Stability and Corrosivity of Packer Fluids

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What is required of a fluid to be left in the casing-tubing annulus of a well? This question has been given careful consideration from time to time over the past twenty years, and yet is still a matter of controversy. There are logical explanations for why the packer mud problem has in the past become acute, has appeared to be solved, and then has reappeared in somewhat different form. To understand the situation, one should keep two things in mind: (1) Operations are simplified if the fluid used for drilling the well can be left as the packer fluid and (2) performance of a packer fluid involves consideration of hydraulic properties (density, rheology, gelation) as well as corrosion characteristics.

A brief review can illustrate how changes made to provide a better drilling fluid have sometimes created packer fluid problems; how packer fluids designed for better hydraulic properties may have made corrosion problems more severe; and how packer fluids designed for corrosion protection have at times resulted in hydraulic problems.

HIGH-pH MUDS

During the 1940's difficulties were being experienced in controlling flow properties of the weighted muds required for drilling abnormally pressured formations. A salt water flow or severe cement contamination would thicken the mud excessively, cause stuck pipe and lost circulation, and result in the hole being lost. Development of the high pH lime-treated mud gave much better tolerance for salt water, cement, and shale solids. This mud came into widespread use for drilling and was customarily left in the casing-tubing annulus upon completion. Although little attention was given to corrosivity of mud at that time, the highly alkaline lime mud probably gave good corrosion protection.

Unfortunately, experience soon showed that this type of mud gelled excessively or even solidified when exposed to downhole formation temperatures for any significant period of time. Laboratory studies reported by Gray, Neznayko, and Gilkeson[1] revealed that free hydroxyl in the high pH mud reacted with silica and silicates to form cementatious materials, resulting in gelation or solidification of the mud. In spite of years of research, no practical solution to this problem has yet been found.

Although raising the pH of a water-base mud that is to be left in a well can lessen the corrosivity, if there is excess alkali and ample clay concentration in the mud, the above reactions will cause gelation and result in a time-consuming, expensive operation when the well is worked over. If there is insufficient clay in the packer mud, settling of weighting material will necessitate washing-over tubing and make workover operations expensive. If the concentration of alkali in mud is exceeded by that of acid formers (such as the thinners and filtration control agents used in most drilling muds) the pH of the mud will eventually drop and the corrosion protection will be lost.

CLAY-BARITE PACKER FLUIDS

When the industry became aware that highly alkaline water-base muds containing a high concentration of organic material were chemically unstable, attention was directed toward formulating clay-water slurries weighted with barite and containing little or no alkali or organic material. Usually the clay selected was bentonite, but attapulgite was also tried. The hope was that the weighted clay-water slurry would show neither settling nor excessive gelation and, when placed in the well annulus, would remain unchanged by time and temperature. Such clay-water slurries, however, are very sensitive to either dispersants or flocculants. Mixing with drilling mud during displacement, or contamin-

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ation from cement or salt water during completion operations, can cause either settling or excessive gelation. Experience has also shown that while this type of mud may be considered relatively noncorrosive, it offers no protection from corrosive contaminants.

MEDIUM-pH DRILLING MUDS

Development of the chromelignosulfonate additives made possible medium pH waterbase drilling muds that had good tolerance for cement, salt water, and drilled solids. There was hope that this type of mud also offered a solution to the packer mud problem, since there was no need for a large excess of the very reactive alkali. By 1960, however, there was ample evidence that a problem still existed.[2] Even then workover problems caused by gelled or settled mud were blamed on improper attention to the solids content and improper chemical treatment of the packer mud when the well was completed. Corrosion problems that were reported tended to be attributed to some contaminant rather than to any corrosivity developing in the medium pH water-base mud.[3]

By 1965, instances of extreme and obvious corrosion of tubing and casing became too numerous to be ignored. Studies instigated by these difficulties revealed that even the medium pH water-base muds were quite reactive bacterially[4] and electrochemically.[5]

The general instability of commonly-used packer muds was clearly indicated by a survey reported by T. S. Carter[6] of twenty-five wells on the Louisiana Gulf Coast that were worked over during 1966. Data for ten of these wells (for which mud pH information was available) are shown in Table I.

TABLE I

Workover Results of South Louisiana Wells Having Water-Base Packer Fluids

Well	Depth, Feet	Age, Years	Mud pH at Completion	Mud pH at Workover	Sulfide on Tubing	Remarks
2	12,500	5-1/2	10.0	8.4	Positive	Brittle failures of tubing
5	12,980	6-1/2	10.5	8.8	Negative	Casing failure
7	13,600	1-2/3	11.0	7.0	Positive	No failures
8	10,200	1-1/12	11.0	9.2	Positive	Tubing replaced, downgraded
10	11,880	1-1/6	9.0	8.5	Positive	No failures
13	4,200	17	8.0	8.0	Negative	No bacterial activity on sulfide in mud
14	9,400	4-1/3	7.5	7.1	Positive	Severe external tubing corrosion
21	9,000	6-1/3	10.0	8.4	Positive	Tubing failure
23	9,650	4	10.0	7.0	Positive	No failures
25	10,000	7	11.4	9.6	Negative	Tubing failure

The value for mud pH at completion is simply the last measurement reported during completion and may not represent the mud actually left in the well. Similarly, the value for mud pH at workover is representative of the pH range, but the pH of mud circulated from the casing-tubing annulus during workover might vary significantly for different depths. While a direct comparison of the two values might not be valid in every instance, the loss of alkalinity with time is obvious. Muds with initial pH values as high as 10.5 to 11.5 underwent reactions during periods of only one to seven years that dropped the pH values to the range of 7.0 to 9.6.

Most of these wells had tubing or casing failures of some sort and sulfide was found on the outside of the tubing from most of the wells. Even though the muds were obviously reactive with the pipe, there was no simple, direct correlation between mud properties and corrosive attack. Many factors other than the composition of the mud are involved, such as the metallurgy of the pipe, stresses to which it is subjected, and the care taken in handling. The brittle failures of the P-105 tubing in Well 2, for example, occurred during extensive fishing and washover operations made necessary because the 14 lb/gal gyp/lignosulfonate packer mud had settled and stuck the packer.

In Well 8 the salinity of the seawater/lignosulfonate mud may have been a factor in the drastic drop in pH (11.0 to 9.2) and the external corrosion of the tubing during only thirteen months of service.

No failures were reported for Well 10 even though there was sulfide on the tubing and 2000 ppm sulfide was found in the mud that had been treated with sulfited bark extract. External corrosion of the tubing might have been more severe had the exposure time been more than the fourteen months.

The mud left in the 4200-ft Well 13 was essentially native mud lightly treated with quebracho. Bacterial activity was probably stifled by the low concentration of organic nutrient and electrochemical activity was probably limited by the low-temperature fresh-water environment.

The packer fluid in Well 14 was a bentonite/CMC slurry weighted with barite. The sulfide on the tubing and the severe external corrosion probably was caused by contamination of the packer fluid with chemically treated drilling mud during the displacement.

RECOMMENDATIONS FOR WEIGHTED PACKER FLUIDS

Experience has shown that weighted water-base packer fluids, as placed using present pumping techniques, are inherently unstable and corrosive. Yet the economics of a given situation may call for accepting some instability and corrosivity to permit leaving the drilling mud as the packer fluid. For such a situation, sterilization of the mud with a biocide (selected for compatibility) can lessen both the instability and corrosivity. Adjustment of pH to the 11 to 11.5 range will lessen corrosivity at the risk of excessive gelation or settling.

Recommendations for treating water-base packer muds, as well as guidelines for the selection of special packer fluids, were given in a paper by Simpson and Barbee[5] in 1967. Their conclusion was that a properly formulated, electrically, nonconductive oil mud would provide the most stable mud properties and surest corrosion protection for any critical situation. Being directed primarily toward corrosion aspects, that paper did not discuss the formulation of weighted oil muds for optimum hydraulic properties.

Suspension of weighting material in an oil mud is a 'difficult problem' even during drilling operations when the mud does not have to be left quiescent for extremely long periods of time. When an oil mud is to be left in a well for years, the problem becomes impossible unless a mud can be formulated to have a reasonable viscosity while being pumped and to develop a true gel structure to suspend the weighting material under static conditions.

SUSPENSION OF WEIGHTING MATERIAL IN OIL MUDS

The use of oil dispersible clays for suspension of weighting material in oil muds was described in 1961.[7] Recent laboratory studies further emphasize the unique performance of oil dispersible bentonite in permitting the formulation of stable weighted packer fluids. For these tests a 16 lb/gal base mud was prepared in the laboratory to have properties suitable for drilling operations. Composition was 0.58 bbl of diesel oil, 15 lb of high molecular weight soap, 8 lb of oil dispersible organic colloid, 0.1 bbl of water, 444 lb of barite, and 2 lb of oil dispersible attapulgite per barrel of mud. Samples of this base mud were treated with various materials that have been used in attempting to get long-term suspension of barite in oil muds. The results are shown in Table II.

TABLE II

Laboratory Tests of Weighted Oil Mud Packer Fluids

Suspension Agent Added per bbl of Base Mud	None	Water, 0.1 bbl Emulsifier, 5 lb Barite, 59 lb	Oxidized Asphalt 50 lb	Oil Dispersible 5 lb	Bentonite 8 lb
		(Tested Initially at 75°F)			
Plastic Viscosity, cp	39	525	68	78	115
Yield Point, lb/100 sq. ft.	3	250	17	45	95
Initial Gel, lb/100 sq. ft.	2	25	3	28	59
10-min. Gel, lb/100 sq. ft.	2	40	6	31	74
		(Tested Initially at 195°F)			
Plastic Viscosity, cp	12	42	21	20	28
Yield Point, lb/100 sq. ft.	4	5	1	4	43
Initial Gel, lb/100 sq. ft.	2	3	3	13	24
10-Min. Gel, lb/100 sq. ft.	3	6	5	17	26
		(Tested at 75°F After Aging 16 Hours at 300°F)			
Mud Wt, lb/gal (Top Half)	11.0	11.0	11.5	15.0	16.0
Mud Wt, lb/gal (Bottom Half)	21.0	21.0	20.5	17.0	16.0
Plastic Viscosity, cp	51	345	99	87	104
Yield Point, lb/100 sq. ft.	4	105	5	36	68
Initial Gel, lb/100 sq. ft.	1	10	2	32	50
10-Min. Gel, lb/100 sq. ft.	9	20	19	51	55
		(Tested at 75°F After Aging Two Weeks at 300°F, 100 Psi)			
Mud Wt, lb/gal (Top Half)	11.0	11.0	11.0	14.0	15.0
Mud Wt, lb/gal (Bottom Half)	21.0	21.0	21.0	18.0	17.0
		Tested at 75°F After Aging 16 Hours at 300°F, 10,000 Psi)			
Mud Wt, lb/gal (Top Half)	13.0	12.5	13.5	16.0	16.0
Mud Wt, lb/gal (Bottom Half)	19.0	19.5	18.5	16.0	16.0

RESULTS OF LABORATORY AGING TESTS

Examination of data in the first column of Table II shows that the base mud had considerably lower plastic viscosity when tested at 195°F, as compared to the tests at 75°F, but the mud still had a measurable yield point. Severe settling of barite occurred when the base mud was aged only 16 hours at 300°F at a pressure of 100 psi. Mud from the top half of the aging cell weighed 11.0 lb/gal while that from the bottom half weighed 21.0 lb/gal. The settling was no worse after two weeks. Aging sixteen hours at 300°F with 10,000 psi pressure resulted in less settling (13.0 and 19.0 lb/gal, top and bottom). These results indicate that the untreated mud might be used for drilling even with a bottom-hole temperature of 300°F because the mud temperature would be in the 195°F range during circulation. When static, the mud in the bottom of the hole would tend to thin as the temperature approached the 300°F range. The hydrostatic pressure provided by the mud column, however, would cause the viscosity of the oil in the mud to be increasing with depth, and settling might be slowed enough to permit tripping to change bits. The settling would probably interfere with prolonged logging or testing, and the mud certainly would not be satisfactory as a packer fluid.

Thickening of the oil mud with a high concentration of **oxidized asphalt (second column of Table II)** gave what measured as high plastic viscosity, yield point, and gel strengths when tested at 75°F, but the yield point and gel strengths were scarcely higher than those of the untreated mud when tested at 195°F. Settling of barite when aged at 300°F was just as severe, even with a confining pressure of 10,000 psi. This type of additive gave increased plastic viscosity, especially at the lower temperatures where it was not needed and where the principal effect would be to slow the drilling rate drastically. The higher plastic viscosity can reduce the settling rate but does not stop settling of weighting material. A true gel structure is required to prevent settling, and the asphalt does not provide this gel structure as elevated temperature. This mud would not be satisfactory for drilling or as a packer fluid.

Increasing the viscosity of the oil mud with additional **water and emulsified (third column of Table II)** had much the same effect as the addition of the oxidized asphalt and for about the same reasons. Increasing the concentration of emulsified water gave a higher plastic viscosity because of the greater number of water droplets dispersed in the continuous oil phase. The tests at 195°F show that yield point and gel strengths were not improved. Settling when aged at 300°F was about the same as for untreated mud. Water content of an oil mud might be increased as an economical method of increasing plastic viscosity when needed for hole cleaning or as an economical means of improving filtration under certain conditions. Water can certainly be emulsified in oil to increase density in the low-weight range. For long-term suspension of barite in oil muds at elevated temperature, however, materials presently used to emulsify water do not provide the necessary gel structure.

Treatment of the base mud with 5 lb/bbl of **oil dispersible bentonite (fourth column of Table II)** gives a significant increase in yield point and gel strengths even when tested at 195°F. There was far less settling when aged at 300°F and 100 psi for sixteen hours then at 300°F with 10,000 psi pressure. The oil dispersible bentonite gives a reversible gel that develops most of its strength very quickly. This makes possible an oil mud weighted with barite that has a plastic viscosity and yield point low enough for pumping, but a gel strength high enough at elevated temperature and pressure to prevent settling. The aging test of the mud at 300°F and 100 psi showed some settling. This might be significant in a shallow high-temperature well such as a steam injection operation, although intermittent heating and cooling would no doubt create intermittent layers of high-solids mud that would hinder further settling. Performance of this mud would be quite satisfactory as a packer fluid for a deep high-temperature well where the hydrostatic pressure of the mud column would offset the thinning effect of the downhole temperature. It is unfortunate that the stability of the mud is not indicated by the test at 100 psi. Equipment is not generally available in the field for testing at elevated temperature and at pressures in the 10,000 to 20,000 psi range. Treatment therefore must often be based on experience, understanding of the mud additive, and judgement in the evaluation of the 100 psi aging tests.

Treatment of the base mud with 8 lb/bbl of **oil dispersible bentonite (fifth column of Table II)** gave little difference in plastic viscosity but much higher yield point and gel strengths when tested at 195°F. There was no settling of barite when aged at 300°F for sixteen hours using either 100 psi or 10,000 psi confining pressure. This mud would be excellent as a packer fluid. The electrical stability after aging two weeks at 300°F was greater than 500 volts, showing that the mud remained electrically nonconductive. This treatment would provide both stability and corrosion protection.

PLACEMENT OF HIGHLY GELLED OIL MUD PACKER FLUID

Packer fluids must often be pumped through small diameter tubing or a small annulus. At such times a compromise may be necessary to have reasonable fluidity for placement and adequate gelation for assurance that barite will be suspended. The data for 5 and 8 lb/bbl of oil dispersible bentonite illustrate how this compromise can be made. Field aging tests at 300°F and 100 psi would show that the 8 lb/bbl treatment would give sure suspension of barite and would be recommended if no pumping problems were anticipated. For close pumping tolerances, the 5 lb/bbl treatment would be recommended based on the tests at 195°F showing lower yield point with good gel strength.

FIELD EXPERIENCE WITH WEIGHTED OIL MUD PACKER FLUIDS

Close correlation has been found between laboratory tests such as shown in Table II and field results where weighted oil muds have been left as packer fluids. Two wells in the Ship Shoal area of South Louisiana offer good examples. These are 16,000-ft wells with 3-1/2-in. high-strength tubing inside 7-in. casing. Bottom-hole temperature is about 280°F. The wells are customarily drilled with oil mud containing 20 to 30 per cent water by volume.

One well was completed in 1964, with the untreated drilling mud left as the packer fluid. Properties of this mud as treated at flowline temperature of about 120°F are given in Table III.

TABLE III

Untreated Oil Mud Left As Packer Fluid In Ship Shoal Well

Mud Weight, lb/gal	11.3	Electrical Stability, Volts	290
Plastic Viscosity, cp	18	Oil, % by Volume	54
Yield Point, lb/100 sq. ft.	7	Water, % by Volume	30
Initial Gel, lb/100 sq. ft.	2	Solids, % by Volume	16
10-Min. Gel, lb/100 sq. ft.	5		

After two and one half years, the well was worked over to produce from a different zone. There was difficulty in pulling the tubing out of the packer. Eventually the tubing was pulled and a work string used to go back into the well, establishing circulation every 5000 feet. Settling of solids had occurred and the mud weight was found to range from 8.4 lb/gal to 18.4 lb/gal. The lightest mud was in the top of the annulus and the heaviest in the bottom, but there were alternately light and heavy intervals over the entire depth. In spite of the settling, the emulsion remained stable (electrical stability, 240 volts) and the tubing was in excellent condition. There was no sulfide or carbonate on the tubing and no sulfate on bacterial activity in the mud. The oil mud was treated with oil-dispersible bentonite and left as the packer fluid after the workover.

A similar well was completed in 1965, except that the oil mud was treated with oil dispersible bentonite prior to being left as the packer fluid. Properties of this treated mud are given in Table IV.

TABLE IV

Oil Mud Treated With Oil Dispersible Bentonite And Left In Ship Shoal Well

Mud Weight, lb/gal	10.2	Electrical Stability, Volts	200
Plastic Viscosity, cp	43	Oil, % by Volume	52
Yield Point, lb/100 sq. ft.	19	Water, % by Volume	38
Initial Gell, lb/100 sq. ft.	14	Solids, % by Volume	10
10-Min. Gel, lb/100 sq. ft.	20		

When this well was worked over to change production zones after two and one half years, the tubing was pulled from the packer with 30,000 lb in excess of the pipe weight. The mud was circulated through the tubing with no difficulty. The mud weight of the packer fluid circulated from the well varied only from 9.2 to 11.9 lb/gal and the funnel viscosity from 78 to 110 seconds. There was no indication of corrosion of the high strength tubing. The oil mud from the annulus (mixed with the new oil mud used for the workover) was treated with additional oil-dispersible bentonite and left again as the packer fluid. The successful workover operation was accomplished with a minimum of time and expense.

ALKALINITY OF OIL MUD PACKER FLUIDS

An important aspect of the use of oil muds as packer fluids is that lime can be added to provide a reserve alkalinity without the detrimental effects caused by excess lime in water-base packer fluids. The oil muds left in the Ship Shoal wells contained one to three lb/bbl of excess lime, but there was no excessive gelation or solidification such as would have been caused by that amount of lime in water-base muds left for two and one half years at a temperature of 280°F. T. S. Carter[8] has reported data for an 18 lb/gal oil mud of similar composition that was circulated out after being in the annulus of a 15,000-ft well in Terrebonne Parrish, Louisiana for five years. Alkalinity tests showed the mud to still have the equivalent of nearly one lb/bbl of lime. A 9.5 lb/gal oil mud left in the annulus of a 16,000-ft well in Pecos County, Texas for one year still had the equivalent of about two lb/bbl of free lime.

Tolerance for lime and the ability to retain alkalinity after prolonged exposure to high temperature is particularly important when the produced fluid contains acidic materials such as hydrogen sulfide and carbon dioxide. The packer fluid must be able to withstand occasional contamination such as from thread leaks resulting from intermittent production of gas at high pressure. The high molecular weight soap and the amine derivatives in the oil mud provide an oil-wetting film to protect even high strength pipe from the corrosive acidic materials. The reserve alkalinity of the mud serves to react with the acids and retain the desired mud properties. Unlimited contamination from a continuous leak could not be tolerated, of course, but the reserve alkalinity can keep the packer fluid in condition for a reasonable period of time to allow the necessary workover operations to be conducted.

UNWEIGHTED PACKER FLUIDS

Packer fluid problems are greatly simplified if pressures are such that suspension of weighting material is not required. Where no high strength pipe is involved, clear liquids can be treated with concentrations of film-forming corrosion inhibitors sufficient to protect against corrosive effects of contaminants incorporated during placement or while the well is being produced. Care should be taken in selecting the clear liquid to be used as well as in choosing the corrosion inhibitor.

Experience with a 15,000-ft well in Pecos County, Texas offers an example of corrosion that can result if the inhibitor is not effective. When the well was completed in 1965, a 9.5 lb/gal brine treated with about 5000 ppm of sodium bichormate was left as the packer fluid in the annulus between the two strings of C-75 and the S-95 casing. The Ellenburger production containing both hydrogen sulfide and carbon dioxide is known to be corrosive. The brine used as the packer fluid was considered noncorrosive and it was hoped that the chromate would protect against any produced fluid that got into the annulus. After two and one half years leaks had developed in both tubing strings and the well was worked over. When pulled, both strings of tubing were found to have severe external pitting. The worst of the corrosion was in the upper 2600 ft. The well was recompleted, leaving in the annulus a 9.3 lb/gal oil mud containing 5 lb/bbl of lime. Oil dispersible bentonite was used to provide suspension of the calcium carbonate weighting material at the 250°F bottom-hole temperature.

INHIBITED OIL AS A PACKER FLUID

High strength tubing and casing used in sour production can best be protected from cracking by a packer fluid having oil as the continuous phase to keep water and sulfide from contacting the steel. When the packer fluid is a weighted oil mud, the emulsifiers in the mud serve to incorporate contaminating water as a dispersed phase. Where pressures are low enough that unweighted oil can be used as the packer fluid, attention should be given to protecting against contaminating water that is free to migrate and coalesce in the annulus.

Laboratory tests studies of this situation have been made. For one such study, a mixture of 90 per cent by volume of water containing 70,000 ppm sodium chloride was purged with carbon dioxide. Various corrosion inhibitors were added, followed by water saturated with hydrogen sulfide, and the mixture was shaken vigorously in a glass cylinder. The cylinders were then placed in stainless steel cells. Banded prestressed roller bearings (described by Bush, et al[9]) were suspended in the cylinders such that two were immersed in the oil layer and two in the water layer. The cells were capped and aged at 250°F for 30 days. Results of such tests are shown in Table V.

TABLE V

Diesel Oil Packer Fluids Aged 30 Days at 250°F

Inhibitor	Condition of Banded Prestressed Bearings In Oil Layer	Condition of Banded Prestressed Bearings In Water Layer
Blank	Cracked, differential corrosion	Cracked, pitting, differential corrosion
10,000 ppm of Water Dispersible Organic*	Not cracked, no localized corrosion	Cracked, differential corrosion
10,000 ppm of Oil Dispersible Organic**	Cracked, differential corrosion	Not cracked
5,000 ppm Each of Water Dispersible and Oil Dispersible Organic	No localized corrosion, Not cracked	Not cracked, no localized corrosion

*Amine salt with surfactant for water dispersibility

**Amine salt with ammonium hydroxide

In the laboratory tests the combination of properly selected oil-dispersible and water-dispersible inhibitors protected against both surface corrosion and cracking even with prolonged exposure at 25°F. Under the laboratory conditions there was good mixing and ample opportunity for the water dispersible inhibitor to go to the water phase. The short column of oil and water during the aging in the laboratory did not stimulate a long column such as a deep well annulus where there might be more separation of inhibitor, particularly from the brine. Based on the favorable laboratory tests, clear diesel oil treated with mixed inhibitors has recently been placed in the annulus of a deep West Texas well. The placement was made with no difficulty and samples were obtained for continued laboratory studies.

SUMMARY

What is required of a fluid to be left in the casing-tubing annulus of a well? The ideal answer is a fluid that can be pumped without undue difficulty, will gel to suspend weighting material for the life of the well, will protect against any type of corrosive attack, and will degel readily to permit the tubing to be released and the fluid circulated for use in workover operations.

An oil mud treated with oil-dispersible bentonite has been found to fill these requirements under a wide variety of field conditions. Where unweighted oil can be used, combinations of temperature-stable oil-dispersible and water-dispersible amine salts have been effective in laboratory tests and are being tried in the field.

Economics may dictate that something less than an ideal packer fluid be used where high density is required. This usually means leaving the water-base drilling mud as the packer fluid. This practice is not recommended if high strength pipe is involved. The pH of the mud should be adjusted to about 11.5, the mud should be sterilized with a suitable biocide, and a relatively expensive workover operation should be anticipated because of excessive gelation or settling of the mud.

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