IMPLEMENTATION OF A COMBINED LDHI AND PARAFFIN INHIBITOR PROGRAM PROVIDING COMPLETE FLOW ASSURANCE MANAGEMENT

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ABSTRACT

The example is from a subsea infrastructure that was experiencing flow assurance challenges due to both hydrate and paraffin formation. The condensate had a paraffin content of 14.5 wt%. Paraffin control chemicals were being deployed with limited success.

This paper gives a detailed description of the flow assurance root cause failure analysis in a Gulf of Mexico production system that was experiencing severe hydrate and paraffin failure. Details are given on the experimental work performed to develop new products, as well as results of the field applications. The paper summarizes the implementation and ongoing monitoring of this program in the field and provides lessons learned.

Details on the cost savings created in reduced operations and chemical overhead for the operator are given, along with the value savings due to no lost production since blow downs were no longer required.

INTRODUCTION

Increases in subsea developments are a Gulf of Mexico phenomenon now occurring on a global scale. This has led to increases in water depth which also goes hand in hand with complex challenges in flow assurance. There are many flow assurance challenges pertaining to subsea developments, but two particularly challenging aspects of this are hydrate and paraffin blockages which cause major production losses (Luiz *et al.*, 2003).

Hydrates

Gas hydrates were first characterized in the early 18th century by Sir Humphrey Davy (Davy, 1811) and were described when a methane-rich gas combined with water under suitable pressure and temperature conditions. Hydrates form clathrate (cage-like) structures that have two common forms – Type I and Type II (Sloan, 2000) and form most commonly with low molecular weight gas compounds such as methane, ethane and propane. Other gaseous species such as carbon dioxide, hydrogen sulfide and nitrogen can also promote hydrate formation.

Hydrate formations plug flowlines, pipelines and valves, and removal is dangerous and costly. Formation can be catastrophic and can form during steady state flow though abnormal operations such as start-up and shut-in where temperatures tend to be lower and pressure differentials higher (Wylde, 2010). A rare photograph of hydrates removed by a pig in a subsea flowline has been displayed in Figure 1.

Hydrates are most commonly controlled using thermodynamic inhibitors such as methanol and glycols. These chemicals lower the freezing point of an aqueous solution and can also be recovered from the process stream. They do, however, often require very high concentrations (many percent) depending on water production rate and the degree of subcooling. Subcooling can be defined as the difference between the hydrate dissociation temperature, the lowest system temperature and highest system pressure. (Arjmandi *et al.*, 2005).

A new generation of low dose hydrate inhibitor (LDHI) was developed in order to address the shortcomings of thermodynamic inhibitors. There are two types currently available: kinetic hydrate inhibitors (KHI) and anti-agglomerates (AA). KHIs tend to be used for continuous injection, steady state production environments that have lower degrees of subcooling, whereas AAs are used for high subcooling transient operations such as start-up and shut-down events (Phillips *et al.*, 1997).

Paraffins

Crude oils naturally contain paraffin and wax compounds. These can be defined as aliphatic hydrocarbon molecules with the empirical formula C_nH_{2n+2} (n is most commonly >18). Paraffin can exist in three forms:

1. Macrocrystalline: Dominated by straight chained n-alkanes and are typically found in subsea and export pipelines.
2. Microcrystalline: A mixture of cycloalkanes and branched alkanes, often associated with asphaltenes and other solid deposits. These tend to be encountered in tank bottoms as a sludge-like deposit.
3. Semi-microcrystalline: These intermediate for of macro- and microcrystalline paraffins.

When paraffin precipitates, the viscosity of the crude oil increases creating higher drag and pressures. Deposition on the walls of tubulars, flowlines and pipelines can increase surface roughness thus creating a higher differential pressure. Physical restriction of the pipeline can also occur, creating less flow or soaring energy costs to maintain flow. The solubility of paraffin in crude oil goes down due to decreasing temperature. Minor effects that lower paraffin solubility in crude include pressure, asphaltene content, light end alkane removal and the presence of foreign matter. Paraffin deposition occurs via molecular diffusion, typically movement of paraffin molecules to a colder region, e.g. a pipeline wall. Shear dispersion and gravity settling can also have a minor influence (Becker, 1997).

There are two categories of paraffin control:

1. Mechanical methods: Installed as part of the design phase of a project and include insulation, dilution of the paraffin content via mixing of crude streams, hot oiling and pipeline pigging.
2. Chemical control: Use of paraffin solvents, paraffin crystal modifiers, dispersants and pour point depressants.

The best paraffin solvents tend to be aliphatic hydrocarbons. The lower the melting point of paraffin, the greater the solubility in a given solvent. The longer the chain length of a solvent, the higher its paraffin solvency due to lower polarity. Macrocrystalline paraffin has a low solubility in polar solvents whereas microcrystalline paraffin is soluble to an appreciable extent in non-polar solvents (Poole *et al.*, 2008). Paraffin dispersants function through interaction with the paraffin crystal surface causing repulsion of the paraffin particles, and are essentially water wetting agents (Jennings and Newberry, 2008). Typical chemistries include olefin sulfonates, polyalkoxylates and amine ethoxylates. Injection rates can vary from 50 to 500 ppm/v and products are very system specific.

Paraffin inhibitors are classed as either paraffin crystal modifiers or pour point depressants (PPDs). Crystal modifiers rely on co-precipitation with paraffins, and therefore must be injected above the cloud point of a crude oil. This helps to explain why they are system specific. A high efficacy crystal modifier should contain structural sequences capable of co-crystallization with paraffin (dos Santos, 1997). Typical chemistries include ethylene-vinyl acetate copolymers, acrylate polymers / copolymers, maleic anhydrite copolymers and esters. PPDs have been proposed to operate in the same manner as crystal modifiers via nucleation and co-precipitation; therefore, it is not surprising that they are chemically similar. Pour point depressants have commonly been seen functioning as crystal modifiers but the opposite is not as common.

CASE HISTORY BACKGROUND

A simplified schematic of the field layout has been shown in Figure 2. The basic field architecture comprises three satellite dry tree wells (Satellite #1, #2 and #4) that are flowed via relatively shallow subsea flowlines to a host processing production facility where production is commingled with platform wells. Production data of the producing wells has been given in Table 1, and the relevant process trends in Table 2. The incumbent chemical treatment comprised injection of 80 qts/day of a thermodynamic hydrate inhibitor at Satellite 1, 100qts/day of paraffin solvent at Satellite 4 and an additional 80 qts/day of paraffin solvent at the production facility.

There were two main flow assurance challenges, even with the incumbent chemical treatment:

1. Hydrate plugging in Satellite #1 subsea flowline. Operations had to depressurize the flowline daily for hydrate removal. It was observed that the blockage was occurring closer to the main platform than the Satellite because bleed down was faster on the platform side. This was even with injection of 6% of kinetic hydrate inhibitor (10 qts/bbl of water).
2. Precipitation of mixed paraffin and hydrates in Satellite #4 flowline. A photograph of the precipitate has been included in Figure 3. When sampled upstream of chemical injection, the fluids were frozen solid (sample temperature measured as 15°F); however, this is unrepresentative as significant Joule-Thompson cooling would have occurred on removing the sample from system. The total treatment rate of solvent in the system was 3.6% yet had little effect, as the solids were still isolated from the production separator on the main processing platform. It was also noted that there was a significant pressure drop across the choke on the Satellite #4 well, which caused a sharp temperature drop and was the likely root cause of paraffinic solid deposition along with some likely hydrate components.

The challenge was to perform flow assurance root cause failure analysis by designing a series of experiments to replicate the conditions offshore and then determine a suitable mitigation strategy that could be implemented in the field.

HYDRATE EXPERIMENTAL TESTING AND RESULTS

A hydrate evaluation was performed using MULTIFLASH modeling, complimented by subsequent autoclave tests to ensure the performance of the selected products. The paraffin evaluation included pour point experimentation, cold finger work, solvency tests and precipitation methods.

Once a chemical solution had been determined, further test work was performed to evaluate the foaming and emulsion tendencies. These are potentially caused by application of these products to ensure secondary issues did not occur on the host processing production facility.

Hydrate MULTIFLASH Modeling

This is a hydrate prediction code that uses multiphase equilibrium coupled with an equation of state activity coefficient incorporating transport property models. It is wholly accepted as an industry standard software package for hydrate modeling, and provides a quick and effective approach for evaluating hydrate subcooling and mitigation requirements.

The phase boundary diagrams derived from the results of hydrate modeling for Satellite #4 and Satellite #1 have been plotted in Figures 4 and 5, respectively. These plots show the hydrate dissociation and formation temperature and pressure conditions. To the right of the dissociation curve, hydrates are unlikely to form. To the left of the formation curve, hydrates are likely to form and the system can be stated as operating within the hydrate formation window. When the system is operating in-between the dissociation and formation curves, the system is termed meta-stable and hydrates may or may not form and largely depends on the thermodynamics and kinetics of the system.

It can be seen that under any of the current operating conditions, there is no hydrate risk for Satellite #4 well or the flowline. Even with the high pressure upstream of the choke, the temperature was also sufficiently high enough to be well outwith the hydrate formation zone. Moving further downstream past the choke, the system cools but the pressure also decreases keeping operation outside the hydrate formation zone. This substantiates the earlier conclusion that the ice formation observed during sampling fluids from upstream of the choke was caused by large scale JT cooling across the needle valve cooling, and is not occurring in the pipeline.

In contrast, however, the results for Satellite #1 show that as the fluids cool from the departing subsea flowline towards the host platform, the conditions move into the hydrate risk / formation zone. There is not a high degree of subcooling (maximum of 5°F subcooling) and therefore this should be easily controlled using the correct chemistry and is within the operating limits of a KHI.

Hydrate Autoclave Tests

Gas analyses for both Satellite #4 and Satellite #1 were provided by the operator and have been detailed in Table 3. Unfortunately, due to the strict time constraints placed on this project, there was insufficient time to run hydrate tests under the specific field conditions. Therefore, analogous testing performed previously was used instead. These hydrate inhibitor evaluations were conducted according to standard practices for the testing of KHI samples. Specifically, high pressure autoclaves containing deionized water (67 mL) and condensate (133 mL), were dosed with KHI and pressurized with a standard gas. Flow conditions were replicated by a magnetic stirrer (mixing rate 500 rpm). The test temperature was regulated by a digital re-circulating cooling bath. During the course of the tests, cell pressure and fluid temperature were monitored via digital pressure transducer and thermocouple outputs, respectively. Pressure and temperature readings were logged throughout the test.

The results from hydrate autoclave tests performed with a similar paraffinic condensate were used to select the candidate hydrate inhibitor for treating the Satellite #1 flowline. The pressure/temperature plots for these tests can be found in Figures 6 and 7, which are the blank and inhibited tests, respectively. The blank test shows immediate and catastrophic hydrate formation as the temperature falls beneath the hydrate formation temperature. This is manifested as the continuous pressure decline as gas is consumed into the clathrate structure of the hydrates. In the inhibited test, 2% of the KHI tested shows no hydrates formed over the entire 68-hour test period. The KHI was a relatively low-activity, classic chemistry that was blended with an alcohol and glycol matrix and had a synergistic alkoxylated glycol.

PARAFFIN EXPERIMENTAL TESTING AND RESULTS

Paraffin Control Products

The following products (along with the incumbent), were selected for testing based on previous inhibition experience in the same geographic area, as well as the properties of the field condensate:

INHIBITOR A – Blend of EVA and polyacrylate in hydrocarbon solvent
INHIBITOR B – Blend of EVA, polyacrylate and dispersant in hydrocarbon solvent
INHIBITOR C – Blend of EVA, polyacrylate and dispersant in hydrocarbon solvent
INCUMBENT – Aliphatic solvent blend

Condensate Sample Preparation and Fundamental Properties

Two condensate samples were used during this study. The first was a gallon of untreated condensate from Satellite #4 (sampled upstream of the choke) and 2 gallons of treated condensate (sampled from the production separator on the platform). All methods described below were performed on the untreated Satellite #4 sample with the exception of foam and emulsion tendency testing, where the treated sample was used due to consumption of the untreated sample in previous tests.

Prior to sub-sampling, the condensate was homogenized in a water bath at 160°F for 6 hours (with regular agitation) in order to dissolve any paraffin which may have crystallized.

The physical properties measured on the condensate samples relating to paraffin formation have been included in Table 4. The most significant observation is that the Satellite #4 platform riser sample had a lower cloud point, pour point and paraffin content when compared to the untreated wellhead sample. This suggested that paraffin deposition is occurring in the flowline.

Satellite #1 condensate analysis showed that the cloud point was below the flowline temperature, therefore paraffin deposition potential is very low and that any blockage is most likely associated with hydrate formation.

Pour Point Determination

When the temperature of crude oil falls below the cloud point (or wax appearance temperature), paraffin crystals form. Further cooling leads to crystal growth and the formation of a semi-solid or solid gel. This consists of interlocked paraffin crystals, asphaltenes, oil and water. The lowest temperature at which fluid movement of the crude oil occurs is called the pour point. ASTM D97–96a was used to test the treated and untreated condensate samples.

Due to the small volume of untreated condensate, pour point depression tests were performed as a pre-screening tool. Various concentrations of paraffin treatment chemicals were tested in order to gauge their suitability and potential dose rates. The results have been summarized in Table 5 and this holds many important trends. Firstly, the typical Gulf of Mexico injection rate of 500 ppmv was wholly inadequate for this highly-paraffinic condensate and had little or no effect on the pour point. It can be seen that the incumbent chemical had next to no effect on the pour point – even when used at the field application rate of 60,000 ppm/v – showing that solvent-based diluents were not suitable for such a high paraffin-containing condensate. The final observation was that 2,500 to 5,000 ppmv of an inhibitor chemistry showed a large reduction in the pour point with the best performing product being Inhibitor B, as it reduced the pour point to just 5°F when applied at 5,000 ppmv.

Cold Finger Paraffin Deposition Tests

Cold finger testing efficiently evaluates the performance of paraffin dispersants and crystal growth modifiers. The protocol is founded on the fact that the paraffin in the crude oil will deposit on a cold surface whose temperature is below the cloud point. The apparatus used has been photographed in Figure 8, and a schematic given in Figure 9.

Crude temperature is maintained by being immersed in a water bath, and into this is placed the cold fingers which are connected to a chiller bath. Efficient paraffin dispersants will prevent paraffin crystals depositing on the surface of the cold finger. Comparative determination of the mass of paraffin gained from treated and untreated crude allows assessment of inhibition efficacy. A 200 mL sample of condensate was carefully poured into each of the pre-heated cold finger flasks, which were then immediately placed into the water bath at 150°F (temperature above the cloud point) to ensure no paraffin deposition occurred on the walls of the flasks. One of the four cells was always an uninhibited (blank) test and the other three cells contained inhibitor. The cold fingers were then immersed into the crude oil and set to a temperature of 50°F (worst case shallow seabed temperature). The test was run for 3 hours (the calculated residency time in the Satellite #4 subsea flowline) after which the cold fingers were removed from the flasks and left to stand for 10 minutes to allow any liquid crude oil to drop from the cold finger. The deposition on the cold fingers could be determined without the need for scraping or use of solvent because deposition occurred on pre-weighed removable sleeves.

The results of the cold finger experiments have been summarized in Table 6. This test is one of the best tools for ranking different chemicals and dose rates. However, it should be noted that although this test can give an indication of the applied dose rates, it does tend to overestimate the inhibitor requirements. Also the percentage inhibition values are used for ranking products in the lab and will not necessarily reflect results seen in the field. Photographs were taken immediately after removal of the fingers on conclusion of each test. Examples have been shown in Figures 10 and 11.

Excellent inhibition (91%) was seen using 5,000 ppmv of Inhibitor B. Although this was a high dose rate, it was a fair reflection of the high paraffin content of the condensate. During the test, the dispersion properties exhibited by Inhibitor B could clearly be seen, as the paraffin crystals that formed on the finger broke off immediately and remained dispersed in the bulk hydrocarbon phase. The incumbent chemical on the other hand performed poorly, showing only 13% inhibition when dosed at field injection rates of 60,000 ppmv. Most of this efficacy could be attributed to a dilution effect rather than any inhibition or dispersion.

INFLUENCE OF RECOMMENDED CHEMICALS ON THE PROCESS

Foaming Propensity Testing

Due to the very high concentration of chemical required to be used for the control of hydrate and paraffin, it was required to ensure there was no adverse foaming creating effects on the produced fluids. Addition of high concentrations of any production chemical has the potential to induce foam formation due to the surfactancy properties exhibited by many chemicals.

The method used was based on an ASTM standard and has been described in detail in a previous publication (Wylde, 2010). In this case, a 100 mL fluid sample was placed in a 250 mL graduated cylinder at 150°F, and the sample sparged with nitrogen at 0.2 ml.min^{-1} for 2 minutes. The initial foam height and the time to collapse after cessation of gas flow were recorded. The various paraffin and hydrate inhibitors recommended were added to the solution and sparging of gas continued. Both the initial foam height and the time to collapse of the foam were recorded. Tests were performed for two fluids: pure condensate and a 50/50 produced water/condensate mixture.

Tests were performed using 2,500 ppmv INHIBITOR B, 5,000 ppmv INHIBITOR B and 2% of the recommended KHI hydrate inhibitor added based on total fluids (worst case).

Results have been summarized in Table 7, and the testing showed that the addition of any concentration of paraffin inhibitor induced no additional foam formation when compared to the blank – see Figures 12 and 13. Addition of the KHI resulted in a small volume of additional foam when compared to the blank, but as soon as the gas flow ceased the foam broke very quickly. In summary, none of the tests indicated that a foam problem would affect the process upon application of any of the recommended chemical treatments. Pure condensate was observed to foam more than the condensate / water mixture.

Emulsion Tendency Testing

The application of any production chemical can potentially lead to increased emulsion formation and process upsets due to the presence of surfactant and / or surface active components. Given the importance of efficient oil and water separation, the influence the recommended products had on this process had to be investigated.

Field condensate was used for this study in combination with produced water. The tests were performed at 150°F to prevent paraffin precipitation – it is acknowledged that this is higher than the current process temperatures but the experiment is still valid to say whether an emulsion problem will be worsened by the presence of inhibitor.

Appropriate volumes of oil and water were measured out into prescription bottles, dosed with the appropriate chemical to test and then shaken hard 200 times. Immediately after shaking, time lapse photography was used to record water separation volume and speed. All tests were performed with a 50:50 water / condensate mixture. Four tests were performed; a blank and individual tests with addition of 2,500 ppmv inhibitor B, 5,000 ppmv inhibitor B, and 2% KHI. Figure 14 shows the results of the tests. In summary, there was a slight effect on fluid separation displayed by all chemicals but not anything that was deemed at all significant as all tests fully separated in under 30 seconds. This was well within the fluid residence time in the platform separators.

FIELD APPLICATION

Combining the laboratory results and analysis of field data, it was clear there was a severe paraffin deposition challenge in the Satellite #4 well subsea flow line. In order to ensure the maximum benefit of any implemented paraffin inhibition program, it was proposed that an initial solvent treatment was performed to remove existing deposition. The 4”, 2-mile pipeline volume was approximately 5,277 gallons (125 bbl). Production rates of 36 barrels liquid give a residency time of approximately 3 hours (taking into account the gas rate also). The operator decided to perform a solvent batch treatment prior to injection of paraffin inhibitor. A slug of 1,750 gallons (42 bbl) of a mixed aromatic and aliphatic solvent was pumped into the flowline. Production was brought back online at a reduced choke to displace the solvent through the flowline.

Following on from the solvent treatment, 5,000 ppmv (based on condensate production) of Inhibitor B was injected immediately upstream of the satellite #4 platform well choke to prevent further wax deposition occurring in this flowline. The success of this treatment was evaluated through regular monitoring of pipeline pressures and analysis of fluid samples that ensured the physical properties of the condensate samples were unchanged across the pipeline.

Simultaneously, an injection of the recommended KHI started at the existing injection point upstream of the Satellite #1 choke. Injection began at 2% based on water production (25 qts/day). This rate was optimized based on pressurization of the pipeline during application.

Upon implementation of the dual chemical treatment program, impressive results were seen with a clear step change in performance. Field measurement of pour point and paraffin content showed that deposition was unlikely to be occurring in the flow line as paraffin content was identical upstream of injection and at the host facility. The pour point was also much suppressed, evidenced by the lower viscosity of the condensate on the platform, and paraffin solids in separator samples were no longer apparent. This latter point helped to alleviate separation problems experienced in the separators with respect to interface level control problems, which would periodically cause the field to shut-in.

The efficacy of the hydrate control strategy was even more impressive. Under the incumbent treatment, Satellite #1 flowline suffered almost daily incidences of hydrate formation and required total tieback shut-down and flowline depressurization. As the field is essentially unmanned, this required daily trips to the field by operator personnel and significantly added to the operating costs. When the new KHI was introduced to the field, these incidences were completely eliminated.

The injection of both chemicals was shown to have no detrimental effect on the platform processing operation with respect to foaming or emulsion stability.

Based on the first three months of treatment, and taking into account the additional production time available due to the elimination of shutdowns, it was estimated that the additional revenue to the operator was in the order of $800K along with an operational cost savings of $100K (e.g. helicopter charter costs). The chemical treatment costs for this same period was $50K, so the NET benefit to the operator was approximately $280K per month.

CONCLUSIONS

The Satellite #1 flowline had a low subcooling hydrate flow assurance challenge that was not addressed by the incumbent chemical treatment. Modeling and process compatibility testing led to the recommendation to inject 25 quarts per day of a new KHI (2% based on water rate) via the existing injection point. When this treatment was implemented, the daily shut-ins and associated flowline depressurization operations were eliminated, showing that an effective hydrate control was in place.

Satellite #4 had a very high paraffin content and the incumbent chemical treatment was not effective. This was indicated by reduced paraffin in the fluids arriving at the platform. Furthermore, separation challenges associated with paraffin solids were experienced on the processing platform.

A range of testing was performed and led to the recommendation that 25 quarts per day of inhibitor B (5,000 ppmv based on condensate) be applied. It was crucial to inject this upstream of the choke on Satellite #4 due to the local JT cooling that occurred across the choke, which was likely to be inducing large scale paraffin precipitation. When this treatment was implemented, wax deposition was prevented in the flowline, as demonstrated by fluid analysis across the flowline. Additionally, the process separation issues caused by previous paraffin deposition were eliminated.

The correct chemical formulation and optimization created a significant cost savings in reduced operations and chemical overhead for the operator. Significant value savings were created due to no lost production as shut-downs were no longer required. The overall cost and value benefit to the operator was approximately $280K per month.

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Table 1
Production figures for the field complex.

Well	Choke (%)	FTP (psia)	Gas (mmcf/day)	Condensate bbl/day	Water bbl/day
Main platform	13	5143	4.589	2	137
Satellite #1	16.75	5800	10.409	249	8
Satellite #2	17	1626	3.191	11	44
Satellite #4	9	7403	5.670	30	6

Table 2
Relevant process trends

	Pressure (psia)	Temperature (°F)
Satellite 1 #1 Flowline	1400 – 2000	80 – 90
Satellite #4 Flowline U/S choke	4350	122
Satellite #4 Flowline D/S choke	1250	70.1
Platform Production separator	1200	63.2
Satellite #4 riser on Platform	1255	63.8
Platform well riser on Platform	1175	64.7
Satellite #1 riser on Platform	1600	60.1
Subsea temperature (approx.)		60

Table 3

Satellite #4 and Satellite #1 produced gas compositions

Component	Satellite #4 (mol %)	Satellite #1 (mol %)
Nitrogen	1.665	0.232
Carbon dioxide	1.081	1.074
Methane	92.966	92.068
Ethane	2.973	4.102
Propane	0.654	1.252
i-butane	0.230	0.545
n-butane	0.128	0.289
i-pentane	0.048	0.154
n-pentane	0.042	0.087
Hexane	0.048	0.197 (Hexanes +)
Heptane +	0.165	N/A

Table 4

Condensate physical properties relevant to paraffin deposition

Property	Satellite #4 Platform Riser	Satellite #4 Wellhead	Satellite #1
Cloud point (°F)	98.6	145	23
Pour point (°F)	69.8	96	3.2
Paraffin content (%)	10.8	14.3	2.9

Table 5

Summary of pour point experimentation on Satellite #4 condensate

Chemical	Dose rate (ppmv)	Pour point (°F)
Blank	N/A	96
INHIBITOR A	500	96
	2,500	79
	5,000	67
INHIBITOR B	500	91
	2,500	46
	5,000	5
INHIBITOR C	500	91
	2,500	58
	5,000	31
Incumbent	500	96
	5,000	94
	60,000	86

Table 6
Result summary for cold finger wax deposition.

	Dose rate (ppmv)	Weight (g)	Inhibition (%)	Removal Comments
Blank		26.1507		Soft, easy to remove
WAX INHIBITOR A	500	18.7740	28.2	Soft, easy to remove
WAX INHIBITOR B	500	15.7684	39.7	Soft, easy to remove
WAX INHIBITOR C	500	16.1920	38.1	Soft, easy to remove
Blank		14.5600		Soft, easy to remove
Incumbent	60,000	12.6600	13.0	Soft, easy to remove
WAX INHIBITOR B	2,500	4.4200	69.6	Soft, easy to remove
WAX INHIBITOR B	5,000	1.3700	91.0	Soft, easy to remove

Table 7
Summary of the foam testing results.

	Foam build up rate						Foam break (seconds)
	20	40	60	80	100	120	
100% Condensate							
Blank	20	22	22	22	22	22	3
2,500 ppmv INHIBITOR B	4	4	4	15	16	16	2
5,000 ppmv INHIBITOR B	5	5	5	30	30	30	7
2% KHI	80	80	40	50	20	20	6
50:50 Water: Condensate							
Blank	5	5	5	5	5	5	1
2,500 ppmv INHIBITOR B	3	3	3	0	0	0	0
5,000 ppmv INHIBITOR B	3	3	0	0	0	0	0
2% KHI	0	2	2	2	2	0	0

Figure 1 - Rare Photograph of Hydrates Being Removed From a Subsea Pipeline

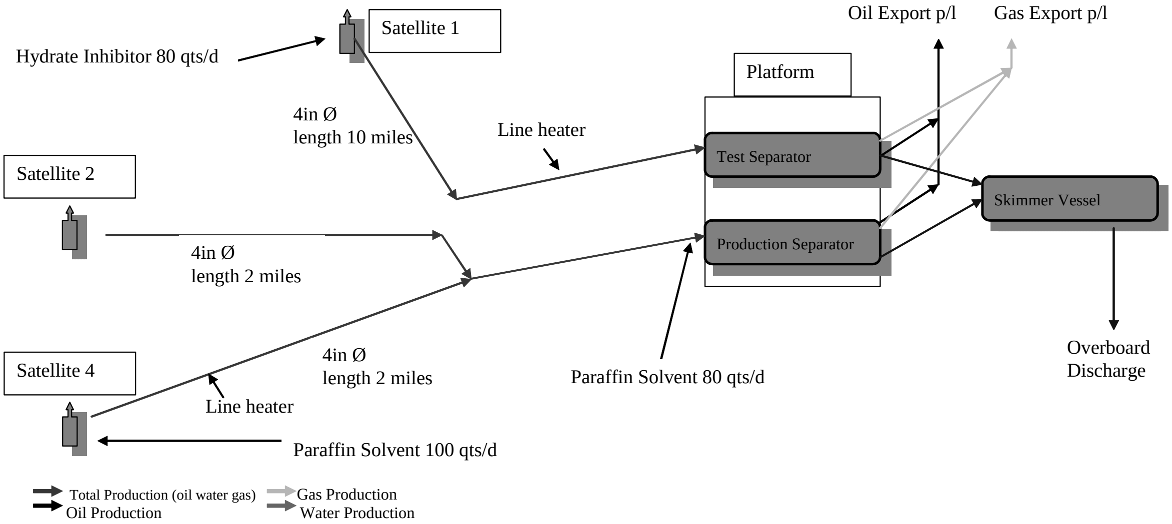

Figure 2 - Simplified Field Layout and Initial Treating Strategy

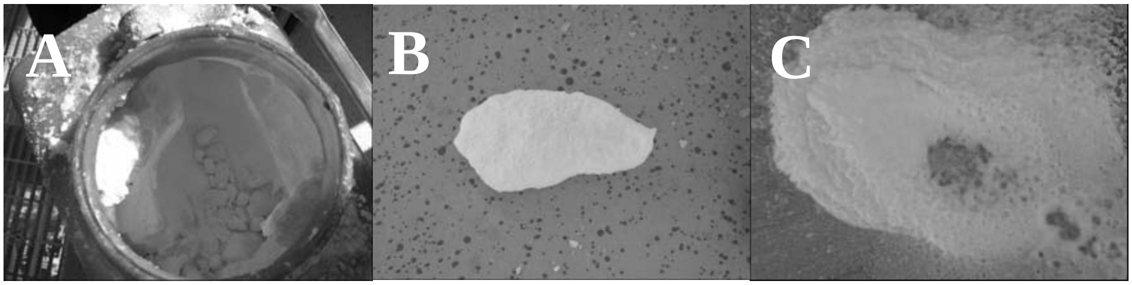

Figure 3 - Photographs of sample taken off the Satellite #4 flowline (A), when isolated (B) and solids from the production facility separator (C).

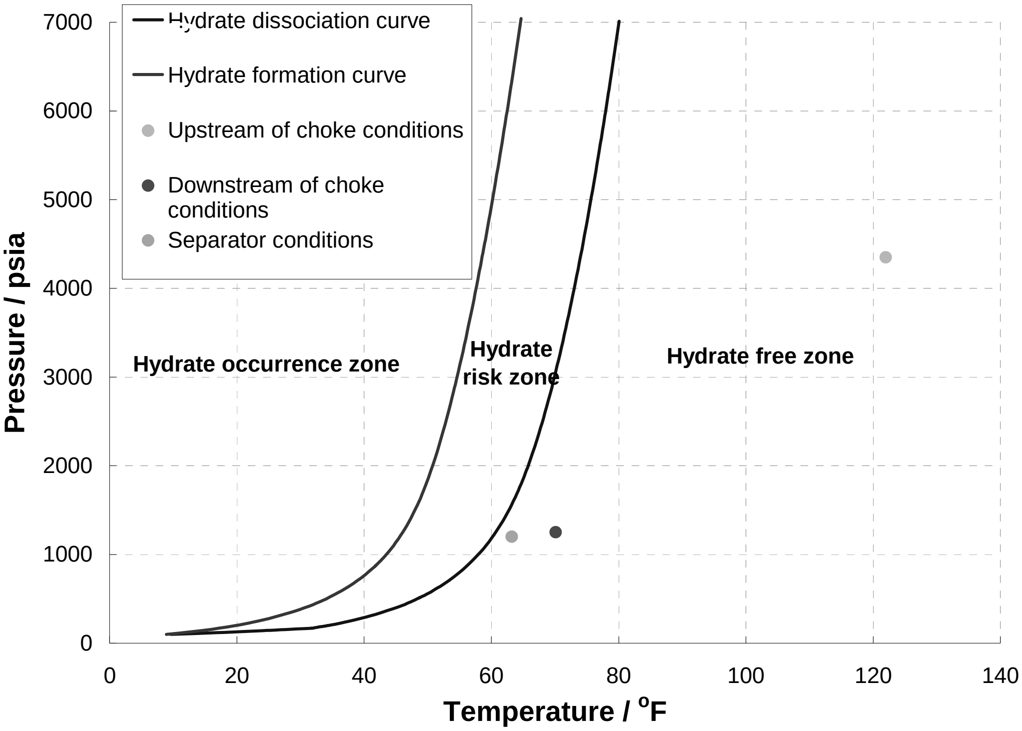

Figure 4 - MULTIFLASH Modeling Output for Satellite #4 Showing Operation Outwith of the Hydrate Occurrence Zone

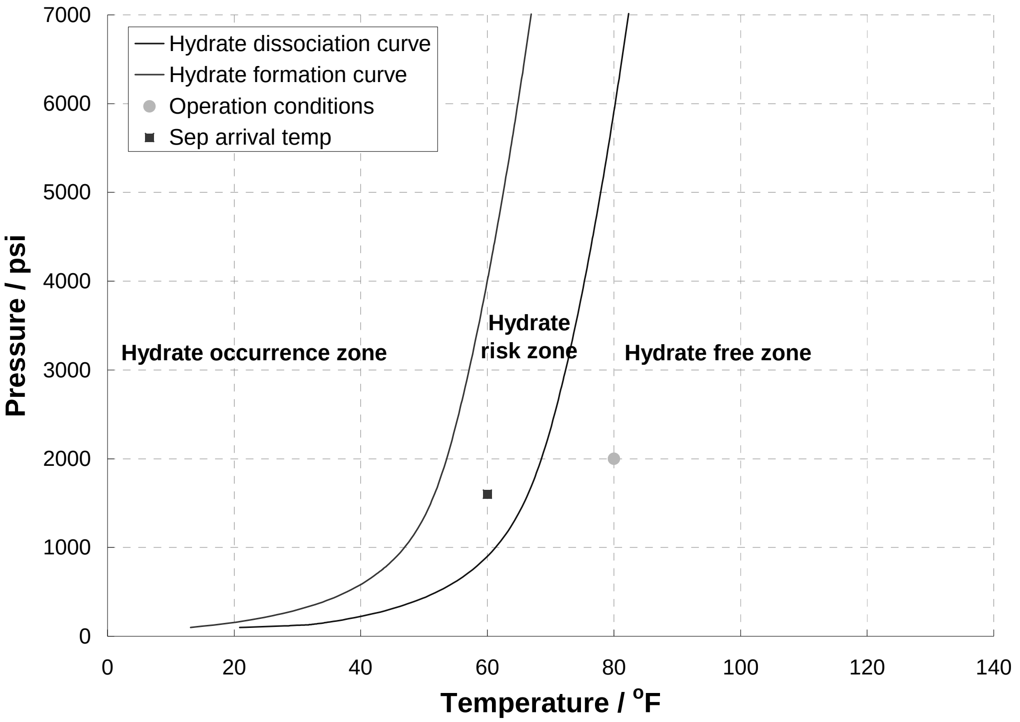

Figure 5 - MULTIFLASH Modeling Output for Satellite #1 Showing Operation in the Hydrate Risk Zone

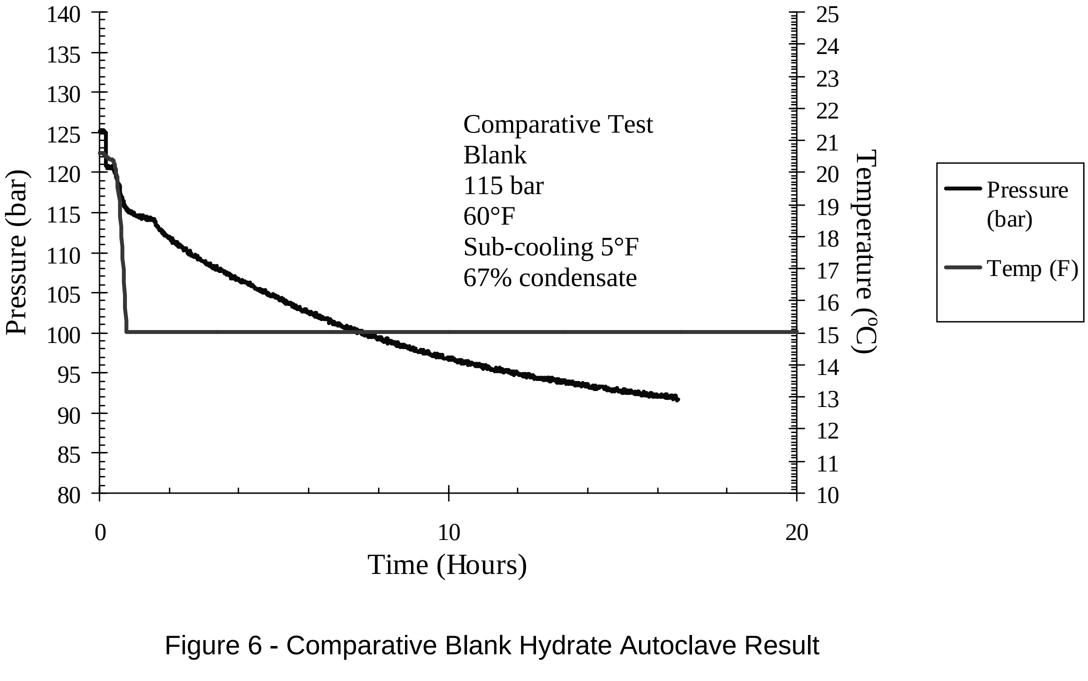

Figure 6 - Comparative Blank Hydrate Autoclave Result

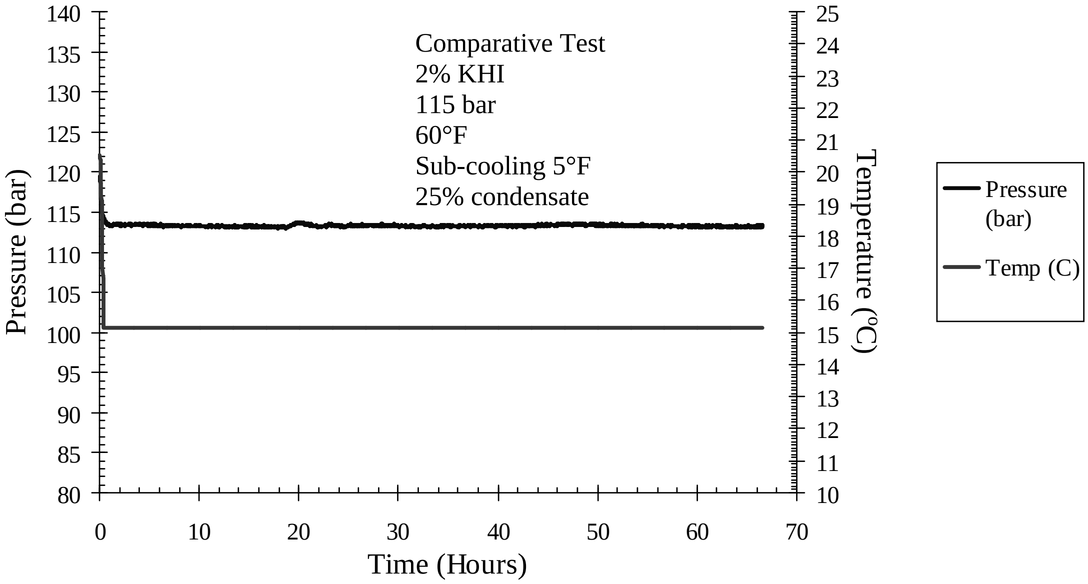

Figure 7 - Comparative 2% HYDRATE INHIBITOR X Autoclave Result

Figure 8 - Photograph of the four cell cold finger apparatus used during testing. The chiller bath is out of view on the right-hand side.

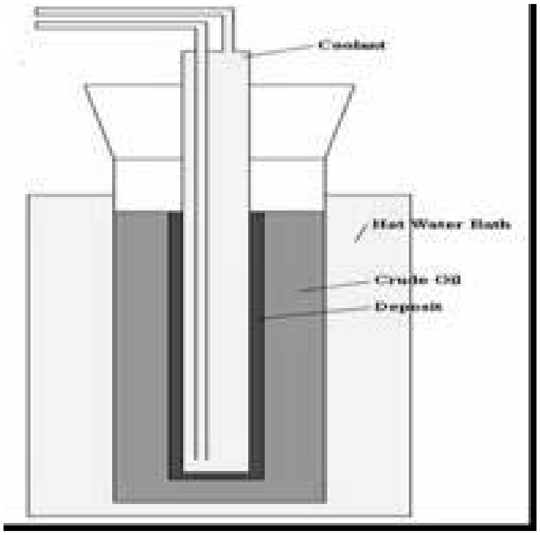

Figure 9 - Schematic of a Single Cell in the Cold Finger Apparatus

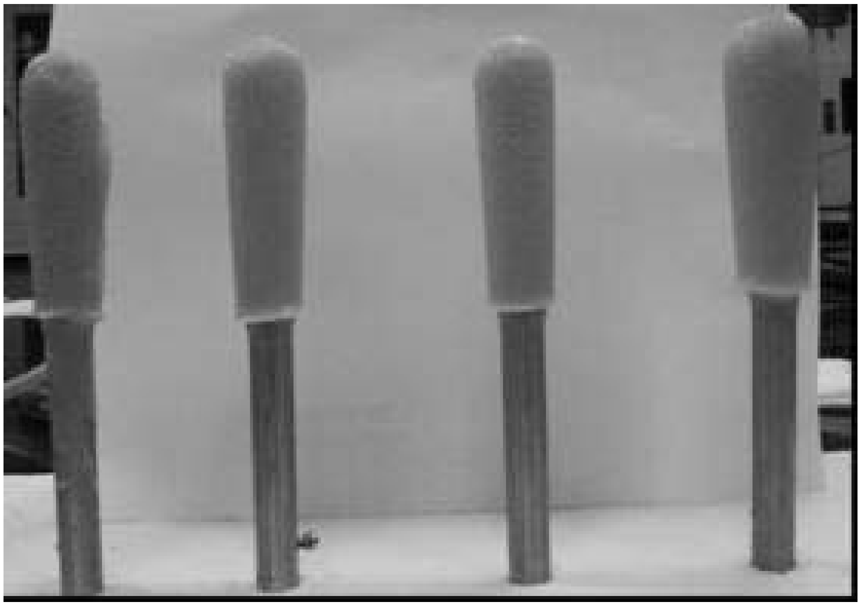

Figure 10 - Cold finger sleeves after removal from the cells. From left to right: 500 ppmv inhibitor C, 500 ppmv inhibitor A, 500 ppmv inhibitor B, and the blank.

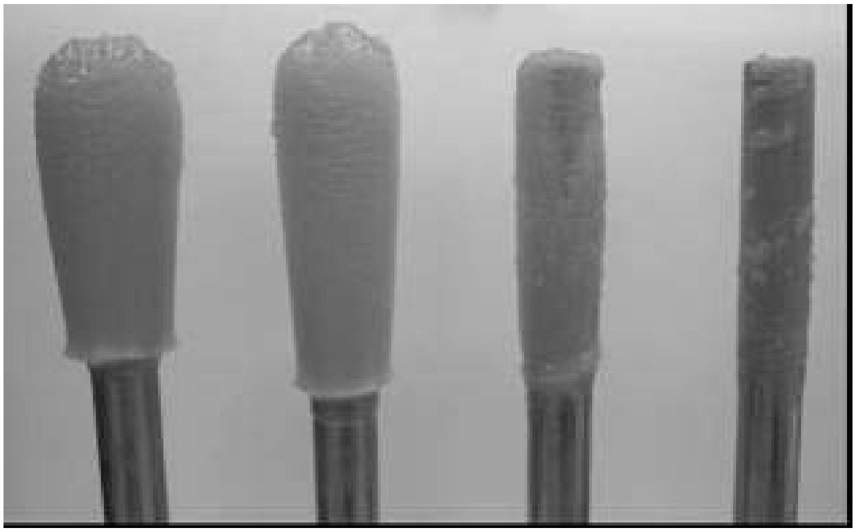

Figure 11 - Cold finger sleeves after removal from the cells. From left to right: blank, 60,000 ppmv Incumbent, 2,500 ppmv Inhibitor B, 5,000 ppmv Inhibitor B.

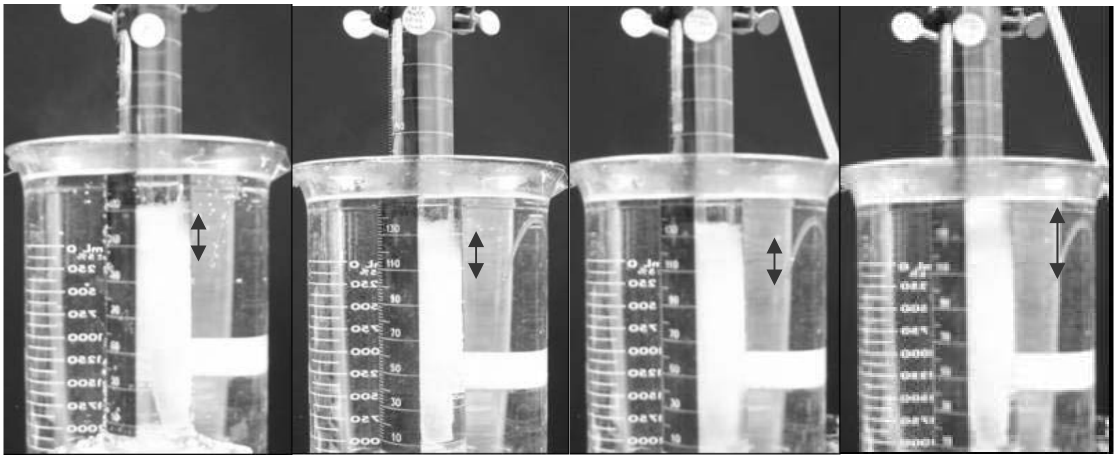

Figure 12 - Foam tests using 100% condensate – foam height annotated. From left to right: blank, 2500 ppmv Inhibitor B, 5000 ppmv Inhibitor B, 2% KHI.

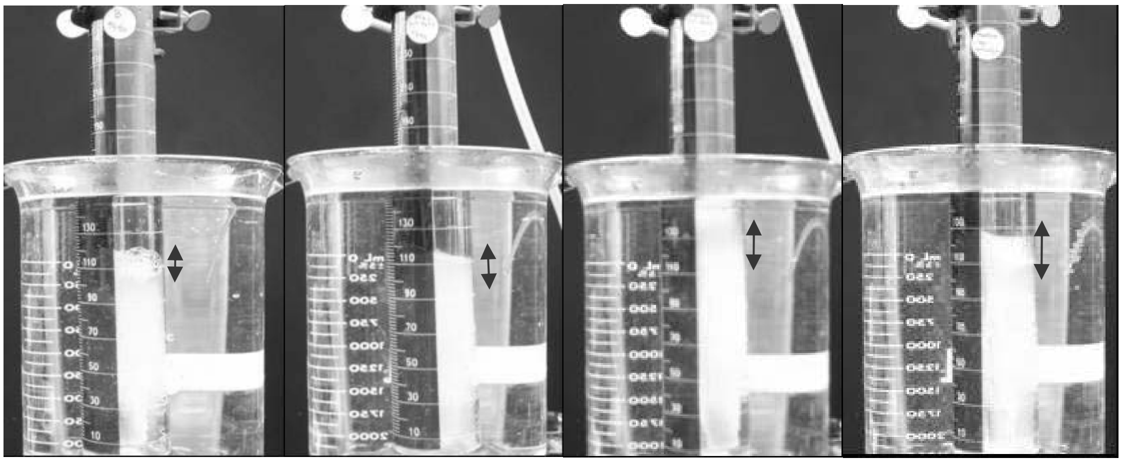

Figure 13 - Foam tests using 50% condensate, 50% produced water mixture – foam height annotated. From left to right: blank, 2500 ppmv Inhibitor B, 5000 ppmv Inhibitor B, 2% KHI.

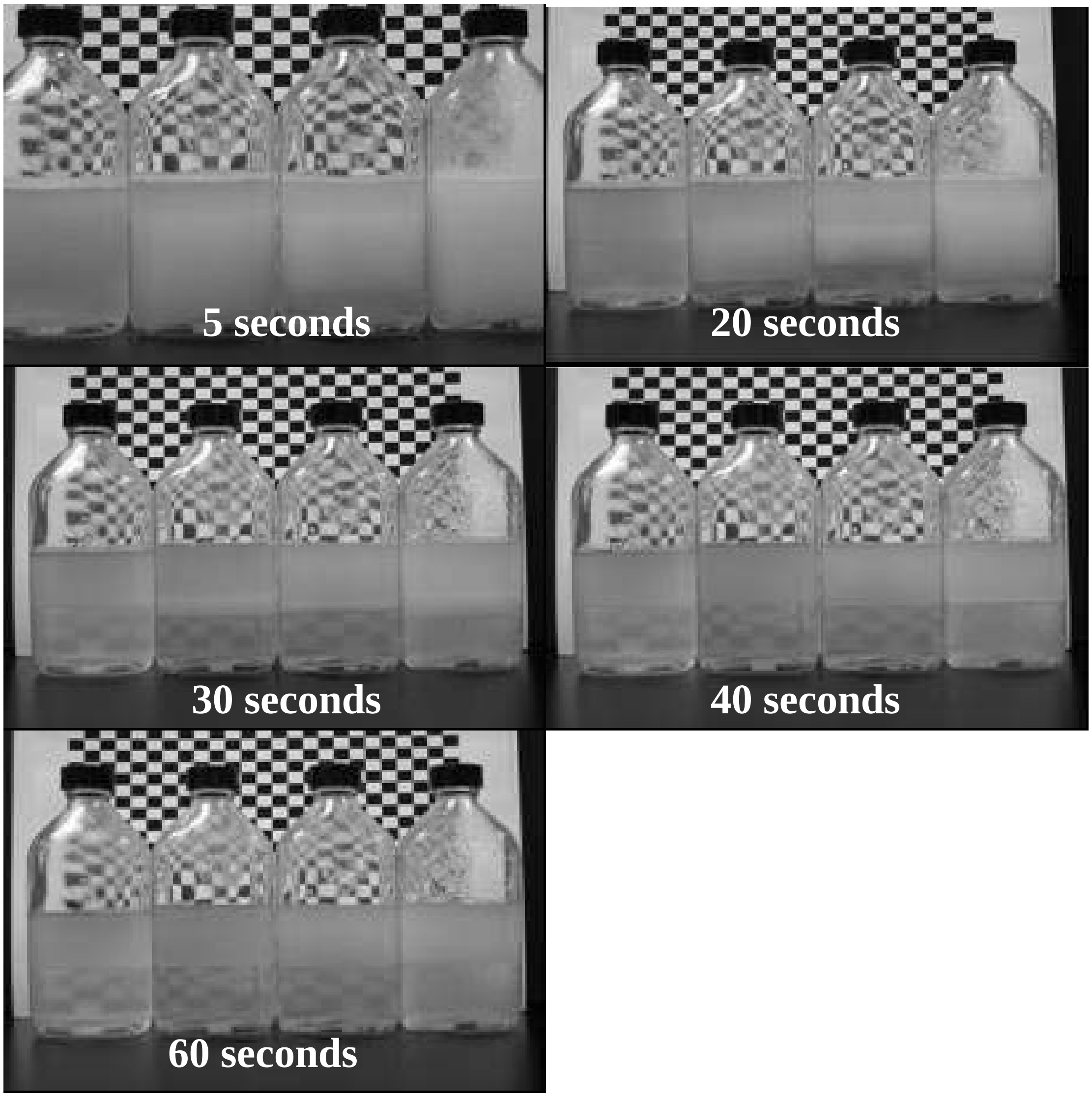

Figure 14 - Time lapse photographs of fluid separation experiments. In each photograph from left to right: blank, 5000 ppmv inhibitor B, 2500 ppmv inhibitor B and 2% KHI. Time annotated on the individual photographs.