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73

CORROSION98

NOVEL CHEMICAL DISPERSANT FOR REMOVAL OF ORGANIC/INORGANIC "SCHMOO" SCALE IN PRODUCED WATER INJECTION SYSTEMS

W. M. Bohon and D. J. Blumer
ARCO Alaska, Inc.
Anchorage, Alaska USA

A. F. Chan and K. T. Ly
ARCO Exploration & Production Technology
Plano, Texas USA

ABSTRACT

"Schmoo" is the smelly, black goo found coating the inside of produced water piping at the Prudhoe Bay oil field; it is essentially oil-coated particulates of iron sulfide. Layers more than 1" thick have been found in some injection well lines. Schmoo causes several significant problems: It can plug injection wells, requiring expensive well work to unplug the wells. Worse, colonies of bacteria grow under heavy layers of schmoo, corroding pits in the pipe, and necessitating very expensive repairs. These problems prompted the development of a novel dispersant to remove the schmoo. The novel dispersant consists of two nonionic surfactants - an alkyl polyglycoside and a linear alkyl ethoxylate - dissolved in an aqueous solution of sodium hydroxide. Field tests of the dispersant were very successful, and treatment of water injection wells with the dispersant was adopted as standard practice: 28 water injection wells have now been treated successfully, preventing well plugging, and in many cases, improving injectivities. Other applications, such as cleaning vessels and removing formation damage in production wells, are currently being explored.

Keywords: Organic/inorganic scale, schmoo, alkyl polyglycoside, nonionic surfactant, dispersant, corrosion, produced water, injectivity.

SUMMARY

"Schmoo" is the smelly, black goo found coating the inside of produced water piping at Prudhoe Bay and at other oil fields. Schmoo forms upstream in the production system and is essentially oil-coated particulates of iron sulfide; thus, it can be thought of as a combination organic/inorganic "scale." Prodigious amounts accumulate in the produced water piping. Pigging is used to remove the schmoo from the large-diameter distribution lines, but the small-diameter injection well lines cannot be pigged. Layers 1" or more in thickness have been found coating the inside of some well lines. Originally, the schmoo was just thought to be a smelly nuisance; however, it is now recognized to cause several significant problems. The schmoo can slough off, plugging injection wells. This often happens when the wells are swapped from produced water to miscible gas injection, which is done periodically. Expensive well work is then required to remedy this situation. Worse, colonies of bacteria grow under the schmoo, corroding pits in the pipe and necessitating replacement of the very expensive lines. Furthermore, the schmoo protects the bacteria from attack via biocides.

The loss of several well lines prompted an effort to find a chemical means to remove schmoo. A dispersant originally developed to remove oil-based drilling mud (oil-coated particulates) was identified as a likely candidate. The novel dispersant consists of two nonionic surfactants - an alkyl polyglycoside and a linear alkyl ethoxylate - dissolved in an aqueous solution of sodium hydroxide. The dispersant was reformulated for the job of schmoo removal. Field tests of the dispersant were very successful: At the time of writing, 28 water injection wells have been treated; none of the treated wells plugged following their swap from produced water to miscible gas injection, and many of the wells showed improved injectivities. It is not yet known, however, if the removal of the schmoo is sufficient to mitigate corrosion in the well lines. Use of the dispersant has been adopted as standard treatments to water injection wells. Other uses, such as cleaning vessels and removing formation damage in production wells, are also being explored.

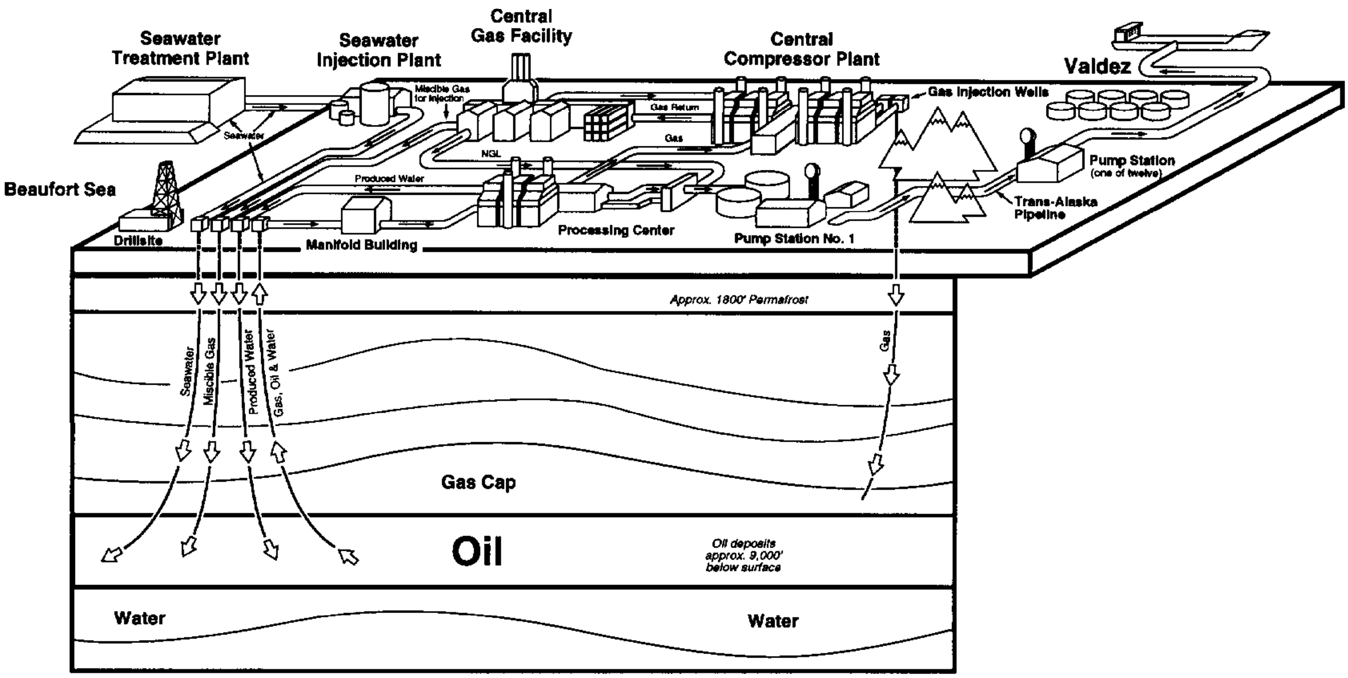
INTRODUCTION

Prudhoe Bay Overview

The Prudhoe Bay oil field is located on the north coast of Alaska several hundred miles above the Arctic Circle. In many ways, it is similar to other oil fields. However, it is also unusual in a number of ways. One way that it is not typical is the scale of the operations: The production gathering system and associated piping include over 1,200 miles of pipelines (not including the 800-mile Trans-Alaskan Pipeline) of which the largest pipe is 60" in diameter. Because of the Arctic location, virtually all 1,200 miles of piping are above-grade. This fact greatly facilitates inspection of the piping by radiography and ultrasonics - key parts of the corrosion control program at Prudhoe Bay. Another way it is not typical is that, because of the scale of the operations, the field is divided into two areas, with each area being operated by a separate oil company: the Eastern Operating Area (EOA) is operated by Atlantic Richfield (ARCO), and the Western Operating Area (WOA) is operated by British Petroleum (BP). Even though the field is operated by two companies, operations between the two are coordinated.

A diagram of the Prudhoe Bay production process is shown in Figure 1. Oil, water, and gas are produced by 880 production wells. The production from a group of wells (24 on average) is combined at one of 37 small facilities called "drill sites". The produced fluids are transported from the drill sites to one of 6 central processing facilities through large-diameter (16" & 24") pipelines. At each central processing facilities, the liquids are separated from the gas, and then the oil is separated from the water. The processed oil is combined with oil from other nearby oil fields and shipped to market via the Trans-Alaska Pipeline. Currently, Prudhoe Bay produces about 700,000 bbl/day of oil.

FIGURE 1. PRUDHOE BAY PROCESS DIAGRAM



Multiple fates await the produced gas. Some produced gas is processed to recover the NGLs (butane & propane) which are subsequently blended with the sales oil. Some produced gas is made into Miscible Injectant (MI) by enriching its CO_2, ethane, and propane content. MI is miscible with oil at reservoir conditions; it is distributed to selected drill sites for injection into the reservoir as an enhanced oil recovery process. Some produced gas is compressed and distributed to the drill sites for use as artificial lift (AL) gas; AL gas is used in many of the producers to help lift liquids to the surface. Some produced gas is burned as fuel in turbines to drive gas compressors, pumps, and electric generators. However, most of the produced gas is simply compressed and (re)injected via 22 injection wells into the gas cap for reservoir pressure maintenance. About 7,500,000,000 scf/day of produced gas is processed into NGLs, MI, AL gas, burned as fuel, and/or reinjected.

The produced water is pressurized at the central processing facilities and distributed to selected drill sites for reinjection. This is done both for reservoir pressure maintenance and as a waterflood oil recovery process. Until very recently, seawater was also treated and distributed for injection. Over time as the amount of produced water increased, seawater injection wells were converted to produced water. Seawater injection at Prudhoe Bay ceased in 1996. About 750,000 bbl/day of produced water is reinjected via 188 water injection wells (of these, 138 are also used intermittently to inject MI).

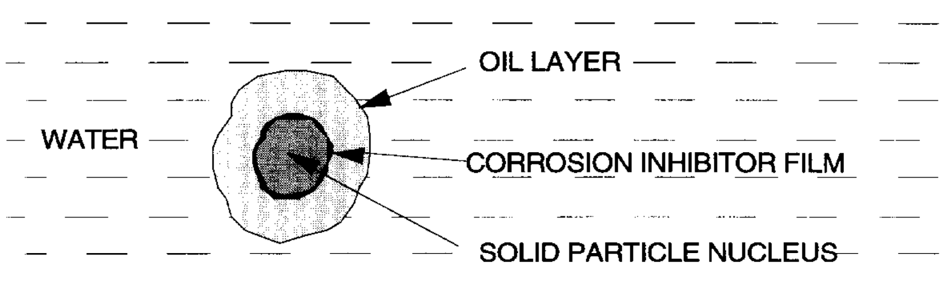
The produced water injection system piping is plagued with an organic/inorganic scale referred to as "schmoo." The source of the schmoo scale, the problems it causes, and the innovative remedy are the subjects of this paper.

The Birth of Schmoo

Schmoo is born as "oil-coated dust" in the production piping system. Solids are produced along with the oil, water, and gas. In descending order of size, these produced solids include hydraulic fracturing proppant (~1,000 microns), formation sand (~100 microns), formation fines (~10 microns), and precipitates - typically iron sulfide (~1 micron). The iron sulfide precipitate results from the reaction of dissolved iron in the produced water and hydrogen sulfide generated by sulfate-reducing bacteria. Corrosion inhibitors are added to the produced fluids to mitigate internal corrosion in the production system piping. As these corrosion inhibitors are surface-active chemicals, they tend to coat any surface that they contact, including produced solids. (Adsorption onto produced solids can constitute a significant parasitic loss of inhibitor.) The adsorbed inhibitors promote the oil wetting of whatever surface to which they are attached. As a result, the produced solids become encapsulated in a film of oil. A cross-section of single particle of schmoo is shown in Figure 2.

The larger oil-coated solids typically settle out in the vessels designed to separate the gas from the liquids, and the oil from the water. (The accumulation of these oil-coated solids in the separation vessels cause problems worthy of a separate paper in their own right.) The finer oil-coated solids - primarily the iron sulfide particulates - do not settle in the separation vessels; rather, they pass on through with the liquids. A large amount passes through with the water into the produced water system. Dispersed in water, the oil-coated dust particles are somewhat "sticky"; the particles stick to most anything they bump into - usually a pipe wall or each other. The resulting accumulation of oil-coated dust is known as "schmoo". Accumulations more than 1" in thickness have been found in some well lines.

FIGURE 2. CROSS-SECTION OF A SINGLE PARTICLE OF "SCHMOO"



Schmoo is black and greasy in appearance and its composition is highly variable. An analysis of a typical schmoo sample is presented in Table 1. The inorganic solid particulates that make up about 15-20% of the schmoo's mass are sufficiently fine that they cannot be felt when rubbed between fingertips. About 80% of the schmoo's mass is hydrocarbons and corrosion inhibitors, although it does contain some bacteria and trapped water. Its foul odor originally lead field personnel to incorrectly believe that schmoo was primarily biomass (bacteria). This lead to several cleaning and prevention schemes that were not particularly successful. Schmoo has a particularly obnoxious quality: like a concentrated dye or ink, a little bit goes a long way. It is particularly despised by field personnel who come into contact with equipment coated with it.

TABLE 1. LABORATORY ANALYSIS OF SCHMOO SAMPLE

Analysis	wt. % of Total Sample	Cations	wt. % of Total Sample
Toluene Solubles	82.35	Fe	3.56
Asphaltenes	10.04	Ca	0.04
Pentane Solubles	72.31	Mg	0.03
Acetone-Methanol Solubles	3.88	Al	0.01
Organic Solvent Insolubles	13.77	Ba	0.01
Sulfides	0.16	Mn	0.00
Loss on Ignition	7.27	Cr	0.00
Ash After Ignition	6.50	Sr	0.01
Acid Insolubles	0.12	P	0.01
Acid Solubles	6.38		

The Problem with Schmoo

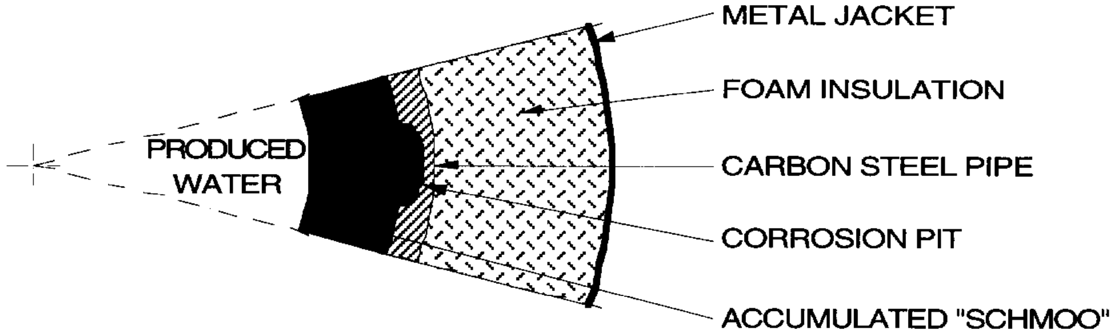
Originally, schmoo was just thought to be a smelly nuisance; it is now recognized to cause several significant problems. Firstly, the schmoo can cause plugging of the injection wells. Most often, this does not happen gradually as one might expect. The primary reason for this is that the produced water is injected into the formation above hydraulic fracture pressure. As a result, as the rock face gradually becomes plugged, the fractures grow, exposing new rock face.

Rather than plugging gradually, injection wells usually plug suddenly. Most of the injection wells at Prudhoe Bay are in water-alternating-gas service, or "WAG" - a form of tertiary oil recovery. For a period (e.g., 6 months), a WAG well will inject produced water (PW). Then, for a period, the well is switched to injecting miscible injectant (MI). The PW and MI are delivered to each WAG well via separate surface lines, but the well's injection tubing is alternately exposed to both fluids. Thus, during the period that the WAG well is on PW, schmoo accumulates on the wall of the injection tubing. When the well is subsequently swapped to MI, the MI gas removes the water and lighter hydrocarbons, drying out the schmoo. Like mud under a hot sun, the drying schmoo cracks and flakes off the tubing wall. The sloughed schmoo is carried down the tubing where it packs off in the perforations, plugging the well. If a WAG well plugs, it usually plugs within a few days of being swapped from PW to MI. In 1996, on average, about 1/3 of the WAG wells plugged when swapped from PW to MI. There is no plugging problem associated with the swap from MI back to PW, however. Wireline operations have measured over several hundred feet of solid fill covering the perforations in some plugged WAG wells.

Once plugged, an expensive fill clean out (FCO) is required to restore well injectivity. An FCO involves the use of a coiled tubing unit (CTU): coiled tubing is run down the well; a high pressure jet of a solvent (usually diesel + xylene) is used to wash out the well. The fill-laden solvent is produced back up the well in the annulus between the coiled tubing and the well tubing. The solvent and removed fill must then be disposed of. This process is undesirable because the FCOs are expensive, they tie up a CTU when it could be doing more productive work, the solvent and fill are a disposal problem, and the injection well isn't meeting its required injection rate while plugged. Some wells do not respond to the FCO, and more severe treatments are initiated, including acidizing or hydraulic fracturing.[1]

Schmoo causes a worse problem than plugging injection wells: Schmoo promotes corrosion in the produced water system piping. The schmoo itself is not corrosive, being mostly hydrocarbons plus corrosion inhibitor. In fact, a test conducted with corrosion coupons showed that a thin layer of schmoo is a pretty good protective coating, acting as an effective barrier between the pipe and the produced water, which is corrosive. However, heavy accumulations of schmoo apparently promote the formation of bacteria colonies on the pipe wall. In a process analogous to the formation of cavities in teeth, these bacteria corrode holes in the pipe. The damage caused by the bacteria is characterized as isolated pitting: Except for a few, well-defined pits, the pipe is mostly undamaged. The pits are well-defined, sharp-edged, and are roughly circular in shape. This is in stark contrast to the corrosion typical in the production system where overlapping pits form almost continuous networks, and are exaggerated dimension in the direction of fluid flow (many times longer than they are wide). Pits found in the produced water well lines are up to 1" in diameter and have been found to extend up to 0.35" in depth (80% of typical 0.432" pipe wall). A schematic of a corrosion pit under a layer of schmoo is shown in Figure 3. A photograph of such corrosion pits found in an 8" water injection well line is shown in Figure 4. Approximately 1" of schmoo had to be removed to expose these pits.

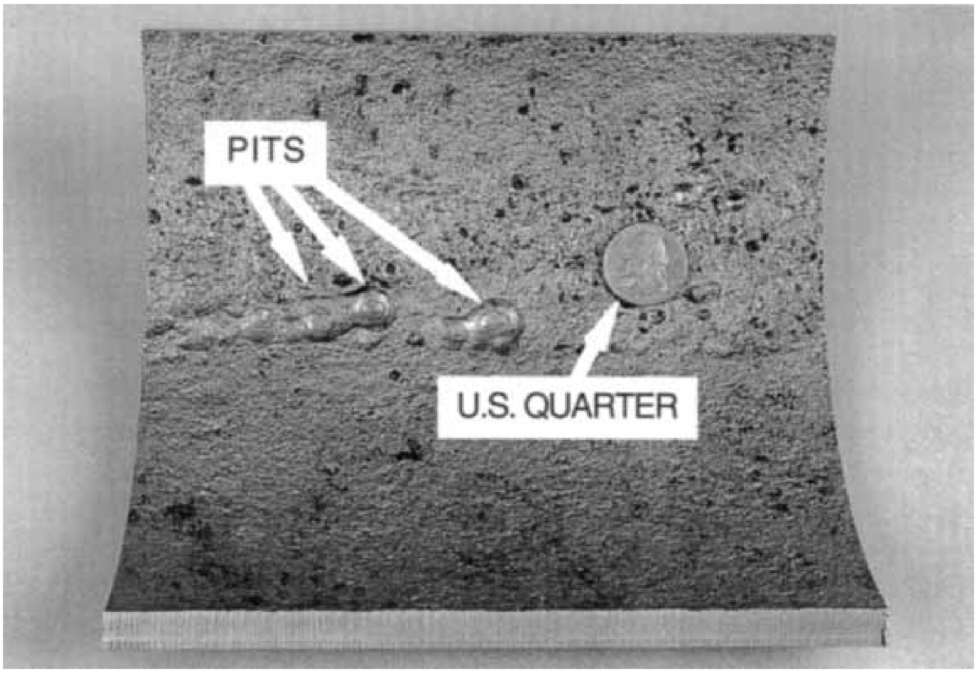
FIGURE 3. SCHEMATIC OF A CORROSION PIT UNDER A LAYER OF SCHMOO



The accumulation of schmoo is controlled in the large-diameter distribution lines by pigging. Cleaning pigs are run through the lines about once every 90 days; the scrapings are diverted to surface tanks and collected for disposal. Prodigious amounts of schmoo are removed from the distribution lines by pigging. As an example, 70,000 lbs of schmoo were recently removed from one 16" x 7,000' PW line; this works out to be about a schmoo accumulation rate of 2.5 lbs per square foot per 90 days - equivalent to a layer thickness of about 0.5". Although this is somewhat of an extreme example, it certainly is not isolated. More typically, schmoo accumulates in PW distribution piping at a rate of about 0.5 lbs per square foot per 90 days - equivalent to a layer thickness of about 0.1".

Pigging the distribution lines does not remove 100% of the schmoo - certainly a thin layer of schmoo "paint" is left by the pig. However, for whatever reason, the pigging appears to be adequate to mitigate corrosion in these lines: severe, isolated pits have not been observed in these lines. However, it is not possible to pig all PW lines. The small-diameter well lines (typically 6" or 8" pipe) that carry the PW to the individual injection wells cannot be pigged. Accumulations of schmoo of over 1 inch thick have been seen in some well lines. These heavy layers of schmoo show up in radiographs which are taken while inspecting the lines for corrosion. Although the internal diameter of the well lines is significantly reduced by such thick schmoo layers, this does not pose a operational problem: water velocities are sufficiently low, less than 5 ft/sec typically, that there is little pressure drop along the line. Although heavy schmoo accumulations in well lines do not restrict the water flow rates significantly, the schmoo apparently creates an environment that promotes bacteria growth (or, at least, does not retard bacteria growth) allowing isolated colonies to form, leading to scattered pitting.

FIGURE 4. PHOTO OF CORROSION PITS IN PW INJECTION WELL LINE



Including both the Eastern and Western Operating Areas, there are about 188 PW well lines at Prudhoe Bay. The cost of replacing one well line is several hundred thousand dollars. In late 1995, several water injection well lines in the EOA were replaced due to corrosion under schmoo. The high cost of their replacement and the potential stakes represented by the remaining PW well lines elevated the priority of mitigating corrosion in these lines. Control of the corrosion via a biocide seemed the most likely route, but with the heavy schmoo layers acting as protective armor, treatment of the bacteria using a biocide alone seemed impractical. What was needed was a means of removing the schmoo from the well lines, thus exposing the bacteria to attack. Various schemes were evaluated, including mechanical means. However, these were discarded in favor of a chemical means of removing schmoo. A search for a suitable (i.e., inexpensive) chemical was initiated.

EXPERIMENTAL

Plan of Attack

If a chemical could be found that would economically remove the schmoo, then the plan was to treat every WAG well immediately prior to the well being swapped from PW to MI. In this manner, there would be no schmoo in the well tubing to be dried by the MI and slough. This should prevent the wells from plugging and subsequently eliminate the need for expensive FCOs (fill clean outs).

Treating the WAG wells just prior to the swap to MI was good timing from the perspective of the surface water lines, as well. As previously explained, produced water is delivered to the well via a separate line than delivers the miscible gas injectant (MI). During the time that WAG wells are injecting MI, the water lines are shut in (stagnant). Cleaning the schmoo out of the well lines just before they are shut in may help control the growth of bacteria, especially while the lines are stagnant. If cleaning the lines alone does not achieve this end, then the well lines could be shut in with some amount of an appropriate biocide added to the fluid in the lines. This would provide an extensive exposure period for the biocide to penetrate any biofilms, effectively sterilizing the line. It is true that as soon as the line was put back on PW, it would be re-inoculated with bacteria. Even so, as long as the bacteria "decided" to colonize locations on the pipe other than where they were before, subsequent bacterial corrosion damage would not be additive to previous damage. The life of the well lines would be thus greatly extended even though corrosion associated with bacteria was not entirely eliminated.

Evolution of a Schmoo Dispersant

Over the past dozen years, oil field chemical companies have tried to find a chemical schmoo remover, but no promising candidates were identified. Even the harshest solvent/acid systems typically could do no better than 50-60% removal, though these could not be used in contact with the pipe. For several years, little progress was made. With the advent of the corrosion problem, the impetus was increased for finding an effective, inexpensive treatment.

Previously one of the authors had developed and been using successfully for several years a new class of nonionic surfactants.[2-5] A dispersant system had been developed to clean oil-based drilling mud out of wellbores prior to cementing casing. Oil-based muds offer certain advantages, but form a tenacious filter cake which can be difficult to remove. If the wellbore is not adequately cleaned prior to cementing, the bond between the cement and the wellbore will be compromised. The new dispersant proved highly effective, efficiently removing oil-based drilling mud filter cake. It was thought that the dispersant, or a modification thereof, might be well suited to the job of schmoo removal as well.

At first, the two applications may not seem related, but in fact the two are really quite similar. Oil-based drilling mud is basically a slurry of oil and clay (fine solid particulates); thus, the filter cake in the wellbore is essentially compacted oil-coated "dust". As explained, schmoo too is essentially oil-coated "dust". Although the "dust" in the schmoo is different from the "dust" in the filter cake, the two hydrocarbon "glues" binding the dust particles together are quite similar; a dispersant that was effective at removing one would likely be effective at removing the other.

The dispersant consists of two surfactants dissolved in a sodium hydroxide (caustic) solution with a small amount of an alcohol added. The breakthrough was in the use of a novel surfactant - an alkyl polyglycoside (APG), which is basically a sugar lipid molecule. The APG class of compounds is relatively new, having been commercialized in the late 1980's.[6] This hydrophilic surfactant is used in combination with a second lipophilic surfactant, a linear alkyl ethoxylate (LAE). Together, the two achieve efficient dispersion of the hydrocarbon oil-phase that "glues" the solid particles in the filter cake (or schmoo) together. Once the glue that binds the solids is removed, the remaining solids are easily washed away. The two surfactants are dissolved in a strong caustic solution as there is a synergy between the caustic and the surfactants: The surfactants act quicker and are more efficient in the very high-pH environment. Also, it probably does an excellent job of killing any bacteria that come into contact, due to its highly alkaline pH. A small amount of linear alcohol (C4, C5, C6) is added to stabilize the solution and to promote the formation of a microemulsion phase. Otherwise, the caustic and two surfactants will separate into a dense phase and a light phase. This is not to say that the ingredients are separating; both phases contain all ingredients, but in different ratios. The alcohol stabilizes the solution, keeping it a single, homogeneous phase.

This new dispersant had previously been optimized to remove oil-based drilling mud filter cake. Although it would undoubtedly remove schmoo, the best performance would be obtained if it were reformulated specifically for schmoo removal. Samples of Prudhoe Bay schmoo obtained from the pigging of the PW distribution lines were subsequently sent to the laboratory for this purpose.

Cleaning Test Procedure

Evaluation of the various dispersant formulations was done using a cleaning test. Metal coupons (strips of carbon steel sheet stock) were first weighed. Schmoo was then applied to the coupons, and then the schmoo-coated coupons were baked at 110 F in an oven. This process was repeated until the schmoo layer was about 6 mm (0.25") thick. The coupons were then reweighed - the difference being the weight of schmoo applied. Each coupon was then submerged in 30 cc of test dispersant held in a 42-cc vial; the coupons were then allowed to soak undisturbed for the prescribed length of time (typically 3 hours). During this soak time, the temperatures of the vials were maintained between 130-150 F in an air bath. After the prescribed time, the vials were placed in a rotator (held in a 60° angle from the horizontal plane) and the rotated at 24 rpm for 15 minutes. Rotation of the vials provided a controlled and reproducible amount of agitation to remove any lightly adhering schmoo residue. The coupons were then removed, dried, and reweighed. The difference between the pre- and post-soak weights was the amount of schmoo removed by the dispersant. The amount of schmoo removed divided by the amount of schmoo applied was the "schmoo removal efficiency" for that combination of formulation, soak time, and temperature. Such cleaning tests were performed for various dispersant formulations, with each test series being repeated three times to test reproducibility. When testing different formulations, typically the total weight % of the nonionic surfactants was held constant (APG + LAE = constant), and the relative amounts of the two surfactants were varied ($0 < APG / (APG + LAE) < 1$). The results were plotted as the schmoo removal efficiency versus mole weight % of APG.

RESULTS AND DISCUSSION

With soak time and temperature held constant, the dispersant formulation was systematically varied in exposure tests to find the optimum schmoo removal efficiency. Figure 5 shows the results typical of such "schmoo removal efficiency" vs. formulation tests. As can be seen in Figure 5, schmoo removal efficiencies well in excess of 90 per cent were readily achieved. Figure 6 is a photograph of schmoo-coated coupons after they were cleaned during such exposure tests. The optimum formulation was chosen as the one with the best cleaning efficiency with the lowest chemical ingredient cost and which remained stable.

FIGURE 5. EXAMPLE OF SCHMOO REMOVAL TEST RESULTS

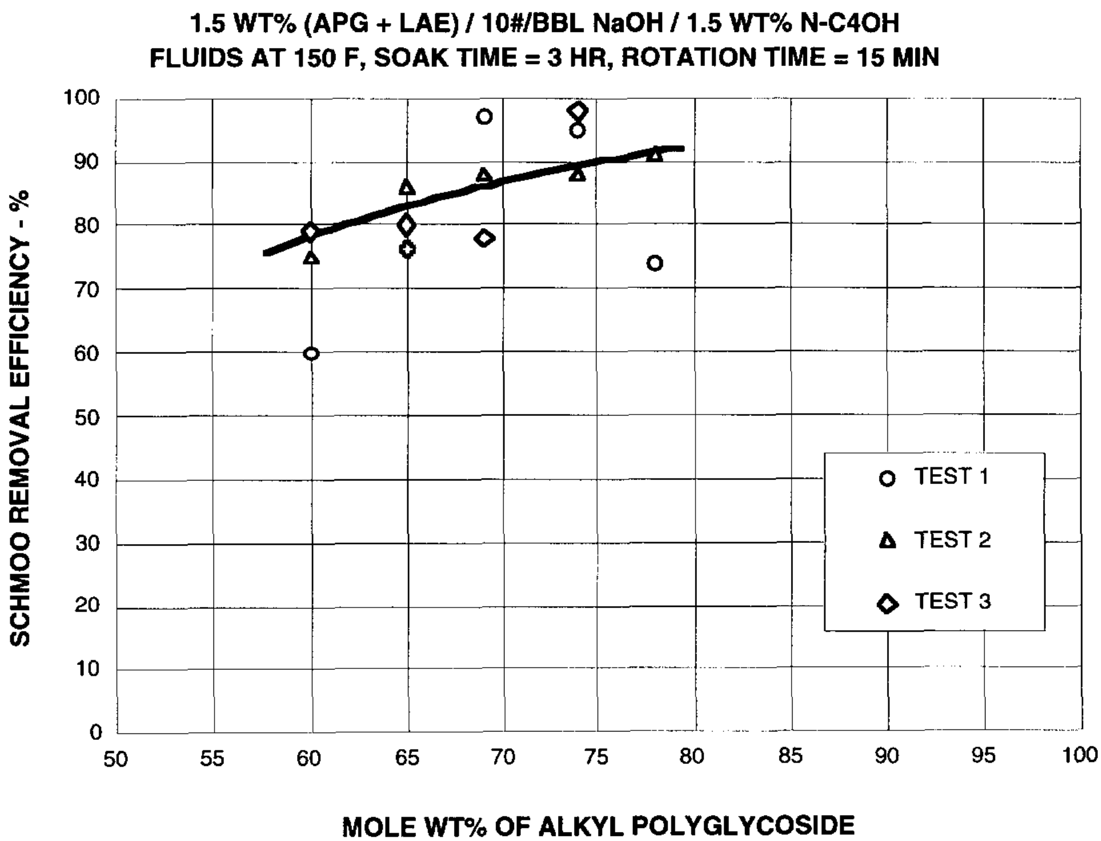
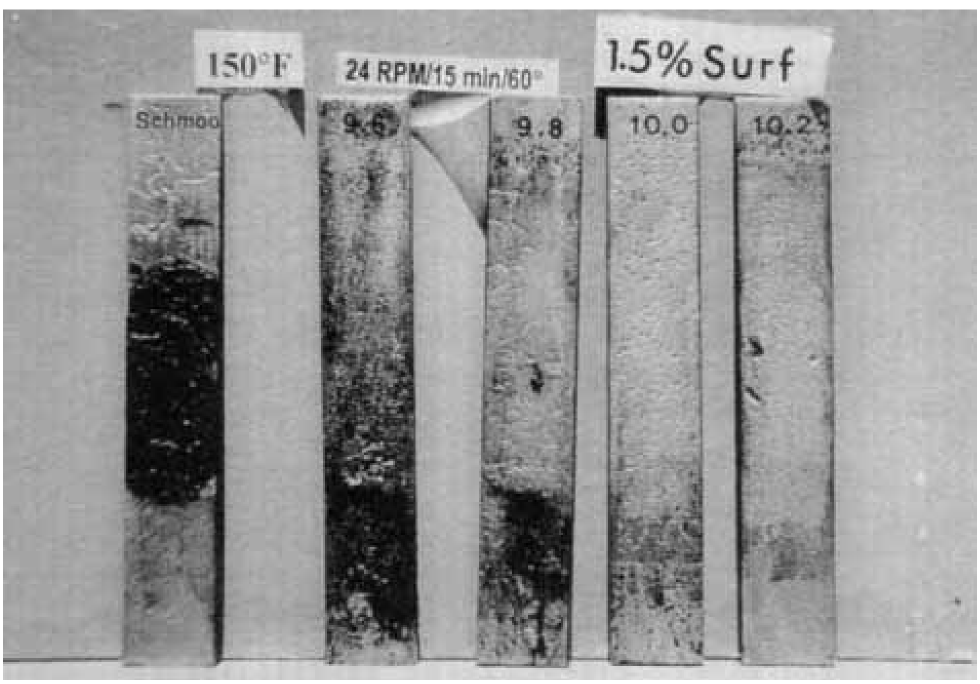


FIGURE 6. PHOTO OF SCHMOO-COATED COUPONS CLEANED IN EXPOSURE TESTS



From the cleaning tests, the dependence on schmoo removal efficiency versus soak time was determined. As might be expected, schmoo removal efficiency improves with longer soak times, but the rate of improvement diminishes with increasing soak time. In the end, a soak time of 3 hours was selected as this gave very good schmoo removal efficiencies without being an undue operational burden.

The "optimum" temperature was set by somewhat similar considerations. The Prudhoe Bay produced water system operates at approximately 150 °F (the temperature of the produced fluids at the surface). It was known from the cleaning tests that the schmoo removal efficiency improves with increasing temperature. It was decided to set the temperature for the treatments at 150 F as this gave good results, would not cause any stress to the system piping due to differential thermal expansion, was easily achieved in the field, and was about as high a fluid temperature that could be handled without being an undue hazard to personnel. (It should be noted that at somewhat slightly cooler fluid temperatures, i.e. 130 F, schmoo removal efficiencies were markedly reduced.)

Economic Evaluation Criteria

It was hoped that avoiding the cost of FCOs on WAG wells that otherwise would have plugged (about 1 in 3) would pay for the chemical treatment of all the WAG wells. The treatment costs were expected to be a fraction of the FCO cost, roughly 20-30% or so. In this case, the side benefits of freeing up the CTU (Coil Tubing Unit) and the ability to inject the recommended amounts of fluid would justify the treatments. The treatment program would thus be economic whether corrosion in the surface well lines was effectively mitigated or not. This is a very good situation in that it would likely be a year or more into the program before it becomes apparent whether corrosion in the well lines is being controlled. A rapid estimate of the economic viability of the dispersant treatments was attractive, even if incomplete. Thus, even though the "main" goal of the program is to mitigate corrosion in the well lines, the immediate success or failure of the schmoo removal chemical would be judged on its ability to prevent the need for fill clean outs in WAG injection wells.

Although the majority of water injection wells at Prudhoe Bay are WAG wells, there are about 50 water-only injection wells. Once the value of the schmoo remover was demonstrated in WAG wells, treatments would be expanded to include the water-only wells, too. These would be treated at some regular interval (e.g., twice a year).

First Field Test

With the formulation optimized and the soak time and fluid temperature established, it was time to test the dispersant in the field. The well selected for the first test was a PW WAG injection well that had a history of requiring a FCO following each swap from PW to MI. Since success was determined by whether or not wells plugged following the swap from PW to MI, and it was impossible to know whether a well would have plugged without the treatment, the effectiveness of the dispersant would have to be based on statistics. By selecting wells that have had a consistent history of plugging, the test would be that much more "definitive," requiring the least number of treatments in order to judge the dispersant's effectiveness.

Ingredients to make the dispersant were shipped to a blending facility in Fairbanks, Alaska. There, 520 bbls of the schmoo dispersant were blended (in four batches) in a 7,200-gallon, stirred, stainless steel blending tank. The blending tank was equipped with a load cell weighing system calibrated at ±5 lbs precision, which allowed accurate measurement of the ingredients. The blended dispersant was then loaded into four 6,300-gal tanks for transport. Just prior to shipment, the dispersant was heated to ~155-160 F via steam heating coils in the tanks. (The insulated tanks retain heat very well, only losing about 1-to-2 F per day.) The dispersant was then trucked the remaining 516 miles to Prudhoe Bay.

On February 20, 1997, the schmoo dispersant was pumped into the first test well. The procedure used was simple. The well was shut in at the PW manifold. A chemical injection line was connected to the well line. Schmoo dispersant was pumped into the well line, displacing the PW out of the well line and well tubing (total volume of the well line and well tubing was 520 bbls). While the ambient temperature was ~-20 F, the solution in the tanks was above 150 F, as desired. The dispersant was allowed to soak in the piping for approximately 3 hours. After which, the well was put back on PW to flush dispersant into the reservoir. After about a 4-hour flush, the well was shut in, and subsequently swapped to MI. For the first time in many swaps, the test well made the change to MI without plugging. The first test was a success!

Immediately prior to treatment, the test well had been taking PW at a rate of about 21,800 BWPD. During the flush following the treatment, PW injection rates improved markedly, eventually stabilizing at about 27,300 BWPD (choke setting and injection pressure were the same before and after the treatment). This caused us to realize that in addition to keeping wells from plugging and (hopefully) mitigating corrosion, the dispersant might also be useful for improving injectivities by removing schmoo in the perforations and in the near-wellbore region of the formation. The simple, single-step process used in the first test well was modified to become a two-step process designed to maximize collateral improvement to well injectivity. This two-step process has been used ever since.

The two-step treatment is illustrated in Figures 7 and 8. Figure 7 depicts Step 1: The injection well has been shut in (no longer flowing PW), and the well line, well tubing, and wellbore below the tubing have been filled with schmoo dispersant (150 F). Once filled, the piping is allowed to soak for 3 hours.

Figure 8 depicts Step 2: After the first 3-hour soak, the well is briefly put back on PW injection only long enough to displace most (~75%) of the dispersant in the piping. The well is then shut in again, leaving schmoo dispersant in the lower portion of the wellbore, across perforations, and in the near-wellbore region of the formation. The well is then allowed to soak for another 3 hours. After the second soak, the well is put back on PW for a few hours to flush the dispersant out of the piping and into the formation away from the well. At this point, the well is (hopefully) free of schmoo. The well is shut in and subsequently swapped to MI.

The second field test of the schmoo dispersant wasn't performed until some months later in May. The delay was due to the lead time required to obtain some of the dispersant ingredients, and in part to no suitable (i.e., troublesome) test wells being available. However in May, three wells with histories of plugging were scheduled to be swapped to MI. The first of these (test No. 2) was treated on May 8th using for the first time the two-step procedure depicted in Figures 7 and 8. Again, the test was a success. Injection rates before the treatment were 16,700 BWPD; after the treatment, 19,400 BWPD even though injection pressure was 5% lower. The well made the swap to MI without plugging.

FIGURE 7. INJECTION WELL TREATMENT WITH SCHMOO DISPERSANT - STEP 1

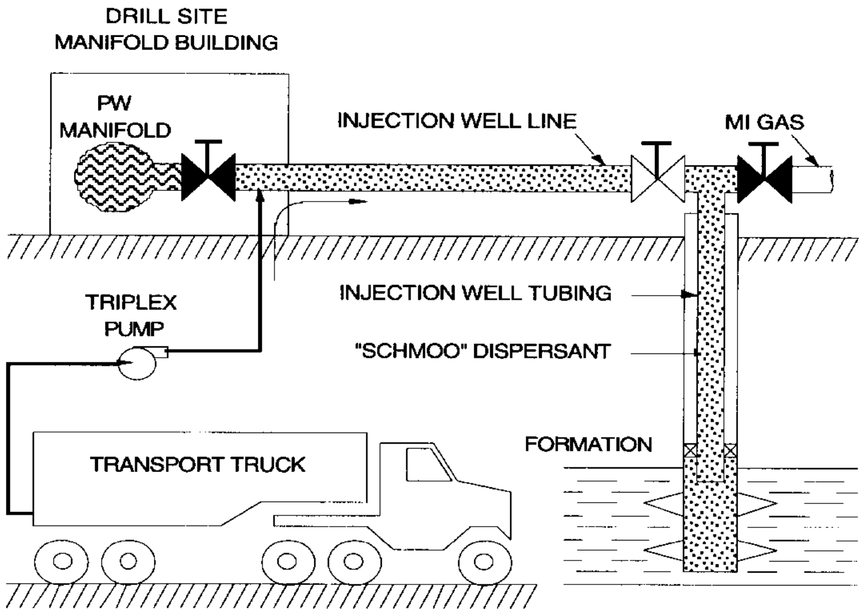
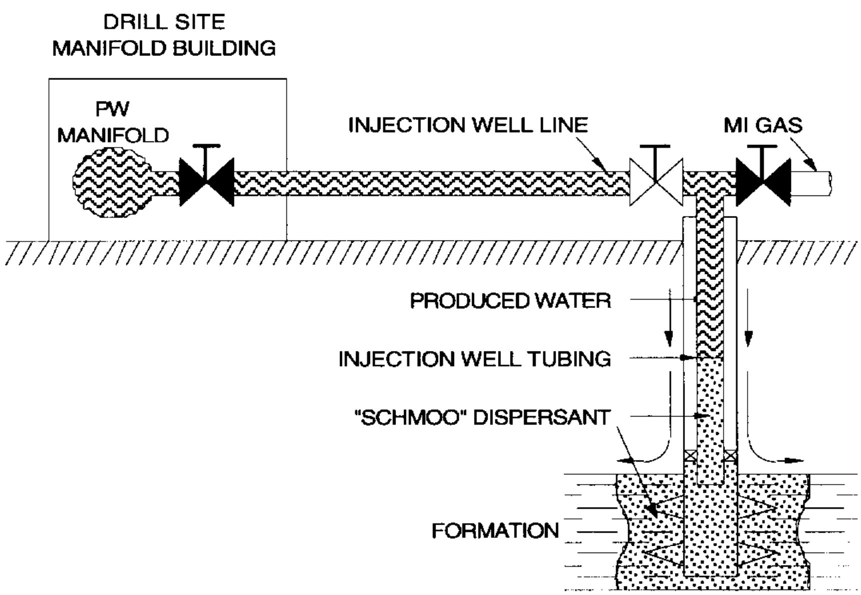


FIGURE 8. INJECTION WELL TREATMENT WITH SCHMOO DISPERSANT - STEP 2



The third field test, performed on May 12th, produced dramatic results. Prior to treatment, water injection rate was 7,900 BWPD with a line pressure of 1,962 psi. After the treatment, injectivity improved so significantly, that the well could not be operated at the same choke setting (line pressure). To keep from over-injecting the well, the well had to be choked back (line pressure reduced). Even so, injection increased to 10,300 BWPD with a line pressure of only 1,642 psi. Again, the well made the swap to MI without plugging.

At that point, even before the results of the fourth field test were known (later proved equally good), it was obvious that the treatments were having marked effects on injectivity and appeared to be equally successful in preventing well plugging. Operations made the decision that (in the Eastern Operating Area) treatment of WAG wells with schmoo dispersant prior to being swapped to MI would become standard operating procedure. With that, the test phase ended and the full-scale operation phase began.

Schmoo Dispersant Concentrate

With the transition of the treatments with schmoo dispersant to "standard operating procedure" status, the consumption of schmoo dispersant would increase dramatically. In its "as-used" form, the dispersant is 95% water. Hauling water the 516 miles from Fairbanks to Prudhoe Bay is an expensive proposition, and not at all necessary as water is one resource readily available at Prudhoe Bay. The cost of transporting the fully diluted schmoo dispersant from Fairbanks to Prudhoe Bay cost essentially the same as the dispersant ingredients! Clearly, this was not an acceptable situation.

Blending the ingredients at Prudhoe Bay to make the dispersant on site was possible, but not practical. For one thing, there was no existing blending facility that was either operational or could be made operational for a reasonable amount of money. For another, it seems that doing anything at Prudhoe Bay (or anywhere in the Arctic) costs at least twice as much as doing it most anywhere else. What appeared to be an optimum solution was to produce a concentrate in Fairbanks, truck the concentrate to Prudhoe Bay and store it on site. The concentrate could then be diluted with readily available hot water to produce schmoo dispersant on demand.

The objective was to develop a formulation of sufficient concentration to make the transportation costs small compared to the cost of chemicals, yet yield a stable fluid (no phase separation), and be easily handled (viscosity not too high). Balancing these competing requirements, resulted in the selection of a 6X concentration for the pre-blend. This reduced the transportation cost by approximately 70% to a reasonable percentage of the total. Higher concentrations would somewhat further reduce transportation costs, but the resulting viscosities became so high that handling the concentrate became onerous.

Currently, a 6X concentrate is pre-blended in Fairbanks, trucked to Prudhoe Bay, and stored in insulated tanks until needed. The concentrate is diluted with readily available hot water (160 F) on an as-needed basis to yield fully diluted schmoo dispersant at 150 F.

Raw Ingredient Improvements

As previously discussed, the schmoo dispersant is a reformulation of a chemical originally developed to remove oil-based drilling mud filter cake. The original application has fairly stringent performance requirements: drilling fluids may be exposed to a temperature gradient of 200 F or more (bottom-hole vs.

surface temperature). Practically speaking, a filter cake dispersant needs to be stable (no chemical decomposition) at temperatures of up to 300 F. This severely restricted the specific APG and LAE surfactants that could be used. Perhaps not too surprisingly, the particular surfactants capable of withstanding 300 F are more costly than their less-capable counterparts.

As a schmoo remover, however, the dispersant is only exposed to a small temperature gradient, and would never be exposed to temperatures much above 150 F: the high-temperature capabilities of the higher-cost surfactants were not needed. The schmoo dispersant concentrate was subsequently optimized using lower-cost surfactants. Interestingly, these lower-cost surfactants resulted in a dispersant with better cleaning performance than the initial formulation. Now, as a result of the development of a concentrate and substitution of lower-cost APG and LAE, the schmoo dispersant is quite economical.

Current Track Record

At the time of this writing, a total of 28 WAG wells have been treated with schmoo dispersant prior to being swapped to MI. All 28 wells were successfully swapped from PW to MI: Per the definition of success/failure, a perfect track record. The treated wells and treatment dates are listed in Table 2. It is interesting that in October, two WAG wells were swapped to MI without benefit of SBG treatments (due to unavailability of equipment). One of these two wells subsequently plugged. This is taken as evidence that the lack of need for FCOs in treated wells is due to the treatments, and not due to some fundamental change in the wells' behaviors.

Table 2 also lists "before" and "after" PW injection rates and injection pressures. The "before" values were recorded immediately before the SBG treatment, and "after" values were recorded a few hours after the treatment (after injection pressures and rates had stabilized). However, it is difficult however to assess from raw numbers whether the data represents improved injectivities. To properly see whether the treatment had a beneficial effect on well injectivity, the data must be plotted on a graph of the well's injectivity (rate vs. pressure). Figure 9 is the injectivity graph for Well 03-04, which was treated with SBG dispersant on 10/23/97. The white dots in the graph show the injection rates vs. injection pressures for the previous 21 days. The dashed line is a least-squares straight line fit to this data, defining the operating curve for this well (prior to the treatment). The single, black, "before" dot identifies where the well was operating immediately before the start of the treatment. As can be seen, the "before" dot falls squarely on the 21-day operating curve. The "after" data point (black square) shows where the well was operating after the treatment. As can be seen, in this case, the "after" data indicates a significant improvement in injectivity.

It is true, however, that not all treated wells showed improvements to injectivity similar to Well 03-04. In several cases, both the "before" and "after" data fell on the operating curve of the well. This is taken to indicate that injectivity in these wells was not significantly impaired prior to the treatments. However, it is believed that this does not indicate that the well would not have plugged following the swap to MI had the well not been treated. All injection wells accumulate schmoo while injecting PW. It is quite possible that a well could plug following a swap to MI even though its injectivity was not significantly degraded by the schmoo (the wells inject PW above fracture pressure).

TABLE 2. WELL TREATMENT HISTORY

NO.	DATE	WELL NO.	VOLUME	BEFORE TREATMENT PWI (1)	BEFORE TREATMENT FTP (2)	AFTER TREATMENT PWI (1)	AFTER TREATMENT FTP (2)
1.	02/20/97	03-07	520 BBLS	21.8	2,045	27.3	1,983
2.	05/08/97	03-17	363 BBLS	16.7	1,900	19.4	1,819
3.	05/11/97	09-22	316 BBLS	7.9	1,962	10.3	1,642
4.	05/11/97	09-40	232 BBLS	3.4	1,941	6.3	1,855
5.	06/13/97	09-10	300 BBLS	6.3	1,963	6.5	1,828
6.	06/13/97	09-19	300 BBLS	18.0	1,795	20.0	1,751
7.	06/14/97	16-11	270 BBLS	2.6	1,023	4.0	1,080
8.	06/15/97	13-22	300 BBLS	10.3	1,233	12.5	1,133
9.	06/16/97	12-33	270 BBLS	5.5	1,422	6.0	1,284
10.	07/07/97	17-08	300 BBLS	7.0	1,365	7.2	1,290
11.	08/17/97	03-10	300 BBLS	30.0	1,940	34.5	1,925
12.	08/18/97	12-20	300 BBLS	5.2	1,121	5.5	1,258
13.	08/18/97	14-27	300 BBLS	7.7	1,460	7.7	1,515
14.	08/28/97	16-10	240 BBLS	8.5	1,815	7.4	1,720
15.	08/28/97	16-16	300 BBLS	13.7	1,915	17.0	1,910
16.	09/06/97	12-27	300 BBLS	6.5	1,129	6.5	1,075
17.	09/12/97	14-21*	450 BBLS	8.0	1,190	5.4	1,445
18.	09/27/97	09-17	300 BBLS	18.5	1,525	17.6	1,427
19.	10/13/97	14-21*	440 BBLS	7.0	1,400	6.5	1,420
20.	10/13/97	14-25	100 BBLS	11.5	1,130	7.8	1,117
21.	10/20/97	12-23	300 BBLS	12.0	1,280	12.5	1,067
22.	10/23/97	03-04	485 BBLS	29.5	1,980	30.5	1,900
23.	10/23/97	03-06	275 BBLS	20.5	1,700	20.5	1,630
24.	10/23/97	03-07	510 BBLS	17.0	1,845	19.6	1,730
25.	11/04/97	14-36	300 BBLS	9.6	1,130	11.8	1,175
26.	11/07/97	17-15	240 BBLS	4.1	1,835	5.5	1,858
27.	11/08/97	16-03	270 BBLS	8.1	1,797	12.0	1,841
28.	11/18/97	16-02	300 BBLS	13.0	1,600	15.0	1,642
29.	11/20/97	03-11	300 BBLS	7.6	1,877	9.8	1,856

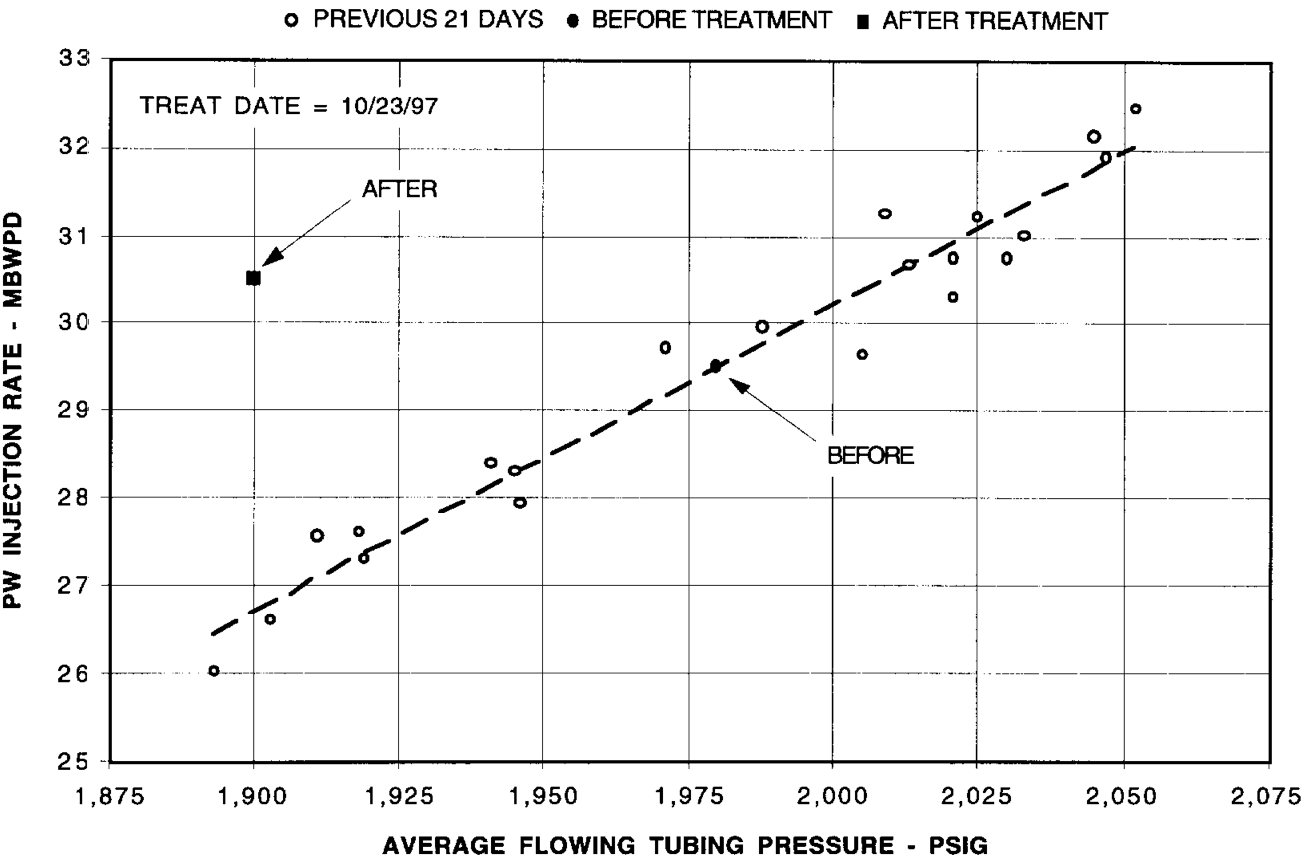
NOTES:

1. PWI = PRODUCED WATER INJECTION RATE, MBWPD.
2. FTP = FLOWING TUBING PRESSURE, PSIG.

* Well 14-21 swapped to MI on 9/13. Swapped back to PW on 9/20 due to leaking valves. Second treatment on 10/13 done to remove 20' of fill covering lower perforations. Well left on PW after second treatment.

A similar, remedial treatment was tried in the Eastern Operating Area with success. Well 14-21 is listed in Table 2 twice (first treated on 9/12, and again on 10/13). Following the first treatment, the well was swapped to MI. However, soon after the swap, a leaking valve was discovered and the well was swapped back to PW. During the subsequent well work, an ELM - an accurate wire line survey - was run. This survey showed that there was fill covering some of the lower perforations. A second SBG treatment was pumped, this one designed to remove fill from the wellbore. Subsequently, another ELM survey showed that 20 feet of fill had been removed, uncovering the lowest active perforation. The well was left on PW following the second SBG treatment.

FIGURE 9. WELL 03-04 INJECTIVITY



In the Eastern Operating Area of Prudhoe Bay, the schmoo dispersant is primarily being used as a preventative measure in an attempt to keep wells from plugging. In the Western Operating Area, the schmoo dispersant is currently being used as a remedial measure in attempts to unplug wells that have already plugged. This is a very challenging application for the schmoo dispersant as once the schmoo has sloughed and fallen to the bottom of the well, the surface area of the schmoo that is exposed to the dispersant is much reduced. Nevertheless, the two attempts in the Western Operating Area using the schmoo dispersant to restore injection after the wells had plugged were reportedly successful.

It is clear that the treatments have greatly reduced the number of FCOs required in WAG wells - the short-term success/failure criteria for these treatments. As a collateral benefit, the data shows that in many of the wells injectivity has also been improved. However, it will be some time before it is apparent whether periodic removal of schmoo accumulations in the well lines alone is sufficient to mitigate corrosion in these well lines (the primary reason for the treatments) or whether additional measures, such as biocides, will be required.

What's Next?

Numerous other applications for the dispersant have been identified.[7] Its use as a remedial treatment rather than as a preventative treatment on plugged wells is still evolving. Dispersant is being used as the solvent rather than diesel + xylene for fill clean outs with coiled tubing. It is being tried in production wells as a means of reversing formation damage left by drilling muds. The dispersant may provide a means of removing accumulations of oil-coated solids from separation process vessels without requiring a plant shut-down and a vessel entry. Dispersant will be tried as a pill (chemical slug) in front of the cleaning pigs run through the PW distribution lines; this may improve cleaning effectiveness and ease disposal problems, possibly even allowing the dirty water to be sent down-hole. And further optimization of the formulation itself may be yet possible.

CONCLUSION

A novel dispersant consisting of two surfactants - an alkyl polyglycoside (APG) and a linear alkyl ethoxylate (LAE) - dispersed in an aqueous solution of sodium hydroxide has proven highly effective at removing heavy layers of schmoo (oil-coated particulates) found inside of the produced water piping system at Prudhoe Bay. By doing so, the plugging of water injection wells has been greatly reduced, as has the expense associated with cleaning out plugged wells. In many of the treated wells, injectivities have also been improved. Furthermore, it is expected that removal of the schmoo will also mitigate the corrosion in the water injection well lines.

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7. Patents pending.