Moisture measurements in power transformers

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It is well documented that moisture in mineral oil cooled and insulated power transformers has detrimental effects. Doubling the moisture content in a transformer could have the effect of halving the life expectancy of the unit, dramatically reducing the expected return on investment.

This article will look at some of the methods of determining the amount of moisture that will affect the operation of the unit and the subsequent management of the oil and paper systems.

Moisture effects in an operating transformer

When a transformer is delivered to a client the insulation should be dried to 0.5% by dry weight. During the operation of a transformer there are a number of factors that will influence the gradual production and contamination of the system. Moisture has a profound effect on mineral oil, and will cause the dielectric strength of the fluid to drop considerably.

Firstly, atmospheric moisture will have an impact, and this more specifically in units that have open breathing (breathe to atmosphere via a breather filled with a desiccant). If the desiccant is not maintained correctly the oil will absorb the moisture from the atmosphere as the transformer temperature cycles. The hotter the oil the more it will absorb moisture.

Secondly, in transformers that are either open breathers or sealed units (sealed meaning that the unit does not breathe to atmosphere directly), the paper degradation by-products and the natural gassing of transformer oil will produce moisture in small quantities (approximately 0.5 to 1 ppm per year). Transformers that do not use paper based insulating material are not as likely to have this phenomenon, but will have the natural gassing of oil producing small amounts of moisture. Coming back to the breakdown by-products of paper, a hydroxide (OH) molecule is given off when the cellulose chain is severed by heat and electrical stress. With most insulating fluids some hydrogen is always given off during normal operation and even in greater quantities during over loading and fault conditions.

From an insulating fluid perspective we find that, as most insulating fluids are hydro-carbon based, small amounts of hydrogen are given off during operation. With ever present oxygen there is a combination of hydrogen and oxygen to form H2O – moisture. With an increase in moisture in the system, cycling occurs that brings further destruction and thus the deterioration begins and will only get worse over time. Without intervention the life of the transformer will be severely curtailed.

Monitoring

There are a number of methods used to monitor moisture in transformers, and traditionally an oil sample would be extracted from the transformer and sent to a laboratory for analysis. However, there are serious flaws in the process, and typically the results are not reliable. These flaws are introduced early in the process, typically at the sampling stage, which could introduce moisture and contaminate the sample. Transporting the sample in a tin also poses a risk to atmospheric contamination due to temperature cycling. The accuracy of the Karl Fischer titration method employed at the laboratory also plays a role in the veracity of the result received. However, there are techniques that can be used to reduce these flaws and a good point to start with is training the sampler. Furthermore, changing the containers in which moisture samples are taken will have an affect. Traditionally, a square or round tin is used. These containers are not the best receptacle and glass syringes are better for this sampling.

Then there is the question of what must be done with the result when it is received. Moisture-in-oil is very dependent on the operating temperature of the transformer, especially when the sample was taken. Without the transformer’s temperature reading at the time of sampling, the result obtained is only significant to the moisture-in-oil and nothing else. Without the temperature no calculations can be done to determine the moisture in paper or relative saturation. The only information you will have is that the oil has moisture in it.

As a transformer operates, moisture will move from the insulation body (thin and thick insulation) into the oil as it heats and will move back to the insulation from the oil as it cools. This phenomenon is called equilibrium. If the transformer loading and ambient temperature were to remain constant for a long period of time, eventually moisture movement would cease and a state of equilibrium would be reached. The insulation system will always seek to obtain an equilibrium state, but with constant load changes and ambient temperature fluctuations hardly ever occurs in real life. This is also very difficult to predict as different parts of the system (both oil and solid insulation) are not at the same temperature. Thus equilibrium is merely an assumption of where the moisture may be at a specific point in time or temperature. To add to
Moisture in oil measurement

As stated in the previous section, the usual process is for an oil sample to be taken and analysed to obtain a result. Don’t throw this data away as it is still useful. With correct sampling techniques one can obtain good results. However, it is suggested that this data is used as your first line of monitoring and with some applied thought it can paint a useful picture in understanding the moisture status and trigger further action. Fig. 2 shows the value of plotting the data on a set of inverted equilibrium curves. If most of the plotted points fell below the green line, the transformer is generally dry. If, however, the data points fell between the two curves, it is a warning to take further measures. Lastly, if the majority of data points fell above the two curves, the insulation and oil are generally wet and correctional action is necessary.

If the data points are in the category between and/or above the two curves, an alternative method of moisture-in-oil measurements can be employed. This method is an excellent alternative as it can be done online and has benefit in that it produces real time data.

By employing a moisture-in-oil probe to measure the dynamics of the moisture and temperature at the same time, it is easier to detect when too much moisture is leaving the solid insulation system, and the rate at which it is being given off by the solid insulation. Using this method the moisture movement can be tracked and monitored for a period of time (a week is preferable). In conjunction with moisture measurement it can be noted what the exchange rate is when the load is fluctuating. Monitoring it for a week will reveal loading patterns in most cases. These patterns will, in most cases, repeat the cycle every week and shows up any sharp increases of moisture movement.

The probe’s location and oil flow is extremely important. It must be placed in a location that has rapid oil flow or at least a steady flow over the probe tip. Normally this would be placed in the cooling system (inlet to or outlet from the cooler bank) or in pumped oil flow. Another location is in the flow of the online gas-in-oil monitor. The bottom main tank sampling point is not always the best location as there is little movement over the tip of the probe and in this case the measurement would merely measure the oil close to the probe tip.

One of the outstanding benefits of this method is the rate of change; an important factor and especially important if there are rapid changes in load growth and rapid temperature changes occurring. Too much moisture in the system with rapid load changes can cause detrimental conditions with disastrous results.

With rapid load growth and wet insulation, there is a dynamic that leads to insulation failure very quickly. An example follows:

The transformer is cold and the oil is cold, with the moisture predominantly embedded in the solid insulation. Sudden high loading will drive moisture out of the solid insulation rapidly and the oil, not being able to absorb the now free moisture, will cause a low dielectric zone where the moisture cannot be moved away (high saturation zone). A characteristic of oil, is that at low temperature it is not capable of absorbing the quantity of moisture being driven out of the paper and will only be able to do so once a higher temperature is obtained. In an operating transformer the volume of oil takes time to reach higher temperature. (Like a kettle put on to boil, there will be aggressive heating of the moisture near the element but it takes time for the water to boil). This creates a very low dielectric strength in areas where there is insufficient oil flow (see Fig. 3). To add to the problem, when oil is cold the viscosity is higher (thicker) and the oil is then
sluggish and does not flush the moisture away. This set of conditions can often lead to an insulation system break down and a flash over will occur.

Most on-line dissolved gas analysers have moisture detection built in and will measure moisture along with the gases, however it is important that a temperature-in-oil probe is fitted and the temperature monitored along with the moisture. From this data a very good idea of the relative saturation can be calculated and this parameter will be most useful in determining the state of the transformer in terms of moisture.

Using moisture in oil measurement to determine moisture in cellulose is a tricky business as the equilibrium plays the major role and due to the fact that different parts of the transformer are at different temperatures and states of equilibrium. In most cases a set of equilibrium curves are used to determine the amount of moisture in paper. There are a few technical papers that attempt to evaluate the mechanism, but there is still much doubt as to their accuracy.

**Moisture in paper measurement**

Moisture in cellulose is a difficult parameter to measure. There are two main methods to determine this and the results are not always reliable.

Firstly, taking a paper sample means that the unit must be out of service. Either a hatch on the transformer has to be removed and some paper (or board) removed from the unit, or the unit must be removed to a workshop environment where it is easier to access paper and board. However, in both cases you will need to contend with atmospheric conditions which will influence the outcome of the analysis. This requires a skilled technician who will ensure that the location where the insulation was removed is restored. Furthermore, the sample has to be handled extremely carefully. Any outside influence, such as atmospheric conditions and handling, will contaminate the sample and render it useless, and give incorrect results. Temperature and relative humidity at the time of taking the sample will have a significant impact.

The insulation’s diffusion rate plays a key role in the transfer of moisture between insulation and oil. Larger blocking or thick insulation is not as badly affected and good results can be obtained if handled correctly. Larger blocks of insulation are normally affected by surface moisture e.g. between 1 – 1.5 mm deep. Deeper moisture is locked in and will take much effort to release, i.e. longer periods of high temperature and vacuum.

Using this method of moisture determination, outside of a controlled environment, is challenging at the best of times. There are too many obstacles to make this method a cost effective way of measuring moisture.

**Moisture in air measurement**

In this method of measurement there are again some questions as to the accuracy of the results. This method can only be used to determine the moisture in air, and to some degree moisture in insulation. Here again, the question of equilibrium state and as mentioned before there is still some doubt as to when all the components in a transformer are in equilibrium.

To perform this measurement the transformer must have all the oil drained out, and cannot be performed online. This technique is normally used during manufacture and repair either in a workshop or onsite. The unit is filled with extremely dry air and left to stand for at least 48 hours with as little temperature variation as possible. There are two important things to remember: is the insulation “oil impregnated” or “dry” as these two parameters will have a significant effect on the results. Dry paper has the ability to transfer moisture far quicker than that of oil impregnated paper insulation.

A dew point probe (of high accuracy) is needed. It must be installed in such a way that it has air flowing over the tip. The transformer tank must be pressurised with dry air (dew point temperature below -50°C) to greater than atmospheric air pressure (typically 25 kpa) and left to stand for a least 48 hours. The duration of the measurement should be between 10 – 15 minutes and the data logged over that time period. If the technician performing the test touches the probe with his fingers the initial reading will be significantly higher until that moisture has dissipated. If this happens the test’s duration should be lengthened.
data has been captured, the initial data should be discarded and ideally the flatter section of the data taken and averaged. The averaged data must then be applied to the “Pipers” chart and the moisture in paper read off the chart.

The method is an indication of surface moisture, but there is still doubt as to the accuracy of this method and there are better means of determining moisture in paper.

System approach

The system approach is far more refined and uses an electrical means to measure the “system” rather than trying to measure one of the components (either oil or air) and calculating the resultant moisture. This method is finding greater acceptance and is improving as the technology matures and gains momentum. Frequency domain spectroscopy (FDS) or variable frequency dissipation factor measurement (tan delta) takes both oil and solid insulation into consideration. The instrument uses the data measured (dielectric dissipation factor or tan δ) and models the measured data to a known curve which then equates to moisture in oil and moisture in insulation, i.e. taking the whole insulating system into consideration.

Obviously this measurement cannot be done online and the transformer will need to be disconnected from the network. The windings are normally lumped together by connecting all the terminals together, i.e. HV terminals (all phases), LV terminals (all phases) and tertiary terminals (all phases) all being separated thus having three entities. Typically three tests are carried out: CHL, CL and CH are performed on the transformer.

Depending on the instrument, the test will vary the frequency from 100 down to 0.001 Hz (the frequency range can be set). Once the tests are completed the data set measured is modelled against a predefined set of curves and matches the closest curve to the data. From the modelling performed, the instrument will give an accurate determination of not only the moisture in insulation but also moisture in oil, i.e. system moisture. Fig. 6 shows typical curves measured and the various observations made.

The FDS can be used in both situations: dry air (no oil in the transformer tank) and oil filled transformers, making it a very useful tool in both field and workshop applications.

Management

Many people ask how much moisture should be allowed or is good practice. This question needs to be divided into three categories:

- New
- In repair process
- In service

A new transformer should be dried to a value of 0.5% or below.

There is a trade-off. To dry the unit to very low values takes a number of cycles to dry the windings. Depending on the methods and technique, these drying cycles have a tendency to lower the degree of polymerisation (the shortening of fibres in the insulation material) and thus shorten the life of the unit’s insulation. Again some manufacturers will oil-impregnate the windings early in the process and thus it is more difficult to remove moisture in the drying cycle, but it works both ways, the insulation will not absorb moisture as readily. However, left unimpregnated the insulation will get wetter quicker and take longer to remove the moisture. Careful monitoring of air condition in the manufacturing plant is necessary to prevent the cellulose based winding from absorbing moisture. With the FDS technique, both oil-filled and non-filled units can now be tested once tanked.

It is suggested to perform an FDS measurement prior to testing the unit (in the manufacturing plant), on arrival at site and prior to energising. A transformer should be dried to between 0.8 – 1.2% after repair.

In the case of repairs, the values will be dependent on the wetness of the unit prior to the unit being repaired. The degree of polymerisation plays a major role in this decision. If the DP is found low, the dry-out may damage the insulation to the point of no return. The number of drying cycles will deplete the paper life. The more heat applied, the greater will be the ageing effect on the cellulose. If the cellulose’s degree of polymerisation is already low then drying to an unnecessarily low value will only cause further loss of life.

It is suggested to test the unit prior to repairs and after repairs, and also prior to energising the unit.

Transformers in service should typically be <2% for large units (e.g. 100 MVA and above) and <2.5% in the lower power range.

Good maintenance practice would be to test the transformer every 2 to 5 years with the FDS method, but as stated above keep your moisture-in-oil data to keep the finger on the pulse.

Conclusion

Keeping the transformer dry is the preferred practice. To do this, a molecular sieve or other online drying technology can be deployed for continuous drying of the oil and solid insulation system, and thus avoiding the major dry outs when the unit is found wet.

Measuring moisture in an operating transformer is not practical without the oil temperature being taken along with the sample. However, for reliable results it is best to have a trained sampler to take the sample from the transformer using the correct techniques and equipment, and transporting the sample reliably to the laboratory. Oil sampling is still a good first line defence, but follow up measurements must be made if the transformer shows signs of undue increases unrelated to variations from the sample process.

The other methods that are mentioned in this article are second tier methods and are used to gather further and more detailed condition information. However, in many cases these methods have flaws due to their techniques. A good solution is the frequency domain spectroscopy technique which has made this uncertainty a thing of the past.

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