CIGRE- 547

2022 CIGRE Canada Conference & Expo
Calgary, Alberta, Oct.31 – Nov. 3, 2022

Using Automated Infrared Transformer Monitoring to Reduce Maintenance Costs

Richard Harada
Angelo Rizzo
Systems With Intelligence
Canada

Richard.Harada@systemswithintelligence.com

SUMMARY

This session will explain how infrared technology is used to monitor substation assets including transformers and their subsystems. Users will learn how automated infrared monitoring provides utilities with real time data from their substation assets that will enable them to determine the operating condition and detect thermal anomalies. Being able to thermally monitor assets continuously and remotely will help utilities to detect faults before failures occur, reduce on site inspections, and perform maintenance based on the equipment condition rather than on a time-based schedule.

The paper will show how APM reduces overall O&M costs while at the same time increase operational efficiencies. Infrared Thermography plays an important role in finding anomalies in the electrical system. However, automation, advancements in the technology and integration with asset management systems unlocks a new level of information that can be used to optimize operations. This information can be used to optimize the usage of this equipment, avoiding unplanned outages, and move to a “Just in Time” maintenance schedule.

Infrared measurements are affected by many environmental factors including temperature, humidity, wind, distance, and emissivity of the target object. With these factors in mind, it is difficult to obtain an accurate temperature measurement in an outdoor environment. It is often more meaningful to use comparative measurement; comparing the temperature differences between like components instead of trying to measure an absolute temperature value. A comparative measurement will effectively cancel out the environmental variables. This is a particular advantage in the electric power industry since the power system runs on three phases, so in many cases inside a substation, it is possible to measure like components on different phases, i.e., measuring the temperature difference between the A, B and C phase transformer bushings. In this case, instead of trying to calculate what an absolute temperature value should be, it is simpler and more meaningful to compare temperatures between phases. Typically, the temperature of like components in a balanced load should be within 1°C of each other, if not there could be a load problem or a component problem in the system. The International Electrical Testing Association, NETA, has established a guideline of comparative measurements and relative comparisons to ambient temperature where a temperature difference of 1 to 3°C indicates a possible deficiency whereas a difference of more than 15°C indicates a major discrepancy that requires immediate remediation.

Advancements in infrared technology and the communications around it make automated thermal monitoring more widely available through reduced cost, ease of use and accessibility to the data. Automated thermal inspections can be used for more than just finding thermal anomalies in the electrical system. With advanced analytics correlated with external information such as load and environmental conditions, thermal sensors can isolate and help utilities pinpoint the most common problems before failures occur. An automated, on-line monitoring system provides a constant source of asset temperature data and infrared images that can be fed into a machine learning system to learn the normal operating range and detect

anomalies that are indicators of impending failures. The output of the automated analysis will provide the recommended action for the utility to take to correct the condition. The utility is therefore performing maintenance and repairs based on the actual condition of the assets that results in a more efficient use of resources and equipment.

KEYWORDS

Infrared, Thermography, Transformer Monitoring, Asset Performance Management, Condition Based Maintenance

Introduction

Some of the most common failures on transformers are in the subsystems that are physically located outside the main enclosure or tank of the transformer, making them suitable targets to monitor with infrared sensors. The operation of the transformer is only as good as its worst performing subsystem, therefore monitoring and maintaining the performance of each subsystem is equally important.

The transformer subsystems that are the leading causes of unplanned outages in substations are bushings at 21.6%, onload tap changers at 29% and the cooling system at 8.7%. [1] From the Canadian Electricity Association report on Forced Outages, these subsystems and components together make up the majority of substation outages.

This article will look at how these subsystems can be better monitored to provide health data and advanced warning of failures to reduce the number of unplanned outages that utilities must deal with. With this data, utilities can begin to deploy Transformer Intelligent Condition Monitoring, (TICM), to strive for, "optimal preventive maintenance planning, reduced equipment unavailability and increases in reliability", [2] with their available resources.

Background on Thermal Imaging

Thermal imaging is able measure the infrared radiation from an object and convert it into a temperature value. An important feature of thermal imaging is that it is 'non-invasive', it uses a sensor that can measure temperature values without physically touching the object therefore it is not required to power down equipment to install the sensor to make the measurements. Infrared measurements are affected by many environmental factors including background temperature, humidity, wind, distance, and emissivity of the target object. Thermal imaging sensors output a temperature value based on an equation that takes into account the measured thermal radiation, emissivity of the target, distance to target and background temperature.

The total radiation power received by the camera can be written:

$$W_{tot} = \varepsilon \cdot \tau \cdot W(T_{obj}) + (1 - \varepsilon) \cdot \tau \cdot W(T_{bak}) + (1 - \tau) \cdot W(T_{atm}),$$

where ε is the object emissivity, τ is the transmission through the atmosphere, $W(T_{obj})$ is the radiation due to object temperature, $W(T_{bak})$ is the radiation due to (effective) temperature of the object's surroundings, or the reflected background temperature, and $W(T_{atm})$ is the temperature of the atmosphere. [4]

The above equation has variables to account for environmental conditions but that still does not account for wind. Wind has a major effect on thermal temperature measurements and is pretty much impossible to account for instantaneous wind conditions in an outdoor setting. With these environmental factors, it is therefore extremely difficult to obtain an accurate absolute temperature measurement in an outdoor environment. It can be much more meaningful to use comparative measurement, comparing the temperature differences between like components in conjunction with monitoring absolute temperature value. A comparative measurement will effectively cancel out the environmental variables. An advantage in the electric power applications is that the power system runs on three phases, so in many cases inside a substation, it is possible to measure like components on different phases, i.e., measuring the temperature difference between the A, B and C phase transformer bushings. [3]

In this case, instead of trying to calculate what an absolute temperature value should be, it is simpler and more meaningful to compare temperatures between phases. Typically, the temperature of like components should be within 1ºC of each other, if not there could be a load problem or a component problem in the system. The International Electrical Testing Association, NETA, has established a guideline of comparative measurements and relative comparisons to ambient temperature. As outlined in Table 1, NETA has recommendations for actions to take when comparative readings reach defined levels.

Temperature difference (ΔT) based on comparisons between similar components under similar loading.	**Temperature difference (ΔT) based upon comparisons between component and ambient air temperatures.**	**Recommended Action**
1ºC - 3ºC	1ºC - 10ºC	Possible deficiency; warrants investigation
4ºC - 15ºC	11ºC - 20ºC	Indicates probable deficiency; repair as time permits
- - - - - -	21ºC - 40ºC	Monitor until corrective measures can be accomplished
>15ºC	>40ºC	Major discrepancy; repair immediately

Table 1. Recommended temperature thresholds and actions for monitoring electrical components. Source: NETA World - Infrared Inspections and Applications.

Absolute temperature value monitoring can be used to monitor temperature fluctuation over the course of the day, week and seasonally to monitor if there is a trend in the asset temperature that could be an indicator of impending problem.

Portable infrared cameras have been typically used by thermographers to periodically inspect substations and other key areas of the grid. While periodic scanning is useful, automated, and continuous thermal monitoring has many advantages such as being able to provide measurements during changing environmental and load conditions, as well as being able to provide the data directly to operators, SCADA, and asset management systems.

Monitoring the Online Load Tap Changer with Infrared Sensors

Since the OLTC is one of the highest failure rate subsystems of the transformer, it is a key subsystem to monitor to ensure it is operating optimally. Some of the more common failure modes in the OLTC produce heat that can be detected by an infrared sensor. These failure modes are mostly due to the defects in the contacts including alignment problems, wear, pitting and coking. The effect of these defects is to create reduced surface area between contacts which will cause an increase in temperature due to the I^2R factor. Since the infrared sensor is reading the temperature of the OLTC enclosure, an absolute temperature reading would have little value. A temperature threshold may never be reached on a very cold and windy day or a false alarm may be generated on a very hot day. To overcome the environmental variables, a comparative measurement should be made between the OLTC enclosure and the main tank of the transformer. If the OLTC enclosure ever exceeds the temperature of the main tank, then there is some localized heating taking place. If the defect is only in one phase, then the localized heating may be evident in that section of the OLTC enclosure.

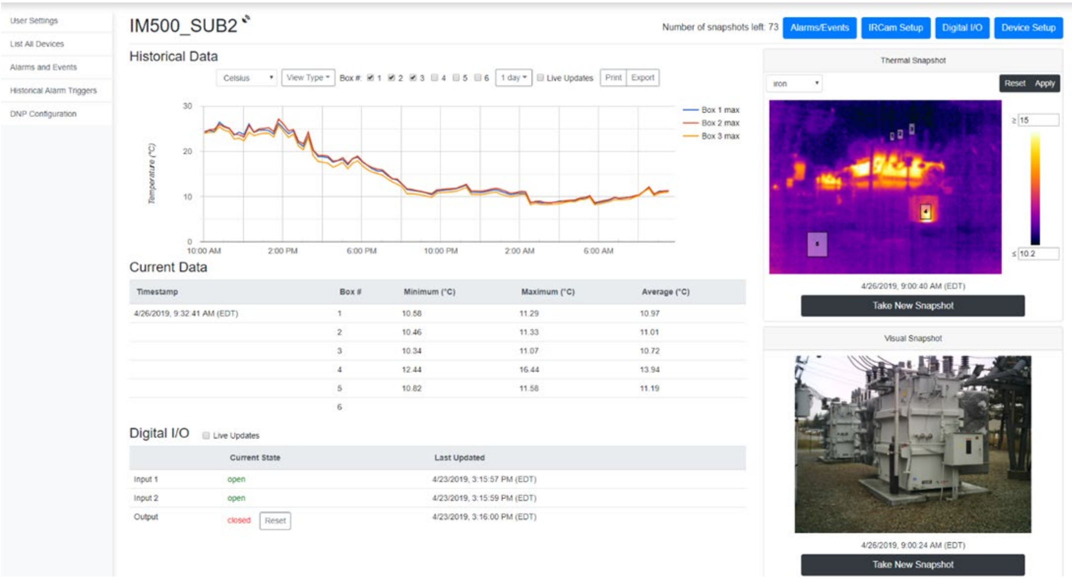

Figure 1. In this figure, A, B and C phase bushings are being monitored. The temperatures vary greatly but all 3 track together. Source: Systems With Intelligence Inc.

The problem may exist at only one OLTC setting if only one set of contacts is defective. Possibly an overload condition caused current to flow beyond the rated capacity of the contacts and caused pitting on that set of contacts. This means excessive heat will be generated only when the OLTC is in that position. It can then be determined which contacts are damaged by correlating the rise in temperature delta with the switch position.
It may also be the case that heat problems are detected at a particular time of the day. This could indicate a problem with the contacts that only shows up under heavy load. The I^2R factor will produce more heat in the contacts when there is high current flow, a problem that may not be revealed by periodic thermal scanning.

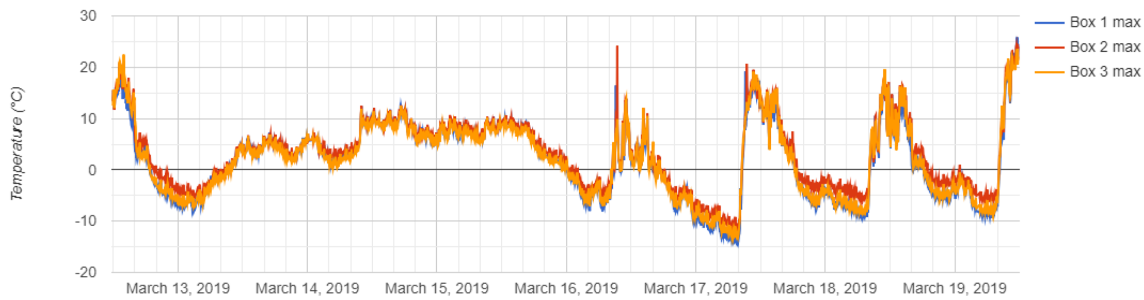

Fig 2. Temperatures vary depending on the day of the week due to load factors as well as environmental factors. Source: Systems With Intelligence Inc.

Depending on the conditions, the overheating problems in the OLTC may be transient, only occurring under specific conditions or on a particular set of contact points. Due to the transient nature, periodic infrared inspection may miss the problem where an automated, real-time monitoring system will find it. Additionally, an automated system will collect and store temperature data, allowing it to be trended and correlated with weather and load current to further narrow down the problem. OLTC temperature data can also be correlated with the tap position to help isolate which contact points require maintenance.

SYSTEM, COMPONENTS	DEFECT or FAULT	FAILURE MODE
SELECTOR SWITCH **Dielectric** Solid insulation: - between taps, - to ground, - between phases - barrier board & bushings Liquid insulation : - Across contacts Adjacent studs in combined selector diverter tapchanger	• Excessive water • Oil contamination • Surface contamination • PD of low energy • Abnormally aged oil	Destructive PD Localized tracking Creeping discharge Excessively aged/ overheated Cellulose → Flashover
Electrical Connections Contacts - Selector contacts - Change-over switch/course fine Through bushings	• Poor connections • Misaligned contacts • Silver coating disturbed/worn • Poor contact pressure	Overheating → gassing Sparking/ arcing Overheating Carbon build up between contacts
Mechanical Drive shaft Selector contacts	• Damaged or broken • Incorrect alignment with diverter switch operation • Travel beyond the end stop	Out of synch operation of selector & diverter switches arcing
DRIVE MECHANISM Drive shaft Mechanical end stops Motor and gear drive Control equipment Auxillary switches	• incorrect timing • operation beyond end stop • broken gears • missaligned coupling • worn,damaged, broken auxilliary switches.	Incorrect operation of the selector switch in relation to diverter Tap changer jammed on a tap-will not operate

▲ Infrared Sensor Detection ▲ RGB Camera Detection

Table 2. From CIGRE TB 227. The figure shows failure modes of an OLTC that can be detected using an infrared sensor or an RGB (visual) camera. Similar failure modes can be detected on other primary and secondary equipment.

The Cooling System

Proper operation of the cooling system is critical for optimal operation of the transformer and preservation of its life expectancy. An overheating transformer can damage the winding insulation, causing shorts and possible catastrophic failure. Monitoring of the cooling system ensures that all its components are correctly functioning, and transformer is operating within its designed temperature ratings.

Using infrared temperature monitoring allows several cooling system components to be monitored using a single sensor. The infrared sensor detects the heated oil as it enters the top of the radiators and cooling oil as it flows down. This pattern will show the oil being cooled as it moves through the system when it is operating correctly. Deviations between radiators can indicate several issues such as failing pumps, blocked radiators, coolant level problems, or leaks. Comparative thermal measurement can be done between like radiators to determine that they are operating correctly. Comparative measurement can also be done between the top and bottom of the radiator to determine the cooling delta that is being provided. Coolant level in the conservator can also be monitored.

Cooling fans are an integral part of the system and are required to provide air flow through the radiators to dissipate heat from the coolant. As the fans operate, the motors will generate a heat pattern that can be monitored by the infrared sensor. Comparative measurements can be made between cooling fans to ensure they are operating at the same temperature. Fan motor temperature measurements should also be correlated with the fan control signals to ensure they are operating when they are supposed to be and are not overheating due to worn bearings etc.

Transformer Bushings

Bushings are among the most common subsystems on the transformer that fail. Many bushing tests, measurement or monitoring techniques require an outage to perform the test or to install the test equipment. Infrared sensors can monitor bushing temperatures without a physical connection making it an easier and more economical method to continuously monitor many points without the high cost of installation.

Before failure, it is likely that the bushing will develop excessive heat that can be detected using an infrared sensor. The most common deficiencies that are detected with infrared sensors are due to insulation degradation causing arcing or a mechanical connection problem with an I^2R fault. As with most situations it is recommended to use comparative measurement between the bushings to eliminate the environmental effects on the temperature reading. Any temperature difference of more than 4ºC is an indication of a problem that requires repair. [2] Alarms should be set in the monitoring system to alert operators of the condition so maintenance can be scheduled.

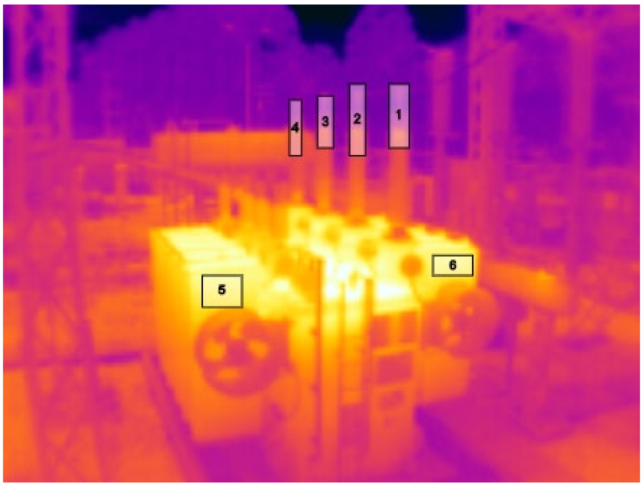

Figure 3. Snapshot from a thermal sensor shows a visual representation of asset temperatures. Source: Systems With Intelligence Inc.

Monitoring the Main Tank

The infrared sensor will only be capable of monitoring the outer wall of the main tank however there is still valuable information that can be obtained, especially when correlated with other data. As it has been stated that an accurate absolute temperature is difficult to obtain in an outdoor environment, however, the temperature pattern and rate of change can be an indication of problems in the transformer windings. If temperatures of the transformer tank are increasing under the same weather and load conditions, it may be an indication of internal arcing. This may also be indicated by a hot spot in localized area of the tank since arcing occurs at a very high temperature.

Thermal Imaging as an Alternative to Equipment Specific Sensors

There are many other pieces of equipment around the transformer that should also be monitored with thermal imaging including arrestors, CTs, VTs, breakers, disconnect switches etc. as these devices have insulation, and connection points that can degrade and become an issue in the substation. Often these pieces of equipment can be monitored with separate, specialized sensors. Separate sensors may require extra communications and software to gather and interpret the results. The thermal system can be used to monitor multiple systems and provide a common interface and consistent data format to

Processing the Data

Automated thermal systems collect data continuously providing a wealth of information to the utility. Systems with built in analytics can raise alarms as soon an out of tolerance condition is reached providing the utility an opportunity to correct the problem before a failure occurs. Additionally, the data can be stored and exported to other systems such as SCADA or asset management. Machine learning systems can analyse and detect anomalies from thermal data and images, correlated with other data such as weather, time of day and electrical load. Machine learning can go into much further detail and enable more accurate detection of faults in transformer components than manual data interpretation.

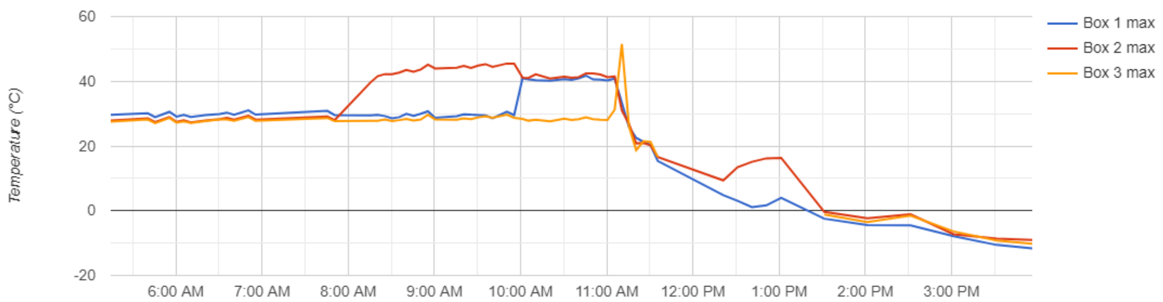

Figure 4. Diverging temperatures are indicators of load or component problems. Source: Systems With Intelligence Inc.

Thermal asset monitoring systems constantly gather thermal data and images from hundreds of points so leveraging the power of machine learning can assist asset managers in the analysis of the data.

With data gathered over a period of time, machine learning can learn the normal temperature patterns. Over the course of the day, ambient temperature, sunlight, and electrical load are among the many factors that can influence the temperature of an asset and its subsystems. The environmental factors also change over the course of a year as seasons change, the amount of daily sunlight changes, average temperature changes and the electricity usage vary. Thermal sensors gather data and provide an isolated view of the asset and that when analysed on its own may lead to a conclusion that there is a problem with the asset. However, if the same data is looked at in coordination with system load, environmental conditions, time of day, seasons etc a pattern will emerge as to what the normal and acceptable temperature limits are for those conditions.

In automated thermal monitoring system, temperature thresholds are configured based on standards and operating knowledge of the system. Machine learning can take an extra step to separate normal data from anomalous data. Anomaly detection is an important part of machine learning where the goal is to:

1. Learn to recognize normal data

2. Estimate the abnormality of new data
3. Set an anomaly threshold

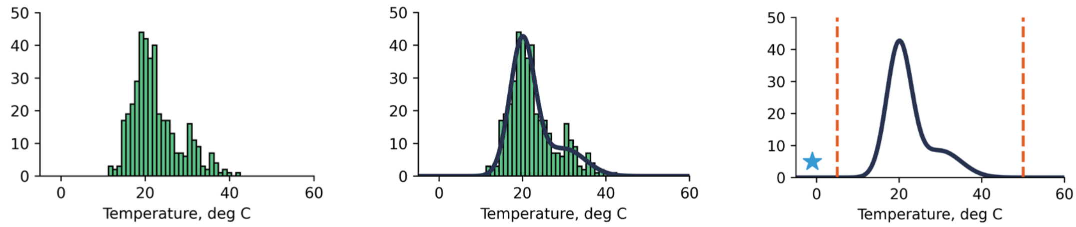

Figure 5. Machine learning will detect when readings fall outside of the normal temperature range. Source: METSCO Energy Solutions.

By accounting for confounding variables such as weather, time of day and electrical load, machine learning enables more accurate detection of true faults in electrical assets. [4] By monitoring temperature data over time, machine learning will be able to predict how temperatures will continue to trend and will be able to assist utilities predicting the health of their assets and subsystems in the future.

Using Thermal Data for Asset Performance Management

Condition-based maintenance (CBM) and reliability-centred maintenance are practices included in Asset Performance Management with the purpose of improving reliability and availability of assets. Condition-based maintenance replaces time-based maintenance, allowing utilities to deploy resources to service assets based on their health index instead of by schedule. Condition-based maintenance requires continuous monitoring so utilities can track the health of assets to ensure that maintenance service is done before any failures occur. The concept of CBM allows utilities to optimize resources and reduce unnecessary services and therefore reduce travel and expenses. As discussed, continuous thermal monitoring is a technology that can be deployed to monitor assets and collect health data under all conditions and that will be able to detect a high percentage of the most common failures.

Reliability-centred maintenance (RCM) similarly provides efficiencies in expenditures occurred compared to a time-based maintenance strategy but as the name implies it puts more emphasis on the reliability for the safe and continuous operation of the system. Both CBM and RCM deploy strategies of continuous monitoring, but RCM takes into account more elements of predictive maintenance.

Summary

Advancements in infrared technology and the communications around it make thermal monitoring more widely available with reduced cost, ease of use and accessibility to the data. Automated thermal inspections can be used for more than just finding hotspots in the electrical system. With advanced analytics correlated with external information such as load and environmental conditions, thermal sensors can isolate and help utilities pinpoint the most common electrical system problems before failures occur. An automated, on-line monitoring system improves the safety of utility operations by reducing operator exposure to hazardous environments while reducing maintenance costs and unplanned outages through deployment of Asset Performance Management. With the data fed into a machine learning system, utilities will be able to reliably detect anomalies and predict future maintenance requirements more reliably.

BIBLIOGRAPHY

[1] Canadian Electricity Association, Forced Outages Report

[2] Cigre Working Group A2.44 - GUIDE ON TRANSFORMER INTELLIGENT CONDITION MONITORING (TICM) SYSTEMS

[3] Don A. Genutis, Netaworld – Infrared Inspections and Applications, 2006

[4] FLIR – IR Thermography – How It Works