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New Surfactant Allows for Higher Internal Phase in Non-Aqueous Systems

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Abstract

A higher internal phase non-aqueous or invert system can now be achieved due to the development of a new surfactant. With this new advancement in surfactant chemistry, non-aqueous fluids with oil/water ratios as low as 20/80 can now be utilized in a broad range of applications including reservoir drill-in fluids, solids-free pills for placement in the open hole, screen-running fluids, and packer fluids. Non-aqueous carrier fluids can also be formulated for conventional alpha-beta water packing where the rheology profile approaches Newtonian.

The new surfactant now makes it possible for a higher internal aqueous phase to provide stable emulsions even at higher temperatures. These systems maintain manageable low-end rheological properties for drilling and completion applications. A variety of brines can be utilized for the internal phase allowing for higher densities to be attained with less solids concentration especially at a higher water ratio. The higher internal water phase means that less oil or synthetic fluid is needed in the drilling or completion system thus leading to potential cost savings in the make-up of the system and subsequent cleanup and disposal costs.

This paper will explain the chemistry of the new surfactant and the laboratory testing for a variety of new applications for this technology which include drilling, gravel packing and screen and liner running systems.

Introduction

Since the inception of oil-based drilling fluids, or “muds” (OBMs) many attempts have been made to develop high internal phase ratio (HIPR) invert OBMs.[1-3] The first recorded use of an oil-based emulsion mud was documented as August 1950[4] in the Los Angeles basin where 40% by volume water was emulsified in refined oil. Wright[4] documented the benefits of this novel drilling system as inert to common contaminants especially hydratable minerals, ability to compound to low density, use from well to well with low maintenance, storage without deterioration, etc. all of which are typically inclusive with drilling fluid selection today. However, these early systems lacked fluid loss control, viscosity, and suspension characteristics. These disadvantages are not surprising as these early systems were formulated as solids-free emulsions comprising 15% to 25% by volume water and weighed only 7.9 to 8.1 lb/gal.

In 1987, Daynes et al. proposed a 50/50 oil to water (O/W) ratio system and compared this system to the then conventional 75/25 O/W ratio in an effort to reduce toxicity, cost, and residual oil on cuttings (OCC).[1] The 50/50 O/W systems have intrinsically higher viscosity than 75/25 systems due to the higher dispersed water phase or micelles that emulate fine solids. As such, less viscosifier (gel or clay) was required. Subsequently Daynes et al. found that the clay concentration was reduced from treatment levels of 8 and 9 lb/bbl to ranges of 2 and 3 lb/bbl. However as a result of less oil and more water, additional emulsifier was required. In their study three emulsifiers were required to provide a stable emulsion.

Ezzat and Blatell[2] documented formulations at 40/60 to 50/50 O/W ratio. However these utilized zinc bromide and a polymerized surfactant that necessitated use at higher concentrations when the brine or water phase increased to 60 vol%. They focused on the potential for use as a packer fluid for high-temperature applications while providing one case history for a perforating system and only discussion and no data to support an application as a drilling system.

Nicora et al.[3] studied the potential for invert drilling systems with reduced oil volume to overcome solid concentrations of up to 40 vol% and reported optimization of the rheological properties. However, these authors only documented formulations at 60/40 and 50/50 O/W ratio. These subsequent formulations and systems did reduce the total solids to 18 vol%.

These examples of early studies (*i.e.*, 1954 thru 2001) documented clear objectives (*e.g.*, reduce concentration of solids, reduce OOC) and subsequently discussed inherent limitations (*i.e.*, increased concentration of emulsifiers, use of zinc bromide, and emulsion instability) brought about, in part, by the status quo with invert emulsion chemistry.

Invert emulsion systems rely predominantly on a class of chemistry referred to as amido-amines for formulating O/W ratios that typically range from 60/40 to 90/10, depending upon required density, hydraulics, rheology, logistics, solids and economics. Nicora et al.[3] reported a more traditional O/W range of 65/35 to 85/15 as this ratio in the field is often dictated by the concentration of solids from weighting agents, clay and formation which can reach 35 to 40 vol% of total solids. At this concentration, Nicora et al. reported unacceptable rheology.

In spite of many attempts to develop HIPR OBMs for O/W ratios with higher water (20/80 to 50/50) in the internal phase, the use or success has been very limited.[1-3] The primary focus in the development of invert systems has been on the choices of external phase, internal phase, weight materials and other solids content[3] while maintaining the drilling performance characteristics expected with OBM. Assessments of the aforementioned parameters have produced very limited success toward the development of a HIPR OBM. As such, during the past four decades very little has changed with either emulsifier chemistry or basic invert emulsion drilling fluid technology as the literature provides many examples where only the invert system optimization is prevalent.[5] Exceptions for the emulsifier chemistry are the advances of a reversible emulsifier used to formulate an invert emulsion drilling fluid system,[6-14] lime-free inverts[14-15] and negative alkalinity.[14]

The authors introduce this newly developed emulsifier for formulating invert emulsion systems with HIPR whereby the internal or discontinuous phase is greater than the documented 50 vol% water or brine. This emulsifier can potentially be utilized for formulating reservoir drill-in systems, sand screen running systems, and gravel pack systems. Potential advantages associated with the use of HIPR OBMs are improved performance, reduction of total solids, more efficient and shorter treatments to remove OOC, reduced environmental concerns and reduced volume of base fluid required.

Chemistry of a High Internal Phase Ratio Emulsifier

The chemistry and structure of emulsifiers used to produce inverts is typically inclusive to a class of surfactants known as amido-amines. However, it is possible to carefully tailor or optimize the functional properties of such an emulsifier for application in HIPR invert systems (*e.g.*, 50/50 to 20/80 O/W ratio). The hydrophilic-lipophilic balance (HLB) value plays an important role in designing and optimizing the functional characteristic of such an emulsifier. The modification of surfactant chemistry can alter the HLB value and thus alter the functional properties. This modification of surfactant chemistry can be achieved with either the hydrophilic group, also known as head, or lipophilic group, also known as tail. One approach is to optimize or adjust the correct lipophilic alkyl chain in the molecule while the hydrophilic group is developed through alkoxylation. The introduction of a carboxylic acid group in the molecule introduces a weak anionic character in the surfactant. Subsequently, this provides flexibility for developing and optimizing the performance characteristic of the surfactant.

Chemically, the new-tailored surfactant is slightly anionic without any hydrolysable functionality. The lack of hydrolysable moiety in the molecule differentiates this emulsifier from commonly utilized amido-amine surfactants. As such, this optimized surfactant can be used to produce relatively very stable emulsions using a variety of brines. These brines include: monovalent (*i.e.*, non-formate), divalent, seawater and formates. This relatively weak anionic/nonionic surfactant remains relatively unaffected by the chemistry of these brines as used in the internal or discontinuous phase and still allows formulating an invert system with any base (oil or synthetic fluid) as the continuous phase.

Laboratory Assessment of HIPR Fluids for Drilling

To assess the flexibility of this surfactant, a laboratory study was undertaken which included various brine types, O/W ratios and subjecting the test fluids to temperature. First, three different 30/70 O/W ratio HIPR fluids were formulated for relative comparison as a drilling system using an arbitrary final density of 10.0 lb/gal. The internal phase included the use of calcium chloride, calcium bromide and potassium formate brines (**Table 1**). The concentrations of the wetting agent, lime, barite, as well as the HIPR emulsifier remained constant for all of these formulations.

These fluids were heat aged at 150 and 300°F for 16 hours. The rheological and other selected properties are listed in **Table 2** and measured at 120°F. This data suggests stable rheology, especially at the low end, as well as no indication of progressive gels under these conditions regardless of the brine type. With respect to brine type, the calcium chloride and potassium formate exhibited increased viscosity with the elevated aging temperature. However this viscosity in combination with the lack of progressive gels is conducive to a drilling system that provides effective hole cleaning as well as effective hydraulics.

Next, various fluids were formulated with O/W ratios that varied from 50/50 to 30/70 (**Table 3**). Calcium chloride was arbitrarily selected for use as the internal phase. These HIPR formulations were heat aged at 150°F for 16 hours and the fluid properties were again measured after the heat aging cycle. Only the 30/70 O/W ratio formulation was heat aged at 300°F for 16 hours. Again, the rheology was measured at 120°F to facilitate comparison. The subsequent properties are shown in **Table 4**.

This data shows increasing viscosity and, as expected, this increase corresponds with the increase in the water or brine fraction. This is due to the increase in micelles (*i.e.*, emulsified microscopic droplets of brine) that behave or function as solids thus contributing to and elevating the viscosity. The viscosity exhibited at these O/W ratios is conducive for providing effective hole cleaning as well as hydraulics. The absence of progressive gels is also conducive and is indicative of the ability to break circulation with little to no unanticipated increase in required pump pressure. In addition, the HIPR fluid at 30/70 O/W ratio was stable to 300°F and the subsequent rheological properties are manageable and again conducive for hole cleaning and provided good hydraulics.

For comparison, the rheological data (600- through 3-rpm readings) was then plotted as the natural log of viscosity (cP) versus the natural log of the shear rate (**Figure 1**). This chart included the previous four HIPR fluids plus three invert field systems of similar density from selected wells/hole sections with O/W ratios of 60/40, 70/30, and 80/20. Note the relatively similar slopes with the exception of the 10.1-lb/gal 70/30 field mud. These laboratory-prepared HIPR fluids at

30/70 O/W ratio exhibit similar viscosity at all shear rates and compare well to field invert systems used for drilling intermediate as well as high-angle wellbores. The increase in the brine fraction does not yield rheology or properties that would warrant eliminating these fluids from field use.

Finally as an assessment of relative fluid loss with the use of the HIPR emulsifier, two 50/50 O/W OBM and two water-based systems were formulated to a density of 12.0 lb/gal. The invert systems utilized a paraffin base fluid and required 190 lb/bbl of bridging solids using NaBr as an internal phase. The emulsifier and clay content were varied to minimize fluid loss. The two water-based systems used NaBr as a base brine and 75 lb/bbl bridging solids. The treatment level for the fluid loss additive was also optimized for fluid loss. As these were formulated for use as a reservoir drill-in fluid, all bridging material was calcium carbonate. The HIPR fluid was formulated to an O/W ratio of 30/70 using potassium formate as the internal phase. This blend required 95 lb/bbl of bridging solids.

All five systems were blended, aged for 16 hours with 2 vol% blend of silica flour (50 wt%) and OCMA (50wt%). HTHP fluid loss tests were then performed using a FAO-05 aloxite disks at 250°F with 500-psi differential pressure. The data is shown in **Table 5**. The 30/70 O/W system, as formulated, exhibits a higher spurt, however the 30-minute cumulative fluid loss is comparable with the two 50/50 O/W inverts (5.9 mL versus 4.2 and 5.9 mL) and was less than the two water-based systems (7.0 and 9.5 mL).

The next section explores the use of this emulsifier for formulating an invert gravel packing system.

Water-Packing Systems

The HIPR emulsifiers' unique chemistry allows for use as an invert water-pack carrier system, especially where alpha-beta packing is desired as the subsequent rheology approaches a Newtonian regime while maintaining low viscosity.[16-17] The ability to formulate an invert water-pack system provides advantages over traditional aqueous or water-based systems by reducing risks associated with: brine-sensitive shale rock, brine-sensitive sands, excessive ECD, and even the potential to reduce hydraulics without the addition of a friction reducer.[18] Kelkar et al. warned that "high internal phase fractions would yield high densities at the expense of very high viscosity and low internal phase fractions would yield acceptable viscosity at the expense of reduced fluid densities."[19] This new HIPR emulsifier overcomes this dichotomy as Newtonian-like properties are achievable in either of the aforementioned subsets.

Laboratory Assessment of HIPR Fluids for Water-Packing

A simple laboratory assessment was undertaken to assess the ability to achieve Newtonian properties when formulating an invert system with relatively high internal aqueous phase. For this assessment a low-toxicity mineral oil was used to achieve an arbitrary density of 9.0 lb/gal in a 50/50 O/W ratio HIPR fluid. Several fluids were prepared using two different amido-amines at arbitrary concentrations in an attempt to achieve a Newtonian regime at a 50/50 O/W ratio. The invert fluids were prepared by first blending the emulsifier into the selected base fluid followed with the addition of lime. The internal phase, $CaCl_2$ brine, was added last. Due to the relatively high water ratio, the systems were vigorously stirred at the highest rate attainable while minimizing entrainment of air to ensure complete dispersion and to ensure emulsion stability and to mitigate inconsistency with respect to preparation. The HIPR formulation is shown in **Table 6** and requires only four products as a wetting agent is optional and was not utilized in this phase. After mixing, the rheology was measured using a standard Fann 35 at 120°F. In addition, the low-shear-rate viscosity (LSRV) and the electrical stability (ES) were measured. The initial properties for the HIPR fluid are shown in **Table 7**.

The ES and LSRV laboratory measurements were acquired to assess low-end viscosity and emulsion stability. The ES was measured to confirm that an invert emulsion was apparent. As it was surmised that a lower viscosity would promote the ability to effectively deposit the desired alpha and beta waves/dunes, the measurement and subsequent deficient LSRV would confirm this aspect. Solids suspension of biopolymer fluids has been correlated directly to LSRV measurements at 0.06 sec^{-1} (0.3 rpm).[20] Thus, this method was employed for these invert fluids. Elevated viscosity, especially the low-end, is indicative of the ability to suspend particles (e.g., gravel) thus mitigating the ability to effectively deposit especially when the velocity of the packing fluid is reduced. Solids suspension of biopolymer fluids has been correlated directly to LSRV measurements at 0.06 sec^{-1} (0.3 rpm).[20]

The first assessment (**Figure 2**) compares the ES values. The ES was measured at four temperatures ranging from 40 to 150°F. The two fluids formulated with 1) an amido-amine plus a surfactant and 2) the HIPR emulsifier exhibited more consistent ES across all temperatures as well as the ability to manage the ES value with a change in concentration. From this data, the fluids emulsified with an amido-amine type emulsifier provided relatively greater ES values across all temperatures. Even with decreased concentration, this emulsifier provided elevated ES values. For these fluids, laboratory observations showed a low ES was indicative of less viscosity as would be expected when solids are not introduced.

To further assess the ability to create a HIPR water packing fluid with O/W ratio of 50/50 while mitigating viscosity, these fluids were evaluated using a Brookfield viscometer. **Figure 3** shows a comparison of the LSRV values at 0.3 rpm. These values show that the amido-amine and amido-amine plus surfactant generated more viscosity at this shear rate than the HIPR emulsifier, almost 9.5 to 11 times more. It was surmised after reviewing these results that the combination of low LSRV and stable ES were conducive for further evaluation.

The next phase included a wettability evaluation. This test was performed to confirm that a system formulated with the HIPR emulsifier would continue to function as an emulsion thus mitigating the relatively large water or brine fraction's contact with either water-sensitive shale or the target formation rock. **Figure 4** shows a simple wettability test before and after adding 1.0-lb/gal proppant to a fluid prepared as documented above. This fluid was prepared using 7 lb/bbl of HIPR emulsifier. After blending and aging for 16 hours at 150°F, a small portion or volume was extracted using a plastic pipette and then placed into a beaker of tap water. A stable emulsion or invert upon contact with water will yield a sphere as it seeks to attain the smallest possible surface area.[21] In contrast, if the emulsion or invert exhibits a cloudy dispersion or stingy texture, this indicates poor or unstable emulsified fluid. The fluid prepared with the HIPR emulsifier exhibited sphere-like droplets (**Figure 4** – left side) and is indicative of a stable emulsion with a measured ES of approximately 40 to 80 volts (**Figure 2**).

It is surmised that this fluid would maintain a stable emulsion in a wellbore of similar bottomhole temperature while providing an oil-wet environment as opposed to water-wetting, and potentially damaging the target reservoir rock or shale rock. The authors surmise that the HIPR emulsifier's ability oil-wet as well as maintaining a stable ES in combination with low viscosity and LSRV would provide an alternative for water-packing where shale rock is prevalent, thus lowering the risk for premature sand-out.

To further assess the stability of a fluid formulated with the HIPR emulsifier, static aging tests were performed. Again the fluids were compared to the conventional amido-amine plus surfactant at 4 and 7-lb/bbl concentrations. The before and after-static-aging results are show in **Figure 5**. All samples were statically aged at three different temperatures to simulate a wellbore environment. Before heat aging, all fluids exhibited a stable invert emulsion, as expected, with no separation apparent. After static aging, the fluid formulated with an amido amine type emulsifier showed relatively more syneresis or phase separation, visually up to 15 vol%. In the fluids formulated with an HIPR emulsifier, no separation is apparent. However, the syneresis was readily resolved for the amido-amine fluid with simple agitation as would be typical for any properly formulated invert. The ability of the HIPR emulsifier to mitigate syneresis will prove beneficial for pre-bending and even mitigating separation in the wellbore during static conditions.

As a final comparison, the rheology was measured at 120°F for the previous HIPR fluids plus an invert system with 4-lb/bbl amido-amine plus surfactant. This data was again plotted as the natural log of viscosity (cP) versus the natural log of the shear rate for comparison (**Figure 6**). In addition, several conventional systems were included for reference. Note the HIPR fluids formulated with 50/50 and 40/60 O/W ratios, exhibited relatively similar slopes. These two fluids exhibited lower viscosity than a conventional amido amine fluid. The slopes of the HIPR fluids exhibited a flatter profile versus an HEC slicked system, thus approaching a more Newtonian regime.

Laboratory Assessment of HIPR Fluid for a Screen/Liner Running System

Another potential application of the HIPR emulsifier is the ability to formulate solids-free systems for running sand control screens and liners. In many instances these require a density equal to or greater than the reservoir drill-in fluid used to drill the openhole section through the target reservoir. Often, the risk associated with plugging the selected sand control screen necessitates using solids-free systems. The alternatives include conditioning the used drilling fluid, formulating a new solids-laden system (*i.e.*, using smaller sized weighing agents) or where a higher density solids-free system is required using relatively expensive brines such as cesium formate to attain the required density. Thus, the ability to formulate an invert system to O/W ratios of 50/50 and less provide advantages, especially for completions where oil-based systems are required due to the aforementioned discussion.

For this assessment, laboratory tests were conducted using the HIPR emulsifier to formulate fluids to a density of 10.5 lb/gal. Three different completion brines – 11.8-lb/gal sodium bromide, 11.5-lb/gal calcium chloride, and 11.7-lb/gal potassium formate – were incorporated to assess their compatibility with the HIPR emulsifier. Thus, the O/W ratios varied from 23/77 to 34/66 to attain the target density. These systems were blended in the same manner as described before. The rheology is shown in **Table 8** and was measured at a temperature of 85°F to assess surface conditions. From this data, the use of these brines parallels the rheology measured in **Table 2**. These results indicate that potassium formate brine requires less concentration of the HIPR emulsifier. The fluids formulated with $CaCl_2$ and NaBr exhibit rheology conducive for displacing/running a sand control screen or liner.

Conclusions

A new emulsifier provides the ability to formulate high internal phase ratio (HIPR) systems whereby the internal phase is greater than the typical 60/40 to 90/10 O/W ratio. These systems demonstrate emulsion stability and oil-wetting characteristics even when the brine fraction exceeds 50% by volume. In addition, the systems that were formulated demonstrated comparable rheology and selected properties with typical invert emulsions.

Systems formulated for water packing exhibit low viscosity and mitigate syneresis and potentially provide an alternative for conventional water-packing.

Systems formulated as a screen running fluid provide the potential for greater density where inverts are desired.

The systems formulated for drilling application could provide cost savings and mitigate environmental issues.

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Table 1 – Formulations of a 10.0-lb/gal HIPR Fluid at 30/70 O/W Ratio Using Selected Brines

Products	HIPR Fluids		
	1	2	3
IO C_{16-18}	72	72	72
$CaCl_2$ Brine	287		
K-Formate Brine		287	
$CaBr_2$ Brine			287
Wetting Agent	2	2	2
HIPR Emulsifier	9	9	9
Lime	2	2	2
API Barite	47	47	47

All values in lb/bbl

Table 2 – 10.0-lb/gal HIPR Fluids
Heat-Aged Properties after 150°F and 300°F, Rheology Measured at 120°F

HIPR Fluids	#1 30/70 O/W		#2 30/70 O/W		#3 30/70 O/W	
Prop/Aged-Temp	**150°F**	**300°F**	**150°F**	**300°F**	**150°F**	**300°F**
600-rpm Reading	120	139	156	185	124	132
300-rpm Reading	75	88	99	120	77	84
200-rpm Reading	57	68	74	94	57	69
100-rpm Reading	35	42	47	60	35	41
6-rpm Reading	8	15	11	16	8	9
3-rpm Reading	6	12	10	14	7	7
10-sec gel (lb/100 ft^2)	7	8	10	10	7	7
10-min gel (lb/100 ft^2)	7	8	11	12	8	7
PV (cP)	45	51	57	65	47	48
YP (lb/100 ft^2)	30	37	42	55	30	36
ES (v)	198	152	148	160	207	120

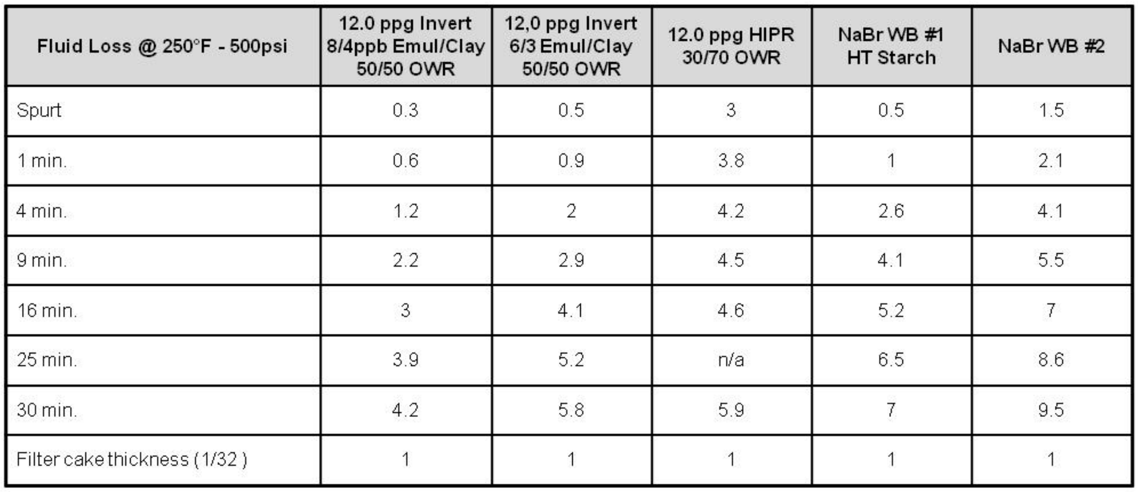
Table 3 - 10.0-lb/gal HIPR Fluids Formulated with Different O/W Ratios

Products/HIPR Fluids	50/50 O/W	40/60 O/W	30/70 O/W
IO $_{C16-C18}$	119	96	72
$CaCl_2$	53	64	76
HIPR Emulsifier	9	9	9
Wetting Agent	2	2	2
Lime	2	2	2
Water	150	181	212
API Barite	85	66	47
All values in lb/bbl			

Table 4 - 10.0 ppg HIPR Fluids Heat-aged Properties after 150°F and 300°F, Rheology Measured at 120°F

	150°F	**150°F**	**150°F**	**300°F**
Readings / O/W Ratio	**50/50**	**40/60**	**30/70**	**30/70**
600-rpm Reading	52	91	172	150
300-rpm Reading	28	53	103	89
200-rpm Reading	19	36	75	64
100-rpm Reading	11	20	46	38
6-rpm Reading	3	5	9	7
3-rpm Reading	2	4	7	6
10-sec Gel (lb/100 ft^2)	3	5	7	6
10-min Gel(lb/100 ft^2)	4	6	8	7
ES (v)	232	207	130	220
PV/YP (cP / lb/100 ft^2)	24/4	38/15	69/34	61/28

Table 5 – Comparison of HTHP Fluid Loss Data at 250°F Using 500-psi Differential Pressure



Fluid Loss @ 250°F - 500psi	12.0 ppg Invert 8/4ppb Emul/Clay 50/50 OWR	12,0 ppg Invert 6/3 Emul/Clay 50/50 OWR	12.0 ppg HIPR 30/70 OWR	NaBr WB #1 HT Starch	NaBr WB #2
Spurt	0.3	0.5	3	0.5	1.5
1 min.	0.6	0.9	3.8	1	2.1
4 min.	1.2	2	4.2	2.6	4.1
9 min.	2.2	2.9	4.5	4.1	5.5
16 min.	3	4.1	4.6	5.2	7
25 min.	3.9	5.2	n/a	6.5	8.6
30 min.	4.2	5.8	5.9	7	9.5
Filter cake thickness (1/32)	1	1	1	1	1

Table 6 – 9.0-lb/gal HIPR Formulation for a Water-Pack Fluid

Products	lb/bbl
Base Oil	128
HIPR Emulsifier	8-10
Lime	2-4
$CaCl_2$ Brine	239
Wetting Agent (optional)	0-1

Table 7 - Properties of a 9.0-lb/gal HIPR Water-Pack Fluid

Property	Value
O/W Ratio	50/50
ES (V)	50-150
PV/YP (cP / lb/100 ft^2)	16/40 to 5/15
6/3-rpm Readings	2/3
Density	9.0 lb/gal (SG of 1.08)
n/K value (Herschel Buckley)	0.8/0.1-0.2

Table 8 - 10.5-lb/gal HIPR Screen Running Fluids Rheology Measured at 120°F

Temperature	85°F	85°F	85°F
Brine Type	**$CaCl_2$**	**NaBr**	**KCOOH**
O/W Ratio	**23/77**	**29/71**	**34/66**
600-rpm Reading	245	205	300+
300-rpm Reading	152	132	240
200-rpm Reading	116	102	195
100-rpm Reading	72	67	140
6-rpm Reading	10	16	49
3-rpm Reading	6	12	42
10-sec Gel (lb/100 ft^2)	7	12	39
10-min Gel (lb/100 ft^2)	6	11	39
PV (cP)	93	73	n/a
YP (lb/100 ft^2)	59	59	n/a

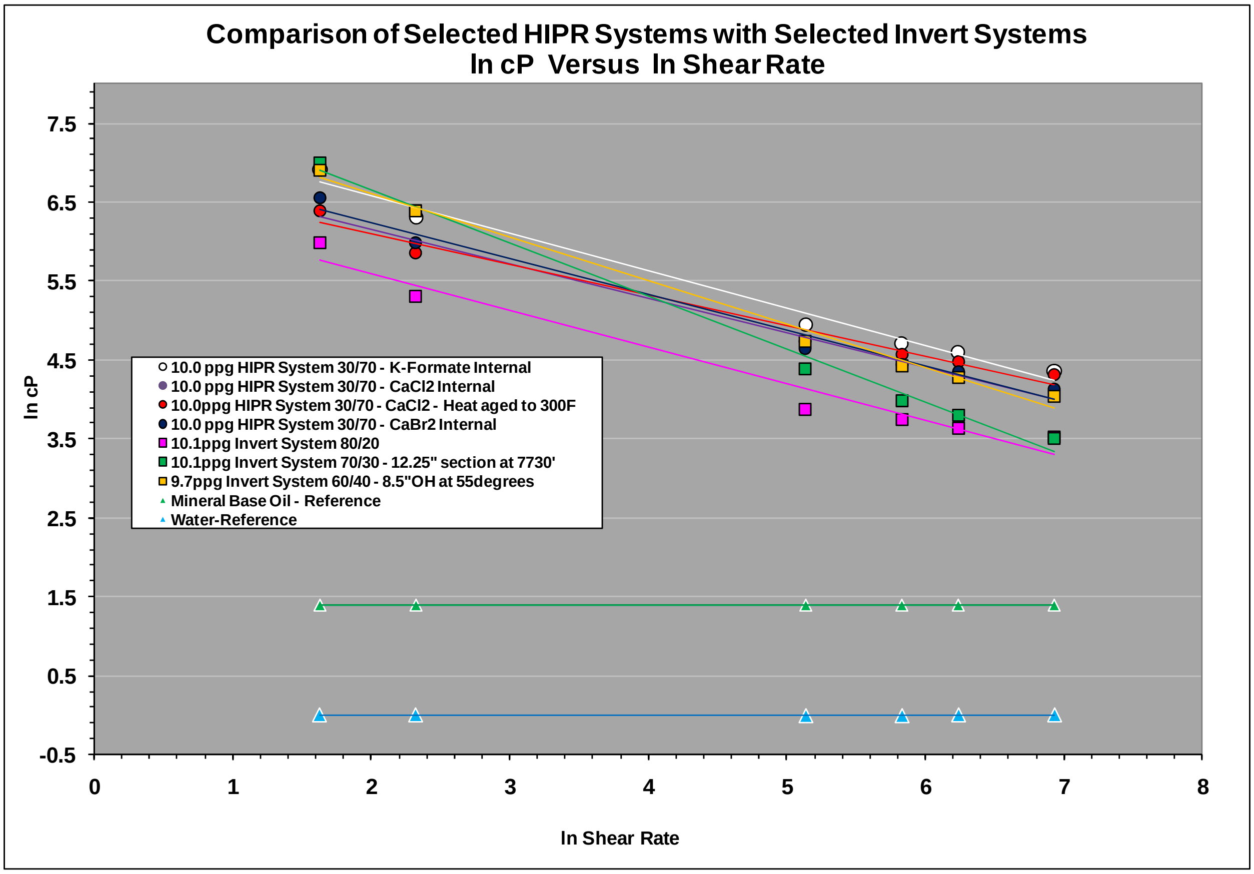


Figure 1. – Comparison of the HIPR emulsified fluids at 30/70 O/W ratio versus three field muds with O/W ratios of 80/20, 70/30, and 60/40.

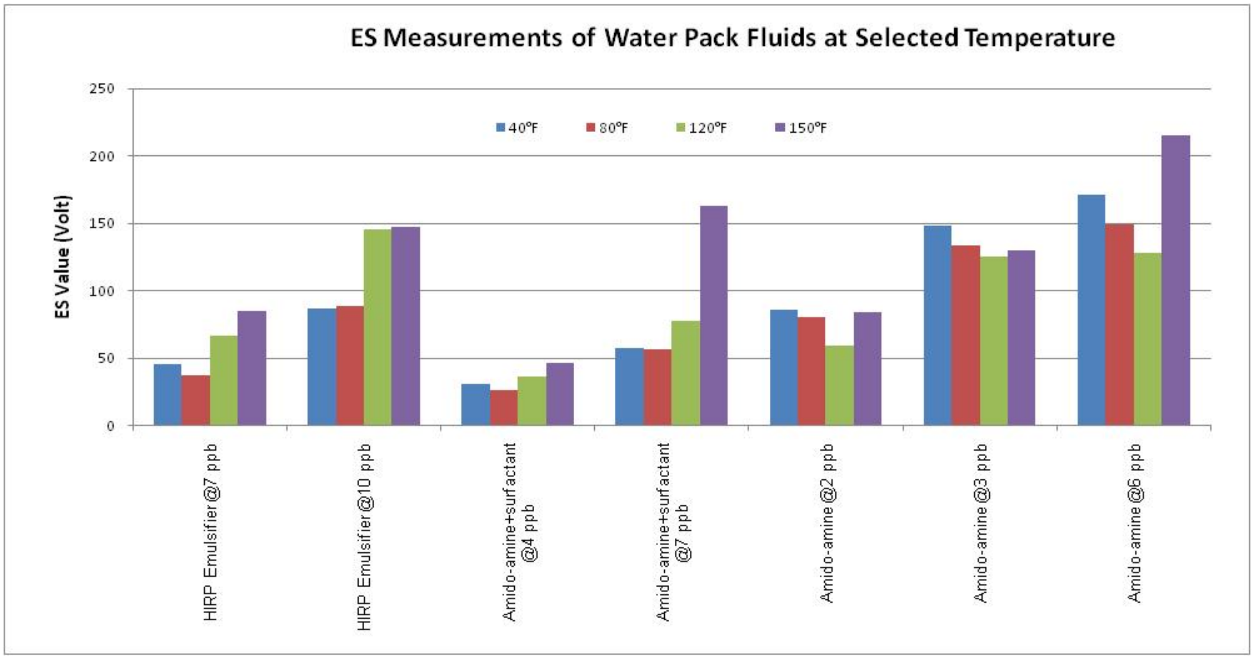


Figure 2 - Effect of ES for water-pack fluids using different types of emulsifiers measured at elevated temperature.

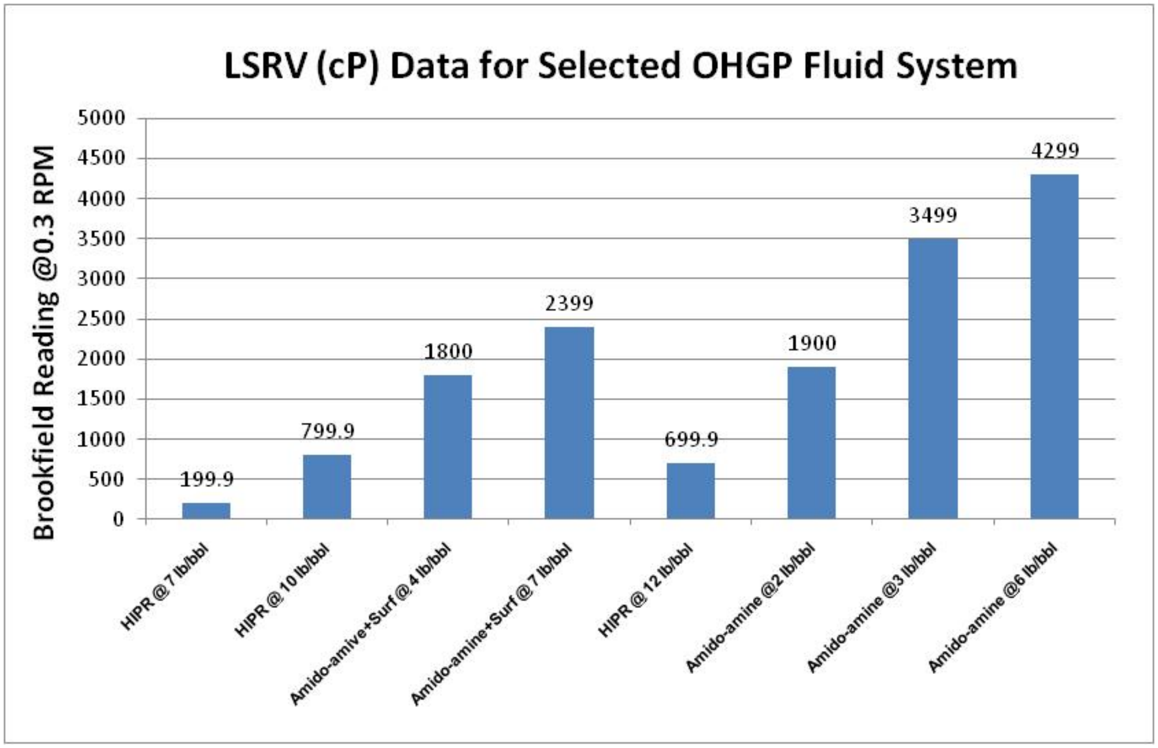


Figure 3 - Effect of LSRV using selected types of surfactants for water-packing fluids versus HIPR emulsifier.

Wettability of HIRP Fluid before adding proppant	Wettability of HIRP Fluid after adding proppant (bottom view)	Wettability of HIRP Fluid after adding proppant (top view)
		

Figure 4 – Digital images showing the 9.0-lb/gal water-packing fluid with 7-lb/bbl HIPR emulsifier in tap water. This simple jar evaluation was performed to document the tendency to remain oil-wet. Note that this system forms beads or droplets which is indicative of an oil-wet texture as opposed to a cloudy, dispersive or string-like texture. The latter is indicative of phase separation or an ineffective emulsifier.

	Before Static Aging	After Static Aging (40°F, 120°F and 150°F) for 16 hours
9.0 ppg water-packing fluid with 7 ppb HIRP Emulsifier	 **Stable and homogeneous emulsion after mixing**	 **Stable Emulsion. No separation. Minor syneresis at elevated temperature.**
9.0 ppg water packing fluid with 4 ppb Amido-amine + surfactant	 **Stable and homogeneous emulsion after mixing**	 **Stable Emulsion. No separation. Minor syneresis at elevated temperature.**
9.0 ppg water packing fluid with 7 ppb Amido-amine + surfactant	 **Stable and homogeneous emulsion after mixing**	 **Stable emulsion. This syneresis will revert with just agitation**

Figure 5 – Comparison of amido-amine and HIPR emulsifiers used to formulate a 9.0-lb/gal water-packing fluid.

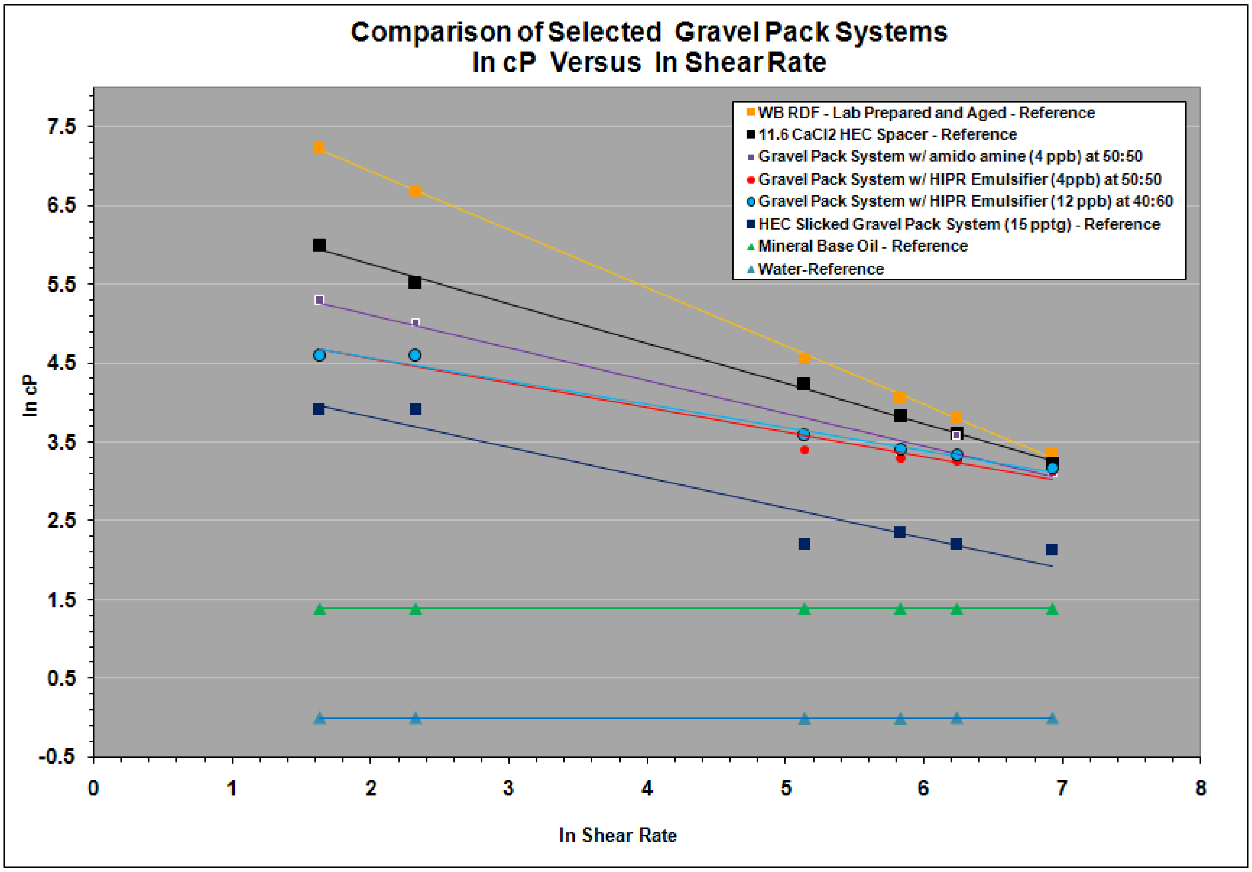


Figure 6 – Comparison of water-pack fluids formulated using HIPR and amido-amine emulsifiers versus conventional systems.