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Understanding Transformer Testing

A GUIDE TO DIAGNOSTIC TESTS FOR OIL-FILLED TRANSFORMERS

Transformer oil testing gives you insight into the true condition of your high-voltage equipment so you can make intelligent, cost-effective transformer management decisions.

This guide covers a range of tests and provides an overview of what the results may mean for your equipment.

SDMyers ACTS 4:12

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INTRODUCTION

Since the turn of the 20th century, transformers have been filled with mineral insulating oil. The primary functions of mineral oil are to act as a **dielectric** and **insulating** material, to provide heat transfer and disperse heat, and to act as a **barrier** to protect the cellulose insulation from the damaging effects of oxygen and moisture.

A secondary function of mineral oil in transformers—and the function that we hope to demystify with this guide—is to act as a **diagnostic tool** for evaluating the solid insulation inside the transformer.

You may be familiar with the idea, "The life of the paper is the life of the transformer." A well-used phrase in the electrical reliability industry, this statement means that the condition of the cellulose insulation is, essentially, the condition of the entire unit. If the cellulose insulation fails, so does the transformer.

As transformer maintenance professionals, we look to the diagnostic function of mineral oil to learn as much as we can about a transformer. We use proven testing methods to collect data from samples, and we leverage what we know from scholarship, research, industry standards, and experience to accurately diagnose faults and to plan remediation.

This guide is an overview of these testing methods, offering a glance into the benefits and limitations of each test. Similar tests are applicable in both mineral-oil-filled and alternative-fluid-filled transformers, with alternatives including askarel, natural and synthetic esters, silicone and Wecosol. Although there is some overlap, this guide will focus on testing for mineral oil transformers.

Thank you for taking the time to educate yourself on this topic, and for trusting SDMyers as your source of information. We hope this guide sheds some light onto the value of oil testing and, most importantly, the value of diagnostic analysis as the most effective tool available for increasing the reliability of your transformer.

- The SDMyers team

TESTS

DISSOLVED GAS ANALYSIS (DGA)

ASTM D3612
Standard Test Method for Analysis of Gases Dissolved in Electrical Insulating Oil by Gas Chromatography

DETECTS
Presence and concentration of hydrogen, oxygen, nitrogen, carbon monoxide, carbon dioxide, methane, ethane, ethylene, and acetylene.

INDICATES
Fault conditions that lead to production of fault gases.

Dissolved Gas Analysis (DGA)

The primary use of dissolved gas analysis (DGA) is as a routine monitoring oil test for electrical equipment. Incipient fault conditions—disruptions in the normal electrical and mechanical operation of electrical equipment—cause the oil to break down, generating combustible gases. The profile of those gases can be interpreted to diagnose whether fault conditions exist, and how severe those faults may be.

DGA is also used to determine the concentration of dissolved atmospheric gases (oxygen, nitrogen, and carbon dioxide) so that the operation of oil preservation systems such as conservators, continuous nitrogen systems, and nitrogen blankets can be evaluated.

DGA is used when new oil is placed in a transformer, or on newly manufactured equipment. Appropriate operation of new equipment may require an extremely low gas content in the newly installed oil—a typical specification value is 0.5% (5000 ppm) by volume of total gas dissolved in the oil. There are several methods for running this (ASTM D831, D1827, D2945), but a complete DGA by method D3612 gives the most comprehensive result. Not only does the test quantify the total gas in ppm, but it also tells which gases are present and in what quantities.

Also performed on samples drawn during factory heat runs (and sometimes during factory electrical testing), DGA can monitor the integrity of newly manufactured equipment. Similarly, most installations of new, large transformers require close monitoring by DGA during the first days, weeks, and months of operation.

KARL FISCHER MOISTURE (KF)

ASTM D1533
Standard Test Method for Water in Insulating Liquids by Coulometric Karl Fischer Titration

DETECTS
Presence and concentration of water in transformer oil.

INDICATES
Potential for further degradation of cellulose insulation.

Karl Fischer Moisture (KF)

Karl Fischer (KF) testing measures water content in transformer oil. Water content is a chemical property of new oil related to its purity. New oil leaves the refining process with very low water content, but can pick up additional moisture during storage, transfer to delivery containers or vehicles, transportation, and installation. A typical specification value for new oil, as received from the supplier, is a maximum of 25 ppm moisture.

When new oil is installed in new equipment, it is typically processed through filters, heat, and vacuum. A typical specification value for new oil leaving the processor to be filled into new equipment is a maximum of 10 ppm moisture.

Once the oil has been installed in the equipment, the moisture content of the oil in ppm no longer tells the complete story. More important values from an operational and maintenance standpoint are the percent saturation of the oil and the percent moisture by dry weight of the solid insulation. These are calculated using the moisture content of the oil in ppm and the temperature of the oil at the time of sampling. A typical specification for percent moisture by dry weight for a new unit, prior to energizing is 0.5%.

As an in-service oil test, moisture content is a critical parameter. Again, the critical values are the percent saturation and the percent moisture by dry weight calculated from the oil temperature and the moisture content in ppm reported by the Karl Fischer Titration.

LIQUID POWER FACTOR (PF)

ASTM D924
Standard Test Method for Dissipation Factor (or Power Factor) and Relative Permittivity (Dielectric Constant)

DETECTS
The dielectric strength of insulating oil.

INDICATES
Loss of dielectric properties of liquid insulation.

Liquid Power Factor (PF)

Dissipation Factor, or Liquid Power Factor (PF), is a measure of the dielectric losses in an insulating liquid when used in an alternating current electric field.

Dissipation factor and liquid power factor are not exactly equivalent, but they vary by less than one part in a thousand up to a value of approximately 5% for the liquid power factor. They are essentially interchangeable for the values that are likely to be encountered in operating electrical equipment.

Liquid power factor is an electrical property of the oil. It relates both to the function of the oil and to its purity. Highly refined oil, free from contamination, has a very low liquid power factor. Moisture, oxidation, and contamination all serve to increase the liquid power factor. For new oil as received from a supplier, typical specification values for liquid power factor are ≤ 0.050% when measured at 25° C and 0.30% when measured at 100° C.

Liquid power factor is a particularly useful in-service tool for testing and monitoring oil because the test is sensitive to moisture, the oxidation of the oil, and contamination from outside sources. Frequently, the pattern of increase for the 25° C and 100° C values can be used to identify specific conditions of concern.

OXIDATION INHIBITOR CONTENT (DBPC)

ASTM D2668
Standard Test Method for 2,6-Ditertiary Butyl Para-Cresol and 2,6-Ditertiary Butyl Phenol in Insulating Oil by Infrared Absorption

DETECTS
Presence and concentration of oxidation inhibitor.

INDICATES
Occurrences of oxidation within the insulation.

Oxidation Inhibitor Content (DBPC)

This test measures the two compounds used as added oxidation inhibitors and reports the total content of the two compounds as total oxidation inhibitor. This is a test of the chemical properties of the oil. The test is performed on both new oil—for acceptance testing—and as a maintenance and monitoring test on in-service oil.

New oil is typically characterized as being either Type I (uninhibited), with a maximum inhibitor content of 0.08 weight percent, or Type II (inhibited), with a maximum inhibitor content of 0.30 weight percent. An appropriate specification range for acceptance of inhibited oil is 0.20 to 0.30 weight percent inhibitor.

For in-service oil, inhibitor should be replenished if the inhibitor content decreases to below 0.1% by weight. Under normal circumstances, mineral oil dielectric fluid will not generally oxidize if the inhibitor content is properly maintained.