

NADFs are complex, non-Newtonian, macro-emulsions in which the internal aqueous phase is not only present as discrete droplets but is also frequently adsorbed onto organophilic clays (OPCs) and other particulates. Microscopic observations show that these solids–brine–surfactant complexes contribute substantially to stability: surfactants (emulsifiers/wetting agents) reinforce the wettability and integrity of particulate-associated aqueous structures, not just free droplets. Consequently, stability arises from the combined effects of interfacial films and the adsorption of brine on solids dispersed in the continuous oil phase.

Understanding the "fit-for-purpose" nature of these fluids requires a deep dive into the thermodynamic and kinetic mechanisms that govern their stability. Fundamentally, all emulsions are thermodynamically unstable. The process of emulsification involves a massive increase in the interfacial area between the two immiscible liquids. The goal of a "fit-for-purpose" NADF is not to achieve thermodynamic stability, which is impossible, but to maximize kinetic stability. This is achieved by creating a significant energy barrier that prevents droplets from coalescing over the operational life of the fluid.

### *Mechanisms of Emulsion Breakdown*

Emulsions fail through several distinct physical processes. Distinguishing between these is vital for interpreting ES data (Alias, 2013; Tadros, 2013).

- Creaming and sedimentation: Driven by density differences between the phases (described by Stokes' Law). While not a breakdown of the emulsion itself, it leads to phase concentration.
- Flocculation: Droplets clump together but retain their individual surfactant films.
- Coalescence: The actual rupture of the interfacial film, where two droplets merge into one larger droplet. This is the ultimate failure of the emulsion.
- Ostwald Ripening: The migration of molecules from smaller droplets to larger ones through the continuous phase, driven by the Kelvin effect.

Image 1 illustrates an emulsion where flocculation and coalescence has begun to occur. This process is irreversible and eventually leads to a complete separation of the oil and water phases (bulk separation), which would be indicated by a catastrophic drop in ES and the presence of "free water."

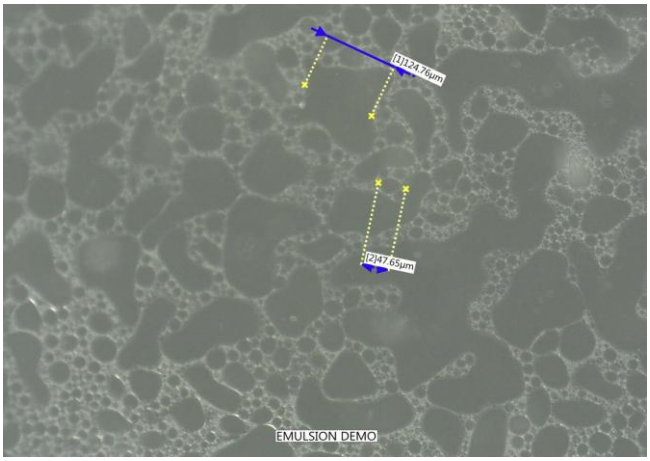


*Image 1: A 50:50 oil:water ratio invert emulsion fluid is pictured under 300x magnification via optical microscope. Emulsion droplet size, size variance, and low contact angles indicate a weak emulsion.*

In the field, a qualitative but highly reliable indicator of an invert emulsion's health is the visual luster or "sheen" of the fluid. A stable, well-conditioned NADF typically exhibits a characteristic glossy appearance, signifying that the solids (such as barite and drill solids) are thoroughly oil-wet and encapsulated within a robust continuous oil phase.

As the emulsion begins to suffer—whether due to surfactant depletion, water contamination, or the transition of solids from an oil-wet to a water-wet state—the fluid undergoes a noticeable "dulling" (Image 2). This flat, matte appearance occurs because water-wet solids migrate toward the aqueous phase or the interface, creating a grainy texture that scatters light rather than reflecting it. This visual change often serves as a critical leading indicator of emulsion instability, appearing even before a significant decline is measured in Electrical Stability (ES) or an increase is seen in HTHP fluid loss.

*Image 2: A field-captured sample of NADF that has encountered significant water intrusion whereby the emulsion and oil-wettabilty has suffered, resulting in a dull, grainy look*

To counteract these breakdown mechanisms, surfactants (emulsifiers) are introduced. These molecules adsorb at the oil-water interface, lowering interfacial tension and providing stabilization through two primary modes:

1. Steric stabilization: Long-chain lipophilic tails of the emulsifier extend into the oil phase. When droplets approach, the "crowding" of these chains creates an entropic repulsive force.
2. Interfacial film strength: Modern NADF chemistry often utilizes a combination of primary and secondary emulsifiers to create a "rigid" or highly viscous interfacial film. This film acts as a mechanical barrier against coalescence.

The concentration and type of emulsifier directly influence the dielectric breakdown voltage (Ali, Shmidt, and Harvey, 1987). However, over-treating to achieve a higher voltage may simply add excess surfactant to the continuous phase without further strengthening the interface already saturated with emulsifier.

### *Physics of Electrical Stability*

The industry's reliance on the ES test (API RP 13B-2) stems from its simplicity at the wellsite. However, a review of the physics reveals a gap between what the test measures and what "stability" implies.

The work of Growcock et al. (1994) transformed our understanding of the ES test. It was observed through optical microscopy that during an ES test, droplets do not simply "pop". Instead, the electric field causes the water droplets to polarize and align in the gap between the electrodes.

As the voltage increases, these droplets form a conductive bridge. The ES value is the voltage at which the dielectric breakdown occurs—specifically when the current reaches 61±5 µA (American Petroleum Institute, 2014). Therefore, ES is a measure of the fluid's dielectric strength, not necessarily its chemical robustness. During an ES test, breakdown is driven not only by droplet alignment but also by voltage-induced "expression" of the aqueous phase from OPCs and other solids. As the field increases, brine desorbs from particle surfaces and coalesces into larger droplets. These droplets, together with partially de-wetted solids, then aggregate to form a short-circuiting conductive bridge across the electrodes. The recorded ES therefore reflects the onset of this electrically driven restructuring—not an intrinsic, stand-alone measure of chemical stability.

Several factors that can lower ES values without indicating a "weak" emulsion:

**Droplet Size:** Smaller droplets, created by high-shear environments like the bit, are known to help improve and stabilize an emulsion. This is seen when mixing energy is first applied to fresh mud being built at a mud plant, for example, whereby the ES is low and begins to increase as the emulsion is further established and more stabilized.

While it is a fundamental truth of emulsion chemistry that smaller water droplets provide greater kinetic stability, this does

not always translate to a higher ES value. To understand this paradox, consideration must be given to the conductive bridge theory. Unlike coalescence, which is a chemical failure, ES is a measurement of dielectric breakdown across an electrode gap. In high-shear environments, the resulting smaller droplets are more numerous and more tightly packed. This increased droplet density reduces the spatial gaps between the aqueous phase, allowing a conductive bridge to trigger at a lower voltage threshold. Consequently, a decrease in ES following high shear can indicate improved physical stability and superior droplet dispersion.

During drilling operations, high shear at the bit reduces droplet size (improving physical stability), yet operators often see the ES value "plateau" or even drop slightly despite adding more emulsifier. This is attributed to the fact that the ES test is measuring the dielectric breakdown of the spatial arrangement of the droplets, not the chemical integrity of the surfactant film itself. While initial shear separates the droplets into a smaller physical size, additional shear reduces droplet film strength (Growcock 1994).

**Solids Content:** Solids (such as weight material, organophilic clay, or drill solids) act as "carriers" or "stepping stones" for water droplets. A high-solids fluid will naturally have a lower ES than a "neat" fluid, regardless of the emulsifier's effectiveness. Weight materials with a lower resistivity, such as hematite, will have a lower ES than barite (Growcock 1994). This does not imply the emulsion is weaker in these systems, but rather that the *solids* are facilitating the electrical bridge at lower voltages.

**Aqueous Phase Salinity:** The conductivity of the internal phase (brine) plays a role. The composition of the aqueous phase significantly impacts the voltage required to bridge the gap.

**Temperature:** Increased temperature reduces the viscosity of the continuous phase, allowing droplets to migrate and align more rapidly, which artificially lowers the ES value.

**Viscosity:** Thin fluids allow more interaction between water droplets, allowing them to more readily coalesce versus thicker fluids.

### *ES Measurement Evolution*

The concept of quantifying emulsion stability via electrical breakdown was first formalized by B.C. Crittendon in 1958. These early instruments, which remained the industry standard for decades, were characterized by manual operation. A "good" reading depended heavily on the technician’s ability to turn a knob at a steady, consistent rate.


*Image 3: Fann Model 23C legacy ES Meter*

These older units (as illustrated in Image 3) utilized a square wave oscillator and were inherently "spiky." The rapid rise and fall of voltage in a square wave create erratic electrical stresses on the fluid. This often led to premature dielectric breakdown, where the current reached the threshold not because the emulsion failed, but because of a transient voltage spike. Also, manual testers were prone to the "solids effect." If weighting agents or drill solids settled on one side of the electrode probe, they could create a low-resistance path, resulting in highly erratic values. Because of these hardware limitations, the API goal of maintaining results within a 5% margin of error was historically met only about half the time.

During the era of manual testing, mud engineers were faced with three compounding factors:

1. **Inconsistent Hardware:** The "spiky" square wave and manual ramp rate produced unreliable data.
2. **Base Oil Shifts:** The introduction of mineral oils and synthetics presented naturally different dielectric responses than diesel (discussed later)
3. **Legacy Chemistry:** Older fatty-acid soaps were physically coarser and more sensitive (discussed later)

Engineers utilized a safety-margin approach. Because the meters were inconsistent and the emulsions were less robust, the prevailing field practice was to treat the fluid until the ES was as high as possible. A high ES served as a buffer against both the unreliability of the meter and the potential for emulsion breakdown.

The current generation of ES meters (as illustrated in Image 4), governed by API RP 13B-2, addresses the technical flaws of the legacy instruments. The most significant improvement is the replacement of the square wave with a sinusoidal waveform. The sinusoidal wave provides a much smoother application of energy, allowing the water droplets to polarize and align in a more predictable manner without the interference of erratic spikes. Furthermore, modern meters utilize an automated voltage ramp, increasing the potential at a perfectly consistent rate.


*Image 4: OFI Testing Equipment modern-style ES Meter*

The API RP 13B-2, 4th Edition (2005) and subsequent editions explicitly state that the values obtained with the new sinusoidal, automated instrument may be significantly lower than those from the older square-wave models. The documentation notes that for the exact same fluid, the "modern" reading can be as low as half (50%) of the value generated by a legacy manual meter.

### *Redefining the "Fit-for-Purpose" Framework*

The legacy view—that a higher ES is always better—ignores the complexity of the data presented across numerous studies. If a fluid has an ES of 300V but shows zero high-temperature/high-pressure (HTHP) filtrate and no free water, it is considered effectively stable.

Chasing a high ES often leads to the over-addition of emulsifiers. This is not only a misallocation of resources but can also be technically detrimental. Excessive surfactants can:

- Alter the wettability of the formation.
- Disperse drill solids too finely, making them difficult to remove with mechanical separation equipment.
- Increase the equivalent circulating density (ECD) by elevating the plastic viscosity (PV)

The absolute value of ES is less important than the trend over time. A fluid that maintains a steady 400V throughout a 10,000 ft interval is significantly more stable than a fluid that fluctuates between 200V and 800V, even if the latter's average ES is higher. The American Petroleum Institute acknowledges this in Recommended Practice 13B-2 (2014):

*Chemical composition and shear history of a drilling fluid control the absolute magnitude of ES in a complex fashion. Consequently, interpreting the oil-wet state of a drilling fluid from single ES measurements is not appropriate. Only trends shall be used in making treatment decisions based on ES values.*

Analogously, meteorologists watch falling barometric pressure—not an absolute value—to anticipate atmospheric instability. Likewise, declining ES trends are more diagnostic of emerging emulsion risk than any one-off, high absolute reading.

The following table shows properties from a 13.2 lb/gal field oil-based mud. Upon taking a 20% v/v water flow/intrusion, the emulsion breaks down as evidenced by the drastic ES value drop, increase in rheological profile, increase in overall total HTHP filtrate, and the existence of free water in the filtrate.

Treatment with modern-day emulsifier at 4.0 lb/bbl results in a reduction of fluid loss, removal of free water, and a thinning improvement in rheological profile. The ES value slightly increases from 179V to 237V - still a large variance from the original 434V. This is partly explained by the now lower oil:water ratio (more droplets dispersed throughout the fluid).

*Table 1: 13.2 lb/gal oil based drilling fluid key property comparison*

| Fluid/Test | 13.2 lb/gal OBM | 13.2 lb/gal OBM + 20% v/v water flow | 13.2 lb/gal OBM + 20% v/v water flow + 4.0 lb/bbl emulsifier |
|---|---|---|---|
| 600 rpm | 70 | 134 | 96 |
| 300 rpm | 41 | 80 | 56 |
| 200 rpm | 30 | 59 | 41 |
| 100 rpm | 18 | 36 | 24 |
| 6 rpm | 6 | 11 | 6 |
| 3 rpm | 5 | 9 | 5 |
| PV, cP | 29 | 54 | 40 |
| YP, lbf-100ft$^2$ | 12 | 27 | 16 |
| 10 sec gel, lbf-100ft$^2$ | 6 | 11 | 6 |
| 10 min gel, lbf-100ft$^2$ | 8 | 14 | 8 |
| HTHP FL, cc @ 250F, 500 psid | 3.1 | 8.2/2.2 | 2.6 / 0.0 |
| HTHP Cake 1/32" | 2 | 8 | 2 |
| ES, volts | 434 | 179 | 237 |
| HTHP Filtrate Image |  |  |  |

## Advancement of Base Oils & Surfactant Chemistry

The evolution of NADFs from diesel-based systems to synthetic-based fluids has fundamentally altered how the industry interprets ES. Early chemistries necessitated high ES values as a safety margin, whereas modern surfactant technology provides superior stability that is often decoupled from the absolute ES voltage mentality.

### *Base Oil Evolution*

The transition from diesel to synthetic base oils (Friedheim 1997) significantly impacted the dielectric environment of the drilling fluid.

Diesel is a highly non-polar, hydrocarbon-rich mixture with very low conductivity, which naturally supports high ES readings. In contrast, some synthetic base oils—particularly esters and certain olefins—possess higher dielectric constants or slight polarity. The ES value is a function of the dielectric breakdown of the continuous phase. Synthetic oils often allow for a more rapid "bridging" effect or lower breakdown threshold compared to diesel, leading to naturally lower ES values in fluids that are, in fact, chemically more stable.

Synthetic oils often have flatter viscosity-temperature profiles. Since ES is inversely proportional to the mobility of droplets within the base oil, the different "thinning" characteristics of synthetics at high temperatures (compared to diesel) mean that the electrical breakdown occurs at different energy levels, regardless of the surfactant film strength.

### *Legacy to Advanced Surfactant Chemistry*

The shift from simple fatty-acid soaps to engineered polymeric and polyamide surfactants has moved the industry from quantity-based stability to quality-based stability. Early invert emulsions relied heavily on the reaction between fatty acids (like tall oil fatty acid) and lime to create calcium soaps. These emulsions were often "coarse" with relatively large droplet sizes. To ensure the fluid would not break under downhole conditions, operators added massive quantities of emulsifier to achieve high ES values, often >1000 volts. In these older systems, a drop in ES was a genuine warning of imminent coalescence because the surfactant film was fragile. High ES was the only proxy for a "safe" buffer of excess surfactant.

Modern surfactants, such as oil-soluble low HLB materials, are far more efficient at the interface (Błaż et al., 2021). Advanced emulsifiers - such as polyamides, dimer/trimer acids - create a much tougher, thinner, and more elastic interfacial film. These "stickier" molecules prevent coalescence even at very low concentrations. High-performance surfactants allow for the creation of much smaller water droplets (micro-emulsions). Smaller droplets are physically more stable but can paradoxically lead to lower ES values due to closer packing and easier bridge formation.

Modern chemistry has rendered the "absolute ES value" an outdated KPI, as supported by three key technical realizations:

1. Efficiency vs. concentration: Modern surfactants saturate the oil-water interface much more effectively. Once the interface is saturated, adding more surfactant to "chase" a higher ES value does not improve emulsion stability; it only increases the cost and risks detrimental effects on fluid rheology (Miller 2024).
2. Stability at low OWR: Advanced chemistry allows for stable fluids at low Oil-Water Ratios (e.g., 50/50 or 60/40) (Ihenacho 2016) vegetable oil study. At these ratios, droplets are physically closer together. While the ES may be lower (e.g., 300–400V) compared to an 80/20 diesel mud, the kinetic stability is often superior because the modern surfactant prevents the droplets from merging.
3. Wettability vs. ES: ES is a poor indicator of oil-wettability (Ali, 1987; Growcock et al., 1994). Modern secondary emulsifiers focus on keeping solids oil-wet, which is critical. A fluid with a "low" ES of 400V that keeps all drill solids oil-wet and produces no HTHP free water is technically superior to an older 1000V system that might still struggle with water-wet solids or barite sag.

### *Electrical Stability Field Data*

Field data gathered from >15,000 wells from 2013-2025 in the Permian Basin reveal an average electrical stability of 451 volts (Figure 1).

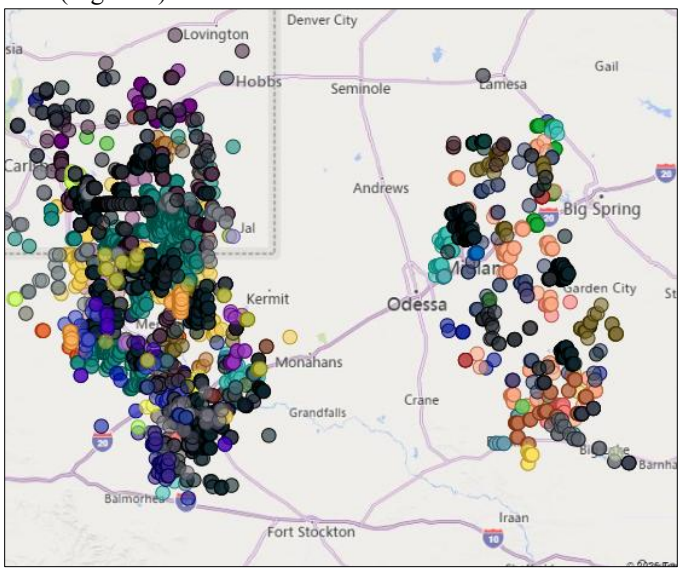


*Figure 1: Over 24 different operators and >15,000 wells reveal an average electrical stability of 451 volts per well.*

The validity of moving toward a "fit-for-purpose" interpretation of Electrical Stability is most clearly demonstrated when analyzing one of the largest known longitudinal data sets of its kind. This study incorporates over 400,000 individual ES readings collected from 2010 to the present, spanning every major US Land basin—including the Permian, Bakken, Anadarko, Eagle Ford, DJ, and Haynesville.

Historically, a common field heuristic suggested that an ES below 500V represented a "weak" or "at-risk" emulsion, with many operators mandating treatments to maintain values above 800V or even 1,000V. However, the statistical reality of the last decade and beyond contradicts this requirement. In this data set of nearly half a million data points (Figure 2), the median ES is 448 volts, with an average of 475 volts. These figures are statistically significant; they represent the "operational normal" for modern NADFs across thousands of successfully drilled wellbores. If the legacy belief—that an ES below 500V indicates an unstable fluid—were true, this data set would be characterized by widespread reports of excessive HTHP filtrate, phase separation, cost-overruns, and diminished drilling efficiencies relative to other providers. Instead, it reveals that the vast majority of US Land drilling occurs safely and efficiently within the 300V to 550V window.

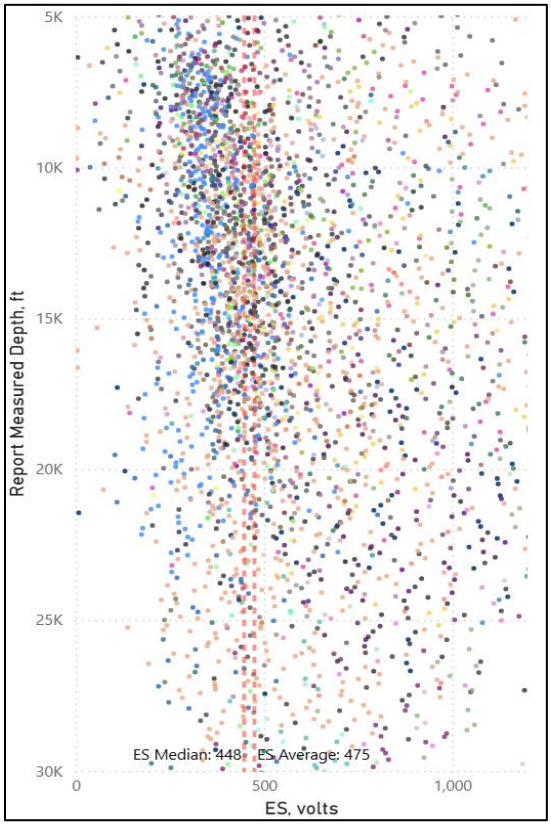


*Figure 2: Scatter plot of 400,000+ ES readings vs. Measured Depth. The heavy clustering between 350V and 600V demonstrates the industry standard for stable operation in the modern surfactant/automated-meter era.*

More evidence that these "lower" ES values are sufficient lies in the secondary scatter plot of High-Temperature/High-Pressure HTHP filtrate shown in Figure 3. While the ES values hover in the 400-500v range, the associated HTHP filtrate measurements remain tightly controlled, with an average of 8.37 ml and a median of 7.50 ml. The fact that the median filtrate remains at 7.50 ml despite a median ES of 448V confirms that the kinetic stability provided by modern surfactants is absolute. There is no statistical correlation in this 400,000-point set suggesting that an ES of 450V leads to higher fluid loss than an ES of 1,000V. This confirms that the emulsion is not "weak"; it is simply optimized.

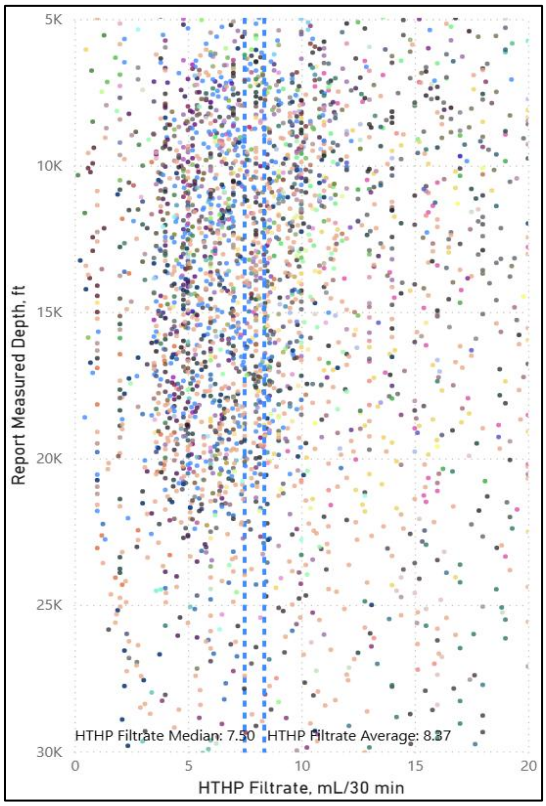


*Figure 3: HTHP Filtrate vs. ES Correlation. The median filtrate of 7.50 ml across the 400V–500V ES range provides indirect evidence that lower ES values do not compromise emulsion integrity or filtration control.*

The cluster of data points around a 448V median and a 7.50 ml HTHP median suggests that chasing higher ES values is statistically unnecessary. For an operator, "treating to 1,000V" when the statistical norm and operational success reside at 450V represents a significant misallocation of chemical resources. By accepting the 300V–550V range as the "stable baseline," operators can reduce:

- **Excessive Emulsifier Costs:** Avoiding the "diminishing returns" phase where more surfactant increases voltage but provides no additional reduction in HTHP filtrate.
- **Rheological Drag:** Preventing the unnecessary increase in Plastic Viscosity (PV) associated with over-treatment.
- **Solids Dispersion Issues:** Minimizing the risk of "over-dispersing" drill solids, which makes them harder to remove with shakers and centrifuges.

To verify the "Fit-for-Purpose" threshold, the data set

of >100,000 points was segmented into specific voltage brackets to compare the probability of success. The results demonstrate that while filtrate control technically improves as ES increases, the industry is operating on a curve of diminishing returns. While legacy standards might suggest chasing 1,000V, the top 10% of field performance (P10) is practically identical at 400V as it is at 1,000V (Figure 4). This confirms that modern surfactant chemistry achieves filtration integrity through interfacial quality rather than electrical magnitude. The marginal gain of ~1 ml in median filtrate does not justify the significant chemical expenditure and potential rheological drawbacks associated with over-treating a fluid to double its electrical stability.

| ES Bin (Volts) | Sample Size (n) | $P_{10}$ (Top 10%) | $P_{50}$ (Median) | $P_{90}$ (Risk) |
|---|---|---|---|---|
| 100 - 200 | 3,074 | 3.5 ml | 8.80 ml | 18.00 ml |
| 200 - 300 | 20,653 | 3.2 ml | 8.00 ml | 16.80 ml |
| 300 - 400 | 33,484 | 3.4 ml | 8.40 ml | 17.00 ml |
| 400 - 500 | 29,419 | 3.2 ml | 7.80 ml | 15.80 ml |
| 500 - 600 | 21,906 | 3.0 ml | 7.40 ml | 14.60 ml |
| 700 - 800 | 10,154 | 3.0 ml | 6.80 ml | 13.40 ml |
| 900 - 1000 | 3,350 | 3.2 ml | 6.60 ml | 12.80 ml |

*Figure 4: Probability-based performance distribution (P10, P50, P90) of HTHP filtrate relative to ES voltage. Note the nearly horizontal P10 line, indicating that top-tier filtration is consistently achieved in the 300V–500V range without the need for high-voltage over-treatment.*

## Conclusions

- The large statistical data set suggests a much lower ES value is necessary versus legacy “rules” related to higher absolute ES values. Provide that modern chemistries operate with high integrity at significantly lower absolute voltages than previously assumed.
- The correlation of a 7.50 ml median HTHP filtrate with sub-500V ES readings proves that "lower" ES values do not equate to "weak" emulsions. In modern surfactant systems (polyamides/polymeric), kinetic stability and filtration control are maintained via interfacial tenacity rather than the high-surfactant-concentration "brute force" required by legacy chemistries.
- The transition to automated sinusoidal ES meters has fundamentally lowered the numerical output of the test while increasing its reliability. Consequently, what was once an 800V reading on manual square-wave hardware is now a more accurate ~450V. This shift signifies that modern industry "lows" are an artifact of superior measurement precision, not a decline in fluid quality.
- Chasing ES values beyond the established fit-for-purpose framework leads to diminishing returns where additional chemical costs do not yield further HTHP reductions. Instead, over-treatment risks detrimental increases in PV and the potential over-dispersion of drill solids, which complicates solids control efficiency.

## Acknowledgments

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## Nomenclature

*BHA =Bottomhole Assembly*
*PV = Plastic Viscosity*
*HTHP = High Temperature High Pressure*
*ES = Electrical Stability*
*NADF = Non Aqueous Drilling Fluid(s)*

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