

# Enhancing Electrical Stability in Invert-Emulsion Drilling Fluids: A Focus on Aqueous Phase Composition

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## Abstract

Electrical stability refers to the ability of a suspension or emulsion to maintain its stability and resist phase separation when subjected to an electric field. The concept of electrical stability is especially important in the oil and gas industry, where it plays a crucial role in the performance of invert-emulsion drilling fluids, however, the absolute value of the electrical stability is not as important as how the value trends over time. Stable invert-emulsion drilling fluids, which are complex water-in-oil emulsions stabilized by emulsifiers, help prevent wellbore instability and maintain the integrity of the well during drilling operations.

Most chemical compositions suggested to be electrical stability boosters typically include different emulsifier configurations which are meant to change the droplet shape and increase the voltage needed to break the emulsion. Traditional methods include using maleated fatty acids such as tall oil or vegetable oil. The structure of these molecules allows them to interact with the calcium ion in the internal phase multiple times causing them to bend and take up more room at the interface. This reduces the radius of the emulsion droplets and increases stability.

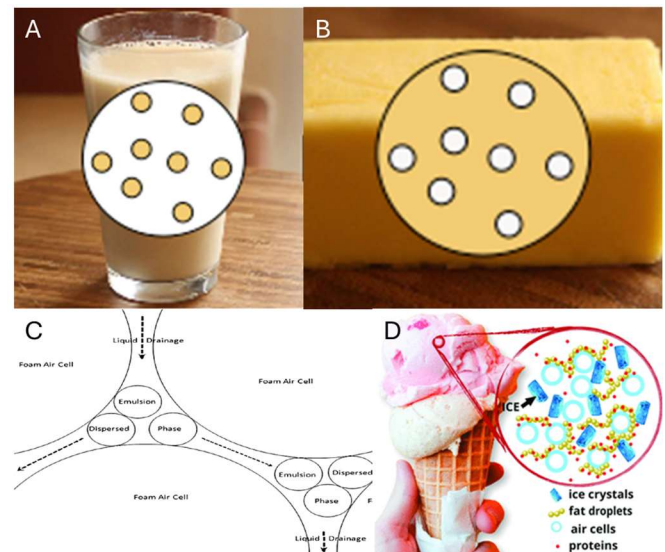
The authors will present a comprehensive examination of research that seeks to alter the composition of the aqueous phase, as opposed to the oil phase or the emulsion itself, in an effort to enhance the stability of emulsion droplets.

## Introduction

Emulsions are dispersions of two incompatible liquids in which one liquid is the solute or internal phase and the other liquid is the solvent or external phase. These liquids mix while shear is applied, but separate when the shear is removed. A surface-active agent, surfactant, is added to the mixture to facilitate compatibility between the liquids. This stabilizes the mixture and the internal phase stays dispersed for longer periods of time (Van Zantan, 2012).

Common examples of emulsions are milks produced from animals, such as cows or goats, or from plants, such as tree nuts, oat kernels, or soybeans, see **Figure 1A**. These all produce direct emulsions; those with water as the external phase. If the fat portion of cow's milk is removed from the water portion and sheared, then an invert emulsion or oil external emulsion, is produced known as butter, see **Figure 1B**. This emulsion is

stable because the external phase is very viscous and does not allow the internal phase droplets to coalesce. Foams are an emulsion between water and air with the water forming a thin film between the air bubbles, see **Figure 1C** (Green, 2013). Ice cream is a much more complex emulsion containing water in the form of ice, fat, and air, see **Figure 1D** (Azerado, 2019). In this case, the fat droplets and air cells are emulsified into the water phase using protein molecules and stabilizers. The fat content and air volume in the ice cream affect the “mouth feel” of the ice cream.



**Figure 1** Examples of common emulsions

In the Oil & Gas industry, both direct and invert emulsions are used depending on the desired fluid properties and the formation being drilled. Direct emulsions are typically used when a saturated brine is required to drill through salt formations where a lower density fluid is desired. Examples of these fluids are those containing lubricant or refined oil including Diesel. A lubricant is intended to reduce the metal to metal and metal to rock friction during drilling operations. The use of oil in the fluid reduces the density of the fluid below the density of the external phase. Surfactants with a hydrophilic-lipophilic balance (HLB) greater than 8 are used to stabilize these emulsions. Materials used in these fluids need to be water dispersible or soluble. Invert emulsions, commonly referred to

as oil-based muds, contain a base oil as the external phase, and utilize brine as the internal phase. The materials used in these fluids need to be oil dispersible or soluble. The properties of both types of fluids should remove cuttings from the well-bore, cool and lubricate the bit and drilling assembly, stabilize the formation, and minimize fluid lost to the formation.

Direct emulsions are stabilized by adjusting the HLB of the surfactant or surfactant package to match the internal and external phases found in the fluid. This is done by changing the HLB of the surfactant package from one value to another value in a regular interval, for example, using packages with HLB's of 6, 7, 8, 9, and 10. The package that shows the most stable emulsion is the correct package to use. They are further stabilized by using rheology modifiers, such as xanthan gum, to reduce the ability of the emulsion droplets to coalesce or the addition of solid particles that act at the interface with the surfactant package.

Invert emulsions can be more difficult to stabilize because the range of HLB's used to make these fluids are from 3 to 6 and there are options available for rheology modification (Błaż, 2021). Surfactant concentration, addition of colloidal particles, and the application of shear are available options for increasing stability in these fluids (Van Zantan, 2012).

A structuring agent can be used to form a three-dimensional network around the internal phase droplets of emulsions, thus enhancing the interactions. This idea was also tested for emulsion stability using a diethanol amine modified dimer acid as the structuring agent in an invert emulsion and found to be effective at low concentration (Huang, 2018).

The stability of an invert emulsion fluid is measured by applying an increasing voltage across a gap between two electrodes to break down the emulsion. A more stable emulsion results in a higher voltage applied before breaking the emulsion in the gap (API, 2023).

In this paper, the authors will present a cationic colloidal particle which is soluble in the water phase of oil-based muds and interacts with multiple surfactant molecules. Data supporting this is also presented.

## Experimental

### Equipment and Procedure

Standard drilling fluid laboratory equipment was used including a balance accurate to two decimal places, an overhead mixer, a high shear mixer, an 8-speed viscometer, and an emulsion stability (ES) meter. Fluids were mixed using an overhead mixer for one hour and then sheared for five minutes at 6000-rpm using a square-holed emulsion screen. Fluid viscosities were measured using an 8-speed viscometer at 150 °F and the emulsion stabilities determined using an ES Meter at 150 °F. Fluids were then dynamically aged (HR) at 150 °F overnight. After cooling the fluids, they were then mixed for 10 minutes, and the viscosities and ES were determined at 150 °F. The fluids were then HR at 250 °F overnight, cooled, and mixed for 10 minutes before retesting the viscosity and ES data at 150 °F. The ES test for this study included measuring the ES at least three times and constraining the values to be

within 5% of each other; other measured values were rejected.

### Materials

Standard solid materials were used to make oil-based drilling fluids such as organophilic clay (OC), calcium hydroxide (lime), barite, and fluid loss control agent (FLCA). Standard Evaluation Base Clay (SEBC) was used in some 12 pound per gallon (ppg) fluids. Liquid materials included lab stock drilling fluid with 12.6 ppg density (LSDF), diesel, emulsifier, wetting agent (WA), and 25% calcium chloride brine (brine).

For the ES enhancing additive (ESEA), combinations of diatomaceous earth (DE), precipitated silica (PS), HT stable clay (HT), rod-like clay (RC), ultra-fine calcium carbonate (UFCC), organophilic rheology modifier (ORM), or cationic colloidal particles (CCP) were utilized. Reacted alkene (RA), modified bio-oil (MBO), modified fatty acid (MA), reacted lipid (RL), fatty acid (FA), or dimer alcohol (DA) were combined with the solid materials.

### Fluid Formulations

Fluid formulations are shown in **Tables 1** and **2** with units in barrels (bbl) or pounds per barrel (ppb). The formulation for the fresh built 12 ppg fluids with 70/30 oil to water ratio (OWR), shown in **Table 1**, was used for the bulk of the testing. The fluids shown in **Table 2** were used for additive refinement and confirmation testing. The 12 ppg fluids had a 70/30 OWR, the 14 ppg fluids had an 80/20 OWR, and the 16 ppg fluids had an 85/15 OWR. SEBC was added to the 12 ppg fluid containing LSDF to determine its impact on the ESEA performance.

**Table 1** Formulation for Fresh built 12 ppg Fluid

Material	Amount
Diesel, bbl	0.535
OC, ppb	6
FLCA, ppb	4
Lime, ppb	4
Emulsifier, ppb	9
WA, ppb	3
Brine, bbl	0.252
Barite, ppb	204.3
ESEA, ppb	6

**Table 2** Formulations for Fluids containing Field Fluid

Material	12 ppg	14 ppg	16 ppg
LSDF, bbl	0.2	0.2	0.2
Diesel, bbl	0.417	0.451	0.42
OC, ppb	4.8	4.8	4.8
FLCA, ppb	3.2	3.2	3.2
Lime, ppb	3.2	3.2	3.2
Emulsifier, ppb	7.2	6.4	4.8
WA, ppb	2.4	2.4	3.2
Brine, bbl	0.203	0.109	0.057
Barite, ppb	132.4	285.3	399.5
ESEA, ppb	6	5	4
SEBC, ppb	36		

## Results and Discussion

Initial testing, using the 12 ppg fluid in **Table 1**, focused on a combination of DE, RC, and CCP with additions of either RA, MBO or RL or blends of two. Two 12 ppg control fluids replaced the ESEA with 10 pounds per barrel (ppb) of UFCC. Results for the control fluids are shown in **Tables 3** and **4** while comparative results are presented in **Tables 5** and **6**. The Plastic Viscosities (PV) in centipoise (cP), the Yield Points (YP) in pounds per 100 ft<sup>2</sup> (lb/100 ft<sup>2</sup>), and Electrical Stabilities in Volts (V) are shown in the tables.

**Table 3** Control Fluid Properties after HR at 150 °F

Formulation	Control A	Control A-2
PV*	22	24
YP*	3	3
ES*	157	163

\*For units see text

**Table 4** Control Fluid Properties after HR at 250 °F

Formulation	Control A	Control A-2
PV	22	24
YP	6	4
ES	208	214

**Table 5** Fluid Properties with initial ESEA after HR @ 150 °F

Blend	A	B	C
PV	31	30	26
YP	16	8	7
ES	388	152	169

**Table 6** Fluid Properties with initial ESEA after HR @ 250 °F

Blend	A	B	C
PV	44	37	34
YP	21	12	10
ES	286	250	275

Looking at this initial data, it was clear that the initial ESEA formulations increased the ES of some of the fluids after aging. Blend A increased the ES particularly after aging at 150 °F. This effect was accompanied by an increase in both the PV and YP of the fluids with 2-5 times increase in YP after aging at 150 °F and 2-3 times increase in YP after aging at 250 °F. **Tables 7** and **8** show more of this trend and it was decided that the RC caused this effect, and it was removed from subsequent ESEA formulations. The use of combinations of liquid in the blends reduced the effectiveness for increasing the ES, but also reduced the effect on fluid rheology, compare data from Blend A and Blends D and E.

**Table 7** Fluid properties with blends after HR @ 150 °F

Blend	D	E
PV, cP	29	27
YP, lb/100ft <sup>2</sup>	8	9
ES, V	338	166

**Table 8** Fluid Properties with blends after HR @ 250 °F

Blend	D	E
PV, cP	42	39
YP, lb/100ft <sup>2</sup>	14	18
ES, V	253	250

The next series of ESEA used blends that reduced the amount of RC or replaced it with HT. Unfortunately, the fluids became thin and no longer supported the barite resulting in sag during the viscosity measurements after aging the fluids at 250 °F. Data is shown in **Tables 9** and **10** includes the low-shear yield point (LSYP) determined by using the equation  $2 \times 3 \text{RPM} - 6 \text{RPM}$  and the 10-minute gel (10 M Gel) in lb/100ft<sup>2</sup>. While two of these blends increased the ES dramatically after aging at 150 °F, they were also thick. After aging at 250 °F, all the fluids were thin with barite settling and the resulting ES's were like those measured previously.

**Table 9** Fluid Properties with ESEA Blends from Table 9 after HR @ 150 °F

Blend	F	G	H	I
PV	27	29	27	25
YP	5	18	9	16
LSYP	3	11	5	6
10 M Gel	5	11	7	9
ES	158	444	319	359

**Table 10** Fluid Properties with ESEA Blends from Table 9 After HR @ 250 °F

Blend	F	G	H	I
PV	33	38	35	33
YP	9	7	5	5
LSYP	1	0	0	1
10 M Gel	2	0	2	2
ES	248	285	233	251

Because of the thin fluids, a solid rheology modifier was added to the ESEA blends, and it was determined that PS more readily absorbed the liquid portion compared to DE. The fluid properties when using these different blends are shown in **Tables 11** through **13**. The rheologies of the fluids were more in line with the desired rheological properties. They still showed an increase in ES compared to the control fluid formulation. Blend M was further examined because it did exhibit a high ES value after aging even though it initially did not compare well with the other blends or the blank fluid in the fresh built 12 ppg fluid. **Figure 2** shows a chart of the ES values for comparison.

**Table 11** Initial ES for Fluids with Final ESEA Blends before aging

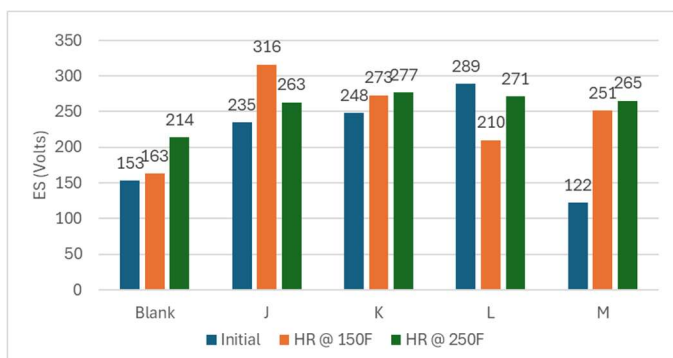
Blend	Blank	J	K	L	M
ES	153	235	248	289	122

**Table 12** Fluid Properties with Final ESEA Blends after HR @ 150 °F

Blend	Blank	J	K	L	M
PV	24	28	27	25	24
YP	3	7	5	9	7
LSYP	3	2	2	2	1
10 M Gel	4	6	6	6	6
ES	163	316	273	210	251

**Table 13** Fluid Properties with Final ESEA Blends after HR @ 250 °F

Blend	Blank	J	K	L	M
PV	24	36	28	36	33
YP	4	6	8	10	13
LSYP	1	2	0	0	1
10 M Gel	3	5	5	6	5
ES	214	263	277	271	265

**Figure 2** ES Values for 12 ppg Fluids with Final ESEA Blends

The final ESEA blends were added to the 12 ppg fluid formulation shown in **Table 2**. The resulting data are presented in **Tables 14** through **16**. Here the ES increase is not as expected and the ES's for all the fluids was lower than expected, possibly due to the addition of SEBC to the fluids. The fluid labeled as "Blank" did not contain an ESEA blend. The fluids containing the different ESEA blends maintained a higher ES after aging at 250 °F, see **Table 16** and **Figure 3**. The viscosity profiles of these fluids also more closely resemble that of the fluid without ESEA.

**Table 14** Initial ES for Fluids with Final ESEA Blends and SEBC before aging

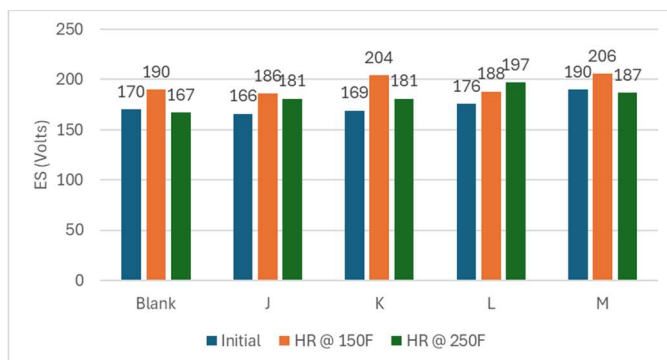
Blend	Blank	J	K	L	M
ES	170	166	169	176	190

**Table 15** Fluid Properties with Final ESEA Blends and SEBC after HR @ 150 °F

Blend	Blank	J	K	L	M
PV	37	41	45	46	49
YP	16	23	32	29	24
LSYP	6	10	15	13	14
10 M Gel	12	18	25	20	23
ES	190	186	204	188	206

**Table 16** Fluid Properties with Final ESEA Blends and SEBC after HR @ 250 °F

Blend	Blank	J	K	L	M
PV	38	43	49	50	42
YP	16	17	20	22	22
LSYP	5	6	9	8	7
10 M Gel	10	13	14	16	15
ES	167	181	181	197	187

**Figure 3** ES Values for 12 ppg Fluids with ESEA Blends and SEBC

Blends K, L, and M were also evaluated in the 14 and 16 ppg fluids shown in **Table 2**. Blend J was not tested because it did not result in an improved ES value compared to the blank until after aging at 250 °F. This was due to the drop in ES value for the Blank fluid after aging at 250 °F. Selected fluid properties are shown in **Tables 17** through **19** for the 14 ppg fluids and **Tables 22** through **24** for the 16 ppg fluids.

**Table 17** Initial ES Values for 14 ppg Fluids

Blend	Blank	K	L	M
ES	417	464	458	458

**Table 18** Fluid Properties for 14 ppg Fluids after HR @ 150 °F

Blend	Blank	K	L	M
PV	22	29	28	24
YP	7	13	9	12
LSYP	2	5	4	6
10 M Gel	6	9	8	8
ES	431	498	505	506

**Table 19** Fluid Properties for 14 ppg Fluids after HR @ 250 °F

Blend	Blank	K	L	M
PV	22	25	28	26
YP	6	14	9	11
LSYP	1	4	5	5
10 M Gel	1	7	6	7
ES	402	457	487	490

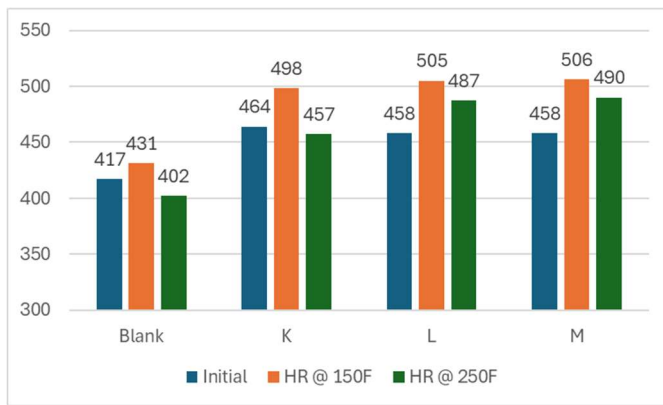


Figure 4 ES Values for 14 ppg Fluids

For the 14 ppg fluids, the fluids with the ESEA blends initially all have ES values that are about 10 % higher than the value for the blank fluid, see **Figure 4**. This increases to about 15% after aging at 150 °F. The rheology profiles of the fluids are similar after aging at 150 °F with the LSYP and 10-minute gel values being only slightly higher, but acceptable. After aging at 250 °F, the ES values for the fluids with ESEA blends are 14, 21, and 22 percent higher for Blends K, L, and M, respectively. The rheology profiles for the fluids with the blends are comparable and acceptable.

Table 20 Initial ES Values for 16 ppg Fluids

Blend	Blank	K	L	M
ES	445	534	542	527

Table 21 Fluid Properties for 16 ppg Fluids after HR @ 150 °F

Blend	Blank	K	L	M
PV	33	33	37	35
YP	16	27	18	23
LSYP	6	10	10	9
10 M Gel	10	14	13	13
ES	436	566	558	557

Table 22 Fluid Properties for 16 ppg Fluids after HR @ 250 °F

Blend	Blank	K	L	M
PV	36	33	36	32
YP	18	22	19	19
LSYP	5	8	7	8
10 M Gel	9	11	11	11
ES	442	530	598	564

Initially, the 16 ppg fluids with ESEA blends all have ES values about 20% higher than the Blank fluid. After aging at 150 °F, these fluids have ES values that are about 30% higher than that for the Blank fluid and all are more than 120 volts higher, **Tables 20 to 22**. In addition, the rheological profiles of the fluids are similar with YP values that are slightly higher. The fluids containing Blends L and M continue to have ES values that are more than 120 volts higher than that for the Blank fluid, see **Figure 5**. The rheological profiles are similar and acceptable for the fluids.

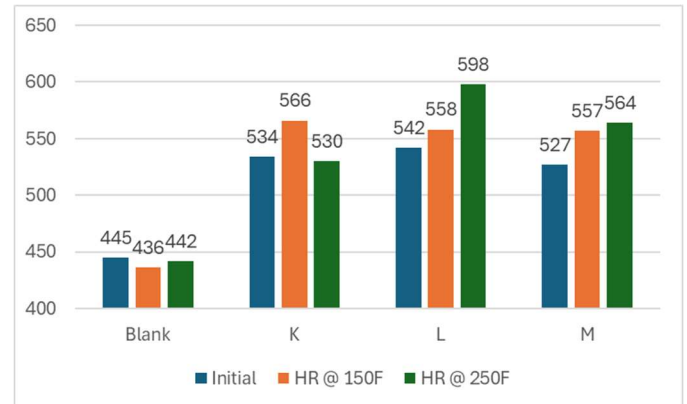


Figure 5 ES Values for 16 ppg Fluids

Because the ESEA blends show higher ES values after aging, the ability of Blend L to increase ES values with only shear were elucidated and the results are shown in **Figure 6**. A Blank fluid and a fluid containing Blend L were mixed for 1 hour and the ES values for each were measured at 120 °F. The fluids were then sheared for 5-minute increments and the ES values for each fluid were measured after each increment. After this, the properties of the fluids were determined, and the fluids aged at 250 °F. The properties before and after aging are presented in **Tables 23 and 24**. The fluid containing Blend L maintained a higher ES value with an acceptable rheological profile throughout this series of tests.

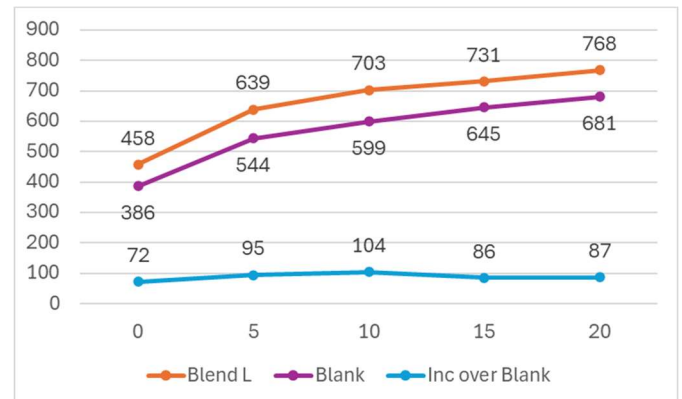


Figure 6 ES vs shear time for 16 ppg fluids without and with ESEA

Table 23 Fluid Properties for sheared fluids before HR @ 250 °F

Blend	Blank	L
PV	34	30
YP	17	29
LSYP	7	10
10 M Gel	12	15
ES	695	775

**Table 24** Fluid Properties for sheared fluids after HR @ 250 °F

Blend	Blank	L
PV	32	29
YP	15	22
LSYP	6	9
10 M Gel	9	11
ES	603	687

## Conclusions

This work shows that a blend of materials can be put together that enhances the Electrical Stability of oil-based muds even before shear is applied. This effect is improved with shear and is important for fresh built fluids before they are shipped from a mud plant. The ESEA blends contribute to the interface of the fluid emulsion, the rheology of the external phase, and the composition of the internal phase.

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