

WG -K3[FINAL Draft 13.2] 9-16-09 bap
Reducing outage durations through
improved protection and autorestation
in distribution substations.

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1.0 Introduction and evolution of protection schemes

This discussion will primarily address the subject of reducing outages / durations and autorestation applications within the distribution substation.

The early distribution substation had limited technology available to the electric industry. For example, the high voltage transmission line was connected to a power transformer via a manual fused switch, and the feeder load was connected to a distribution bus. When a fault or overload occurred on the transformer, the only option was to blow the fuse, putting the customers in the dark until a switchman could be dispatched to the substation. See figure 1.

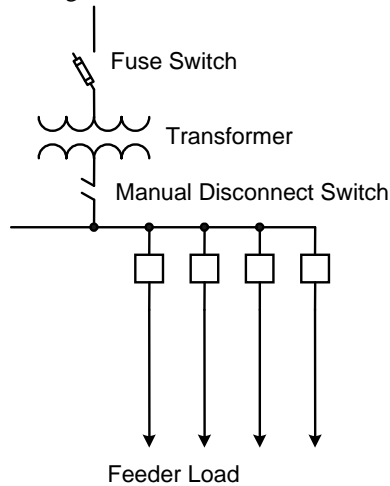


Figure 1 -Fused Protection

As time progressed, the fuse protection scheme was replaced by electromechanical relays. This provided a more precise protection method but still did not provide a way to automatically pick up the customer load. One such initial scheme cleared the transformer fault by having the electromechanical relays close a high voltage grounding switch. This put a ground on the transmission system, where the transmission line relays then dropped the line section that fed the faulted transformer.

As the customer load increased, this resulted in not only the need for larger transformers, but multiple transformers in a substation. Switch manufacturers also responded by providing switches for the high voltage side that were capable of breaking light faults on the low side of the power transformer.

As protection technology evolved, movement away from the time overcurrent (TOC) protection scheme

to a differential protection scheme occurred. This provided for defined “zones” that identified faults in the area of the transformer, bus, or feeder breaker, and also significantly reduced the time required to recognize and clear a fault. Not only did this reduce the time that the fault was on the system, but it also reduced the equipment damage due to the fault. One such example is shown in Figure 2.

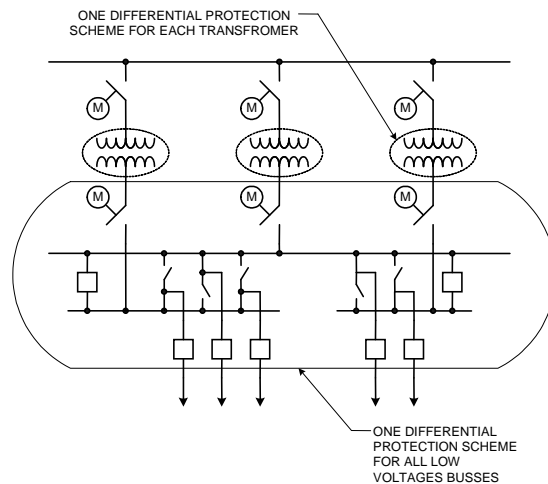


Figure 2 - Differential Zones

With multiple transformers, there was now the potential for more than one source of power for the customer in the substation. While the customer is only hooked up to one source at a time, manual switching can transfer the feeder load from one bus to the other. In the case where automation exists, there are methods to transfer the feeder load from one bus to another through multiple sources.

As new substations were built, the differential protection schemes, coupled with bus tie breakers allowed for the automatic closing of the bus tie breaker once the “bad” transformer was isolated. This was typically accomplished by monitoring switch positions and operating auxiliary relays if the reclosing logic was satisfied.

A common configuration of a substation may typically grow to two or more transformers, however, the initial load requirements may only require one transformer.

Figure 3 is a typical example of one such two transformer substation. For simplicity, only one

feeder per bus is shown, while in reality, this would usually be multiple feeder breakers on each bus.

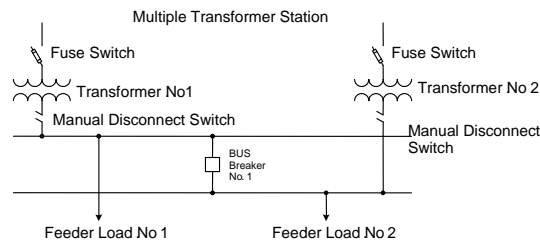


Figure 8 - Multiple Transformer Station

For many power companies, history has shown us that almost all bus faults are temporary in nature. Examples of this would be foreign interference due to animal faults, bird streamers or bird nests, dropped or blown objects, tree branches, etc. While the ideal situation would be to remove all possibilities of foreign interference, this would generally be cost prohibitive. Animal guards, fencing, containment walls or enclosed substations within a building would be some examples of passive preventative measures.

In any case, if a fault occurs, and the source is removed for a short period of time and then automatically restored, the customer can be picked back up, significantly reducing the outage time.

With the technology available where the fault location can be determined to be in the bus zone and not in the transformer zone, the transformer can be isolated from the fault, wait a predetermined amount of time, and then reclosed back in.

For example, when a fault occurs on the low voltage distribution bus, the relay protection trips the motor operated switches, clearing the transformer, and then the bus tie breaker closes which restores power to the customer.

Another topic to consider is that it is bad for the transformers to be overloaded, as this results in decreased life or failure. You may not want to try and autorestore the entire station load onto one transformer if the loading on the two transformers exceeds a certain value. Should this occur, you stand the chance of overloading the remaining transformer, and it could also be damaged or fail which would also result in extended outages. There are schemes that monitor transformer MVA and temperature loading. Should it be determined that the loading exceeds a predetermined value,

autorestation is turned off. Once load returns to an acceptable limit then it is automatically enabled.

It should be noted that there is always some equipment risk to automatically restore the substation and pick the customers back up, if the fault was permanent. However, autorestation for substation events can have a drastic effect on the reduction of extended customer outages for non-permanent faults.

In new substations, microprocessor based relays are replacing the old electromechanical relays for several reasons. Among those reasons is the added features and capabilities that are offered with the newer technology that an Intelligent Electronic Device (IED) offers. Retrievable files include settings, event records, disturbance or oscillographic records, fault location, etc. Input/output logic can perform what could be construed as adaptive functions to some extent. Adaptive settings can react to load level changes and adjust settings accordingly. This would be advantageous for winter peak temporary settings. Taking advantage of these new functions offers reliability enhancements to remove failure prone auxiliary relays that are used for the logic necessary for autorestation.

By taking advantage of the internal logic functions, wiring on the relay panels can be greatly reduced, and relay communications can take place over fiber optics cables or Local Area Networks. The relays can be time synchronized to GPS time. This allows comparison of all fault records and sequence of events files to analyze events that take place.

Many power companies are now measuring or keeping track of reliability indicators for outages and interruptions. Further information on this subject can be seen in Appendix-A.

2. Fault Duration, Reduction Methods, and Function Utilization of micro-processor relays

Protection relays are no longer simply a single function device that only mimics the electromechanical relay function that it replaced. In addition to the operate function and output contacts, there are other various features built into multifunction distribution relays that enhance the protection. Forms of programmable logic control have manifested themselves with names such as input/output logic, ladder logic, and similar terms. Multiple settings, setting groups, and even adaptive

settings may be offered [1], [2]. Winter/summer settings, load related, or storm related temporary reclosing sequence settings are just a couple of examples currently in use.

2.1 Coordination of multiple overcurrent elements or devices

Using multiple overcurrent elements can reduce operating time of the relay for certain faults. When overcurrent elements are set to coordinate at maximum fault levels with downstream devices, the coordinating margin at lower currents is usually greater resulting in longer clearing times. Definite time elements can be set to decrease clearing times in this mid-current area.

2.2 Double Feeder Fault Coordination Scheme

A double feeder is a term used to describe two independent feeders routed on the same pole structures. A double feeder fault is when both feeders are involved in a common fault. When this happens, each feeder tends to experience approximately half of the fault current available at each feeder relay. However, the main bus breaker's relay will see the entire available fault current. This condition lends itself to the possibility of the main breaker timing out and tripping before the feeder breaker and is extremely difficult to coordinate for between the main and the feeder breaker relays. This scheme has been devised whereby the main breaker utilizes a second 51-2 TOC element. The 51-2 element will typically have the same minimum pickup value setting as the 51-1 element in the main breaker, but the time setting will be set to operate slightly faster. Once the 51-2 times out, it gives permission to the feeder that is still processing fault current to trip. Therefore, the feeder trips immediately before the main breaker trips the entire bus.

2.3 Breaker failure- stuck feeder breaker

In the above, it was described how coordination between the bus breaker and feeder breaker might be performed in order to avoid tripping the bus breaker for a feeder fault. On the other hand, where a feeder breaker is stuck closed, or for whatever reason, fails to trip once its protective relays have called for a trip, traditional relaying typically waits for the TOC relays on the bus breaker or transformer to backup the feeder breaker and trip that portion of the station out for what appears to the transformer as an acute overload condition, when in reality it is being subjected to fault current.

In the case where the feeder relay has the capacity to communicate to the bus breaker or transformer relay, then the ability to get a faster trip on the transformer exists as a local breaker failure type of trip. This removes the fault much faster than waiting on overload protection to pick up, which in turn, reduces the potential damage to all of the involved equipment, as well as lessening the I²t cumulative damage.

Local breaker failure protection centers around the failure of a breaker to trip. It can typically fall into a few categories- (a) The trip coil or coil and linkage has gone bad; (b) The mechanism has frozen up; (c) The mechanism operates but the interrupters remain closed.

Local breaker failure schemes may assume that the problem associated with the trip coil failure will try and retrip the breaker to a second trip coil if so equipped. However, in the case of mechanism or interrupter problems, then the only recourse is to take a step back and trip the next upstream device. Many, if not most, distribution breakers only contain a single trip coil.

Another way of accomplishing breaker failure protection is to rely on TOC or overload relays.

The new microprocessor relay and its ability to communicate upstream can signal the upstream device to go ahead and trip if it senses that a trip failure has occurred and that fault current is still present and a trip output is still being called for.

By the same token, communication can also be utilized to accomplish remote breaker failure protection, which could be used between the substation devices and field sectionalizer devices as well for isolation of faulted feeder sections and automatic pickup in the field.

2.4 Fast clearing of bus faults utilizing communications between feeder and bus relays

With the use of microprocessor relays for bus and feeder protection, a scheme can be utilized to speed up tripping of the bus relay for bus faults without overtripping for feeder faults. This is achieved through communications between the feeder relay and the bus relay. Communications between the two relays could be via hard-wire or through a station LAN.

The instantaneous overcurrent element in the feeder relay would be set to detect feeder faults and send a "block" signal to the bus relay. This is done by connecting a feeder relay output to a feeder bus relay input. This feeder instantaneous element must be set higher than the maximum load on the feeder, taking into consideration cold load pickup and any other operating conditions that could result in higher feeder load than normal.

For the bus relay, an instantaneous overcurrent element would be set above maximum bus load, with margin, and above the feeder instantaneous element which sends the block signal to the bus relay. Via the use of relay logic equations, tripping by this element would be conditioned on lack of receipt of a blocking signal from the feeder relay. A delay of about three cycles should be implemented to allow the blocking signal from the feeder relay to be "recognized" by the bus relay. This way, a near instantaneous tripping is achieved eliminating the need for an expensive differential protection for the feeder bus.

This is an example of a scheme requiring the transfer of protection related data between different devices.

This scheme allows for the use of the instantaneous overcurrent unit at the low side of the transformer feeding the busbar, to provide a fast trip in case of a fault in the busbar. To coordinate with the instantaneous units at the feeders, any pick-up signal from the feeder relays must be sent to the transformer relay to block its instantaneous unit. See figure 4, representing a fault in a feeder.

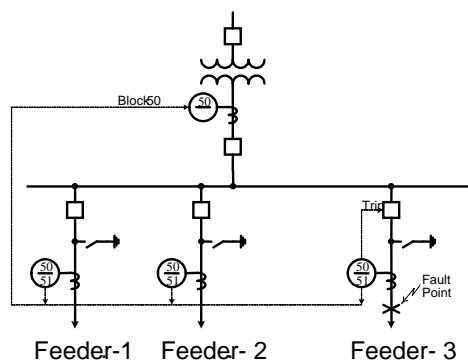


Figure 4

Figure 4. Coordination of instantaneous units

A similar scheme could be implemented between the transformer and the bus protection relays to speed up tripping for transformer low voltage bus faults (ahead of the feeder bus zone).

One application for fast clearing of bus faults involves sequence protection. In a multiple transformer station with a closed bus tie breaker, by detecting which side of a bus tie breaker is faulted allows for tripping out only the affected transformer that the fault is on, as opposed to tripping out both transformers.

2.5 Applying negative sequence overcurrent protection.

The availability of negative sequence overcurrent elements in most modern microprocessor relays makes it possible to take advantage of their insensitivity to balanced load to achieve faster clearing of bus phase-phase (and phase-phase-ground with high ground resistance) faults. In order to achieve this, negative sequence relay settings should be applied to both the feeder and the feeder bus relays.

On the feeder relay, the negative sequence overcurrent element would be set to coordinate with the downstream fuse or recloser without taking balanced feeder load into consideration. The negative sequence element setting thus achieved will be more sensitive than the feeder phase overcurrent element.

On the feeder bus relay, the negative sequence element can be set simply to coordinate with the negative sequence element on the feeder relay, again without consideration for bus balanced loads. The settings thus achieved will be much more sensitive than the bus phase overcurrent element.

One should remember that the negative sequence elements do not respond to balanced three-phase faults.

More information on the use of negative sequence elements and how they could be set to coordinate with downstream phase elements can be found in reference [3].

2.6 Applying a fuse saving scheme (allowing instantaneous tripping on first reclose cycle).

Where faults tend to be temporary in nature out on the distribution feeder, quick trip and reclose cycles may allow for the de-energization of the fault without blowing the feeder lateral fuses. This scheme has a few undesired results. It makes it hard to find the fault location if it tends to happen over and over again; all of the digital clocks in the customers houses go into the blink mode, which result in customer complaints; adds to wear and tear on the breaker for numerous operations. However,

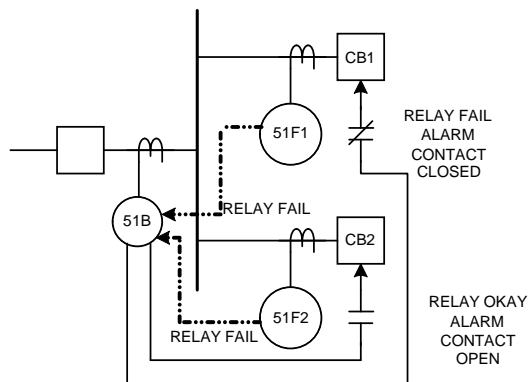


Figure 5 –
Bus Protection Backup For Feeder Protection
Failure

A scheme as depicted in Figure 5 – Bus Protection Backup Tripping For Feeder Protection Failure, provides fast selective backup tripping coverage for a feeder relay failure (Note: this is not for a circuit breaker failure condition).

As shown in the figure, relay alarm fail contacts are routed to the bus relay, 51B. The purpose of this is to enable alternate feeder protection settings on the bus relay *and disable fast bus protection tripping*. The bus relay in turn, will direct trip commands to each feeder breaker via its own feeder relay alarm contact. In Figure 5, CB1 will be tripped via its 51F1 alarm contact (relay failed) whereas CB2 will not be tripped as the 51F2 alarm contact is open (relay healthy).

The concept is that under normal circumstances the low side relay is active as fast bus protection, and each feeder has its own individual protective relay to clear faults out on each respective feeder. If a fault occurs on a feeder, the feeder clears the fault and simultaneously the faulted feeder relay, via hardwired contacts to the low side protective relay, disables the fast bus elements to prevent fast tripping of the bus for a feeder fault.

where the feeder relays have fault information, the data may aid in the location of the event.

2.7 Relay logic to allow upstream relay to trip correct feeder in case a fault occurs at the same time a feeder relay fails.

In a typical distribution transformer low side protective relay scheme, one scheme may use the low side relay as fast bus protection in combination with a feeder relay failure back up scheme.

If a feeder relay fails, it needs to disable the fast bus to prevent tripping the bus for faults on a feeder and to set a second level overcurrent element on the low side relay and backup the failed feeder relay with the low side relay. This would allow tripping the feeder with the failed relay through the alarm contact. The feeders with the healthy relays have open alarm contacts and unable to trip the feeder breakers.

2.8 Use of broken conductor protection to alarm or trip for downed distribution conductors for high impedance faults.

One of the most difficult types of faults to detect on a distribution system are those involving downed conductors or high impedance faults.

The wire may be simply broken and hanging in mid air. The line may be intact but making contact with a tree branch and thus be a high impedance fault. The line may be broken and laying on the ground or on top of asphalt and is thus a high impedance fault to ground. In this case, there is a very small level of current involved as compared to the overall load current on the feeder. All of these types of conditions are virtually impossible to detect via conventional overcurrent relaying. These are dangerous operating conditions and the public must be protected from harm.

There are several methods in use to detect downed conductors and high impedance faults with various levels of success. For further details see references [4], [5], [6].

Methodologies to detect downed conductors or high impedance faults include the use of voltage detection, current based systems, and complex systems that make use of pattern recognition and artificial intelligence.

In all cases, the individual utility will have to determine whether to alarm or trip when the equipment detects a problem. If the option is to trip, then any false trip could put more people at risk than

if nothing was done; i.e. traffic lights made inoperative, home medical equipment de-energized. If the option is to not trip and alarm only, then there is a risk that the public may come in contact with the line before a crew has arrived at site to investigate.

A voltage based system is basically made up of undervoltage relays installed at multiple locations on a distribution line. Tripping could occur closer to the faulted location by the use of power circuit reclosers or at the substation by a circuit breaker. In all cases, the fault interrupting device would need to have a communication link from the undervoltage relays. The communication link could be power line carrier, fiber, cellular, or even radio. The main advantage of this type system is that the exact location of the problem is known with fairly good accuracy due to the use of a large number of the devices on the feeder. To gain the full benefit of this type system, undervoltage relays would probably need to be installed at the end of every lateral and at several locations on the main line of the feeder. The great number is also the main disadvantage; mainly due to the large expense.

There are also current based systems available. One technique is to use the third harmonic current to detect a problem. Obviously there could be setting problems as the setting would have to be set to ignore normal third harmonic current and still be sensitive enough. This type scheme would probably be employed at the substation and thus the determination of the fault location is more difficult.

A third available scheme makes use of pattern recognition and artificial intelligence. This current based type system is designed to be able to make a distinction as to whether arcing is going on thus indicating that the line may be intact but making contact with something like a tree. The relay must also determine what the background load current is and if there is a sudden increase or decrease, decide if there is a broken phase or downed conductor. Again, this type scheme would probably be employed at the substation and thus the determination of the fault location is more difficult.

2.9 Restricted earth fault protection

Applying restricted earth fault protection to increase sensitivity and reduce clearing times for transformer ground faults could limit transformer damage. Limiting transformer damage could result in faster restoration times.

2.10 Cold Load Pickup

One method to eliminate re-tripping when restoring heavily load feeders after an outage could be accomplished by using a cold load pickup feature.

In the older electromechanical schemes, this most likely had to be accomplished using mechanical stepper relays in conjunction with the reclosing relay and instantaneous elements for phase or ground tripping. In the newer microprocessor relay schemes, this most likely can be accomplished within the functionality of the protection relay when needed.

Note that this feature may be only a part of the distribution setting reclosing philosophy. This reclosing philosophy may roll up several features such as how many recloses are allowed; how many within a certain time window; how fast the breaker is closed back in; whether fast tripping may be delayed in order for feeder lateral fuses to blow, etc.

2.11 Reduce unnecessary momentaries.

Two instantaneous settings using microprocessor relays-

The two settings consist of one low set with a 6 cycle delay that allows the first reclosing operation and one high set that blocks reclosing for the underground cable getaway.

The goal of the low set time delayed response is to reduce unnecessary momentaries for close in faults beyond fused taps with the use of a the time delay and at the same time provide a 6 cycle fast response to transient short circuits. For remote transient main line faults the low set delayed response would still operate much faster then the retarded time current response (cycles vs. seconds).

The following setting philosophy is used for the high and low set instantaneous settings.

1) The high set instantaneous overcurrent setting will be set with no time delay and set to the phase and ground value at the 13.8kV overhead riser pole. The high set instantaneous would block reclosing for bolted underground faults.

2) The low set will be set with a 6 cycle time delay for the following reasons.

a) Reduce unnecessary momentary operations for high magnitude faults by permitting branch fuses to blow before a momentary breaker operation can occur. Note: fuse saving can not be accomplished by a breaker for high magnitude faults due to the

inherent breaker operating time delay (typically 3 - 6 cycles).

b) Reduce the unnecessary operation of the 13.8kV supply breaker due to inrush current balanced or unbalanced as a result of street tie switching. Note: the relays will also be set such that, when switching of the 13.8kV breaker will result in a time delay before the low set instantaneous protection is enabled. This will further prevent risk of inadvertent operation of the 13.8kV source breaker due to inrush current or cold load current.

c) The low set phase instantaneous will be set not to operate for a three phase bolted fault on the low side of a pad mounted transformer.

d) The low set phase and ground instantaneous overcurrent relay will be set not to reach through any pole mounted reclosers. Note: typically the pole mounted recloser will already provide fast curve protection. Coordinating the low set instantaneous settings with the recloser will help maintain selectivity and limit unnecessary momentary operations to a smaller portion of the circuit.

e) The low set phase and ground instantaneous overcurrent relay will be set not to reach through any 13.8Kv customer stations.

f) Set the low set phase and ground instantaneous overcurrent relays only to be activated once during each trip to reclosing to lockout cycle. One fast two slow operations.

Zone Sequencing to reduce momentaries:

What is Zone Sequencing? Zone Sequencing is the use of electronic relay logic to eliminate feeder breaker momentaries for faults that are located beyond distribution field reclosing devices. The objective of Zone Sequencing is to reduce the number of feeder momentaries that occur due to faults beyond field reclosers. Pilot tests shows that Zone Sequencing is effective in reducing feeder momentaries under certain conditions

What conditions are required for Zone Sequencing? Zone Sequencing can be implemented on feeders that have microprocessor relays with certain logic, a feeder protection scheme that uses a Ground Instantaneous (GI), a Short Time Ground (GX) and a Long Time Ground (GT) elements and certain types of Distribution field recloser(s). Having highly accurate and dependable reclose times are essential to the way this particular scheme works.

How does the Zone Sequencing Logic work? When a fault occurs, the GX element will be removed from the relay coordination scheme at the end of the first reclose sequence, if it has not tripped within 1.5 seconds.

Therefore, if the fault is beyond a field recloser, which has a reclosing time just longer than this, the GX element will be removed from the scheme while the recloser is in the open position.

In summary, for all faults beyond a distribution field recloser, the GX element will be removed from the coordination scheme, eliminating unnecessary feeder momentaries associated with the operation of the GX element.

What are the benefits of Zone Sequencing?

The benefits range from Reducing feeder breaker momentaries (MAIFI), Improve customer satisfaction and Improve longevity of the feeder breaker. It also allows the GX and GI relay to be enabled to protect the Feeder Main section without tripping the breaker due to faults beyond a field recloser.

2.12 Transformer Thermal Overload Protection

Thermal overload protection can be used to avoid damaging the transformer due to excessive loading.

Simple overload protection is based upon the amount of load that a transformer can withstand without causing unacceptable damage. All overloads result in a temperature increase that will cause degradation of the transformer insulation components (oil, fiber boards, paper, etc.), which in turn increases the susceptibility for insulation failure. The question becomes one of risk and economics – overload the transformer to a given limit and accept less life, dramatically increase the cooling capability if economically possible, or put in a larger transformer. Sometimes the answer may be to accept the risk and run the transformer to failure.

For the most part, the manufacturer has curves that estimate the amount of loss in life for a given temperature rise experienced by the transformer, as well as heat rise curves for given currents. Conventional alarms are usually set for a set temperature of the oil and of the hot spot, but this is not predictive but rather reactive to the temperature that the transformer has already succumbed to.

If the IED provides the adaptive characteristic of being able to evaluate the changing data and predict the amount of time before the transformer had to

have load reduced, some evasive action might be able to be taken. This could be either manual or automatic reaction to data or alarms.

Further, if load had to be reduced at the station or feeder level, then preprogrammed actions could be taken. This could be performed at either the station level or the SCADA master level, depending upon where the computer resided.

For example, if all of the data was concentrated at the station level with the appropriate scenario logic in place, then the substation computer could take preprogrammed actions of closing bus tie breakers, communicating with smart field reclosers, or at last resort, dropping feeder breaker load by opening preselected feeder breakers. Obviously, this would need to be a well thought out plan with dynamic logic to account for varying loads, transformer temperatures, and other variables. These “selected rolling blackouts” could make use of the studies involved in selecting underfrequency load shedding settings in determining loads and essential customer feeders.

2.13 IEDs can provide logical inputs/outputs

Using internal logical input/outputs available for control and autorestoring can eliminate auxiliary relays and the potential failure mode that these have presented over the years.

Wiring from one relay to another has always presented various restrictions or concerns, not to mention the added costs of wiring. Multiple dry contacts might be required to be wired between relays and panels, which might be located in close or not-so-close proximity to each other. The use of auxiliary relays has historically had some misoperations attributed to various types of failures of the auxiliary relay itself with very little that could be done in terms of early warning of a problem. On the other hand, making use of a single input might be mapped to several outputs, which in turn could be wired or communicated to adjacent or peer IEDs. Some self-checking diagnostics of I/O hardware may be available. This further allows timestamping of the events within the Sequence of Events (SOE) function of the IED. This provides a detailed event log that is especially helpful in troubleshooting misoperations.

2.14 Impending Failures

Other functions being implemented may be valuable in preventing faults or problems before they manifest themselves in failures.

These detections could in theory prevent the outage from occurring in the first place. Detections of specific identifiable signatures could also aid in post analysis of what initiated the failures.

Examples that come to mind include loose or noisy connections, fuse failures, impending arrestor or insulator failures, capacitor failures, sporadic foreign interference identification. Incipient splice failure detection in underground cable is already available [14], and similar techniques should be able to be used to detect incipient arrestor failure as well as incipient capacitor can failures. Bushing failures have traditionally been predicted through manual testing. Field tests are currently underway to provide in-service predictive impending conditions.[15] [16]

2.15 Partial Discharge Monitoring In Transformers

Partial discharges in transformers are small electrical arcs between phase-to-ground or phase-to-phase. In transformers, partial discharges are mainly caused by containments in the oil or partial failures of the solid insulation around the windings. Contaminants in the oil are indicative of a mechanical problem (e.g. pump introducing metal slivers into the oil) or a failure of the sealed tank that allows air, water, or other contaminants into the oil. Partial failures of the winding insulation are indicative of an incipient fault. In either case, detection of these conditions through monitoring of partial discharges can allow early interdiction through maintenance to avoid a more severe failure causing a customer outage.

Several devices are currently available to monitor partial discharges on in-service transformers. In general, the principles employed by these devices fall into two categories: monitoring high frequency electrical signals and monitoring acoustical signals. The devices look for signature signals of partial discharge activity using various algorithms and filtering techniques. The monitors can be permanently installed or portable and used as part of a regular transformer inspection routine.

2.16 Arc-Flash Mitigation

One of the concerns facing the field personnel while working on the facilities is if an arc occurs should an accidental contact take place. One remedy in place for many years was to put the feeder on “one-time” where the automatic recloser switch gets turned off for the duration of the work on the line. However, this only stops the feeder from reclosing. Of course the drawback to this action is that the

customers go in the dark for all faults and do not automatically reclose as they would normally do. Another technique is to enable additional instantaneous relay elements when the recloser is turned off, typically the phase elements. These would be enabled only while the work is in progress as a unwanted trip could also occur as well. Microprocessor relays and their programming abilities have made this easier to do. For further information, refer to the IEEE-PSRC WG-K9 report on this subject [7], expected to be released in 2009.

3.0 Faster Detection

One way that the secure operation of the microprocessor relay can be enhanced is through higher sampling rates. When less samples are made available to an algorithm, the process may require more blocks of data before it can reach a secure conclusion. This may also manifest itself in faster operate times than devices with substantially less samples of data. This also allows for actual rather than curve fitted oscillographic records. Too low of a sampling rate can actually miss a fast event.

4.0 Faster Remediation through IED communication. How communication affects protection.

4.1: IED Communication

IED communication still sounds like black magic to one that comes from the electromechanical world of hard-wired contacts and operate coils. Messages get sent over fiber optics or other communication paths which get decoded into logic commands. In some cases, data gathering may occur over one network, and control communications over another faster network. Redundancy is another use of this function to back up traditional protection paths. [8]

For example, one such system would be the use of communications to “tell” the upstream transformer protection that a feeder breaker has failed to trip for a fault and to go ahead and initiate a trip without waiting for what typically is TOC relays to pickup. This removes the fault from the system more quickly, resulting in less local damage. This also may include the identification of the stuck breaker for the breaker failure action. See section 2.3

Some forms of peer-to-peer communication is available that can pass data between devices or databases. Peer-to-peer communications are implemented to continuously broadcast on the network shared information such as counters, voltage or current magnitudes, angles, or other high resolution data between devices. Each device on the

network shares its own data with every other device such as relays, switches, breakers, RTUs, metering, load tap-changers, voltage regulators, etc. The speed of communications is dependent on the type of communication medium used (fiber optic cables, twisted copper wires, etc.) and the data shared between all devices.

Traditionally, protective relays and recloser control devices in distribution systems were applied without the use of communications between devices. Coordination between upstream and downstream devices is attempted by implementing shorter time delays on the downstream protective devices.

Communications enhances protection and automation in distribution systems and provides high speed substation bus reconfiguration and automatic load shedding to prevent transformer overload tripping. Additional benefits such as flexible and improved automation schemes; flexible control and interlocking schemes; selective and flexible automatic backup schemes offer the possibility to reduce power outages and permit customized autore restoration schemes in distribution substations.

Without communication, only a limited number of TOC devices can be coordinated in series before clearing time of the longest-set device becomes objectionably long. Using intelligent relays and communication between devices to provide tripping supervision, clearing times can be much faster.

Section 2.4 describes a fast bus protection scheme based on communications between the feeder and bus relays.

Within a small geographic area, such as within a substation between feeder relays and the transformer secondary main circuit breaker, this scheme may be implemented with hard-wired logic by connecting outputs from one relay to inputs on another. IED’s could be interconnected with various network configurations.

Over a more dispersed area, relay to relay communication may be accomplished using dedicated fiber-optic transceivers or multiplexers to route messages over a fiber network. Relays that support IEC-61850 can send and receive GOOSE/GSSE (Generic Object Oriented Substation Event- Generic Substation Event) messages over a LAN (Local Area Network) connecting the various relays together [12], [13]. Use of a communications network allows the greatest flexibility for future circuit reconfiguration.

As additional series interrupter devices are added, it is simply a matter of connecting the relay communications to the network and configuring the multiplexers or addressing to route messages to and from the appropriate relays.

As an illustration of the possibilities offered by the communication between devices, here are some examples of the logic schemes and automatic functions that can be implemented.

4.2. Voltage restoration in “H” type substations

The function described below makes use of the substation communication system to interchange the required data and commands between the involved devices.

In substations of the type represented in figure 6, this function allows for an automatic transfer of the HV line feeding the substation in accordance to the desired (programmable) operation conditions and the availability of voltage in the feeding lines.

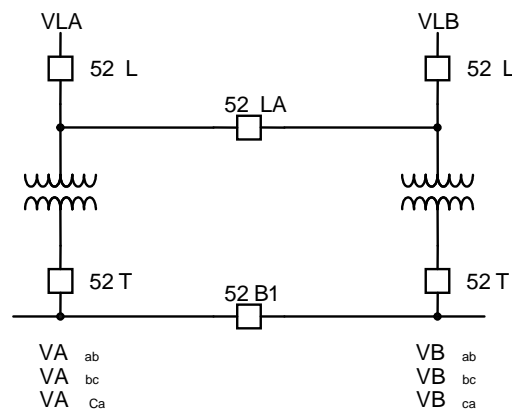


Figure 6 – “H” type substation

The function has four different set status: MANUAL (function disabled), Preference A, Preference B or Preference BOTH.

If both voltages VLA & VLB exist, the breakers 52LA, 52LB and 52LAB are arranged to feed the station according to the set preference.

If one of the voltages is missing, the arrangement is changed so that both MV busbars stay energized.

When the voltage returns, the preferential arrangement is re-established.

If both voltages are missing, no action is taken.

Due to the fact that only one phase voltage is available from the HV lines, this logic is complemented by taking into account the voltage measured in the three phases of each MV busbar.

A faulted transformer function is also included in this scheme. In case of a trip of, say, transformer A, if 52LAB is open and there is voltage in Line B, the automatic function closes breaker 52LB and sets itself to MANUAL.

4.3. Automatic service restoration

The objective of this automatic function is to act as a trained operator would do when the busbar voltage drops to zero.

The logic performed is described below. See figure 7 as a reference. In this figure, the arrows pointing towards the busbar indicate sources with capability to restore the service at the bus.

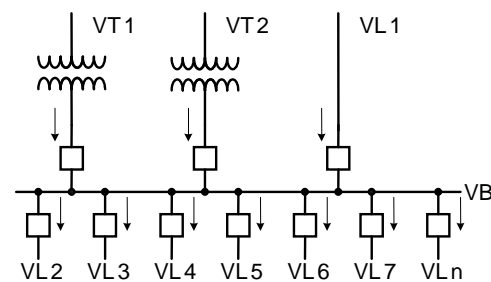


Figure 7– Automatic service restoration

If $VB = 0$, then open all breakers

Wait until any of the voltages (from a source with restoration capability) appears. Then close the breaker and check if busbar voltage VB stays.

If VB goes to 0 again, open the breaker (if still closed), indicate fault in busbar, and stop.

If VB stays OK, then continue the restoration process according to a pre-programmed sequence, always checking VB after closing a breaker.

If, for example, when closing L4 breaker, VB goes to zero, open all breakers, indicate fault in the line (i.e. L4), and start all over again (without including L4 in the new process).

4.4. Other schemes

Other logic schemes implemented in the substations that make use of the substation communication system are:

- Capacitor bank automatic connection / disconnection, by measuring reactive power flow and/or following a pre-scheduled calendar.

- Load restoration schemes (after underfrequency load shedding).

5.0 How Communication affects restoration and analysis (i.e. oscillographic and event records)

5.1 In past years, data retrieval was confined to fault records from devices such as Digital Fault Recorders (DFRs). However, today's IED microprocessor relays have the capacity for oscillographic records, event records, and setting records that can be accessed from the relay to a computer.

This access may be local or remote from different ports on the relay. The availability of remote access allows for record retrieval and analysis by one group of people, while another is in route to the substation for investigation and restoration. This also allows for the remote analysis to determine if devices in the station operated properly or if a possible misoperation occurred. In many cases the records out of distribution protection relays are the only data records that are available to analyze a fault and whether everything operated correctly. Access may be via the dial-up phone line method, or some type of Wide Area Network (WAN) or Intra-Net.

In the case of dial-up, rather than have a dedicated phone line connected to each IED, a more typical application may involve some type of phone line sharing device or port switcher. Dial up lines can present remote access security issues should a hacker get into the IED.

In the case of the WAN or Intra-Net, then a more typical connection may involve a port switcher or router with an Ethernet type of setup.

5.2 Remote access security

Local password access tends to limit what could be viewed by all, but changes could be confined to a select group of authorized users utilizing higher level passwords. This was typically implemented for front panel button access, or possibly through a portable PC connected to a serial port on the relay. In some cases, the concern here was more associated with someone making an error, more so than

someone going in and purposely making changes that would cause problems.

Remote access introduced the problems associated with hacker security.

Security is usually addressed through the use of passwords, and generally, there may be a password for the first level of connecting to the relay, and a second or third level to retrieve or make changes in settings. Some systems even involve an automatic dial-back system where the interrogator may have to be preauthorized and preset in the system so that only previously identified phone numbers are allowed access. However, in the more typical substation environment, this is not generally used or even available.

Recent events have forced utilities to go to the use of what is referred to as "strong passwords" in order to thwart hackers from getting into the devices and causing problems. Strong passwords typically contain several letters, upper and lower case, several numbers, and even some characters. Exceeding a number of attempts to log in can generally cause the relay to disconnect and lock out from the communication. This prevents automated hacking if so equipped. Security may be generally undertaken at both the corporate level as well as the substation level for the network communications, as well as using hardware and/or software firewalls.

6.0 Data Utilization for automated and post analysis of faults and events.

6.1 Distance to fault can be automatically calculated and displayed. [9], [10]

Many microprocessor feeder relays include a feature called 'distance to fault', which provides an indication of the location of the fault relative to the relay. This is accomplished using an algorithm with the measured current and voltage quantities during the fault. The distance to fault value is then available for use as part of the fault record and as an output of the relay in the form of digital or analog data. This data can then be passed to the SCADA system where the system operator can initiate sectionalizing or direct work crews to the closest upstream switch. This tends to be more accurate in a point-to-point primary system as opposed to a typical distribution feeder type of arrangement containing multiple taps and laterals.

Another, less sophisticated method of implementing a distance to fault function in devices that don't have

an internal algorithm or voltage elements is to use the magnitude of the fault current. The concept is that the closer the fault is to the source (substation) the higher the magnitude of fault current. By selecting ranges of current and associating them with the line length, the operator can get an approximate location of the fault. The biggest shortcoming of this method is that it cannot account for fault impedance. A close-in high impedance fault will have a similar magnitude of fault current as a distant low impedance fault.

By using this data, it is possible to reduce the outage time by locating the fault more quickly.

Both of the above techniques have shortcomings when the feeder circuit branches or has a source or tied to another hot feeder. In the case of a branch, the relay cannot tell whether the fault is on the main circuit or the branch. In the case of a source, the fault current provided by the source is not seen or accounted for by the relay and therefore the distance to fault calculation is less accurate.

6.2 Automatic Load Transfer on Loss of a Source

For the case of a split distribution bus with a bus tie breaker that is normally operated in the open position, an automatic load transfer scheme can be implemented (refer to Figure 8). Such a scheme would be applicable if the station planning criteria allows the total station load to be carried by one transformer. The automatic closing system monitors pre-fault total MVA load for both transformers and determines the average MVA load before the initiating event if the planning criteria does not allow the total station load to be carried by one transformer.. For conditions that cause the loss of one of the sources (high side bus faults, high side breaker failure, or transformer faults), the bus tie breaker (52E) can be closed automatically to supply the other feeders. Initiation of automatic closing is blocked if loading on the remaining transformer would exceed the published Transformer Ratings after Auto-Close.

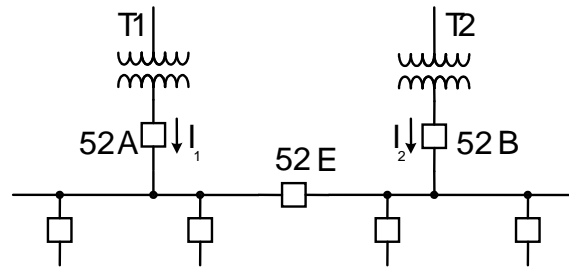


Figure 8 – Transformer load function

Automatic closing for the bus tie breaker is typically controlled by a permissive switch and/or by SCADA. The SCADA system also has continuous status of the automatic closing scheme. Automatic closing is supervised by one or more of the following functions

- Bus tie breaker is open.

- The low side breaker associated with the deenergized transformer is open.

- The low side breaker associated with the remaining transformer is closed.

- Total transformer load was below a predetermined level for a predetermined time prior to the automatic close initiating event.

- The energizing bus is alive.

If required the above functions may be augmented by a sync-check/voltage-check function..

An enhancement to the automatic closing scheme is to incorporate different seasonal load limits. For example, different summer and winter load limits can be used. Selecting which limit is in effect is accomplished by a mode switch and/or by SCADA.

6.3 Selective Automatic Sectionalizing

A selective automatic sectionalizing scheme can be implemented on a configuration where one breaker feeds two or more individual circuits (sections) through motor operated switches. The protection for all of the circuits is provided by the breaker and associated relaying. The individual circuits each have fault detectors to determine which circuit the fault occurred on.

A typical automatic sectionalizing scheme goes through a series of reclosing attempts by sequentially isolating part of the circuit. This process can take from several tens of seconds to several minutes, depending on the number of sections, the number of reclosing attempts for each configuration, and the reclosing interval.

A selective automatic sectionalizing scheme uses the fault detectors on the individual sections to know where the fault occurred (See Figure 9 below). The scheme can reduce the number of reclosing attempts and the outage time of the non faulted circuits by opening the switch of the faulted circuit after a minimum number of reclosing attempts.

Since this logic is more complicated than typical reclosing, a programmable device such as a small PLC is often used to implement the scheme rather than an off the shelf reclosing relay.

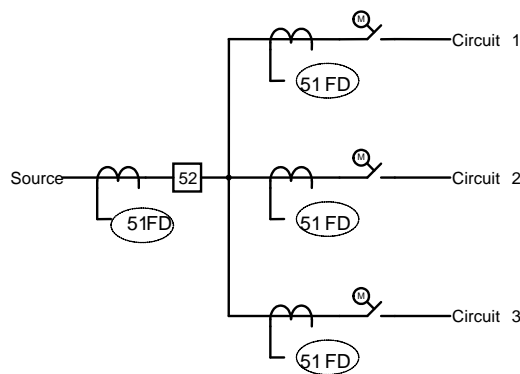


Figure 9
Selective Sectionalizing Scheme Using Fault Detectors

breaker controls (e.g. a maintenance switch in the breaker or the reclosing cutoff switch) automatically applies the primary reclosing sequence to the secondary breaker. Since the secondary breaker may only have live bus/live line/sync check as its normal reclosing permission, it will not attempt to reclose if the primary breaker did not successfully reclose first, leaving the faulted circuit out of service. By automatically applying the primary reclosing sequence to the secondary breaker, the secondary breaker can automatically attempt to restore the circuit.

Similar schemes can be used for breaker and a half bus configurations. [11]

6.5 Line Sectionalizer

Automatic line sectionalizers have long been used in conjunction with reclosers, or reclosing relays controlling circuit breakers. The sectionalizer control has a fault current detector that arms a counter, and the counter registers a count when the fault is interrupted. After the set number of counts, the sectionalizer opens to isolate the faulted section of the circuit. Opening of the sectionalizer occurs during the circuit dead time between reclose attempts by the source side circuit breaker. The sectionalizer must be set to trip one or more counts before the source-side recloser goes to lockout.

6.4 Automatic Ring Bus Reclosing

For ring bus configurations, an automatic ring reclosing scheme can be employed to close the ring after a fault has occurred, restoring the reliability of the ring configuration. When a fault occurs, both breakers associated with the faulted circuit open. One of the breakers is the primary reclosing breaker, which attempts the reclosing sequence. If the first breaker successfully recloses, the second breaker then automatically recloses to complete the ring bus.

An enhancement to this scheme utilizes a motor operated disconnect switch on the circuit. If the primary reclosing sequence is unsuccessful, the motor operated switch is opened and one more reclosing shot is attempted. If the final reclosing attempt is successful, the secondary breaker then restores the ring.

Another enhancement to this scheme allows the secondary breaker to assume the primary reclosing sequence when the primary breaker is out of service (e.g. for maintenance). A contact from the primary

Enhancement of the basic recloser / sectionalizer scheme is achieved by applying intelligent controls and communication to the motor-operated switches used for sectionalizing (Refer to Figure 10). By communicating switch status, fault detection status, and circuit loading information among themselves, the sectionalizing switches can determine the fault location. Faults can be isolated with fewer reclosing shots by the circuit breaker. After the fault is isolated and the fault location determined, the appropriate switches automatically reclose to re-energize the unfaulted line sections. Applying an intelligent switch to the normally-open of a looped feeder, or as a connection to a feeder from another substation, allows line sections beyond the faulted section to be re-energized from the alternate source.

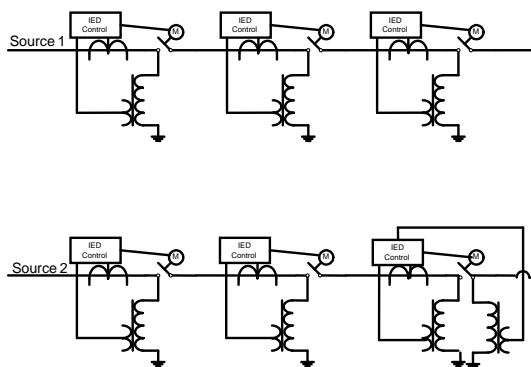


Figure 10– Intelligent Controls & Communication

6.6 Relay Self Diagnostics

All modern microprocessor relays have built in self diagnostic logic for self monitoring the health of the relay. Depending on the sophistication of this logic, the relay can monitor most of its internal functions [1, 2]. By combining this self monitoring with other internal logic, such as loss of potential and/or loss of current detection, the user can have a very good indicator of the health of the relay. A combination of relay alarm and output contacts can be wired into annunciator points and passed to SCADA for early indication of a relay problem. This early warning can help reduce the possibility of a relay misoperation or failure to operate.

6.7 Oscillography and SOE Capabilities of Microprocessor-based Relays

6.7.1 Oscillography Recording

As a standard feature, digital relays support some level of oscillographic recording. The number of records, record length, sample rate, etc. varies from relay to relay. Relay records can aid troubleshooting and analysis of system events to a great degree if configured properly. They can provide additional coverage as compared with dedicated DFRs, which typically may not have enough points to adequately monitor the distribution equipment and logic levels. The extended coverage may go as far as having the same secondary signals recorded by more than one device. This allows independent confirmation of one record versus the others, and troubleshooting problems internal to the relays, secondary circuits, VTs and CTs.

Typical characteristics and options related to disturbance recording of digital relays are described in Appendix-B. This covers such things as analog filtering for ac signals, digital filtering for ac inputs,

de-bounce filtering for dc inputs, sampling rate, programmability, available memory, etc.

6.7.2 Protection-specific recording

Various protection-specific signals could be recorded by protection relays. Examples are communications-based digital inputs such as IEC-61850 GOOSE/GSSE or proprietary digitally transmitted teleprotection signals; derivatives of input currents and voltages such as magnitudes, angles, symmetrical components, differential currents; or internal flags created by user-programmable logic or protection and control elements.

Typically, the above signals are inputs to protection and control elements of a relay and therefore are very valuable for analysis. This is because they reflect the real measurements performed by the relay itself, after the magnetics and usually after the filters. For example, when extracting a negative-sequence current from a DFR record in software, one uses a generic approach being typically a full-cycle Fourier filtering. This may not reflect the actual filtering of the relay as manufacturers use proprietary algorithms. Recording the actual protection signals calculated internally is thus an advantage over the DFRs when looking at what the relay was acting on. However, what the relay records and what the system actually experienced may be somewhat different depending upon where the waveform was recorded relative to filter and magnetics effects. Saved sample rates may be lower than initial sample rates.

Also, some signals, such as communications-based I/Os and other logic levels, are not easily recordable by standard DFRs.

6.8 Data and data formats

6.8.1 Data format and extra content

Older relays used proprietary or plain ASCII format to store the records. New solutions apply the COMTRADE standard which does not fit the application perfectly. For example, digital signals or variable sampling rate records were not originally intended for recording in COMTRADE.

In addition, extra content may be added to the records. For example, the point in time when a fault location is performed may be marked by a special character. The active settings could be stored within the record to create a complete picture of relay operation. Fault location may also be merged with

the oscillography to create a single comprehensive record.

6.8.2. Sequence of Events Recording

Another feature is Sequence of Events (SOE) recording. DC inputs/outputs, internally generated pickup, dropout, operate and other flags, digital points in the user-programmable logic, communication-based inputs, user-programmable pushbuttons, and other signals can be programmed to log events. Typically a short string describing the event is stored with the appropriate time stamp.

6.8.3 Programmability

Modern relays support – on a per-point basis – an enable/disable setting for event recording. A multi-function relay processes hundreds of digital flags that potentially could be of interest. The user is given a freedom to enable some events only in order to conserve the memory, avoid showers of unnecessary event logs, and make future analysis easier. The application, history of the protected primary equipment, known problems with the secondary equipment including the relay itself would dictate an optimum set of enabled events.

6.8.4 Time stamping and resolution

The SOE records have limited value if the relay is not synchronized. Without time synchronization, the SOE record provides relative sequence of events within its contained “system”. They may be superimposed on other records manually using primary power system events recorded in the oscillography as “synchronizing” or “reference” marks (fault inception, breaker operation, fault clearance, etc.).

Older relay designs and low-end digital relays do not support accurate time synchronization. Modern high-end relays support time synchronization via IRIG-B time signals. Typical time accuracy is in the range of a few microseconds.

Other means of synchronization include Ethernet-based algorithms such as Simple Network Transport Protocol (SNTP), which allows synchronization via TCP/IP with the accuracy of a few milliseconds.

Accuracy of time-stamping should not be confused with the resolution. Care must be taken when analyzing SOE records created by relays:

- DC input signals are typically monitored by a periodic scan.

- DC inputs are subject to “contact de-bouncing” algorithms.
- Communication-based inputs, such as IEC-61850 GOOSE/GSSE or proprietary digital teleprotection signals, may be time-stamped when the digital packet starts arriving, when it arrived, or when it got decoded, validated and used for the first time.
- Operations of output contacts are typically time-stamped when the digital part of the relay sends the command to close or open a given contact.
- Internal flags in the relay such as outputs from protection or control elements are asserted in course of serial calculations. Some flags are asserted at the beginning of the process, while some at the end of this process.

Further details on this subject can be seen in the appendix B6.

6.8.5 Formats and memory limitations

There is no single standard format for SOE records in the domain of protective relaying. Single events can be reported and retrieved via well-defined mechanisms of known SCADA protocols. SOE files are typically recorded in freely selected ASCII format.

Modern relays support thousands of SOE entries, limited only by the size of the memory configuration. Automated analysis software programs would be the next logical progression for future development.

6.9 Transformer and Breaker Reliability Monitoring Capabilities of Microprocessor-based Relays

6.9.1 Circuit Breakers

Dedicated breaker monitoring stations allow direct and comprehensive monitoring of health and wear of a breaker at the expense of increased overall installation cost. Basic breaker monitoring functions, however, are possible utilizing signals already wired to microprocessor-based relays. Modern relays allow for monitoring of selected breaker wear indices and stress factors at no, or low extra cost.

Breaker arcing current, or accumulated duty is defined and measured as an integral of the squared current waveform over the period of time between

the poles starting to depart and complete interruption of the current. This integral is proportional to energy dissipated within the breaker and therefore reflects stress imposed on the breaker during operation. The per-pole I^2T values may be reported on a per operation basis and/or accumulated by the relay to indicate the total wear or remaining “life” of the monitored breaker.

Breaker time is defined and measured as time elapsed between the trip signal and the breaker main contacts coming open. The pole opening is detected based on the ac current going to zero. The operating time is measured by modern relays with reasonable accuracy and reported on a per-pole basis, or for the last pole that opened.

Fault current is typically reported by “fault report” or “fault location” features of digital relays.

Discrepancy between auxiliary contacts and breaker current can be measured with some accuracy by comparing a dropout time of a built-in overcurrent function with a time of the auxiliary contacts. This monitoring function allows detecting severe mechanical problems or issues with the auxiliary contacts.

Breaker flashover monitoring functions are available to monitor opened breakers. Corrective actions could be performed for intermittent flashover that otherwise will remain undetected.

Counters could be set to count breaker operations. Both the number of operations and the rate-of-change can be polled from the relay in order to estimate breaker wear and pinpoint problems with the primary equipment.

6.9.2 Transformers

Transformer nursing stations – due to their relatively high cost – may be justified for some transformers only. Simple transformer monitoring functions are available in microprocessor-based relays at no, or low extra cost.

Hot spot temperature estimation models

These are available for safe overload of transformers. These models are well established and use mathematical approximation of the heating / cooling processes in order to estimate temperature of the hottest spot being the major stress factor for the insulation. These models use current or power measurements, one or more direct temperature measurements (ambient, top and bottom oil, etc.),

status of the fans (running or not) and transformer data to calculate the hot spot in real time. The calculated value can be used to alarm, control the fans, shed the load, or even trip the transformer.

Transformer thermal models

These are often available to estimate remaining life of the protected transformer. Based on the well-established correlation between the temperature and degradation of the insulating materials, a relative “used” or “remaining” life is calculated (years or percent). Monitoring the value and rate-of-change of the remaining transformer life allows identifying weakest units within a given population of transformers. This real time picture is especially valuable when some transformers are intentionally overloaded to maintain service while “burning out” quicker than other units. An overload-leveling scheme is conceivable to use up transformer life in a way harmonized with long-term expansion and retrofit plans.

Through fault counter

A counter can be programmed within a transformer relay to count through faults. Through faults via their electro-dynamic flexing and thermal effects tend to degrade transformers. The accumulated, squared through fault currents reflect the total exposure of a transformer to dynamic forces and thermal effects. Breaker arcing current feature could be programmed to measure this.

Tap changer operations

Counters can be set up to independently count operations of tap changers. Breaker arcing current feature can be set to accumulate the total squared current being switched by the on-load tap changers.

The above simplistic wear measures prove valuable when obtained and logged automatically into enterprise databases via communication protocols, inter-correlated, and subsequently used on larger populations of equipment over extended periods of time.

Using historical data overlapped with analysis of subsequent failures and events allows developing experimental thresholds for relative equipment health. This allows for the prediction of failures with reasonable accuracy in order to optimize spares and schedule retrofits, obtain impartial measures of relative capabilities of various types and brands of the primary equipment, and move toward data-driven maintenance and testing schedules.

Off-the-shelf software is available to set up self-learning reliability models for any type of equipment using arbitrarily selected wear / stress indices. Breaker and transformer monitoring data produced by modern microprocessor-based relays seem to be well suited for such software packages.

Summary:

Incipient detection methods may provide a method to alarm or de-energize a piece of equipment prior to a primary failure.

High speed fault detection can reduce the fault duration time, and thus limit equipment damage.

Autorestitution techniques can reduce the outage time to the customers significantly in many cases.

A subsequent working group will be formed to address the subject of reducing outages in substations.

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Appendix- A: Reliability Indicators

Below are some of the Reliability Indicators that are being measured throughout the power utility industry:

.....
CI: Customers Interrupted

.....
CMI: Customer Minutes Interrupted

.....
SAIDI:
System Average Interruption Duration Index
The average interruption duration

The total time without power for the average customer per year, measured in minutes.
(Service Unavailability)

= $\frac{\text{Sum of customer minutes interrupted}}{\text{Total number of customers served}}$

.....
CAIDI (Customer Average Interruption Duration Index): How long it takes to restore power on average for the customers interrupted, measured in minutes

.....
Momentaries: number of times service is lost to customers, and restored in less than one minute (this time window may vary between companies)

.....
CAIFI (Customer Average Interruption Frequency Index): How often the average customer is interrupted, measured in times per year.

.....
MAIFI:
Momentary Average Interruption Frequency Index

The number of momentary interruptions experienced by the average customer per year

= $\frac{\text{Total no. of customer momentary interruptions}}{\text{Total no. of customers served}}$
(Where no. = number)

.....
SAIFI:
System Average Interruption Frequency Index

Frequency of momentary interruptions
How often the average customer's lights are out, measured in times per year.

= $\frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$

SAIFI is measured in units of interruptions per customer. It is usually measured over the course of a year, and according to IEEE Standard 1366-1998 the median value for North American utilities is approximately 1.10 interruptions per customer.

.....
Following are excerpts from an article that appeared in Transmission & Distribution World, Dec 1, 2003 , which goes further into this subject:

The Impact of Regulatory Policy on Reliability

Byline: Cheryl Warren, National Grid USA Service Co.

The regulatory purview in the United States has shifted from stranded assets and generation to the power grid and distribution reliability. Regulators are becoming increasingly concerned with every issue relating to the delivery of reliable power to customers.

Each state has the right to mandate distribution reliability standards and targets, creating potentially 50 different regulations throughout the United States. Some states have no reliability regulation at all. Today, regulators may participate in the National Association of Regulatory Utility Commissioners (NARUC) where they can share ideas, but no requirement exists to adopt the same approach on any issue. Looking 20 years down the road, it is conceivable that a federal standard could be enacted as has been done in other countries. The U.S. Department of Energy (DOE) has expressed a desire to begin regulating distribution reliability at the federal level. However, it will take years to change the status quo because most states are unwilling to forgo this right, and who can blame them?

The most common metrics used by state regulators include system index calculations SAIFI, SAIDI and CAIDI. To a lesser extent, CAIFI and MAIFI are used. These indices, as well as the factors that affect them, are defined in the **IEEE Guide on Electric Power Reliability Indices 1366-2003**. In short, they are engineering metrics that track frequency and duration of customer and system interruptions. These indices are applied on system, circuit and customer levels for planning and regulatory reporting purposes.

The guide also clarifies some of the other supporting definitions. Some states are adopting IEEE 1366 as the basis for their regulation to remove definition variability that often makes comparisons difficult.

Appendix- B:

Characteristics of Digital Relays

B-1 Relay A/D and Automatic Checking

The analog input component of a digital relay consists of the relay connections to the current and voltage circuits, internal isolation transformers, signal conditioning (filters), multiplexers, and A/D converters. This component converts the current and voltage analog signals to digital signals for the microprocessor to use. The analog input component is partially checked by the relay self-test feature [1], [2]. Additional verification of correct operation comes from:

- The relay self-monitoring loss of potential and/or loss of current functions.
- Comparing the metering quantities calculated by the relay to another independent intelligent electronic device (IED) (another digital relay or panel meter).
- Analysis of fault records to verify the pre-fault and fault current and voltage data is correct.

In an automated control platform, a central control unit (often a PLC or similar device) collects instantaneous metering values (e.g. MWatts and MVARs) from the digital relays and other IEDs and compares them on a line-by-line, breaker-by-breaker, or bus-by-bus basis. For example, if a distribution line has two digital relays (system 1 and system 2 or primary and backup) the two sets of instantaneous metering values should be nearly identical. If they differ by more than a small tolerance, then one or the other relay has an analog input component problem and an alarm is generated.

The protection-specific signals may be recorded differently as compared with fast-sampled ac inputs.

First, the magnitudes, angles and other derivatives of the raw waveforms are typically calculated at the different, slower pace compared with the A/D sampling. For example, a relay may sample at 64 s/c but calculate the magnitudes 16 times a cycle. These signals when recorded will not change between the moments of their calculation.

Second, the relay logic may be executed at yet different rate, sometimes different for various protection functions. For example and Instantaneous OverCurrent element (IOC) may be executed 16 times a cycle, while a Time-delayed OverCurrent element (TOC) element may be executed only 2

times a cycle. Output flags from such internal protection and control elements when recorded will not change between the moments of their execution.

Third, some signals may be generated asynchronously with respect to the main sampling clock. For example, the communication-based inputs may be activated at any time. Typically, the change in state when recorded will be aligned with the moment of the first usage of such input flag.

Analog filtering for a/c signals

Any digital device, both a relay and DFR, must include an anti-aliasing analog filter. The purpose of anti-aliasing filtering is to eliminate higher frequencies that would otherwise overlap with the lower portion of the spectrum due to finite sampling rates of digital devices. The cut-off frequency of the analog filter must not be higher than half the sampling frequency. Protective relays, particularly models that use only filtered quantities for their main protection and control functions, do not calculate harmonics, or apply comparatively low sampling rates, would have their analog filters set comparatively low. As a result, the signal spectrum being effectively recorded becomes limited to few hundred Hz.

Modern relays sample at 64 to 128 samples/cycle (3,840 and 7,680 Hz at 60 Hz power system, respectively) and have their cut-off filters set well above 1kHz yielding a comparatively good spectral coverage.

Another aspect of analog filtering is the design of the filter itself. When high order filters are used, their gain may not be ideally flat in the pass-through frequency band. This should be factored in when a detailed harmonic analysis is done using records produced by protective relays.

Typically, the analog filter of digital relays is a low-pass filter allowing the sub-harmonics and dc components to go through. However, the frequency response of the input magnetic modules at low frequencies may alter the low frequency components (at the level of few Hz). This should be considered when analyzing sub-harmonics and decaying dc components.

B-2 Digital filtering for ac inputs

Digital relays often perform digital pre-filtering prior to applying phasor estimation algorithms such as the Fourier transform to obtain input quantities for their protection and control algorithms. The

primary objective of digital filtering is to filter out low frequency signals, dc component(-s) in particular. To do so the filters must include a differentiating portion that ideally should match the L/R constant of the primary circuit, hence the name of a “mimic filter”.

As a rule digital relays record raw samples, prior to digital filtering. This not only widens the resulting frequency spectrum of the recorded waveforms, but also ensures that the stored information does not depend on any proprietary digital signal processing algorithms. Whether the recorded data is raw or filtered needs to be understood by the user.

B-3 De-bounce filtering for dc inputs

Modern relays allow recording status signals of dc inputs connected to the relay. However, as a rule, protective relays apply user-selectable or hard-coded de-bounce filtering. Typically, a relay would record the input status after de-bouncing. This means that the record reflects signals validated and used for protection and control and not signals as they appear across the input terminals of the relay. Knowing the time duration of the de-bounce timers one may apply an approximate correction to obtain the original signals before de-bouncing. Details of the de-bouncing algorithm must be known to perform this correction more accurately.

B-4 Sampling rate

Older relays sample much lower than modern relays. In some cases, this was as low as 4 samples per cycle and then utilizing curve fitting to make the oscillographic record look clean. Modern relays sample at 64 or 128 samples per cycle proving relatively good spectral coverage.

Unlike a typical DFR, a relay may apply a variable sampling rate. In order to increase accuracy of digital measurements for protection, control and metering, microprocessor-based relays track power system frequency in order to maintain a constant number of samples per cycle. This results in variable spacing between the recorded samples. It is strongly recommended to use software that recognizes variable sampling rate formats to view, analyze and play back relay oscillography files.

Exceptionally, microprocessor-based relays would sample and record at a constant rate and re-sample the actual samples in software to maintain a constant number of samples per cycle for its protection and metering functions. Also, a constant sampling rate is obtained when the frequency tracking feature is disabled, or the effective tracking signal is not

applied to the relay at a time of producing the record.

Typically all the raw ac signals – past the anti-aliasing filter – are recorded.

Some relays sample and work at a fixed sample rate per cycle, allow saving decimated samples in order to save the memory. Typically, the decimating factor is a power of 2. Thus, every sample, every other sample, every fourth sample, every eight sample, etc. could be recorded as per user setting.

B-5 Programability

Some microprocessor-based relays allow user configurability of the oscillography records. Available levels of programmability include:

- Triggering condition could be user programmable to allow producing records from a number of conditions both internal and external to the relay.
- Recording rate: all or decimated samples could be saved. The decimation factor is often a user setting.
- Content: A number of user-programmable digital and analog channels may be available. The analog channels may include signal calculated in real time by the relay such as magnitudes and angles, positive-sequence quantities, power, differential currents, etc., or input signals other than ac currents and voltages such as transducer inputs. Digital channels may include digital inputs, operands created internally such as pickup or operate flags for various protection elements, auxiliary flags of user programmable logic, etc.
- Division between the pre- and post-trigger data is often user-programmable.
- Number or duration of records is often user programmable in order to maximize the recorded information based on available memory and anticipated duration of the power system events of interest.
- Treatment of old records is often user-programmable as well. The choices are to overwrite automatically or forbid new records to protect the old ones.
- Clearing the records could be user-programmable as well allowing easy or automated clearance of old records.

B-6 Time stamping and resolution

SOE records have limited value if the relay is not synchronized. Without time synchronization, the SOE record provides relative sequence of events only that may be superimposed on other records manually using primary power system events recorded in the oscillography as “synchronizing” or “reference” marks (fault inception, breaker operation, fault clearance, etc.).

Older relay designs and low-end digital relays do not support accurate time synchronization. Modern high-end relays support time synchronization via IRIG-B time signals. Typical time accuracy is in the range of a few microseconds.

Other means of synchronization include Ethernet-based algorithms such as Simple Network Transport Protocol (SNTP), which allows synchronization via TCP/IP with the accuracy of a few milliseconds.

Accuracy of time-stamping should not be confused with the resolution. Care must be taken when analyzing SOE records created by relays:

- DC input signals are typically monitored by a periodic scan, not by event-driven truly instantaneous hardware. The scan period could be as short as few hundreds of microseconds or as long as a few milliseconds. This limits the resolution of time stamping for these group of signals.
- DC inputs are subject to “contact de-bouncing” algorithms. These validate the input signals particularly for critical applications such as Breaker Fail Initiate. The de-bouncing algorithm yields two events for each change of the input. The first event is when the dc voltage across the terminals changes, while the second event occurs when the digital de-bounced flag is asserted for further usage. Some relays allow setting the de-bounce time to zero, bringing the two events together. The de-bounce time must be factored-in when analyzing time stamps of dc inputs recorded by digital relays.
- Communication-based inputs such as IEC-61850 GOOSE/GSSE or proprietary digital teleprotection signals may be time-stamped when the digital packet starts arriving, when it arrived, or when it got decoded, validated and used for the first time. The above “events” could span over tens or hundreds of microseconds. Relay design details must be known in order to make analysis of relay SOE records accurate with respect to the communication-based I/Os.

- Operations of output contacts are typically time-stamped when the digital part of the relay sends the command to close or open a given contact. Actual dc voltage or current associated with the contact start changing hundreds of microseconds to a few milliseconds later.
- Internal flags in the relay such as outputs from protection or control elements are asserted in course of serial calculations. These calculations may last few hundreds of microseconds on modern relays to a few milliseconds in older or low-end relays. Some flags are asserted at the beginning of the process, while some at the end of this process. Typically, however, all flags are time-stamped with the same time – either the beginning or the end of such “protection pass”. Sequence of internal calculations must be known in order to make analysis of relay SOE records accurate with respect to the internal flags.

B-7 Available memory

Modern relays allow recording tens of thousands of samples. For example, with a limit of 40,000 samples, sampling at 64 samples per cycle and recording 8 ac channels, one could record for about 80 power system cycles total; decimating the record to 16 samples per cycle, one could make a recording for about 320 power cycles, etc.

Available memory is one major differentiator between microprocessor based relays and full-featured DFRs.

Often, the memory could be flexibly managed by configuring the content and the recording rate.