

PAINT INDUCED ELEVATION OF OIL POWER FACTOR IN ELECTRICAL EQUIPMENT

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ABSTRACT

An increase in the power factor of oil after a few years of service has been observed in transformers, tap changers, and power distribution switchgear. The increase is most evident when measured at 100° Celsius and none of the other standard properties measured, interfacial surface tension with respect to water (D971), dissipation factor (D924), acid acceptance (D974), dielectric breakdown voltage (D877), dielectric constant (D924), and color (D1500), show any deviation from acceptable levels. The elevated power factor is self-correcting over time spans of a few additional years. This behavior has been tracked to paint used on surfaces inside the equipment. This is the second paper by the authors that documents the unexpected impact of subtle chemical interactions between the oil and other materials present in electrical equipment on the performance of that equipment¹. This paper specifically documents how paint exposed to oil in electrical equipment affects the electrical properties of the oil. All of the paints reported here have and currently do successfully pass the ASTM D3455 tests with new oil and are in use throughout the industry.

INTRODUCTION

In 2004 an investigation was initiated by Kuhlman Electric Corporation to understand the cause of an increase in the oil power factor detected in five relatively new transformers. This phenomenon had been noticed by one of the authors (Smith) in two transformers in 2003. The oil was filtered through Fuller's Earth and the power factor dropped to acceptable levels. A year later the power factor was beginning to climb again and three other transformers were detected with elevated oil power factor. A team of independent consultants and laboratories was assembled to assess the impact, cause, and remedy for this condition.

One of the first steps was to assess the frequency of new transformers exhibiting elevated oil power factor. The results were surprising. Relatively few transformers had developed this condition early in their lives and those that did tended to be in the hotter climatic zones or during the later summer months in regions with hot summers and cold winters.

Another discovery was that the condition was not limited to Kuhlman transformers. Transformers from other manufacturers were showing a similar pattern, as were tap changers, reclosers, and other switch gear. What would eventually become apparent, however, is that all of the equipment had one thing in common, paint on surfaces immersed in the oil.

A timeline study of Kuhlman transformers demonstrated that the first incidence of elevated oil power factor in new transformers occurred about two years after they began using radiators that were painted internally. This was a key discovery. The area of painted surface inside the transformer excluding the radiator was about 50,000 square inches. The area of painted surface inside the radiator was about 150,000 square inches. With three radiators on the transformer that would total 450,000 plus 50,000 or 500,000 square inches of paint, of which 90% was in the radiators. If paint was associated with this phenomenon then this increased exposure should result in an increase in the incidence of the detection of elevated oil power factor. This did seem to be the case. Furthermore, in some cases of reported elevated oil power factor the area of paint used inside the transformer was above the oil level. This didn't mean that the paint above the oil was not exposed to the oil because over time the reflux action inside the transformer would have thoroughly exposed the paint. It did mean that the relative surface area of paint in the transformer was further reduced.

Paint was suspected early on but it was decided to investigate the cause in depth rather than jump at the first apparent solution. Implicating paint was not a trivial action. Paint is widely used in electrical equipment and it is used for a number of good reasons. It significantly improves visibility for visual inspection, it helps control corrosion, it reduces exposure to catalyzing surfaces, and it helps minimize contaminants by locking manufacturing residues in place. The elimination of paint in electrical equipment is not free from consequences.

There was another concern. All of the paints involved had successfully passed ASTM D3455. ASTM D3455 is an accelerated aging test that is supposed to indicate that a material does not affect the electrical properties of the oil used in electrical equipment. If paint was the cause in this case, then the ASTM D3455 had failed to detect the problem. All non-metallic components in electrical equipment were tested using ASTM D3455 with new transformer oil and were accepted based on the outcome of that test. What other materials may have changed at about the same time that paint was added to the radiators? This was not an occasion when an expedient solution would suffice.

A UNIQUE SIGNATURE

What was different about this high power factor oil when compared to the oil in older transformers that exhibited high power factor? As it turned out there were a number of differences. One of the first differences was that only the power factor was affected. Typically an elevated power factor is associated with a decrease in the IFT and/or the breakdown voltage, or an increase in the water content, acidity, and/or the particle population. None of these associations were present in the case of the younger transformers with high power factor (see Table 1).

Oil Sample	PF 100/25 C (D924)	Interfacial Surface Ten. (D971)	H2O ppm	Acid Acceptance (D974)	Dielectric BV (D877/D1816)	Color (D1500)
Trans. 1	4*/0.027	38.1	3	0.019	-/32	<0.5
Trans. 2	5/0.33	41.7	27	0.010	49/31	<1.5
Trans. 3	6*/0.037	36.7	4	0.021	-/34	<0.5
Trans. 4	12.2/1.2	43.2	32	0.007	53/31	<1.5
Trans. 5	15.3/1.15	-	5	0.015	-/41	<0.5
Trans. 6	61.6/1.53	-	5	0.015	-/41	<0.5
Trans. 7	84.7/-	42.5	15	-	55/31	-
LTC 1	2.7/0.091	36.8	29	0.013	52/33	<1.0
LTC 2	17.5/-	42.8	9	-	51/33	-

TABLE 1: Oil Properties for New Equipment with High Power Factors (*Peak Values)

A new tool for investigating insulating oils had been developed by two of the authors (Crutcher and Warner) as part of an EPRI project along with TJH2b. This device is called a MicroCell and is basically a heated copper surface over which oil flows while being observed under a microscope². Photographs 1 and 2 show the MicroCell and how it is used. After observing the oil under carefully controlled conditions the copper heating element can be examined chemically using a Fourier Transform Infrared Spectrophotometer attached to a microscope (Photograph 3). The functional group signature of the film on the copper helps identify the compounds responsible for the behavior of the oil. In this case the behavior of the oil in the cell and its chemical signature were unique. The oil very rapidly reacted with the copper element at a temperature of 120° Celsius, releasing a gas and forming a film on the copper. The chemical signature of the film indicated a low aliphatic hydrocarbon peak (carbon-hydrogen bonding) with much more activity in the carbonyl region (carbon-oxygen bonding, see Figure 1). The films from older transformers with high power factors tend to show high hydrocarbon peaks (see Figure 2).



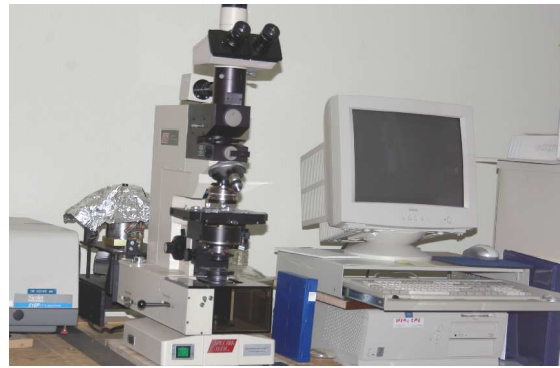
PHOTOGRAPH 1: MicroCell Used to Test Oils for Film-Forming Compounds

The cell is about an inch and a quarter in diameter and designed to fit on the stage of a microscope. The center bar is a copper plated heating element on which the film is deposited as the oil flows through the cell.



PHOTOGRAPH 2: MicroCell Mounted on the Microscope

The heated copper surface can be observed during the test to characterize the reactions occurring at any given time. Temperature and flow rate can also be changed while the system is being observed.



PHOTOGRAPH 3: Fourier Transform Infrared Microscope Spectrophotometer

With this instrument films a few tenths of a micrometer thick with diameters of about ten micrometers can be analyze. The system is used in the reflection mode with a polished copper of stainless steel substrate resulting in a dual-pass transmission spectrum.

The conspicuous presence of the carbonyl signature suggested another series of tests. Many carbonyls can be extracted from oil by water made alkaline using sodium hydroxide. These carbonyls can then be recovered by acidifying the water and agitating it with methylene chloride. The recovered carbonyls can then be analyzed as the residue remaining after evaporating the methylene chloride. Figure 3 shows the results of that analysis with new CrossTrans 106 oil and CrossTrans 106 oil from a three year old transformer with high power factor. It looked like a possible signature for the high power oil but as Figure 4 shows it is actually a signature for “old” oil. That same carbonyl peak was present in every oil sample from field equipment tested this way and it was not present in the new oil used in that equipment. This condition has been verified for three different petroleum based transformer oils; the carbonyl peak is absent in the new oil but is always present in oil within three years of its use in electrical equipment. The presence of carbonyl functionalities is one of the differences between new oil and the oil that materials experience in the real world of their operating environment. A more sophisticated chemical approach would be required to characterize the cause of the high power factor in these oils. Gas chromatography/mass spectrometry (GC/MS) has consistently shown itself to be far too complex and variable from one oil to another to be useful. The MicroCell response and the elevation of the power factor in the absence of a degradation of any other parameter remained the best signature.

PAINT AS A MODEL

Most of the initial observations pointed to paint as the causal agent; so our investigation was narrowed to a study of the paints used in electrical equipment. A number of specific questions needed to be addressed as part of this investigation. First, could exposure to an ASTM D3455 qualified paint increase the power factor of insulating oil? Second, was any chemical compound extracted from the paint by insulating oil? Third, what was the chemical signature of the compounds removed from the paint? Fourth, how critical was the state of cure for the paint? Fifth, was the power factor elevated when this signature was present? Sixth, was the power factor reduced to acceptable levels if this chemical signature was absent? Seventh, could these chemical compounds be removed from the oil? Eighth, could the drop in power factor with time over normal operation be explained? Ninth, if paint causes an increase in oil power factor then why don't all units with paint exhibit elevated power factors?

Test One: Exposing Low Power Factor Oil to Paint

Paints currently in use in electrical equipment were applied to aluminum foil strips two inches wide and twelve inches long. The paints on the foils were cured using those procedures normal to the processing of the equipment to which each paint was commonly applied. The cured paint strips were then immersed in five hundred milliliters of oil. That was a ratio of about one square inch of paint per twenty milliliters of oil (1/20). That compares to about one square inch of paint to twenty-six milliliters of oil (1/26) in the example of the transformer with three attached radiators as provided in the introduction.

One of our first concerns was that the conditions of ASTM D3455 may be too severe for a process that occurs in young equipment as early as the first year. We did duplicate the qualification test using ASTM D3455 with new oil. Then we dropped the time and the temperature for our exposures, but instead of using new oil we selected oil with a low power factor from three different three year old transformers. Two different transformer oils were used, CrossTrans 106 and Diala. These different oils were used to assure that the results were not caused by an anomalous oil selected by accident. Two of the oils were from three year old transformers using CrossTrans 106 and one was from a three year old transformer using Diala. All three oils exhibited the carbonyl signature seen in all “old” oils. The temperature for our tests was dropped to 80° Celsius, from 100° Celsius, and the time was dropped to five days, from 6.25 days. One of the CrossTrans 106 oils and the Diala were from transformers that had never had an elevated power factor of which we were aware. The other CrossTrans 106 oil had had an elevated power factor but it had dropped back to acceptable levels on its own (below 1% at 100° Celsius). The results are shown in Table 2 for three paints. It was evident from this test that qualified paints, paints currently in use in electrical equipment, could increase the power factor of aged insulating oil. These tests were repeated three times with each of the three different used oils and the outcome was the same each time; the power factor increased. The answer to the first question was affirmative, paints qualified for use in electrical equipment by ASTM D3455 using new oil could increase the power factor of the oil actually found in that equipment. These paints would not qualify by ASTM D3455 using “equipment-aged” oil.

Sample	New Oil PF	Aged Oil PF
Paint #1	No Change	+1.2
Paint #2	No Change	+0.2
Paint #3	+0.1	+0.6

Table 2: Change in Power Factor at 100 C

The new oil exposure was for 164 hours in oil at 100 Celsius (ASTM D3455). The Aged oil test was for about 120 hours at 80 Celsius.

Test Two: Was Any Compound Removed From the Paint?

Was it possible that the reaction was to the presence of aluminum foil rather than the paint? The paint coupons were prepared by applying the paint to aluminum foil and then curing the paint on the foil. The painted foil was then exposed to the oil. Although this approach had no effect in new oil it was possible that the aluminum foil might do something in the aged oil. Aluminum foil by itself had no effect on the aged oil but perhaps there was a reaction between the paint and the aluminum foil that was responsible for the effect. If the effect was due to the paint then there should be identifiable chemical compounds from the paint in the oil. One of the tests was allowed to continue for a few months of exposure. These oils were slightly cloudy after cooling down to 18° Celsius. An examination of the oil under the microscope indicated that the phase causing the cloudiness was a suspension of liquid droplets. The oil was centrifuged and the liquid in the droplets was analyzed using micro-FTIR. The results are shown in Figure 5. When a drop of methylene chloride was applied to the surface of the same cured paint for about ten seconds and removed, then analyzed by micro-FTIR the signature was nearly identical (see Figure 6). There is no question about the origin of the liquid droplets seen in the oil exposed to the paint. When the cloudy oil was heated to about 30° Celsius the droplets quickly went back into solution and the oil became clear. The second question was answered, compounds were extracted from the paint by the oil at a temperature of 80° Celsius.

Test Three: Chemical Signature of the Extract from the Paint

The next question had to do with the chemical signature from the paints. We had seen in the answer to question two above, that compounds were removed by the oil from the paint. How uniform was this signature? Many of the paints used in the electrical industry are one-part epoxies. The micro-FTIR

spectrum of the methylene chloride extract from these cured paints looks very similar (see Figure 7). In oils exposed to the cured paints these compounds can be extracted and the FTIR spectrum of these extracts is identifiable as being from the paint. Real world samples of high power factor oil also exhibit this same paint signature (see Figure 8). We have identified an infrared signature for one-part epoxies.

Test Four: Effects of the Degree of Paint Cure

Early in our investigation the paint coupons had been cured a couple of different ways. They had been cured under conditions exceeding the manufacturer’s recommendations, per the manufacturer’s recommendations, and at levels different than the manufacturer’s recommendations. In each case the paints were hard, clean, and with the proper color hue and saturation. They all appeared to be fully cured paint films with no degradation due to the curing process. The question of the importance of the state of cure still persisted. What if as applied in the factory the paint was not completely cured? To resolve this question paint directly out of the tin, completely uncured, was poured into new oil. This was then heated to 80° Celsius for five days and then tested. The results are shown for the same three paints of Table 2 and one other paint in Table 3. Clearly, cure was not an issue for two of the paints. The other paints did contain some compounds in their uncured state that increased the power factor but those compounds also decreased the interfacial surface tension and the breakdown voltage. These paints did not show a decrease in the interfacial surface tension or breakdown voltage in any of their cured states when exposed to oil. The signature of the elevated power factor in real world equipment that we were attempting to characterize did not show changes in the IFT or breakdown voltage. The conditions of cure were not an issue in this case. The third question was answered.

Sample	New Oil PF	Aged Oil PF
Paint #1	No Change	+1.7
Paint #2	+22	--
Paint #3	+24	--
Paint #4	No Change	+1.9

TABLE 3: Change in Power Factor at 100 C

Raw paint was poured directly into both new and aged oil for about 120 hours at 80 Celsius.

Test Five: Does the Paint Extract with this Signature Increase Power Factors?

We know from tests one and two above that when aged oil is exposed to at least some one-part epoxies the power factor increases and this chemical signature is present. We know that some samples from the field that show this anomalous increase in power factor show this chemical signature (see Figure 8). If we removed the methylene chloride extractables from the paint and added that to low power factor oil would the power factor go up? The answer is yes. We exposed twenty square inches of one of the paints to 30 milliliters of high purity methylene chloride for three minutes. The methylene chloride was evaporated down to twelve milliliters and centrifuged to remove any particles and then it was reduced to a volume of one half milliliter. When this extract was added to four hundred milliliters of aged oil with a power factor of just over 1 the power factor went up to 4. The ratio of exposed paint surface to volume of oil was the same in this test as had been the earlier tests where the paint itself was exposed directly to the oil, one square inch of paint to twenty milliliters of oil (1/20). Could the small amount of methylene chloride, less than half a milliliter, cause the change in power factor? Adding five milliliters of clean methylene chloride to five hundred milliliters of oil had no significant effect on the power factor. This test confirms that the compounds that increase the power factor of the oil are in the extract from the paint.

Test Six and Seven: Does the Power Factor Drop if the Signature is Removed?

The compounds from the paint are removed by exposure to metallic copper as seen above and by extraction through Fuller’s Earth or silica gel. That answers question seven in the affirmative: the signature can be removed in at least two ways. This has been demonstrated in field units with Fuller’s Earth and in the laboratory with silica gel and with heated copper. In all cases this was accompanied with a drop in power factor to acceptable levels. These tests were all performed with oils from the field that exhibited the characteristic signature of this high power factor condition. It was conceivable that we were removing some other agent at the same time that was actually responsible for the high power factor. When the low power

factor oil to which the paint extract was added, resulting in a high power factor, was heated with copper the paint signature disappeared and the power factor went down to acceptable levels. These tests confirm that the removal of the paint signature does drop the power factor to acceptable levels.

Test Eight: Why Don't All Units with Paint have Elevated Power Factors

This test has not been performed in the laboratory but we do see a possible explanation in the field units tested. This explanation is presented in more detail in reference 1 by the authors. Simply stated, there are sources and sinks for the active compounds in the equipment. The processes responsible for the extraction of the compounds from the paint are not directly related to the processes responsible for the removal of these compounds in the equipment. Heat from outside the equipment increases the rate at which the active compounds are extracted from the paint. This heat includes things like direct solar radiation and outside temperature, which result in an elevated oil temperature that is not directly associated with the load on the equipment. The rate at which these compounds are removed from the oil is related to the heat and area of exposed copper surfaces in the unit. This is dependent upon the electrical load through the unit. This elevated power factor condition is seen primarily in the summer in hot climates where the equipment is under low to moderate loads. Conditions have to be just right for this condition to arise and samples must be collected for analysis at that time. We have exhausted our funding for this work but this is something that could be demonstrated in the laboratory as well as by careful observation in the field and the collection of field samples at appropriate times.

DISCUSSION

This series of experiments demonstrates that at least some of the one-part epoxy paints currently used in electrical equipment can and in fact do cause an increase in the power factor of the oil in relatively new units. They also suggest why an elevated power factor shows up in only a few units and is even then a relatively short term effect.

The compounds that cause the increase in power factor are relatively reactive. Once they are extracted from the paint they begin to coat exposed copper surfaces. This removes the compounds from the oil and drops the power factor. For most units the rate of depletion is at least as high as the rate of generation. The rate of generation is largely controlled by the surface area of the paint and the temperature of the oil. The depletion rate is controlled by the surface area of the copper and the temperature of the copper. That would suggest that the high power factors would be expected in hot weather when the oil is hotter, and lower power factors would be expected in cold weather. High loading would also tend to reduce the power factor because copper surface would be expected to be hotter. The amount of extractable chemicals in the paint is finite and is a small fraction of the total composition of the paint. Once these compounds are removed there is nothing left in the paint to increase the power factor. If the unit is not tested early in its life these compounds may have already been depleted before the unit's power factor is tested. The observations of a number of units fit this model nicely. These high power factors are most often seen in the southern part of the US and during the summer in central Canada. The power factor drops in the winter. We haven't checked to see if the power factor increases again in these units during the following summer. We may have that opportunity this summer.

It has been clearly demonstrated that paint can increase the power factor of the oil in electrical equipment. It has also been demonstrated that paint has caused an increase in the power factor of oil in some units. These paints tested in new oil do not increase the power factor of that oil under the conditions of ASTM D3455. What is the difference between new oil and oil as little as a year old in electrical equipment? There are a number of differences and some of those differences may involve other non-metallic materials used in this equipment.

There are a number of other non-metallic materials in electrical equipment. These include cellulose, hemi-cellulose, glues, binders, waxes, lignin, polysulfones, polycarbonates, polyesters, and polypropylenes. These materials also have extractable chemicals. These materials are all qualified by the same ASTM D3455 tests that qualified the paints. These materials have not been tested to determine how they may affect the electrical properties of aged oil. There have not been any documented elevated power factor problems where these materials are present and there is no paint. That would suggest that they do not directly cause any problem, but they could aid in the extraction of compounds in the paint that do cause

problems. In an early phase of the research project all of these materials were tested for extractables using hexane as a substitute for oil and found to have none. When it was discovered that over time insulating oil is better modeled by methylene chloride a new series of tests were conducted. Significant amounts of chemicals were found in most of the materials that were soluble in methylene chloride (see Figure 9). Some of these compounds do contain some interesting carbonyl functionalities.

The investigation of these materials will have to wait for now but they can't be considered inert within these oil-filled environments. Changing a glue or a polymer in these environments may have an unforeseen consequence. The extractables from these materials may facilitate the extraction of compounds in the paint or in other materials that raise the power factor of the oil. A change of one of these materials may increase the rate at which one of these compounds is extracted from some other material. The changes that take place in insulating oil over time have always been acknowledged as chemical processes but the nature of these processes has been very poorly understood. They had been assumed to be processes involving the composition of the oil alone as acted upon by the heat, copper catalysis, moisture, and oxygen typical of the operating environment. Oxidation, polymerization, and "reverse refining" are terms that have been applied to the composite process. These are different aspects of the aging process that have been viewed as largely beyond our control due to the chaotic and complex nature of the reactions involved. That view has now been considerably expanded by an awareness of the role of solubility, solubilization, and solvolysis¹. These processes can be tested, modeled, and compensated for or designed around. The discovery of compounds in non-metallic components that are leached into insulating oil will help in our interpretation of processes at work in this equipment.

CONCLUSION

Paint can and does cause an increase in the power factor of oil in relatively new electrical equipment. The condition is not always detected as an increase in power factor but even when it is not detected the compounds extracted from paint are deposited on copper surfaces in the equipment. This occurs with all paints tested to some level. There are many compounds in paint that can increase power factor. It is possible that some paints contain fewer of these compounds. All the paints currently in use in electrical equipment will satisfactorily pass ASTM D3455 when new insulating oil is used as the test medium. Using "aged" oil as part of the ASTM D3455 test will detect the effects of extractables from the paints seen in field equipment.

The condition of elevated power factor due to the presence of paint is wide spread throughout the industry. This phenomenon is a short term effect that will disappear when the extractable compounds from the paint are exhausted. Compounds are extracted from the paint even when an elevated power factor is not detected. These materials deposit on exposed copper surfaces in the equipment. The only way to minimize the affects of paint is to limit the use of internal paints to only those surfaces that must be painted for visual purposes or for corrosion prevention.

REFERENCES

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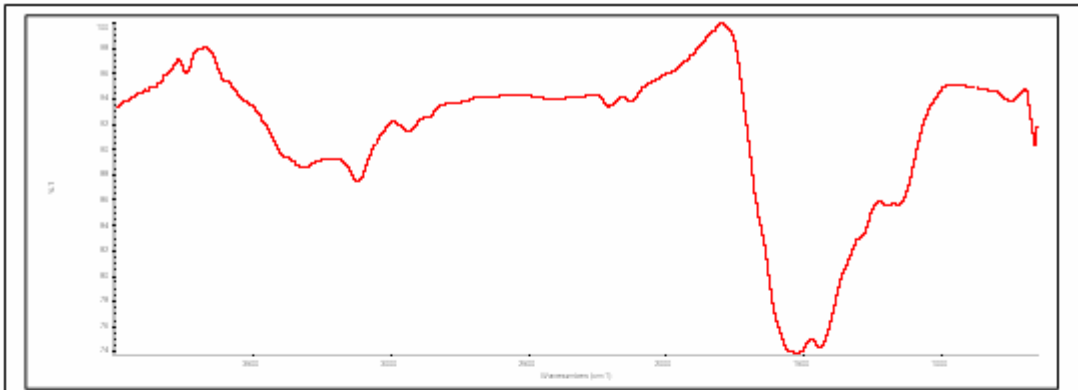


FIGURE 1: Typical MicroCell Film From New Transformer High Power Factor Oil

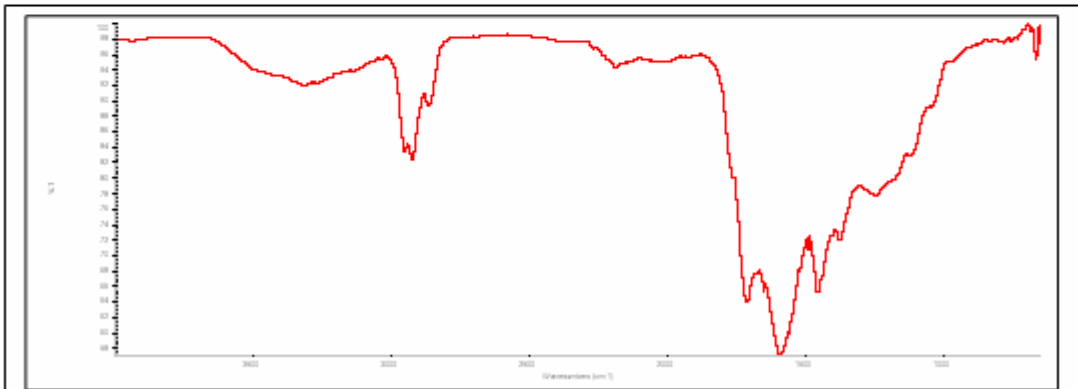
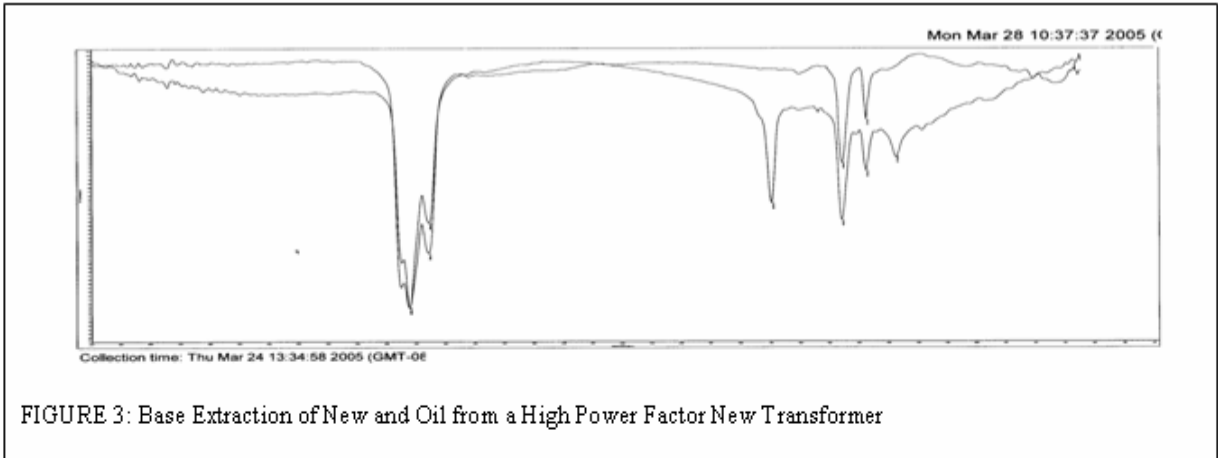


FIGURE 2: Typical MicroCell Film From Old Transformer



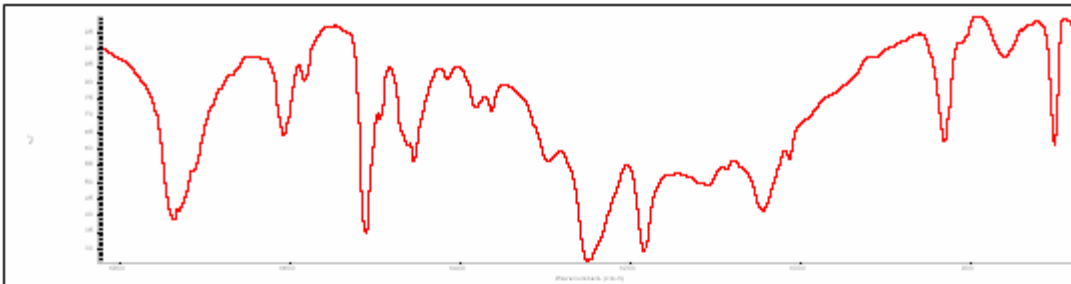


FIGURE 5: The Infrared Spectrum "Fingerprint" Region of a Film-Forming Compound from a Laboratory Test Exposing a Commonly Use Paint to Oil from a Three Year Old Transformer

The oil from the transformer had a power factor of less than 1 at 100 Celsius before the exposure. After five days exposure to cured paint at 80 Celsius the oil had a power factor of 3 when measured at 100 Celsius. The film formed by this oil under the same conditions as the LTC oil above showed this spectrum.

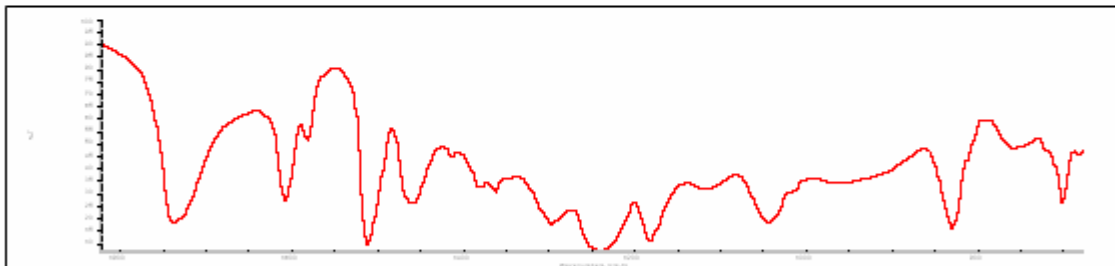


FIGURE 6: The Infrared Spectrum "Fingerprint" Region of a Methylene Chloride Extract from the Surface of the Same Cured Paint Prior to Exposure to Transformer Oil

The paint used in the experiment documented in Figure #2 was extracted by placing a drop of methylene chloride solvent on the fully cured paint that had not been placed in used transformer oil. The drop was lifted and then the methylene chloride was allowed to evaporate. The residue remaining was then analyzed resulting in the above spectrum.

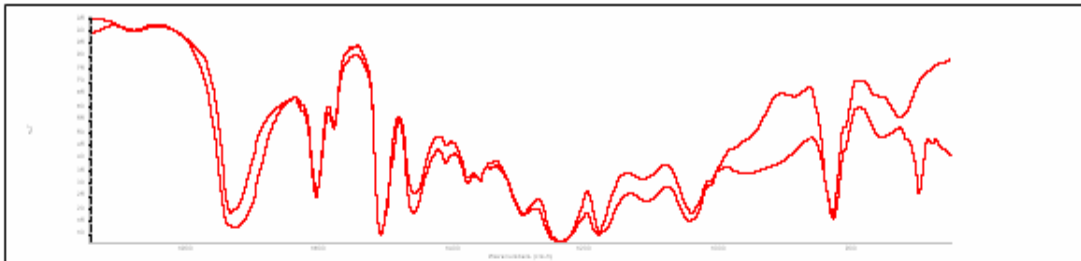


FIGURE 7: Overlay of the “Fingerprint” Region of the IR Spectra from Extracts from Two Paints of the Same General Type from Two Different Paint Companies

These spectra are methylene chloride extracts of two fully cured one-part epoxy paints. The paints are of the same general type though they are produced by different companies and have slightly different compositions. The spectra are nearly identical down to 1000 wavenumbers, where they begin to show differences.

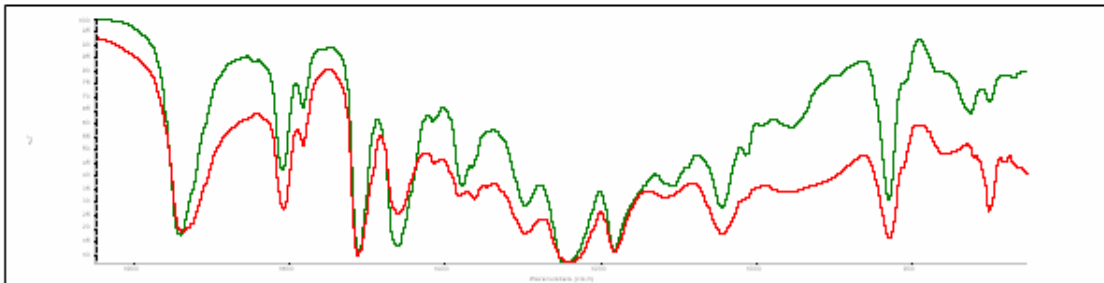


FIGURE 8: Overlay of the IR Spectra from the Paint (lower trace) and the Suspect LTC (upper Trace)

The remarkable similarity of these spectra would seem to implicate extractables from the paint as the dominant film forming components seen in the LTC. There is some difference below 800 wavenumbers. This may indicate a different paint of basically the same formulation.

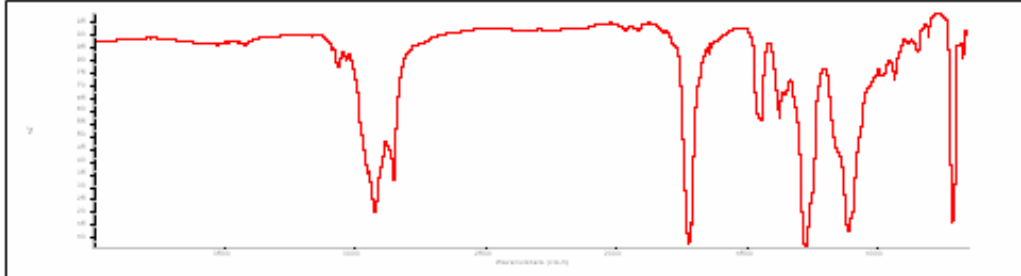


FIGURE 9: The Infrared Spectrum "Fingerprint" Region of a Methylene Chloride Extract from Colored Crepe Paper Used in a Transformer

This is include as an example of extractables from paper, resins, pressboards, plywood, plastics, and other non-metals used in electrical equipment.

Biography

Russ Crutcher

Mr. Russ Crutcher is and has been the owner and principal scientist at Microlab Northwest in Redmond, Washington, USA since 1978. He has been involved in the contaminant and component failure analysis area for the Electrical Power Industry since about 1982. In 1999 he began researching the coking problems in LTC's along with TJH2b on a project funded through EPRI.

Mr. Crutcher was the lead scientist and principal investigator for the Special Materials and Contamination Analysis Laboratory of the Boeing Spacecraft Division from 1972 until he took early retirement in 2001. He taught at the University of Washington's School of Materials Sciences Engineering for 8 years while continuing to work for the Boeing Company from 1981 to 1989. In 1985 and again in 1987 he was invited as a Visiting Scholar to the Civil Engineering Division, Imperial College, London. His background includes working as a crime scene investigator and evidence analyst for the city of Bellevue, Washington from 1970 to 1972.

Russ Crutcher received a degree in Physical Anthropology with minors in Mathematics, Physics, and Chemistry from the University of Washington in 1970.

Phil Hopkinson

Phil Hopkinson is the owner of HVOLT, Inc., a power transformer consulting company that he formed in 2001. He is an IEEE Fellow and long service Transformer Engineer. He has chaired numerous IEEE and NEMA Working Groups and from 2001-2003 was Chairman of IEEE's Policy Development Coordinating Committee. He currently holds 15 US patents, is a Registered Professional Engineer in North Carolina, and is Technical Advisor (TA) to the US National Committee for IEC TC14 for Power Transformers.

From 1966 to 2002, Phil held numerous design and engineering management assignments in the transformer businesses of GE, Cooper Power Systems and Square D Co in liquid filled, dry, and cast resin transformers of all power ratings and voltage classes. He has authored IEEE Transactions papers on the effects of DBPC in Transformer Oil, on Low Voltage surge phenomena in Distribution Transformer windings, and has Chaired NEMA's activities and was primary author of NEMA TP-1 Guide for Energy Efficiency for Distribution Transformers.

Phil Hopkinson received his BS in EE from Worcester Polytechnic Institute in 1966. He also graduated from GE's Advanced Engineering Course in 1970 and simultaneously received his MS in System Science from Brooklyn Polytechnic Institute.

Ray Rettew

Dr. Ray Rettew is a consultant in chemistry and materials sciences primarily for the solution of problems in the Electrical Power Industry. He is a major contributor to HVolt Inc. in the solution of materials problems.

Ray Rettew was the Director of Research and Development for the Square D Company Transformer Business Unit. In that capacity he directed the development of new epoxy resin system to reduce costs for small power transformers. Prior to moving to the Square D Company in 1989 he worked as a group manager for General Electric in the materials development group. Until 1977, when he joined General Electric, was as a research scientist for W. R. Grace & Company developing specialty ceramics.

Ray Rettew received a BS in Chemistry from Clemson University in 1961 and a Ph.D in Chemistry from Emory University in 1966.

Steve Smith

Steve Smith is Vice President of Engineering for Kuhlman Electric Corporation in Crystal Springs, MS where he is responsible for all Design Engineering, Quality, and Test at the Medium Power Transformer facility. He has been with Kuhlman Electric since 1990 and has been with the Medium Power Transformer operation since 1994.

Prior to joining Kuhlman he was Chief Engineer and Senior Staff Engineer for Cooper Power Systems in their Distribution Transformer Business where he held positions in Waukesha, WI; Nacogdoches, TX; and Zanesville, OH. Steve has also worked as a Plant Project Engineer and as a Technical College Instructor. He began his career as a transformer specialist for AEP in Canton, OH in 1972.

Steve is a 1972 Graduate of Ohio State University receiving both MSEE and BEE degrees with electric power systems as his specialty area of study.

Ken Warner

Ken Warner has been associated with Microlab Northwest for five years. He is the principal Fourier Transform Infrared Microscope Spectrophotometer operator for Microlab Northwest and key research scientist. He helped develop the MicroCell for the evaluation of film growth in oil-filled electrical equipment.

Mr. Warner has worked as an analytical chemist for the Boeing Company, Monsanto Chemical Company, and the Inhalation Toxicology Research Institute. He taught classes on Infrared Spectroscopy at South Seattle Community College and was the Principal Analyst for Organic Films in Orbital Environments contract with NASA as part of the LDEF Program.

Ken Warner received a BS in Chemistry and Zoology from the University of Wyoming in 1972. He took additional classes in advanced chemistry at the University of New Mexico from 1974 to 1979.

Jaime LaFave

Jaime LaFave has been affiliated with TJH12b for over five years. She has performed oil quality analysis in determining condition assessment. She is the lead research analyst for equipment condition diagnostic development and is currently integrating x-ray fluorescence into the diagnostics.

Jaime LaFave received a BS in biological sciences and a minor in chemistry at California State University, Sacramento.