

TRANSFORMER LIFE MANAGEMENT (TLM) BULLETIN:

Moisture in power transformers

Transformer insulation system & preservation

The insulation system of a power transformer consists of oil and cellulose. Cellulose is solid insulation (paper and pressboard) that is typically processed using the Kraft method. A major function of these insulation materials/dielectrics is to provide electrical isolation between energized parts of the transformer. However, oil and cellulose serve additional roles as well. For example, the transformer oil also (1) provides sufficient cooling/heat transfer, (2) preserves the core and coil assembly by filling voids in the cellulose, and (3) minimizes the contact of oxygen with cellulose and other materials that are susceptible to oxidation. Meanwhile, the cellulose serves a mechanical function by supporting the windings and a thermal one by creating cooling ducts.

The insulation design incorporates aspects such as amount of, shape(s), and placement of solid materials, the fluid, and the interface between the solids and fluid. Oil has a lower dielectric strength than cellulose but by bringing the permittivity of the oil as close to that of the solid insulation as possible (through, for example, partitioning methods), more of the dielectric stress will be distributed in the solid material, which generally has a better ability to support this stress. This will reduce the stress in the oil, which typically sets the design. [1] In the end, by weight, cellulosic materials (paper and pressboard) make up a comparatively small percentage of a transformer's materials (e.g., 3.5%).

The rate of insulation degradation is related to the presence of moisture, oxygen and temperature in the transformer. The byproducts of insulation ageing are ironically catalysts for the ageing process too, and include: moisture, gas, carbon monoxide/ carbon dioxide, acids and furans. Removal of these by-products will slow down the ageing process.

In addition to (1) removing ageing catalysts (moisture, acids and oxygen), a transformer owner may implement other actions to slow down the ageing process, including: (2) processing the oil to remove moisture, acids, particles, and gases; (3) drying the transformer to remove moisture from the solid insulation; (4) reducing oxygen by maintaining the oil preservation system (e.g., replacing faulty membranes in the oil conservator or maintaining positive pressure in nitrogen blanketed transformers); and (5) reducing the temperature, either by controlling load or increasing cooling.

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Nearly all water in a transformer is in the cellulose. During normal operation at different loads and temperatures, some water moves back and forth between the oil and cellulose. At times the water content in the oil may be doubled, for example during elevated operating temperatures. However, even during these periods, the moisture in the cellulose remains almost the same. In fact, the

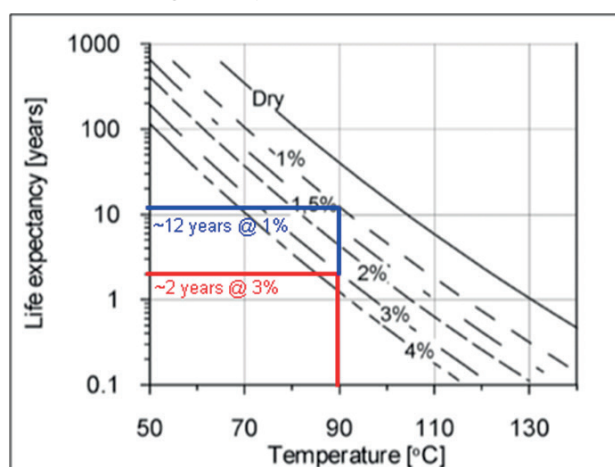


Figure 1. Life expectancy for cellulose at different temperature and moisture content [3]

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average moisture content in the solid insulation is very constant. This is important to note when considering that a moisture in oil test relies on a measure of moisture in a sample of oil at a given temperature as a means to estimate the amount of water in the cellulose through equilibrium tables.

The presence of water in the solid part of the insulation, even in small concentrations, increases its ageing rate, lowers the admissible hot spot temperature of the transformer, and increases the risk of bubble formation and subsequent dielectric failure. In addition, moisture reduces the dielectric strength of transformer oil as well as the inception level of partial discharge activity [2].

Figure 1, which describes life expectancy for the insulation at various temperatures and moisture content [3], illustrates the influence of moisture on ageing. At an operating temperature of 90°C, cellulose with 1% moisture has a life expectancy of about 12 years. At 3% moisture, the life expectancy is only 3 years!

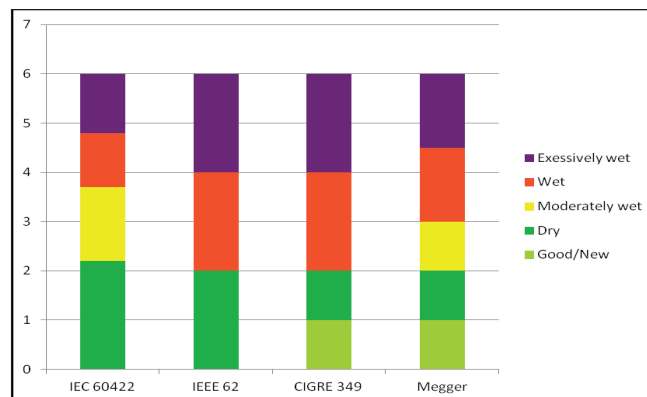


Figure 2. Moisture assessment examples

For these reasons, moisture detection is important to asset managers who are tasked with extending the life of expensive assets such as transformers, as well as with shifting maintenance from time-based to condition-based strategies. Moisture detection also carries implications for system operators who may otherwise unwittingly cause a transformer winding failure through emergency switching and loading if these activities result in an increase in temperature that exceeds a wet transformer's bubble inception temperature.

During manufacture, the cellulose insulation in the transformer is carefully dried out before it is impregnated with oil. The moisture content in the solid insulation of a new transformer is typically targeted to be less than 0.5 % by weight but ultimately depends upon purchaser's and manufacturer's requirements. As the transformer gets older, the moisture content will typically increase around 0.05 % per year for a sealed conservator transformer and by approximately 0.2 % per year for free-breathing transformers. In an old and/or severely deteriorated transformer, the moisture content can be greater than 4 %.

The recommended approximate percent by weight of water in solid insulation according to IEEE C57.106-2002 depends on the transformer voltage class as follows:

- < 69 kV, 3 % maximum
- 69 - < 230 kV, 2 % maximum
- 230 kV and greater, 1.25 % maximum

Other standards and guides only give a classification of the moisture content. Figure 2 depicts moisture categories according to some standards and practices.

While dozens of standards and guides deal with moisture in insulation of transformers and reactors, the moisture phenomena in solid insulation are considered separately to that in the surrounding insulating liquid or gas medium. The IEEE/PES Transformers Committee formed a working group in 2012 to develop a new reference document that will deal with the issue of moisture in a solid-gas, solid-liquid, or solid-liquid-gas insulation of transformers and reactors as a whole and will serve all IEEE standards and guides dealing with moisture as a single knowledge base reference.

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Sources of moisture

There are three sources of moisture contamination in transformer insulation [4]:

- Residual moisture in the “thick structural components” not removed during the factory dry-out or moistening of the insulation surface during assembly
- Ingress from the atmosphere (breathing during load cycles – leaking gaskets and faulty water traps; exposure to humid air during site erection and/or maintenance/repair processes); this is the main source of the buildup of water in transformers. It is desirable to detect maintenance issues that allow for moisture ingress early and repair them because drying/processing transformers is expensive and time consuming. To lend perspective, according to CIGRE 2004, A2-205, the time needed to dry a 400 MVA transformer with 14 tons of insulation from 3% down to 1.5% average humidity with the vapour phase method, typically performed at the factory only, is just over 2 days. It would take nearly 11 weeks (!) with hot oil circulation plus vacuum cycles – it is obviously desirable to avoid this need all together.
- Aging (decomposition) of cellulose and oil.

Excessive residual moisture can remain in some bulky insulating components, particularly in wood and plastic or resin-impregnated materials, which need much longer drying times in comparison to paper and pressboard. Typically, these are supports for leads, support structures in the on-load tap changer (OLTC), support insulation for the neutral coils of the winding, cylinders, core support insulation, etc.

Different insulation materials require different drying durations. The drying time is roughly inversely proportional to insulation thickness in square. However the structure of material is an important factor as well, e.g., pressboard featuring a high density requires longer drying time than low density pressboard. [4].

Moisture measurements

Direct Method

The moisture content in the solid insulation of the transformer may be measured directly by taking a paper sample from the transformer and measuring its moisture content using Karl Fisher titration. However, this is not very practical in most cases. This method (KFT on paper samples) is typically held as the standard to which the validity of indirect moisture measuring methods are judged but, impracticality aside, this method is not without problems.

Karl Fischer titration allows for determining trace amounts of water in a sample using volumetric or coulometric titration. Its principle is to add a reagent (titre iodine) to a solution containing an unknown mass of water until all water reacts with the reagent. From the amount of reagent the mass of water can be calculated.

Several factors may affect the results of KFT analyses, e.g.:

- There is always ingress of moisture from the atmosphere during sampling, transportation and sample preparation. This happens particularly during paper sampling from open transformers.
- Cellulose binds water with chemical bonds of different strengths. It is uncertain whether the thermal energy supplied releases all the water.
- Heating temperature and time certainly changes the released water.

Studies have shown that KFT results may suffer from a poor comparability between different laboratories [2]. Another issue for direct measurements of moisture in cellulose is the uneven distribution of moisture in a transformer. To get a “true” result from KFT analysis of paper, it is important to take many samples and average the results.

The user must be aware of the possibility for variations, and understand therefore, that a deviation in the comparison between indirect methods and this one (i.e., direct measure of water in paper) does not necessarily point out weaknesses of the evaluation methods.

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Indirect methods

Most moisture assessment tools utilize indirect measuring methods, whereby properties of insulation that can be related to moisture content are measured. These include:

- Moisture in oil
 - Absolute values
 - Relative saturation
- Power frequency tan delta/power factor measurements
- Dielectric response measurements
 - Return Voltage Measurement (RVM) – DC method
 - Polarization-Depolarization Current measurements (PDC) – DC method
 - Dielectric Frequency Response measurements (DFR/FDS) – AC method

Of these indirect methods, the ones that have been traditionally applied in the industry to assess water in paper insulation (e.g. moisture in oil measurements and use of equilibrium charts) only provide accurate assessments if moisture equilibrium has been achieved. During the normal operation of a transformer, wherein the temperature inside the transformer varies throughout the day, moisture equilibrium between paper and oil will rarely be attained since the time constants of thermal and moisture dynamic processes are very different [5]. In extreme cases (e.g. a shipping damaged transformer seal), the resulting moisture ingress may be notably far from a state of equilibrium in the transformer during ensuing tests, resulting in a very inaccurate assessment of water in paper by traditional measurements [6]. That being said, measuring moisture levels in oil is probably the most commonly used method for moisture assessment.

Moisture in oil

This approach consists of three steps:

- Sampling of oil under service conditions, noting the oil temperature.
- Measurement of water content by Karl Fischer Titration.
- Deriving moisture content in paper via equilibrium charts.

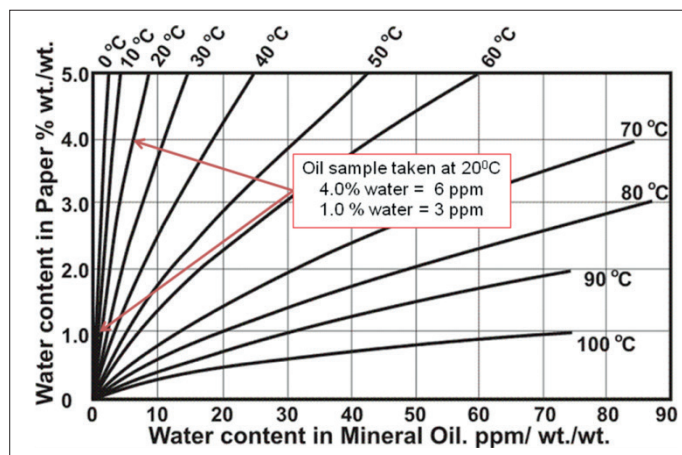


Figure 3. Equilibrium chart for moisture content in paper versus water content in oil at various temperatures

Several equilibrium charts are available; Figure 3 shows the “Oomen” chart. Note the steep gradient in the low temperature region, which severely complicates the ability to read and determine the correct result.

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The moisture in oil method may be affected by substantial errors, e.g:

- Sampling, transportation to laboratory and moisture measurement via KFT causes unpredictable errors.
- Equilibrium diagrams are only valid under equilibrium conditions (depending on a temperature that has not varied for days/months).
- A steep gradient in the low temperature region (especially for dry insulations) complicates reading.
- The user obtains scattered results using different equilibrium charts.
- Equilibrium depends on moisture adsorption capacity of solid insulation and oil.

Extreme variations in moisture estimation have been documented between laboratories that were given the same oil sample [2]. It should be further noted that for dry oils, results also varied within one single laboratory with a typical standard deviation of 20%. In addition, field experiences have shown that water in oil analysis generally tends to overestimate moisture in solid insulation [7].

One step to improve the method of using equilibrium diagrams is to use the *relative saturation* in oil (%) or *water activity* instead of the moisture by weight (ppm). In cases where direct measurements are performed with an oil probe mounted directly on the transformer, the issues and errors with sampling and transportation are removed. Furthermore the moisture absorption capacity is less temperature dependent and the influence of oil ageing on moisture saturation level becomes negligible, since it is already included into relative saturation [4]. However, the method's accuracy depends on proper application of material specific charts for translating RH% to moisture in paper and ultimately requires equilibrium.

Line frequency tan delta/power factor measurements

A tan delta/power factor measurement at line frequency (50/60 Hz) is a measure of the combined losses in oil and cellulose. It is known that the measurement cannot discriminate a dry transformer with service aged oil from a wet transformer with new oil. Moreover, the method is generally insensitive to moisture levels < 2.5% as noted in Figure 4, which describes the relationship between line frequency tan delta values and moisture levels for a new and service-aged typical core-form transformer. The relatively flat slope (response) of tan delta/power factor to increasing moisture levels signifies low sensitivity. The slopes do not become steeper (at which point, power factor becomes more sensitive to moisture) until about 2.6% moisture, in the case of a new transformer.

As given in Figure 4, a 0.3% tan delta/power factor (20°C) measurement may indicate moisture of 0.5% to about 2.5% depending upon the condition of the oil. In one field case, after hot oil had been circulated for 17 days with clay filtering (Fuller's Earth), the transformer tested with a power factor of 0.3% although the moisture contamination was still 2.7% (the relatively low power factor measurement reflected the as-new condition of the oil) [7]. So a (line frequency) tan delta/power factor value alone does not provide much insight into the degree of moisture contamination present.

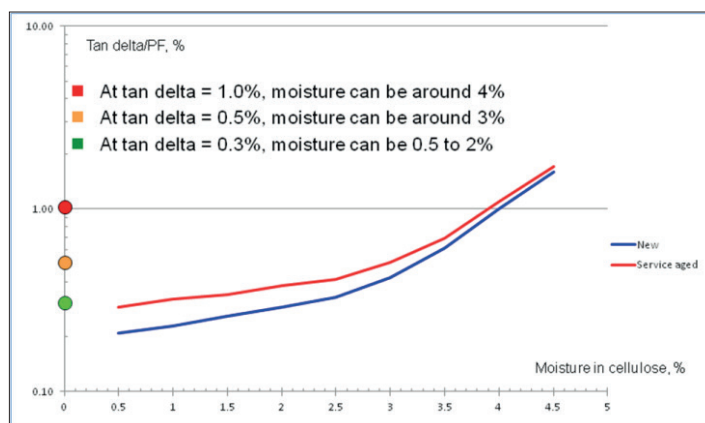


Figure 4. Tan delta (% @ 20C) vs moisture (%) for a new and service-aged typical core-form transformer

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It is also well-known that the standard tan delta/power factor temperature correction factors/tables (TCF) given in standards and many instrument manufacturers user manuals/recommendations, are incorrect for the individual transformer [8]. This adds an additional source of inaccuracy to the method.

In large part due to the inaccuracies with most other indirect methods described above, dielectric response methods have emerged as attractive alternatives. The AC version of this nonintrusive, electrical test method (based on models) is very reliable with high repeatability. There is no need to wait for equilibrium, no inaccuracies due to the sampling and handling of oil, and the test can be performed as part of the suite of electrical tests planned during a maintenance outage.

Dielectric response measurements

Dielectric response measurements can be performed in the time (DC) or frequency (AC) domain, and include:

- **DC methods – Time domain**
 - Return Voltage Measurement (RVM); Voltage vs time**
 - Polarization-Depolarization Current Measurement (PDC); Current vs time**
- **AC method – Frequency domain**
 - Dielectric Frequency Response Measurements (DFR/FDS); Capacitance and dissipation factor vs frequency**

Several tests and experiments [9] have compared use of these dielectric response methods (RVM, PDC and DFR/FDS) to analyze the moisture content for different arrangements of insulation geometry at different temperatures (using the corresponding software programs), against a KFT analysis.

The results of RVM analysis differed notably, although the moisture content of paper was constant during all the measurements. Dependencies on the oil conductivity, the temperature and the insulation geometry appeared. Hence the RVM software used, which did not account for the geometry and oil parameters, was unable to evaluate moisture in oil-paper-insulation systems well.

Results of PDC analysis showed a much smaller influence from insulation geometry and weaker temperature dependence since these influences were already compensated by the interpretation software used. With increasing oil conductivity, the evaluated moisture content increased, although in reality it remained constant. Nevertheless, the simulation results were close to the level evaluated by Karl Fischer titration.

The DFR/FDS analysis provided the best compensation for insulation geometry. At the same time, the paper seemed to become drier with increasing temperature. This actually happens in reality because of moisture diffusing out of the paper, but not to indicated extent. The observed tendency rather reveals imperfect compensation for temperature variations. Similarly as for the other methods, an increased oil conductivity results in a slight increase of the estimated moisture content.

DC and AC measurements (e.g., PDC and DFR/FDS) can be performed at low or high voltage. It is also possible to combine techniques by mathematically converting time domain data to frequency domain data and vice versa [10]. AC methods are generally more reliable in substation environments because they are more robust in high-interference conditions than DC methods, particularly low voltage DC measurements, which are very sensitive to DC interference from e.g. corona [Table 1]. The interference will add to the measured polarization current which the analysis software will interpret as increased moisture in the insulation.

Interference signals	DFR Measurement Technologies		
	Low Voltage DC	Low Voltage AC	High Voltage AC
AC (50/60Hz + harmonics)	Sensitive	Not sensitive	Not sensitive
DC/MLF	Very sensitive	Sensitive	Not sensitive

Table 1. Noise sensitivity for different dielectric response measurement methods

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Dielectric Frequency Response Measurements

The first field instrument for DFR/FDS measurements of transformers, bushings and cables was introduced 1995 [8]. Since then numerous evaluation of the technology has been performed and as an example, several international projects/reports define dielectric response measurements together with insulation modelling as the preferred method for measuring moisture content of the cellulose insulation in power transformers [2], [9], [7], [11].

In DFR tests, capacitance and dissipation/power factor is measured. The measurement principle and setup is very similar to traditional 50/60 Hz testing with the difference that a lower measurement voltage is used (e.g., 200 V_{peak}) and instead of measuring at line frequency (50/60 Hz), insulation properties are measured over a frequency range, typically from 1 kHz down to 1 mHz.

The results are presented as capacitance and tan delta/power factor versus frequency. Measurement setup is shown in Fig 5 and typical DFR results from measurement on transformers in different conditions in Fig 6.

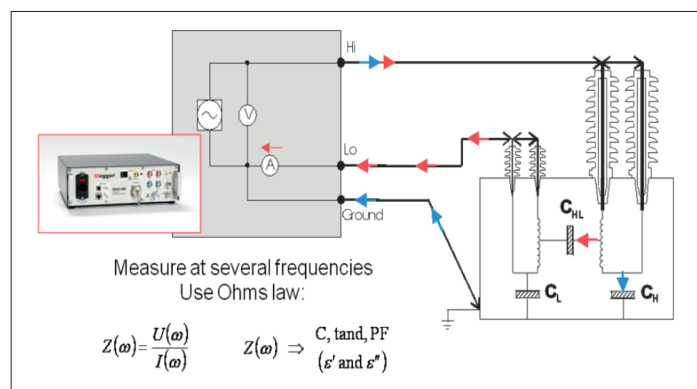


Figure 5. DFR/FDS test setup

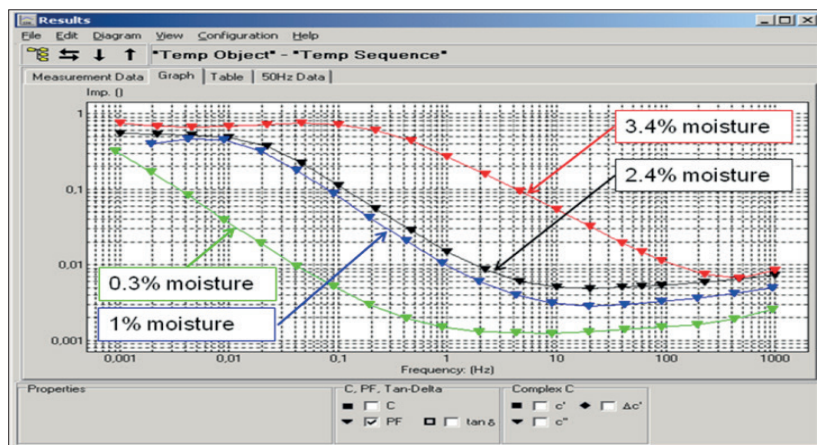


Figure 6. DFR measurements on four different transformers at different temperatures with moisture content ranging from 0.3% to 3.4%

Moisture Assessment

The method of using DFR for determining moisture content in the oil-paper insulation inside an oil-immersed power transformer has been described in detail in several papers and articles elsewhere [2], [9], [11], [12] and is only briefly summarized in this bulletin.

The dissipation factor for an oil/cellulose insulation plotted against frequency shows a typical inverted S-shaped curve. With increasing temperature the curve shifts towards higher frequencies. Moisture influences mainly the low and the high frequency areas.

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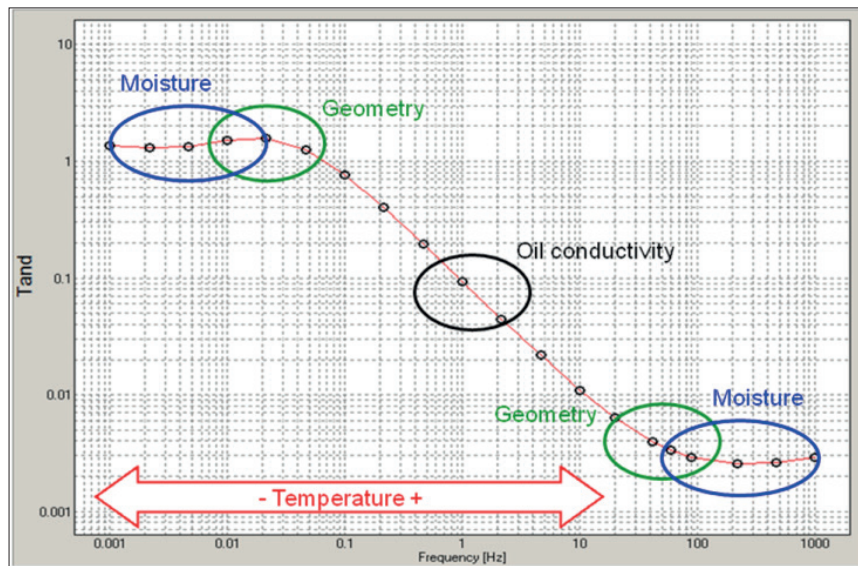


Figure 7. Parameters that affect the dissipation factor at various frequencies

The middle section of the curve with the steep gradient reflects oil conductivity. Fig 7 illustrates parameter influence on the reference curve.

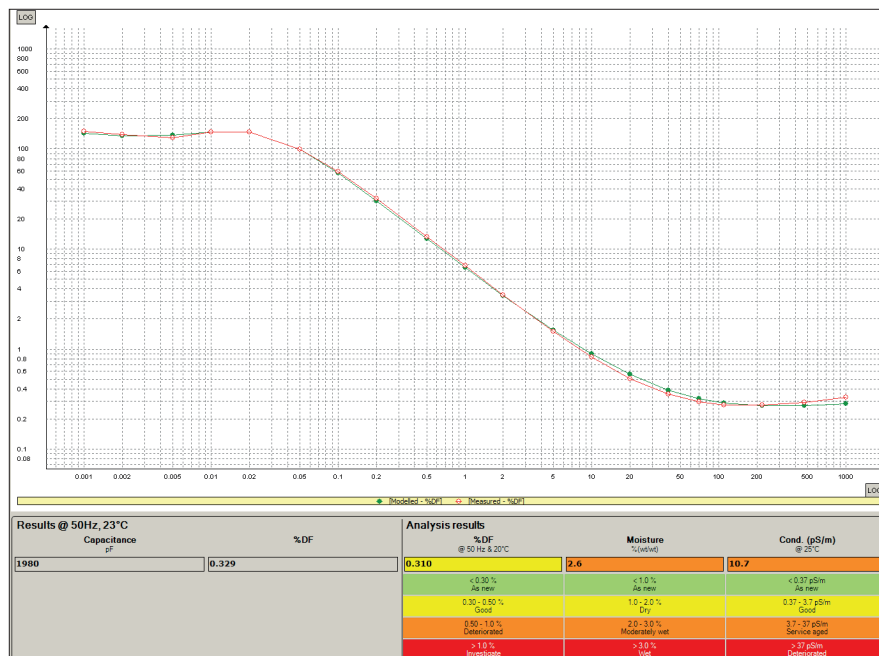


Figure 8. DFR insulation analysis/assessment

Using DFR for moisture determination is based on a comparison of the transformer's measured dielectric response to a modelled dielectric response (reference curve). A matching algorithm synthesizes a modelled dielectric response and delivers a reference curve that reflects the measured transformer. Results are displayed as moisture content along with the temperature corrected line frequency tan delta/power factor and oil conductivity. Only the insulation temperature (top oil temperature and/or winding temperature) needs to be entered as a fixed parameter. Figure 8 depicts results after insulation analysis/assessment.

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