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Potential of Massively Deployed Sensors Applications in Substation Engineering

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Abstract: *Sensors, in general, and overall sensor technology have traditionally had a very limited application in substations engineering. With the advent of the modern communications systems, SCADA[1] systems have the potential of transmitting more data. Enormous potential exists to deliver more real time information and data that may increase the security of large substations, switching stations and of the power grid, and give advance warning of incipient problems which may be developing in substation equipment. This paper surveys the major types of available sensors and possible applications on how these may be deployed in the modern, SCADA monitored substations.*

I. INTRODUCTION

A sensor is a device which converts normally a physical phenomenon (like heat, pressure, vibration, motion, etc.) into an electrical signal. The reasons sensors are deployed in substation are primarily to warn operators of developing equipment and hence system problems, detect any security infringements, and/or monitor equipment status. In the last two decades, as communications techniques and the computer applications have matured, the capability to bring more information back to central monitoring stations and/or any control room has dramatically increased. As an example, the multi-functional digital relays have essentially revolutionized the industry. This would also make adding more and different types of sensors to substations to monitor all major equipment, to enhance operation, and to improve overall security an interesting challenge in the future.

[1] SCADA: Supervisory Control and Data Acquisition

Massively deploying sensors may result in several benefits [1] that includes (but not limited to):

1. Advanced warning of developing problems resulting in a fewer catastrophic failures.
2. More efficient operations of equipment and overall system resulting in lower losses, better conservation of resources and optimum operation.
3. Improved emergency response to problems; operators will have more information to diagnose and deal with problems for both normal and emergency operations.
4. Increased security of power grid, thereby, enhancing the homeland security.

At present, sensors installed in typical substations are primarily limited to voltage and current sensing devices for metering, protection and control. These are accomplished with traditional current and potential transformers (CT's and PT's) and various transducers. These devices will not be addressed in this paper. Some other sensors are applied to alarm for possible equipment failures and to enhance system operation. These consist of (but not limited to):

1. Transformer temperature monitor (oil, winding, tank and core)
2. Transformer nitrogen system failures (low or high pressure or empty supply tanks)
3. Low oil level
4. Rapid-pressure-rise relay, or pressure relief device
5. Power circuit breaker low oil or low gas (SF_6)
6. Protective relay failure alarms
7. Multi-function digital protective relays.

Also, it is quite common to install sensors which would relay circuit breakers, switches, or reclosers

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position status to a central monitoring location or control room.

Since the beginning of the recent war on terrorism some utilities have also begun installing various security devices in substations and monitoring these via the SCADA systems. These may be used to monitor intrusion through fences, and/or entry into control buildings. Video cameras are also being installed. These can be used to monitor the substation area in real time and/or they may only be used to only when intrusion alarms are activated.

Multifunction digital protective relays, metering, CTs and PTs are commonly used in substations and their monitoring by SCADA systems is widely used and well understood. This paper will examine other types of sensors which are rarely, used in substations and will discuss ways they may be of value in a substation or large switching stations.

II. THERMAL SENSORS

Temperature (or thermal) sensors are one of the most widely used devices in a substation. They are commonly used to activate cooling fans or pumps on transformers and can be used to indicate a problem in a transformer or overload situation that causes overheating. Too high a transformer temperature can send an alarm (and/or disconnect the transformer by tripping the breaker) via SCADA and a substation operation and maintenance personnel can be dispatched.

The most common type of temperature sensor is a bi-metal activated device where temperature is translated into mechanical motion. This motion is used to close a set of mechanical contacts that send the alarm (or trip) signal that the temperature of the monitored device is out-of-range.

There are two types of temperature sensors.

1. Contact sensors that require physical contact with the medium being sensed.
2. Non-contact sensors that interpret the radiant energy measurements of a heat source to determine the temperature.

Contact sensors are the most common, relatively inexpensive, and may consist of:

1. Bulb and capillary thermostats
2. Silicon Sensors
3. Thermocouples
4. Thermistors
5. Resistive Temperature Devices (RTDs)

Figure 1 shows a typical inexpensive direct contact sensor of the capillary thermometer type that might be used to measure oil and/or winding temperature in a transformer.

Figure 1: Indicating Type Temperature Sensor

Non-contact sensors consist of infrared pyrometric devices. Two common types are shown in Figure 2.

Figure 2: Non-Contact Temperature Sensors

Thermography is more commonly used practice in substations to detect poor bus connections (cause overheating) and is sometimes done as a routine maintenance procedure on a yearly basis. If a connection is deteriorating it will increase in contact resistance. The current flowing through the connection causes (I^2R) heating which increases the connection temperature. Thermal sensors, if properly insulated, could be embedded in each bus connection. If wireless technology were used, and power supplies used that derived their energy from the conductor being monitored [2], these sensors could send their temperature signals to a controller connected to the SCADA system that would send an alarm, when any connector exceeded its design temperature. Another advantage of this type of thermal sensing is that it would allow operators to operate substation buswork very close to its ratings since direct measurements were being taken to determine when the buswork was being overloaded.

An option that may be chosen would be to do non-contact sensing of buswork temperature. Thermographic cameras could be automated to periodically scan all the buswork in a substation via thermographic robotically operated cameras mounted throughout the substation. When these detect any hot-spots in the substation alarms could be sent via the SCADA system.

A major issue that is of concern to power system's operators today is the loading on transmission and distribution lines. Suggestions have been made that remote sensing could be used to directly detect the sag in power lines to determine when they were being operated at their limits [3]. The same sensors which were used to monitor substation buswork temperature could also be attached to overhead lines to directly measure their temperature. This information could be monitored by transmission systems operators.

Overhead power lines are usually designed with two possible temperature parameters. The first is normal temperature and the second is emergency (or short-time) loading temperature. There are two limiting factors in how much current an overhead line can carry. The first is the annealing temperature of the conductor. The line cannot be allowed to operate with enough current that the temperature exceeds the damage point of the wire. The second constraint is the sag of the conductor. As the line carried more current and heats up it elongates increasing the sag. At some point the clearance above ground could be insufficient to maintain safe margins. One known problem is that the line may sag into vegetation below causing a fault and disconnect the line by tripping the breaker.

Engineers design a line to operate at a certain maximum temperature with a sag that maintains safe clearances. However, the amount of current a line can handle at any particular time is determined by many environmental variables such as wind direction and speed and ambient temperature. A line designed to carry 600A on a hot still day may be capable of carrying far more on a cold or windy day. Also, the design engineer probably used conservative assumptions in their design. Once constructed the line may perform with more capacity than anticipated.

Direct measurement of the line temperature would tell an operator exactly how close to its ratings a line was being operated at any environmental condition. Thermal sensors monitoring lines and relaying real-time temperature information to an operator would allow the operator to determine exactly how much capacity each line contained and would allow overhead lines to be operated at their maximum possible load.

This thermal measurement could also be used to determine the sag of the line. If original sag and tension were known at a certain temperature this information could be used to calibrate a system that could calculate the sag and tension of the line at any other measured temperature.

Real time direct temperature measurements could make it possible to operate a line closer to its limits, thus postponing costly line upgrades or the construction of new lines. It would also make possible the most economic use of the transmission system.

III. CHEMICAL SENSORS

Chemical sensors are used to detect specific elements or compounds. These sensors can also be used to determine concentrations of a particular element or compound. Probably the most common use of chemical sensors today is the oxygen sensor (used in automobiles) shown in Figure 3. Chemical sensors can take the form of [1]:

1. Infrared spectroscopy
2. Mass spectrometers
3. Magnetic mass spectrometers

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4. Chromatography
5. Chemfets

Figure 3: Oxygen Sensor

Electrical conductivity can also often be used to determine the concentration of certain contaminants.

A Metal Oxide Semiconductor Field Effect Transistor (MOSFET) used to detect an ion in solution is shown in Figure 4 with an ion selective membrane, forming an ISFET (Ion Selective Field Effect Transistor). When immersed in solution the ions interact with the membrane. When the concentration of ions is high they will accumulate at the gate, widening the channel between the source and drain, changing the current flow through the device.

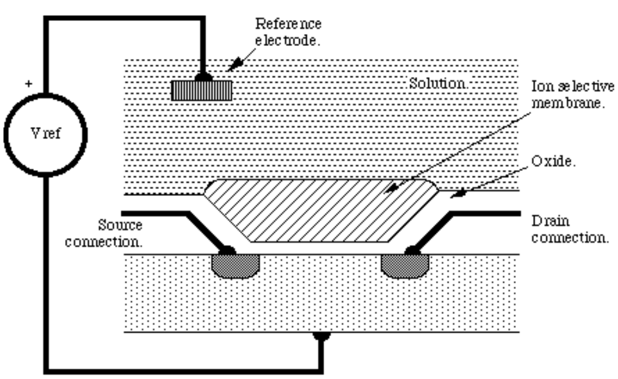

Figure 4: ISFET Sensor

The most obvious applications of chemical sensors in a substation are for gas analysis in transformers, tap changers, and oil filled breakers. The presence of certain compounds, such as acetylene or mositure, in transformer oil can indicate certain internal problems developing in the transformer. The presence of even small amounts of acetylene, for example, indicates that some type of electrical arcing is occurring inside the transformer. Automatic gas sensors are beginning to see use in large power transformers.

Chemical sensors can be developed and used to determine concentrations of the most problematic substances that can occur in transformer oil. The values can be automatically recorded periodically by computer systems and this information can be used to determine trends. This data can be automatically analyzed by computer systems and used to alarm system operators when chemical trends in a transformer indicate the presence of a developing problem. This will allow a utility to plan taking the transformer out of service to remedy the problem before it causes a transformer failure and extended loss of power.

Chemical sensor may also be deployed inside switchgear to measure concentrations of O_3. Ozone is formed during electrical breakdown and arcing in air. If arcing occurs inside switchgear due to the breakdown of insulation it would be expected to form ozone. The concentrations of ozone could be measured and used to alarm or trip the switchgear off-line if arcing is detected.

IV. PHOTOSENSORS

Photosensors detect optical and near-infrared radiation and convert it to an electrical signal. They come primarily in two types [1]:

1. Quantum Detectors
2. Thermal Detectors

Quantuum detectors convert radiation directly to electrons in a semiconductor device. Examples are photoresistors, shown in Figure 5, photo transistors, or photodiodes. Quantum detectors can be manufactured to respond to a variety of light wavelengths.

Figure 5: Photoresistors

Thermal detectors absorb energy and measure the resulting change in temperature. Thermal detectors have the advantage that they respond equally to energy absorbed at any wavelength.

Optical sensors can also be used to detect arcing faults in switchgear. During an arcing fault sufficient current may not be flowing to trip a ground fault device quickly [4]. However, the optical radiation may be used to detect this type of fault and trip a breaker before more severe damage can occur. Optical sensors may be deployed throughout medium and low voltage switchgear used in substations to detect and trip for arcing short circuits.

In recent years the Department of Defense has invested considerable funding in the development of thermal long-wave infrared sensors for use in motion sensing equipment. As security in substations becomes a greater concern, these types of motions sensors can be used in conjunction with other types of intrusion alarms.

V. SHOCK SENSORS

Shock has been defined as "a sudden and violent change in the state of motion of the component parts or particles of a body or medium resulting form the sudden application of a relatively large external force." [1] The rapid rate-of-rise relay (sudden pressure) used in a transformer may come under this definition since it senses the often violent change in internal tank pressure which accompanies a massive internal transformer fault.

Accelerometers may be used as shock sensors for a variety of conditions and can be used to determine the frequency content of a shock. This frequency spectrum may be used to determine the cause of a shock.

Figure 6 shows a typical shock sensor that may be deployed for several applications.

Figure 6: Shock Sensor

It is common to use shock sensors in the form of impact recorder on large transformers that are being transported. These recorders detect and record any acceleration and shock the transformer may be subjected to during transportation and can give the end-user information they may use to either accept or reject, and examine more closely a transformer after it has been transported from the factory to the site of final use. Security systems are another common use of shock sensors.

Shock recorders could be used on large transformers and breakers to detect a variety of unusual conditions. Like rapid pressure rise relays, they may be used to detect the motion of the windings due to both internal and external faults. The information recorded may be used to determine the accumulative effect of these shocks and this information may be incorporated in the evaluation of when a transformer needs maintenance.

Shock sensors and recorders may also be deployed on substation steel structures in high seismic areas to remotely monitor the effects of earthquakes on the structural integrity of substation steel structures. These types of sensor are sometimes used to monitor bridge and building motion to determine effects of shocks and accelerations on the building or bridge structure. After a major earthquake this information can also be used in substations to remotely determine the amount of damage which may have occurred during a seismic event. This information may allow operators to determine if a physical inspection of the substation is needed before the substation is placed back into service. This would allow operators to efficiently use available manpower after a major disaster (like hurricane Katrina) when the utility is trying to restore electrical service as quickly as possible. Having remotely recorded the shock to substation steel may even allow the operators to safely place a substation back into service via SCADA.

Vandalism is another condition which may be detectable using shock sensors. In some areas transformer and steel structures have been damaged by using firearms and firing into the substation at transformers, breakers, control buildings, and steel structures. This is especially a concern with rural substations located in sparsely inhabited areas. Shock sensors can detect shocks due to impacts of bullets on the transformers or steel structures. This information can be used to alarm the system operators to quickly notify law enforcement and physically inspect the structures or devices which may have sustained damage.

VI. SECURITY SYSTEMS

Nearly all the sensors described here and a variety of others may be used in designing the future security systems for electric power industry. Increasingly security in large substation and switching is becoming more vital. Damage to an important strategically located large substation or switching station can interrupt power to thousands of customers and damage to a transmission switching station could black-out large areas of the country for considerable periods of time.

Sensor technologies in the form of intrusion sensors, motions detectors, and cameras are currently being deployed to monitor the security of substations and this trend can be expected to continue. The communication of video information and other security system monitoring data via SCADA systems is also becoming more common.

VII. DATA MINING AND UTILIZATION

When sensors are massively deployed in substations there are also two concerns.

1. How to get all this data back to a central office or control room to a computer system for processing.
2. How to make sure alarms and other vital data is processed and made available to those who can properly act on it.

With the implementation of fiber-optic communications channels to substations, the bandwidth has become available to send vast amounts of data from substations to system operators. Many substations are still not connected via fiber-optic systems and the communications bandwidth to bring back vast amounts of information simply does not exist. However, as utilities upgrade their systems priority should be given to add fiber-optic systems wherever possible to allow intensive monitoring of substation systems in the future. Other types of radio and satellite systems are also available, however, fiber optic systems owned by the utilities seems to be the least costly and most reliable choice in most cases.

The second concern will take changes in the operating procedures of utilities. Too often even the small amount of data and alarms available today is not processed in such a way as to be valuable to system operators. Computer systems must be used to monitor, record, and make the decision of what alarms are important and need to be immediately relayed to operators, and what information can be safely ignored. When alarms are received the operators must have procedures in place to respond to problems monitored in the substations. Security violations relayed from substations must be acted on immediately and will involve the notification of police and/or the military and delays cannot be tolerated. A method of allowing police agencies to monitor security systems directly may be desirable. In some cases, where cameras or other real-time sensors are deployed in a substation, at the beginning of an event that causes an alarm this real-time data must be immediately and automatically relayed to the system operators via the SCADA system so that necessary actions can be taken. It will be extremely difficult, if not impossible, to leave these decisions for the operators to act. New more efficient algorithms and automated system has to be designed.

VIII. CONCLUSION

Traditionally a variety of sensors have already been deployed to monitor conditions, protect major equipment and detect operating status in substations. These are usually used for the transformers, breakers or for major equipment. Often these sensors are not monitored via the SCADA system, although monitoring substation alarms is becoming more common.

As the communication bandwidth becomes available and as SCADA systems become more sophisticated, the ability of monitoring many more types of sensors becomes viable.

Modern electronic and high-technology has made available a vast variety of sensors which may find many useful applications in substations. The challenge for utilities is to determine what sensors should be deployed at what cost and how the vast amount of information which may be made available can be reduced and made useful in the day-to-day optimum operation of the substation. A future paper will address the cost-benefit ratio of such applications.

ACKNOWLEDGMENTS

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