The prolonged effect of short circuit faults on sensitive equipment supplied by distribution feeders can lead to their failure and significant losses. This is pushing the requirements for the performance of distribution protection systems and making them similar to transmission protection systems requirements.

The improvement of power quality during short circuit faults can be achieved in several different ways. Like any other problem that has to be solved, we need first to understand the nature of the problem and its effect on sensitive users. The most common short circuit faults in the system, single-phase to ground faults, are characterised by the fact that they introduce a voltage sag in the faulted phase, and at the same time they result in a voltage swell in the two healthy phases. This is clearly seen in Fig. 1 which shows the recorded waveform and the voltage phasor diagram for a single-phase to ground fault.

The case of two or three-phase faults is quite different. For three-phase faults all phases experience a voltage sag, while for a two-phase fault the two faulted phases will have lower voltages, with the healthy phase having no significant change compared to the pre-fault levels.

Fig. 2 shows a plot of depth vs. duration of actual cases from a high-volume manufacturing plant, with some of them resulting in process shutdown due to variable speed drives and vacuum pumps failures.

There are several factors that determine the voltage level during a short circuit fault on the transmission or distribution system:

- System configuration
- Fault location
- Fault resistance

The first characteristic of a voltage sag, the depth, is something that we cannot control, but we have to study in order to be able to predict or estimate the effects of different faults on sensitive equipment.

The second characteristic of the voltage sag, the duration, is the parameter that we can control by properly applying the advanced features of state-of-the-art multifunctional distribution feeder protection relays. The focus of this paper is the impact of IEC 61850, and especially the use of Goose messages in distributed protection schemes that can reduce the fault clearing time in distribution substations.
The functions in the substation can be distributed between IEDs on the same, or on different levels of the substation functional hierarchy. IEC 61850 defines three such levels:

- **Station**
- **Bay/unit**
- **Process**

These levels and the logical interfaces are shown by the logical interpretation of Fig. 4. IEC 61850 focuses on a subset of the interfaces shown in Fig. 4 with Interface 8 (shown in red) being used for high-speed peer-to-peer communications.

The logical interfaces IF8 is defined as direct data exchange between the bays especially for fast functions like interlocking.

**Distribution bus protection**

The protection and control in substations is distributed in nature by the fact that each protective relay is designed in general to provide primary protection of individual substation equipment such as transmission and distribution lines, transformers, capacitor banks, etc.

The only substation equipment that requires a centralised form of protection in conventional systems is the busbar. Transmission buses are typically protected by bus differential protection relays. They require current signals from each primary equipment connected to the bus to be available at the central location of the bus differential protection. The scheme becomes much more complicated and expensive if the current transformer ratios are different. Things get even worse if the bus differential protection is used in a substation where the bus configuration may change.

Because of the high cost and the increased requirements for maintenance, in many cases bus differential protection is not installed on distribution or sub-transmission buses. As a result, bus faults are cleared by back-up relays with longer fault clearing times caused by the need for time coordination between the distribution feeder relays and the transformer relays. This becomes a significant power quality problem because of the increased duration of voltage sags.

Multiple protective IEDs with IEC 61850 Goose can be connected to the substation LAN and used in distributed bus protection applications for distribution systems.

In case of a fault on any of the protected feeders (F1 in Fig. 5), the feeder protection IED will see a fault. The same fault current will be seen by the transformer protection IED. As soon as the overcurrent protection element of the feeder relay starts, the IED will send a Goose message indicating the detection of a fault on the feeder. The transformer protection IED subscribes to Goose messages from all feeder relays. When it receives the message indicating...
that there is a fault on one of the feeders, the overcurrent protection element that is used for bus protection is blocked. If the fault is on the bus (F2 in Fig. 5), no feeder IED will see a fault, the transformer protection IED is not going to receive a Goose message indicating a feeder fault. This indicates a bus fault and the relay is going to trip the transformer breaker to clear the fault.

The peer-to-peer communications based bus protection requires an operating time for the fault detection of about one cycle for the relays involved. The addition of 0.25 cycle (4 – 5 ms) for the communication message and the safety time delay of 0.75 cycle in the transformer protection relay ensures a total operating time of about two cycles.

The benefit of this scheme is that instead of clearing the bus fault with the long time delay of a coordinated backup transformer protection, the only time delay required will be the longest possible overcurrent element starting time plus a safety margin.

The benefit of the peer-to-peer communications based distributed bus protection is that it provides fast fault clearance for distribution bus faults without the need for any additional protection equipment.

Selective backup tripping

The common approach that many utilities have taken is to use a single protection IED on a feeder. In case of failure of this relay, faults on the line are cleared by the backup over-current protection on the transformer or sectionalising breaker. The problem with this approach is the long fault clearing time that may affect sensitive loads fed by the distribution substation. A solution that significantly reduces the duration of the fault is based on the adjustment that the backup relay can make in its decision to trip based on the knowledge that a specific IED has failed.

This adaptive form of protection uses the normally closed contacts of the feeder relays that close when the relay is healthy. When the transformer or sectionalising breaker relay sees a fault and does not get any blocking signal from any of the feeder relays, it knows that there are two possible cases:

- The fault is on the feeder with the failed relay
- The fault is on the distribution bus

Since the probability of a fault on a distribution feeder is much higher that the probability for a distribution bus fault, the relay first sends a signal (1) to trip the breaker of the failed relay. If this does not clear the fault, then it is clear that the fault is on the bus and it is cleared by tripping the source breakers with signals (2).

The conventional implementation of
this scheme is based on the use of the normally closed contact of an output relay that closes and when it fails. This implementation requires hardwiring between all feeder relays and the dedicated opto inputs of the transformer relay. The IEC 61850 Goose repetition mechanism can be used to eliminate the need of the above described hard wiring. If the transformer protection IED subscribes to Goose messages from all feeder protection IEDs, within the maximum repetition time interval it will receive a Goose message from all healthy IEDs. If one of the feeder protection IEDs fails, it will stop sending Goose messages. This will cause the enabling of the selective backup trip logic in the transformer protection IED.

**Breaker failure protection**

Breaker failure protection is a scheme that is typically used at the transmission level of the system due to the impact of such event on the stability of the electric power system. With the increased reliability and availability of built-in breaker failure protection function in many multifunctional protection IEDs and the increasing requirements for decrease in the duration of distribution faults. The distributed breaker protection scheme can be implementation using two different approaches depending on the location of the breaker failure detection element.

In the first case the breaker failure protection element is in the multifunctional transformer protection relay. When the distribution feeder protection relay operates, it sends a Goose message indicating the change of state of any of the protection functional elements.

The transformer protection relay subscribes to this message, and when it receives the change of value of a feeder protection functional element operate data object to True, initiates the breaker failure protection function. If the breaker fails to trip, the fault current will keep the level of the current above the pickup setting of the breaker failure detection element, the timer will time out and the relay will trip the required breakers to clear the fault as shown in Fig. 8.

Another implementation of the scheme is based on a built-in breaker failure protection in each of the distribution feeder protection IEDs. In this second when the distribution feeder protection relay operates, it initiates the built-in breaker failure protection function. If the breaker fails to trip the breaker failure protection function will operate and send a Goose message indicating the change of state of this protection functional element. The transformer protection relay subscribes to this message, and when it receives the change of value of a breaker failure protection function element Operate data object to True, will trip the required breakers to clear the fault as shown in Fig. 8.

**Functional testing of IEC 61850-8-1 and IEC 61850-9-2 based bay and substation level distributed applications**

The testing of distributed protection functions that are based on IEC 61850 Goose are similar functionally to the testing of hardwired schemes. The main difference is that in this case the test devices need to be able to act as IEC 61850 devices, i.e., to be able to publish and subscribe to Goose messages. If the distributed scheme includes devices located remotely from each other in the substation, we may need multiple test devices with virtual simulators or analog outputs. The simulation of the substation and system environment required for the functional testing of bay and system level functions will require the simulation of multiple IEDs.

A test system designed for IEDs or distributed applications based on IEC 61850 have multiple components that are needed for the testing of the individual functions, as well as a complete application. A simplified block diagram of such a system is shown in Fig. 9.

The first component of the test system is the test configuration tool. It takes advantage of one of the key components of the IEC 61850 standard – the substation configuration language. The configuration tool is used to create the files required for configuration of different components of the test system. It imports different configuration files defined by part 6 of IEC 61850. The test system Configuration Tool reads the information regarding all IEDs, communication configuration and substation description sections.

This information is in a file with SCD extension (for substation configuration description) and is used to configure the set of tests to be performed.

The overall functionality of any IEC 61850 compliant device is available in a file that describes its capabilities. This file has an extension .ICD for IED capability description. The IED configuration tool sends to the IED information on its instantiation within a substation automation system (SAS) project. The communication section of the file contains the current address of the IED. The substation section related to this IED may be present and then shall have name values assigned according to the project specific names. This file has an extension. CID (for configured IED description).

The second component of such a system is a simulation tool that generates the current and voltage waveforms. The specifics of each simulated test condition are determined by the complete, as well as the configured functionality of the tested device or application.

The simulation tool requirements will also be different depending on the type of function being tested. For example, if the tested function is based on RMS values or phasor measurements, the simulation tool may include a sequence of steps with the analog values in each of the steps defined as phasors with their magnitude and phase angle. Based on these configuration parameters the simulation tool will generate the sine waveforms to be applied as analog signals or in a digital format to the tested components or systems. If the tested functions are designed to detect transient conditions or operate based on sub-cycle set of samples from the waveform, an electromagnetic transients simulation will be more appropriate.

The third component of the test system is the Virtual IED simulator that is used to represent components of the system that are not available at the time of testing, for example during factory acceptance testing. During the testing this module send Goose messages that the function or sub-function under test uses as inputs that determine its behavior under the test conditions applied.

The fourth component of the test system is the test evaluation tool that includes the monitoring functions used to evaluate the performance of the tested elements within a distributed sampled analog value based system. Such evaluation tool requires multiple evaluation sub-modules that are targeted towards the specifics of the function being tested. In our case they are based on monitoring the Goose messages from a tested IED.

The fifth component of the test system is the reporting tool that will generate the test reports based on a user defined format and the outputs from the simulation and evaluation tools.

**Conclusions**

The application of IEC 61850 Goose messages allows significant improvements in the protection of distribution substations that reduce fault clearing times and minimise the effect of short circuit faults on sensitive loads. Using such high-speed messages eliminates the need for multiple hard wired connections. In some cases the implementation of a hard-wired distribution protection scheme (such as sympathetic trip logic) in a large substation requires also that all protection IEDs have a significant number of binary opto inputs and relay outputs. The publisher/subscriber mechanism used with Goose messages eliminates this problem.

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