PARTIAL DISCHARGE PROBLEMS WITH TRANSFORMERS IN SERVICE: NEW PERSPECTIVES ON HYDROGEN AND MOISTURE

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Abstract: Partial discharge is a leading cause of transformer failures both in works test and in service. Dissolved gas analysis is widely considered to be a useful tool for identifying developing partial discharge problems in large transformers in service. This paper examines some of the difficulties in using dissolved gas analysis, and other oil tests, to diagnose partial discharge problems. This paper also examines the role that high levels of moisture can have in causing partial discharge. It is concluded that high and variable levels of dissolved moisture and hydrogen can be an indication of serious problems, which can be investigated using off-line electrical condition assessment tests.

1 PARTIAL DISCHARGE IN TRANSFORMERS

Partial discharge is a leading cause of transformer failures both in works test and in service. Its importance has been well understood for many years, and partial discharge measurements have been made on all new large transformers as part of works test for many years [1]. There is thus very wide experience within the industry of investigating partial discharge problems during works test. A wide variety of measurement methods have been developed and the origins of partial discharge during works test have been extensively studied [1, 2].

Dissolved gas analysis is widely considered to be a useful tool for identifying developing partial discharge problems in large transformers in service [3]. Partial discharge is said to give rise to a dissolved gas signature characterised by a high level of hydrogen and low levels of hydrocarbon gases, especially methane. Some recent experience suggests that the usefulness of dissolved gas analysis in detecting partial discharge problems in transformers may have been over-estimated. This recent experience will be one of the main subjects of this paper.

In-depth investigation of partial discharge problems on large transformers in service can be rather challenging. Many of the measurement methods which have been developed for use during works test are either ineffective or unfeasibly difficult to apply during normal service, or even with the transformer at site but not in normal service. Some problems arising during service are similar to those arising during works test, and their origins have been widely studied. Other problems arise mainly or exclusively during service and have, until now, been little studied.

All oil-immersed transformers contain some moisture, even new transformers which have been thoroughly dried. Moisture can be absorbed in service by a variety of mechanisms, leading some transformers to become wet. High levels of moisture in the oil can have a serious impact on the dielectric strength of that oil and hence the transformer [4, 5]. There is emerging evidence that high levels of moisture can also have a serious impact on the dielectric strength of oil-solid insulation interfaces [6]. Migration of moisture with changes in temperature can cause it to become concentrated at oil-solid insulation interfaces, so this is of particular concern. Experience in this area will be one of the main subjects of this paper.

2 CASE STUDIES

The authors will now present a number of case studies of partial discharge problems in transformers. These will focus on the role of moisture in causing such problems, and on the role of hydrogen in detecting them.

2.1 Case study 1

This case study concerns a 100MVA 132/11+11kV transformer at a large industrial plant. This transformer failed within an hour of first energisation, owing to a severe partial discharge fault in the 11kV connections. The cause of the partial discharge fault seems to have been a water leak from one of the openings for the 11kV bushings. It is not clear exactly when this took place.

Figure 1 shows the damage to the LV connections. A pool of free water seems to have collected on the upper surface of one of the cleats securing the LV leads. Evidence of free water was found at various other locations directly under this point.

Figure 1: Damaged LV Connections, case study 1

Various oil samples had been taken from the transformer – during works test, on filling, shortly before energisation and after failure. Levels of moisture were low – between 2ppm and 9ppm, with the highest level being during works test. Breakdown voltage results were good – 75kV or more in all cases.

This case study illustrates one important limitation in the use of oil tests to evaluate moisture levels in transformers. Unless the transformer is in thermal and moisture equilibrium, results can be misleading. In particular, free water can be present in transformers at low temperatures without this being detectable using oil samples.

2.2 Case study 2

This case study concerns a 250MVA 400/110/20kV transmission transformer. This transformer failed after approximately four years' service, owing to a flash-over up the inside of one of the HV windings. The flash-over was the result of accumulated damage by partial discharge to the inter-winding insulation. Partial discharge damage was found on the oil-solid insulation interfaces in areas of high electrical stress throughout the transformer.

Figures 2 and 3 show some of the partial discharge damage to the solid insulation in the transformer. Note how it is concentrated along oil-solid insulation interfaces. The damage was very extensive, affecting all three phases and the end insulation as well as the inter-winding insulation. This suggests a cause affecting all of the insulation in the transformer, e.g. high levels of moisture.

Moisture in oil results had been rather high throughout the life of the transformer and had reached 24ppm at 8°C at about the time of failure. This would be equivalent to approximately 65% relative saturation and is a wholly unacceptable level of moisture in oil according to most widely used criteria [4, 5].

Figure 2: Partial Discharge Damage, case study3

Figure 3: Partial Discharge Damage, case study 2

It is not completely clear how the oil came to be so wet. Possible explanations include incorrect filling on installation, poor breather function or water leaks in service. Some combination of the first two seems most likely.

2.3 Case studies 3 and 4

These case studies concern two identical 170MVA 400/7.9kV SVC transformers.

The transformer in case study 3 failed after approximately seven years' service, owing to severe partial discharge in part of the inter-winding insulation on one phase. Before failure it had a normal dissolved gas signature and normal levels of moisture in oil (maximum 20ppm).

The exact cause of the partial discharge was never found. The manufacturer believed that the cause was most likely micro contamination. The operator believed that the cause was most likely high moisture, making it similar to that for case study 2.

Figure 5 shows the dissolved gas history for the transformer in case study 3.

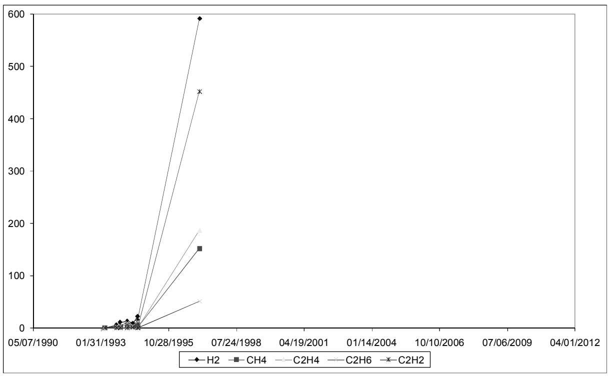

Figure 4: Dissolved Gas Results, case study 3

The transformer in case study 4 was manufactured around the same time as that in case study 3, and installed at a different location. For most of its life it has a rather different dissolved gas signature characterised by a higher level of hydrogen together with moderate levels of methane and ethane. The moisture level has been moderate (credible maximum 16ppm).

Figure 5 shows the dissolved gas history for the transformer in case study 4.

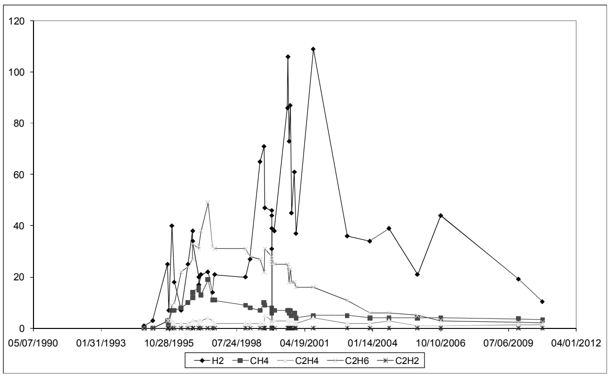

Figure 5: Dissolved Gas Results, case study 4

This case study is believed to be an example of so-called stray gassing. Many hydrogenated oils generate moderate amounts of hydrogen, methane and ethane under service conditions. The relative quantities of gas produced can vary over quite a range. It is thought to be influenced both by the exact type of oil used and the operating conditions.

Case study 5 is typical of stray gassing in Great Britain. In its early stages the dissolved gas signature includes significant quantities of both methane and ethane. In most cases the ethane level is higher than the methane level. In its later stages stray gassing can be more difficult to distinguish from partial discharge as production of methane and ethane tends to cease or slow before production of hydrogen does.

2.4 Case studies 5 and 6

These case studies concern two identical 1000MVA 400/275/13kV autotransformers.

It was noted as part of case study 4 than many hydrogenated oils generate moderate amounts of hydrogen, methane and ethane under service conditions. Many hydrogenated oils also contain excessive amounts of potentially corrosive sulphur.

The transformer in case study 5 was built in the mid 1990s. It failed after approximately eleven years' service, owing to a combination of sulphur corrosion and severe solid insulation ageing in part of the series winding. The failure is discussed in more detail in [7].

Figure 6 shows some of the damage to the series winding. Before failure there had been indications of some stray gassing, which seemed to be reducing.

Figure 6: Damage to Series Winding, case study 5

To mitigate the risk of failure, many users have added metal passivator to transformers considered to be at risk of sulphur corrosion [8]. One possible effect of adding passivator, which has been observed on many transformers is renewed stray gassing. This is often more severe than previously.

The transformer in case study 6 was manufactured slightly later than that in case study 5, and installed at a different location. Following the failure of the transformer in case study 5 the operator decided to add passivator to all of the other transformers of the same design.

Figure 7 shows the dissolved gas history for the transformer in case study 6. Note the renewed stray gassing after the passivator was added. In this case hydrogen was produced, but no other gases. Experience suggests that this experience is typical in transformers with free-breathing oil preservation systems. Methane, ethane and carbon oxides are produced in some cases, especially in transformers with sealed oil preservation systems [9]. Where only hydrogen is produced the dissolved gas signature is difficult to distinguish from that of partial discharge.

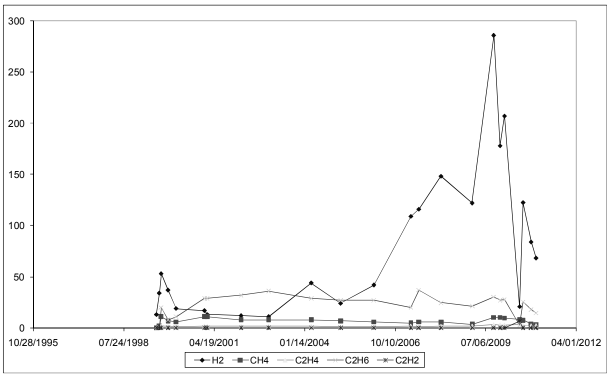

Figure 7: Dissolved Gas Results, case study 6

2.5 Case studies 7 and 8

These case studies concern two identical 220/33kV transformers. They are discussed in more detail in [10, 11, 12]. One transformer showed an unusually high level of hydrogen (hundreds of ppm), with lower levels of other gases, whereas the other did not.

A UHF partial discharge sensor was fitted to each of the transformers to determine whether the high hydrogen level in the first transformer was indeed caused by partial discharge. With the UHF sensor fitted, each transformer was returned to service and monitored for partial discharge. Significant levels of partial discharge were found in the first transformer (case study 7), but not the second (case study 8).

Figure 8 shows the phase-resolved partial discharge patterns measured on the transformer in case study 8

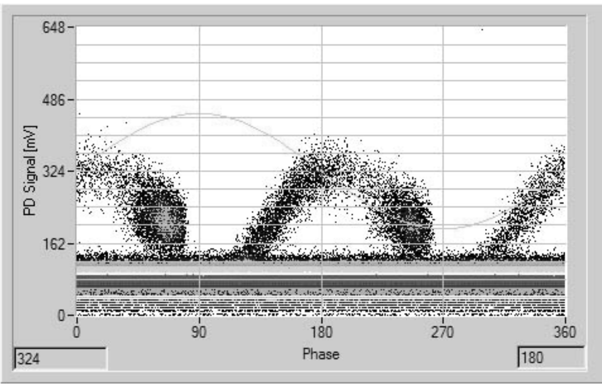

Figure 8: Phase-Resolved Partial Discharge Pattern, case study 8

2.6 Case studies 9 and 10

These case studies concern two identical 240MVA 400/132/13kV autotransformers. These were built in the mid 1980s and installed at the same location. Their dissolved gas signature has been characterised by variable and frequently very high levels of hydrogen. Levels of moisture have also been high variable and frequently very high e.g. 73ppm for the transformer in case study 9 and 158ppm for the transformer in case study 10.

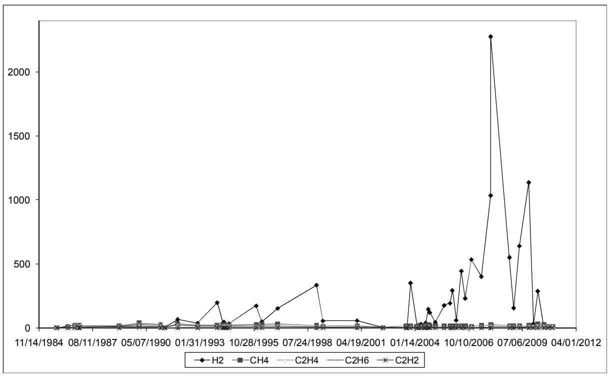

Figure 9: Dissolved Gas Results, case study 9

Figure 9 shows the dissolved gas history for the transformer in case study 9.

It had been thought that the hydrogen in these two transformers was being produced by a chemical reaction, probably involving moisture, especially as attempts on both transformers to measure partial discharge in service using the UHF method proved unsuccessful. Indeed, there are a number of reports in the literature of hydrogen being produced in this way, e.g. [13, 14, 15].

The two transformers were removed from service for electrical condition assessment testing. Selected results of winding capacitance and power factor measurements are listed in Table 1. These are compared with results from two further transformers of a similar design at another location, which have normal dissolved gas signatures and levels of moisture.

Table 1: Selected Winding Capacitance and Power Factor Results

Transformer	Winding Capacitance and Power Factor		
	Main to earth	Main to TV	TV to earth
Case study 9	14 406pF 0.47%	19 446pF **0.48%**	16 625pF 0.45%
Case study 10	14 006pF 0.40%	19 609pF **0.45%**	16 694pF 0.42%
Reference 1	13 551pF **2.44%**	22 316pF 0.31%	18 750pF 0.31%
Reference 2	13 328pF **2.01%**	22 232pF 0.28%	19 377pF 0.29%

The designs for the two pairs of transformers differ in the line connection arrangement and the tertiary arrangement. The two reference transformers are directly connected to GIS on the HV and LV sides, which seems to explain the high power factor results for the main winding – earth insulation. The different tertiary arrangement seems to explain the difference in main winding – tertiary and tertiary – earth capacitance.

The higher main winding – tertiary power factor for the transformers in case studies 9 and 10 is a clear indication of worse dielectric condition. It is believed that high levels of moisture are leading to intermittent partial discharge, in a manner similar to case study 2 and perhaps also case study 3. This case study illustrates the value of off-line electrical condition assessment testing for suspect transformers.

3 CONCLUSION

The value of taking regular oil samples for dissolved gas analysis and oil quality checks is clearly shown by case studies 2, 7, 9 and 10. Note that there was an interval of more than two years between the last oil sample being taken from the transformer in case study 3 and the failure, so they may also have been of value in this case.

The value of making on-line electrical condition assessment tests on suspect transformers is clearly shown by case studies 7 and 8. The value of making off-line electrical condition assessment tests where these are inconclusive is clearly shown by case studies 9 and 10.

Some important limitations of taking regular oil samples for dissolved gas analysis are shown by case studies 1, 4 and 6. In case study 1, oil tests failed to give any warning of the presence of free water as the transformer was not in thermal and moisture equilibrium. Case studies 4 and 6 illustrate so-called stray gassing in hydrogenated oils. Hydrogen generated by partial discharge can be confused with hydrogen generated by stray gassing in some circumstances. However in many cases the methane and ethane also generated by stray gassing can be used to distinguish between hydrogen generated by stray gassing and hydrogen generated by partial discharge.

4 ACKNOWLEDGMENTS

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